Attachment A

Threatened and Endangered Species Correspondence

- J.L. Citta, Jr., NPPD, to J. Hoskins, Missouri Department of Conservation, January 15, 2008.
- J.L. Citta, Jr., NPPD, to R. Amack, Nebraska Game and Parks Commission, January 15, 2008.
- J.L. Citta, Jr., NPPD, to C. Scott, United States Fish and Wildlife Service, Columbia, Missouri Field Office, January 15, 2008.
- J.L. Citta, Jr., NPPD, to J. Cochnar, United States Fish and Wildlife Service, Columbia, Nebraska Field Office, January 15, 2008.

Nebraska Public Power District
"Always there when you need us"

Joe L. Citta, Jr.
Corporate Environmental Mgr.
PH: 402-563-5355

January 15, 2008

Mr. John Hoskins, Director
Missouri Department of Conservation
P.O. Box 180
2901 W. Truman Blvd.
Jefferson City, MO 65102

RE: Nebraska Public Power District
Cooper Nuclear Station

Dear Mr. Hoskins:

Nebraska Public Power District (NPPD) is preparing an application to the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for the Cooper Nuclear Station (CNS). The current 30-year operating license for the station expires in 2014. If the NRC approves the application, NPPD will have the option to continue operating CNS until 2034.

CNS is located in Nemaha County, Nebraska, on the west bank of the Missouri River at river mile 532.5 (Figure 1). Coordinates for the station are 40°21'43" North latitude and 95°38'29" West longitude. CNS is located on approximately 55 acres of a 1,351-acre site that includes 205 acres located on the east bank of the Missouri River in Atchison County, Missouri. Approximately 150 miles of transmission lines were constructed to connect the station to the regional electric power grid.

As part of the license renewal process, the NRC requires that the applicant assess the impact of the proposed license renewal action. This assessment, which is contained in the Environmental Report, addresses specific environmental issues related to the continued operation of the station. NPPD is confident that the operation of CNS will continue to have no significant environmental impacts.

There are no plans to alter current operations during the 20-year license renewal period. Any maintenance activities necessary to support continued operation of CNS will be limited to currently developed areas of the site. No expansion of existing facilities is planned and no additional land disturbance is anticipated in support of license renewal.

General Office
1414 15th Street / P.O. Box 499 / Columbus, NE 68602-0499
***Telephone:** (402) 564-8561 / **Fax:** (402) 563-5551*
www.nppd.com

To ensure that impacts are adequately addressed, we are requesting from your office pertinent information regarding concerns, if any, that you may have regarding potential environmental impacts from the continued operation of CNS.

After your review, we would appreciate your office responding by letter detailing any concerns you may have or confirmation that no concerns exist. If you have any questions or need additional information, please feel free to contact me at (402) 563-5355.

Thank you,

Joe L. Citta, Jr.
Corporate Environmental Manager

Att.: Maps & Photographs

cc: Peggy Horner w/att.
Endangered Species Coordinator
Missouri Department of Conservation

Tom Nagel, Natural History Biologist w/att.
Northwest Regional Office
Missouri Department of Conservation

Rick Buckley (Entergy Nuclear) w/att.

Nebraska Public Power District
"Always there when you need us"

Joe L. Citta, Jr.
Corporate Environmental Mgr.
PH: 402-563-5355

January 15, 2008

Mr. Rex Amack, Director
Nebraska Game and Parks Commission
2200 N. 33rd St.
Lincoln, NE 68503

RE: Nebraska Public Power District
Cooper Nuclear Station

Dear Mr. Amack:

Nebraska Public Power District (NPPD) is preparing an application to the US Nuclear Regulatory Commission (NRC) to renew the operating license for the Cooper Nuclear Station (CNS). The current 30-year operating license for the station expires in 2014. If the NRC approves the application, NPPD will have the option to continue operating CNS until 2034.

CNS is located in Nemaha County, Nebraska, on the west bank of the Missouri River at river mile 532.5 (Figure 1). Coordinates for the station are 40°21'43" North latitude and 95°38'29" West longitude. CNS is located on approximately 55 acres of a 1,351-acre site that includes 205 acres located on the east bank of the Missouri River in Atchison County, Missouri. Approximately 150 miles of transmission lines were constructed to connect the station to the regional electric power grid.

As part of the license renewal process, the NRC requires that the applicant assess the impact of the proposed license renewal action. This assessment, which is contained in the Environmental Report, addresses specific environmental issues related to the continued operation of the station. NPPD is confident that the operation of CNS will continue to have no significant environmental impacts.

There are no plans to alter current operations during the 20-year license renewal period. Any maintenance activities necessary to support continued operation of CNS will be limited to currently developed areas of the site. No expansion of existing facilities is planned and no additional land disturbance is anticipated in support of license renewal.

General Office
1414 15th Street / P.O. Box 499 / Columbus, NE 68602-0499
***Telephone:** (402) 564-8561 / **Fax:** (402) 563-5551*
www.nppd.com

To ensure that impacts are adequately addressed, we are requesting from your office pertinent information regarding concerns, if any, that you may have regarding potential impacts in the vicinity of CNS or its associated transmission lines and corridors, as a result of license renewal at CNS.

After your review, we would appreciate your office responding by letter detailing any concerns you may have or confirmation that no concerns exist.

If you have any questions or need additional information, please feel free to contact me at (402) 563-5355.

Thank you,

Joe L. Citta, Jr.
Corporate Environmental Manager

Att.: Maps & Photographs

cc: Kristal Stoner (GPC) w/att.
Rick Buckley (Entergy Nuclear) w/att.

Nebraska Public Power District
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Joe L. Citta, Jr.
Corporate Environmental Mgr.
PH: 402-563-5355

January 15, 2008

Mr. Charlie Scott, Field Supervisor
U. S. Fish and Wildlife Service
Columbia Ecological Services Field Office
101 Park DeVille Drive, Suite A
Columbia, MO 65203-0057

RE: Nebraska Public Power District
Cooper Nuclear Station

Dear Mr. Scott:

Nebraska Public Power District (NPPD) is preparing an application to the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for the Cooper Nuclear Station (CNS). The current 30-year operating license for the station expires in 2014. If the NRC approves the application, NPPD will have the option to continue operating CNS until 2034.

CNS is located in Nemaha County, Nebraska, on the west bank of the Missouri River at river mile 532.5 (Figure 1). Coordinates for the station are 40°21'43" North latitude and 95°38'29" West longitude. CNS is located on approximately 55 acres of a 1,351-acre site that includes 205 acres located on the east bank of the Missouri River in Atchison County, Missouri. Approximately 150 miles of transmission lines were constructed to connect the station to the regional electric power grid.

As part of the license renewal process, the NRC requires that the applicant assess the impact of the proposed license renewal action. This assessment, which is contained in the Environmental Report, addresses specific environmental issues related to the continued operation of the station. NPPD is confident that the operation of CNS will continue to have no significant environmental impacts.

There are no plans to alter current operations during the 20-year license renewal period. Any maintenance activities necessary to support continued operation of CNS will be limited to currently developed areas of the site. No expansion of existing facilities is planned and no additional land disturbance is anticipated in support of license renewal.

To ensure that impacts are adequately addressed, we are requesting from your office pertinent information regarding concerns, if any, that you may have regarding potential impacts in the vicinity of CNS.

After your review, we would appreciate your office responding by letter detailing any concerns you may have or confirmation that no concerns exist.

If you have any questions or need additional information, please feel free to contact me at (402) 563-5355.

Thank you,

Joe L. Citta, Jr.
Corporate Environmental Manager

Att.: Maps & Photographs

cc: Mr. Steve Anschutz (USFWS) w/att.
Rick Buckley (Entergy Nuclear) w/att.

Nebraska Public Power District
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Joe L. Citta, Jr.
Corporate Environmental Mgr.
PH: 402-563-5355

January 15, 2008

Mr. John Cochnar
U. S. Fish and Wildlife Service
Ecological Services - Nebraska Field Office
203 West Second Street,
Grand Island, NE 68801

RE: Nebraska Public Power District
Cooper Nuclear Station

Dear Mr. Cochnar:

Nebraska Public Power District (NPPD) is preparing an application to the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for the Cooper Nuclear Station (CNS). The current 30-year operating license for the station expires in 2014. If the NRC approves the application, NPPD will have the option to continue operating CNS until 2034.

CNS is located in Nemaha County, Nebraska, on the west bank of the Missouri River at river mile 532.5 (Figure 1). Coordinates for the station are 40°21'43" North latitude and 95°38'29" West longitude. CNS is located on approximately 55 acres of a 1,351-acre site that includes 205 acres located on the east bank of the Missouri River in Atchison County, Missouri. Approximately 150 miles of transmission lines were constructed to connect the station to the regional electric power grid.

As part of the license renewal process, the NRC requires that the applicant assess the impact of the proposed license renewal action. This assessment, which is contained in the Environmental Report, addresses specific environmental issues related to the continued operation of the station. NPPD is confident that the operation of CNS will continue to have no significant environmental impacts.

There are no plans to alter current operations during the 20-year license renewal period. Any maintenance activities necessary to support continued operation of CNS will be limited to currently developed areas of the site. No expansion of existing facilities is planned and no additional land disturbance is anticipated in support of license renewal.

To ensure that impacts are adequately addressed, we are requesting from your office pertinent information regarding concerns, if any, that you may have regarding potential impacts in the vicinity of CNS or its associated transmission lines and corridors, as a result of license renewal at CNS.

After your review, we would appreciate your office responding by letter detailing any concerns you may have or confirmation that no concerns exist.

If you have any questions or need additional information, please feel free to contact me at (402) 563-5355.

Thank you,

Joe L. Citta, Jr.
Corporate Environmental Manager

Att.: Maps & Photographs

cc: Charlie Scott (USFWS) w/att.
Rick Buckley (Entergy Nuclear) w/att.

Attachment B

Historic and Archaeological Properties Correspondence

- J. L. Citta, Jr., NPPD, to M. Miles, Missouri Department of Natural Resources, January 15, 2008.
- M. Miles, Missouri Department of Natural Resources, to J. L. Citta, Jr., NPPD, February 5, 2008.
- K. M. Krumland, NPPD, to M. Miles, Missouri Dept of Natural Resources, May 30, 2008.
- J. L. Citta, Jr., NPPD, to M. J. Smith, Nebraska State Historical Society, January 15, 2008.
- L. R. Puschendorf, Nebraska State Historical Society, to J. L. Citta, Jr., NPPD, February 11, 2008.
- M. Miles, Missouri Department of Natural Resources, to K. M. Krumland, NPPD, June 9, 2008.
- K. M. Krumland, NPPD, to M. J. Smith, Nebraska State Historical Society, May 30, 2008.

Nebraska Public Power District
"Always there when you need us"

Joe L. Citta, Jr.
Corporate Environmental Mgr.
PH: 402-563-5355

January 15, 2008

Mr. Mark Miles
State Historic Preservation Officer
Department of Natural Resources
P.O. Box 176
Jefferson City, MO 65102

RE: Nebraska Public Power District
Cooper Nuclear Station

Dear Mr. Miles:

Nebraska Public Power District (NPPD) is preparing an application to the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for the Cooper Nuclear Station (CNS). The current 30-year operating license for the station expires in 2014. If the NRC approves the application, NPPD will have the option to continue operating CNS until 2034.

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General Office
1414 15th Street / P.O. Box 499 / Columbus, NE 68602-0499
***Telephone:** (402) 564-8561 / **Fax:** (402) 563-5551*
www.nppd.com

To ensure that impacts are adequately addressed, we are requesting from your office pertinent information regarding concerns, if any, that you may have regarding potential impacts to cultural resources in the vicinity of CNS as a result of license renewal at CNS.

After your review, we would appreciate your office responding by letter detailing any concerns you may have or confirmation that no concerns exist. If you have any questions or need additional information, please feel free to contact me at (402) 563-5355.

If you have any questions or need additional information, please feel free to call me at (402) 563-5355.

Thank you,

Joe L. Citta, Jr.
Corporate Environmental Manager

Att.: Maps & Photographs

cc: Rick Buckley (Entergy Nuclear) w/att.

STATE OF MISSOURI
Matt Blunt, Governor • Doyle Childers, Director
DEPARTMENT OF NATURAL RESOURCES
www.dnr.mo.gov

RECEIVED
FEB 11 2008

February 5, 2008

Joe L. Citta, Jr.
Corporate Environmental Manager
Nebraska Public Power District
P.O. Box 499
Columbus, Nebraska 68602-0499

Re: Cooper Nuclear Station (NRC) 55 Acres, Atchison County, Missouri

Dear Mr. Citta:

Thank you for submitting information on the above referenced project for our review pursuant to Section 106 of the National Historic Preservation Act (P.L. 89-665, as amended) and the Advisory Council on Historic Preservation's regulation 36 CFR part 800, which require identification and evaluation of cultural resources.

We have reviewed the information provided concerning the above referenced project, and cannot find any reference in our files that the project area was surveyed for historic architectural and archaeological resources. We have determined that there is a moderate to high potential for the presence of archaeological sites near and within the area of the proposed project, as indicated by the topographic location, and that an historic architectural and archaeological survey should be conducted.

A list of independent historians/architectural historians and archaeological contractors who can perform such services is available through the Department of Natural Resources, Division of Administrative Support. The list can be obtained by calling (573) 751-0958 and requesting the "historians/architectural historians list" and "archaeological contractors list." Note that any 36 CFR Part 61 qualified archaeologist may perform an archaeological survey. If you choose a contractor not on the list, please be certain to include his or her curriculum vitae in the report. We would appreciate one (1) hard copy and one (1) pdf copy of the survey report when it is finished so we may complete the review and comment process.

If you have any questions, please write Judith Deel at State Historic Preservation Office, P.O. Box 176, Jefferson City, Missouri 65102 or call Ms. Deel at 573/751-7862. Please be sure to include the SHPO Log Number **(004-AT-08)** on all future correspondence or inquiries relating to this project.

Sincerely,

STATE HISTORIC PRESERVATION OFFICE

Mark A. Miles
Director and Deputy
State Historic Preservation Officer

c Robert Stout, DNR/OD

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ENV-705.0350

Nebraska Public Power District

"Always there when you need us"

K. Michael Krumland
Environmental Protection Supvr.
PH: 402-563-5329

May 30, 2008

Mr. Mark Miles
State Historic Preservation Officer
Department of Natural Resources
P.O. Box 176
Jefferson City, MO 65102

RE: Nebraska Public Power District - Cooper Nuclear Station
SHPO Log Number (004-AT-08)

Dear Mr. Miles:

In response to your letter of February 5, 2008 I have enclosed the "Phase 1A Literature Review and Archeological Sensitivity Assessment of the Cooper Nuclear Station" for Nemaha County, Nebraska and Atchison County, Missouri. The enclosures include a hard copy of the document and a CD with the document in pdf format.

The report was prepared by Dr. James M. Briscoe for Enercon Services, Inc. Dr. Briscoe's curriculum vitae is included as an attachment to the report. Also, for your information, Cooper Nuclear Station's Administrative Procedure 0.51, "Cultural Resources Protection Plan" is attached to the report.

If you have any questions, please feel free to contact me at 402-563-5329.

Sincerely,

K. Michael Krumland
Environmental Protection Supervisor

Enc.

bc: Joe Citta, Jr. w/o enc.
Dave Bremer w/o enc.
Ricky Buckley (Entergy Nuclear) w/o enc.

Nebraska Public Power District
"Always there when you need us"

Joe L. Citta, Jr.
Corporate Environmental Mgr.
PH: 402-563-5355

January 15, 2008

Mr. Michael J. Smith
State Historic Preservation Officer
Nebraska State Historical Society
P.O. Box 82554
Lincoln, NE 68501

RE: Nebraska Public Power District
Cooper Nuclear Station

Dear Mr. Smith:

Nebraska Public Power District (NPPD) is preparing an application to the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for the Cooper Nuclear Station (CNS). The current 30-year operating license for the station expires in 2014. If the NRC approves the application, NPPD will have the option to continue operating CNS until 2034.

CNS is located in Nemaha County, Nebraska, on the west bank of the Missouri River at river mile 532.5 (Figure 1). Coordinates for the station are 40°21'43" North latitude and 95°38'29" West longitude. CNS is located on approximately 55 acres of a 1,351-acre site that includes 205 acres located on the east bank of the Missouri River in Atchison County, Missouri. Approximately 150 miles of transmission lines were constructed to connect the station to the regional electric power grid.

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General Office
1414 15th Street / P.O. Box 499 / Columbus, NE 68602-0499
***Telephone:** (402) 564-8561 / **Fax:** (402) 563-5551*
www.nppd.com

To ensure that impacts are adequately addressed, we are requesting from your office pertinent information regarding concerns, if any, that you may have regarding potential impacts to cultural resources in the vicinity of CNS or its associated transmission lines and corridors, as a result of license renewal at CNS.

After your review, we would appreciate your office responding by letter detailing any concerns you may have or confirmation that no concerns exist.

If you have any questions or need additional information, please feel free to contact me at (402) 563-5355.

Thank you,

Joe L. Citta, Jr.
Corporate Environmental Manager

Att.: Maps & Photographs

cc: Rick Buckley (Entergy Nuclear) w/att.

NEBRASKA STATE HISTORICAL SOCIETY
1500 R STREET, P.O.BOX 82554, LINCOLN, NE 68501-2554
(402) 471-3270 Fax: (402) 471-3100 1-800-833-6747 www.nebraskahistory.org

February 11, 2008

Joel L. Citta, Jr.
NPPD
PO Box 499
Columbus, NE 68602-0499

RE:

hp_num	descr
0801-050-01	NPPD; COOPER NUCLEAR STATION

Dear Mr. Citta:

Thank you for submitting the referenced project proposal for our review and comment. Our comment on this project and its potential to affect historic properties is required by Section 106 of the National Historic Preservation Act of 1966, as amended, and implementing regulations 36 CFR Part 800.

Given the information provided, in our opinion there will be no historic structures affected by the project as proposed. Should any changes in the project be made or in the type of funding or assistance provided through federal or state agencies, please notify this office of the changes before further project planning continues.

Please retain this correspondence and your documented finding in order to show compliance with Section 106 of the National Historic Preservation Act, as amended. If you have any questions, please do not hesitate to our office at 402.471.4787.

Sincerely,

L. Robert Puschendorf
Deputy State Historic Preservation Officer
Nebraska State Historic Preservation Office

RECEIVED
FEB 13 2008

STATE OF MISSOURI
Matt Blunt, Governor • Doyle Childers, Director
DEPARTMENT OF NATURAL RESOURCES
www.dnr.mo.gov

June 9, 2008

K. Michael Krumland
Nebraska Public Power District
P.O. Box 499
Columbus, Nebraska 68602-0499

Re: Cooper Nuclear Station (NRC) 55 Acres, Atchison County, Missouri

Dear Mr. Krumland:

Thank you for submitting information on the above referenced project for our review pursuant to Section 106 of the National Historic Preservation Act (P.L. 89-665, as amended) and the Advisory Council on Historic Preservation's regulation 36 CFR Part 800, which requires identification and evaluation of cultural resources.

We have reviewed the May 2008 report entitled *Phase IA Literature Review and Archaeological Sensitivity Assessment of the Cooper Nuclear Station, Nemaha County, Nebraska and Atchison County, Missouri* by Enercon Services, Inc. Based on this review we concur with the investigator's recommendations for areas of high potential for the occurrence of archaeological sites in the fifty-five (55) acres of the Cooper Nuclear Station in Atchison County, Missouri. We also concur with the recommendations as presented in the CNS Operations Manual for the survey prior to any project activities and treatment of historic properties.

Please be advised that, should project plans change, information documenting the revisions should be submitted to this office for further review. In the event that cultural materials are encountered during project activities, all construction should be halted, and this office notified as soon as possible in order to determine the appropriate course of action.

If you have any questions, please write Judith Deel at State Historic Preservation Office, P.O. Box 176, Jefferson City, Missouri 65102 or call 573/751-7862. Please be sure to include the SHPO Log Number **(004-AT-08)** on all future correspondence or inquiries relating to this project.

Sincerely,

STATE HISTORIC PRESERVATION OFFICE

Mark A. Miles
Director and Deputy
State Historic Preservation Officer

RECEIVED
JUN 23 2008

MAM:jd

c Robert Stout, DNR/OD

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Nebraska Public Power District
"Always there when you need us"

K. Michael Krumland
Environmental Protection Supvr.
PH: 402-563-5329

May 30, 2008

Mr. Michael J. Smith
State Historic Preservation Officer
Nebraska State Historical Society
P.O. Box 82554
Lincoln, NE 68501

RE: Nebraska Public Power District - Cooper Nuclear Station

Dear Mr. Smith:

Enclosed is the "Phase 1A Literature Review and Archeological Sensitivity Assessment of the Cooper Nuclear Station" for Nemaha County, Nebraska and Atchison County, Missouri. The enclosures include a hard copy of the document and a CD with the document in pdf format.

The report was prepared by Dr. James M. Briscoe for Enercon Services, Inc. Dr. Briscoe's curriculum vitae is included as an attachment to the report. Also, for your information, Cooper Nuclear Station's Administrative Procedure 0.51, "Cultural Resources Protection Plan" is attached to the report.

If you have any questions, please feel free to contact me at 402-563-5329.

Sincerely,

K. Michael Krumland

K. Michael Krumland
Environmental Protection Supervisor

Enc.

bc: Joe Citta, Jr. w/o enc.
Dave Bremer w/o enc.
Ricky Buckley (Entergy Nuclear) w/o enc.
ENV-705.0350

Attachment C

Clean Water Act Documentation

- Nebraska Department of Environmental Quality, NPDES Permit NE0001244
- Water Quality Certification Letter from Nebraska Water Pollution Control Council, June 11, 1971.
- K. M. Krumland, NPPD, to J. Bender, Nebraska Department of Environmental Quality. Letter not dated, sent August 8, 2008.

Nebraska Department of Environmental Quality

Wastewater Section
Suite 400, The Atrium, 1200 'N' Street
PO Box 98922
Lincoln, NE 68509-8922
Tel. 402/471-4220
Fax 402/471-2909

Authorization to Discharge Under the National Pollutant Discharge Elimination System (NPDES)

This NPDES permit is issued in compliance with the provisions of the Federal Water Pollution Control Act (33 U.S.C. Secs. 1251 *et. seq.* as amended to date), the Nebraska Environmental Protection Act (Neb. Rev. Stat. Secs. 81-1501 *et. seq.* as amended to date), and the Rules and Regulations promulgated pursuant to these Acts. The facility and outfalls identified in this permit are authorized to discharge wastewater and are subject to the limitations, requirements, prohibitions and conditions set forth herein. This permit regulates and controls the release of pollutants in the discharges authorized herein. This permit does not relieve permittees of other duties and responsibilities under the Nebraska Environmental Protection Act, as amended, or established by regulations promulgated pursuant thereto.

NPDES Permit No.:	**NE0001244**
IIS File Number	**PCS 36750-P**
Facility Name:	**NPPD Cooper Nuclear Station**
Permittee	**Nebraska Public Power District**
Facility Location:	**Two and one-half miles south of Brownville, Nebraska**
Legal Description	**NE ¼, NW ¼, Section 32, Township 5 N, Range 16 W, Nemaha County, Nebraska**
Receiving Water	**Missouri River, segment NE1-10000 of the Nemaha River Basin**
Effective Date:	**July 1, 2007**
Expiration Date:	**June 30, 2012**

Pursuant to a Delegation Memorandum dated July 26, 1999 and signed by the Director, the undersigned hereby executes this document on behalf of the Director.

Signed this 26th day of June, 2007

Jay D. Ringenberg, Deputy Director, Programs

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Part I. Effluent Limits and Monitoring Requirements

A. Outfall 001- Discharge of Once Pass Through Cooling Water

The discharge of once pass-through cooling water from Outfall 001 to the Missouri River must be consistent with the description provided in the permit application and any supplemental information submitted used in the development of this permit. The discharge from Outfall 001 shall be monitored and subject to the limits set forth below in Table 1

Table 1: Discharge Limits and Monitoring Requirements for Outfall 001

Parameters	Storet #	Units	Discharge Limits		Monitoring Frequency	Sample Type
			30 Day Average	Maximum		
Flow	50050	MGD	Report	Report	Continuous	Calculated or Metered
Temperature	00011	°F	Report	109.4	Continuous	Metered
Interim Total Residual Chlorine [(a)]	50060	mg/L	Report [(b)]	Report [(b)]	Weekly	Grab
Final Total Residual Chlorine [(a)]	50060	mg/L	0.01 [(b)]	0.02 [(b)]	Weekly	Grab
Parameters	**Storet #**	**Units**	**Discharge Limits**		**Monitoring Frequency**	**Sample Type**
			Daily Minimum	**Daily Maximum**		
pH	00400	Standard Units	6.5	9.0	Weekly	Grab

Footnotes:
(a) Monitoring for TRC is required only when chlorine is introduced into any wastestreams.

(b) See Part III for the compliance schedule to meet final total residual chlorine limits.

B. Outfall 002B– Clear Well Discharge and Outfall 004 Emergency Overflow

The discharge of low volume wastewater from Outfall 002B must be consistent with the description provided in the permit application and any supplemental information submitted used in the development of this permit. The discharge from Outfall 002B shall be monitored and subject to the limits set forth below in Table 2.

Table 2: Discharge Limits and Monitoring Requirements for Outfall 002B

Parameters	Storet #	Units	Discharge Limits		Monitoring Frequency	Sample Type
			30 Day Average	Maximum		
Flow	50050	MGD	Report	Report	Quarterly	Calculated or Metered
Oil and Grease	00552	mg/L	Report	10	Quarterly	Grab
Total Suspended Solids	00530	mg/L	30	100	Quarterly	Grab
Parameters	**Storet #**	**Units**	**Discharge Limits**		**Monitoring Frequency**	**Sample Type**
			Daily Minimum	**Daily Maximum**		
pH	00400	Standard Units	6.5	9.0	Quarterly	Grab

Footnotes:

C. Outfall 002C – Floor Drains

The discharge of categorical low volume wastewater from Outfall 002C must be consistent with the description provided in the permit application and any supplemental information submitted used in the development of this permit. The discharge from Outfall 002C shall be monitored and subject to the limits set forth below in Table 3.

Table 3: Discharge Limits and Monitoring Requirements for Outfall 002C

Parameters	Storet #	Units	Discharge Limits		Monitoring Frequency	Sample Type
			30 Day Average	Maximum		
Flow	50050	MGD	Report	Report	Quarterly	Calculated or Metered
Oil and Grease	00552	mg/L	Report	10	Quarterly	Grab
Total Suspended Solids	00530	mg/L	30	100	Quarterly	Grab
Parameters	**Storet #**	**Units**	**Discharge Limits**		**Monitoring Frequency**	**Sample Type**
			Daily Minimum	**Daily Maximum**		
pH	00400	Standard Units	6.5	9.0	Quarterly	Grab
Footnotes:						

D. Outfall 004 – RO Reject and Boiler Blowdown Wastestreams

The discharge of low volume wastewater from Outfall 004 must be consistent with the description provided in the permit application and any supplemental information submitted used in the development of this permit. The discharge from Outfall 004 shall be monitored and subject to the limits set forth below in Table 4.

Table 4: Discharge Limits and Monitoring Requirements for Outfall 004

Parameters	Storet #	Units	Discharge Limits		Monitoring Frequency	Sample Type
			30 Day Average	Maximum		
Flow	50050	MGD	Report	Report	Monthly	Calculated or Metered
Oil and Grease	00552	mg/L	Report	10	Monthly	Grab
Total Suspended Solids	00530	mg/L	30	100	Monthly	Grab
Parameters	**Storet #**	**Units**	**Discharge Limits**		**Monitoring Frequency**	**Sample Type**
			Daily Minimum	**Daily Maximum**		
pH	00400	Standard Units	6.5	9.0	Monthly	Grab
Footnotes:						

E. Outfall 008 – Waste Sample Tank

The discharge of tank waste low volume discharge from Outfall 008 must be consistent with the description provided in the permit application and any supplemental information submitted used in the development of this permit. The discharge from Outfall 008 shall be monitored and subject to the limits set forth below in Table 5.

Table 5: Discharge Limits and Monitoring Requirements for Outfall 008

Parameters	Storet #	Units	Discharge Limits		Monitoring Frequency	Sample Type
			30 Day Average	Maximum		
Flow	50050	MGD	Report	Report	Semiannually	Calculated or Metered
Oil and Grease	00552	mg/L	Report	10	Semiannually	Grab
Total Suspended Solids	00530	mg/L	30	100	Semiannually	Grab
Parameters	Storet #	Units	Discharge Limits		Monitoring Frequency	Sample Type
			Daily Minimum	Daily Maximum		
pH	00400	Standard Units	6.5	9.0	Semiannually	Grab
Footnotes:						

F. Outfall 009 – Sample Tank Floor Drain

The discharge sample tank low volume wastewater from Outfall 009 must be consistent with the description provided in the permit application and any supplemental information submitted used in the development of this permit. The discharge from Outfall 009 shall be monitored and subject to the limits set forth below in Table 6.

Table 6: Discharge Limits and Monitoring Requirements for Outfall 009

Parameters	Storet #	Units	Discharge Limits		Monitoring Frequency	Sample Type
			30 Day Average	Maximum		
Flow	50050	MGD	Report	Report	Semiannually	Calculated or Metered
Oil and Grease	00552	mg/L	Report	10	Semiannually	Grab
Total Suspended Solids	00530	mg/L	30	100	Semiannually	Grab
Parameters	**Storet #**	**Units**	**Discharge Limits**		**Monitoring Frequency**	**Sample Type**
			Daily Minimum	**Daily Maximum**		
pH	00400	Standard Units	6.5	9.0	Semiannually	Grab
Footnotes:						

Part II. Compliance Schedule for Evaluating Cooling Water Intake Structure(s) at Cooper Nuclear Station

The Nebraska Public Power District (NPPD) shall continue to evaluate selected technologies to reduce impingement of fish and shellfish at the cooling water intake structure(s) at Cooper Nuclear Station. The NPPD shall send a report to the NDEQ annually by March 1 that gives an account of the evaluation of selected technologies from the previous calendar year (Jan. through Dec.). This schedule may be modified in accordance with NDEQ Title 119 and written notice from the NDEQ.

Part III. Compliance Schedule for Meeting Final Total Residual Chlorine (TRC) Limits

Upon issuance of this permit, the Nebraska Public Power District (NPPD) shall implement the compliance schedule set forth below for meeting final TRC limits in Table 1 by installing equipment for dechlorination and/or by submitting a study that demonstrates that the TRC limits in Table 1 ought to be modified. This schedule may be revised in accordance with the requirements set forth in NDEQ Title 119 and written notice from the NDEQ. The reporting requirements for TRC in Table 1 shall apply until completion of the schedule set forth below at which time the current final limits in Table 1will apply or revised limits approved by the NDEQ based on an environmental study will apply.
The NPPD shall send a report to the NDEQ every 6 months outlining progress in achieving the compliance schedule set forth below.

1. Six Months
On or before six months after the issuance of this permit, the NPPD shall complete and submit a plan for an environmental study to the NDEQ for review. The study design may include sampling, modeling, or testing that would determine if the final residual chlorine concentration in Table 1 for the effluent discharge from Cooper Nuclear Station to the Missouri River could be revised.

2. One Year
On or before one year after the issuance of this permit, the NPPD shall submit the results of the environmental study to the NDEQ for evaluation. The NDEQ will determine if the study demonstrates whether the current final limits for TRC in Table 1 shall continue to apply or if the current final TRC limits in Table 1 should be revised based on the conclusions of the study.

3. Two years
On or before two years after the issuance of this permit, the discharge form Cooper Nuclear Station shall routinely meet the current final limits in Table 1 or revised limits approved by the NDEQ that are based on the results of the NPPD environmental study.

Part IV. Other Requirements and Conditions

A. Polychlorinated Biphenyls (PCB)

There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid. At the discretion of the NDEQ, this requirement for no discharge of PCBs can be confirmed either by chemical analysis of the discharge effluent or by an engineering study which would demonstrate that PCBs are not present in the final discharge.

B. Radionuclides

The discharge of beta particles and photon emitters from Cooper Nuclear Station to the Missouri River shall not exceed 4 millirems per year. To document compliance with this limit, the NPPD shall submit an annual report to the NDEQ by June 1 of each year for radionuclide releases from Cooper Nuclear Station to the Missouri River from the preceding calendar year (January – December) that provides the date of release and a list of radionuclides released reported in terms of both activity (pCi/l) and exposure (millirems).

C. Narrative Limits

Discharges authorized under this permit:

Shall not be toxic to aquatic life in surface waters of the State outside the mixing zones allowed in NDEQ Title 117 - *Nebraska Surface Water Quality Standard*;

Shall not contain pollutants at concentrations or levels that produce objectionable films, colors, turbidity, deposits, or noxious odors in the receiving stream or waterway; and

Shall not contain pollutants at concentrations or levels that cause the occurrence of undesirable or nuisance aquatic life in the receiving stream.

D. Disposal of Sewage Sludge

The permittee shall dispose of sludge in accordance with 40 CFR Part 503. which is administered by EPA Region VII. Adherence to these regulations does not exempt the permittee from applicable NDEQ requirements.

The permittee preparing and/or applying sewage sludge shall develop all of the information required in 40 CFR Part 503.17. This information shall be retained as required by 40 CFR Part 503.

Any proposed biosolids application site must be approved by the NDEQ prior to the initial biosolids application.

E. Method Detection Limit Reporting Requirements

The minimum detection limit (MDL) is defined as the level at which the analytical system gives acceptable calibration points. If the analytical results are below the MDL then the reported value on the DMR shall be a numerical value less than the MDL (e.g. <0.005).

Appendix A – Standard Conditions that Apply to NPDES and NPP Permits

These general conditions are applicable to all NPDES and NPP permits. These conditions shall not preempt any more stringent requirements found elsewhere in this permit.

A. General Conditions

1. Information Available

All permit applications, fact sheets, permits, discharge data, monitoring reports, and any public comments concerning such shall be available to the public for inspection and copying, unless such information about methods or processes is entitled to protection as trade secrets of the owner or operator under Neb. Rev. Stat. §81-1527, (Cum. Supp. 1992) and NDEQ Title 115, Chapter 4.

2. Duty to Comply

All authorized discharges shall be consistent with the terms and conditions of this permit. The discharge of any pollutant identified in this permit more frequently than or at a level in excess of that authorized shall constitute a violation of the permit.

The permittee shall comply with all conditions of this permit. Failure to comply with these conditions may be grounds for administrative action or enforcement proceedings including injunctive relief and civil or criminal penalties.

The filing of a request by the permittee for a permit modification, revocation and re-issuance, termination or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

3. Duty to Mitigate

The permittee shall take all reasonable steps to minimize, prevent or correct any adverse impact to the environment resulting from noncompliance with this permit, including such accelerated or additional monitoring as required by the NDEQ to determine the nature and impact of the noncompliant discharge.

4. Permit Actions

This permit may be modified, suspended, revoked or reissued, in part or in whole, in accordance with the regulations set forth in NDEQ Titles 119, Chapter 24. In addition, this permit may be modified, revoked and reissued to incorporate standards or limitations issued pursuant to Sections 301(b)(b)(c), 301(b)(b)(d), 304(b)(b), 307(a)(b), or 405(d) of the Clean Water Act and Public Law 100-4 (i.e., industrial categorical standards and municipal sludge regulations).

5. Land Application of Wastewater Effluent

The permittee shall be permitted to discharge treated wastewater effluent by means of land application in accordance with the regulations and standards set forth in NDEQ Title 119, Chapter 12, 002.

6. Toxic Pollutants

The permittee shall not discharge pollutants to waters of the state that cause a violation of the standards established in NDEQ Titles 117, 118 or 119. All discharges to surface waters of the state shall be free of toxic (acute or chronic) substances which alone or in combination with other substances, create conditions unsuitable for aquatic life outside the appropriate mixing zone.

7. **Oil and Hazardous Substances/Spill Notification**

Nothing in this permit shall preclude the initiation of any legal action or relieve the permittee from any responsibilities, liabilities or penalties under Section 311 of the Clean Water Act. The permittee shall conform to the provisions set forth in NDEQ Title 126, *Rules and Regulations Pertaining to the Management of Wastes*. If the permittee knows, or has reason to believe, that oil or hazardous substances were released at the facility and could enter waters of the state or any of the outfall discharges authorized in this permit, the permittee shall immediately notify the Department of a release of oil or hazardous substances. During Department office hours (i.e., 8:00 a.m. to 5:00 p.m., Monday through Friday, except holidays), notification shall be made to the Nebraska Department of Environmental Quality at telephone numbers (402) 471-2186 or (877) 253-2603 (toll free). When NDEQ cannot be contacted, the permittee shall report to the Nebraska State Patrol for referral to the NDEQ Emergency Response Team at telephone number (402) 471-4545. It shall be the permittee's responsibility to maintain current telephone numbers necessary to carry out the notification requirements set forth in this paragraph.

8. **Property Rights**

The issuance of this permit does not convey any property rights of any sort or any exclusive privileges nor does it authorize any damage to private property or any invasion of personal rights nor any infringement of federal, state or local laws or regulations.

9. **Severability**

If any provision of this permit is held invalid, the remainder of this permit shall not be affected.

10. **Other Rules and Regulations Liability**

The issuance of this permit in no way relieves the obligation of the permittee to comply with other rules and regulations of the Department.

11. **Inspection and Entry**

The permittee shall allow the Director or his authorized representative, upon the presentation of his identification and at a reasonable time:

a. to enter upon the permittee's premises where a regulated facility or activity is located or conducted, or records are required to be kept under the terms and conditions of the permit,
b. to have access to and copy any records required to be kept under the terms and conditions of the permit,
c. to inspect any facilities, equipment (including monitoring and control), practices or operations regulated or required in the permit, and
d. to sample or monitor any substances or parameters at any location.

12. **Penalties**

Violations of the terms and conditions of this permit may result in the initiation of criminal and/or civil actions. Civil penalties can result in fines of up to $10,000.00 per day (Neb. Rev. Stat. §81-1508, as amended to date). Criminal penalties for willful or negligent violations of this permit may result in penalties of $10,000.00 per day or by imprisonment. Violations may also result in federal prosecution.

B. Management Requirements

1. **Duty to Provide Information**

The permittee shall furnish to the Department within a reasonable time, any information which the Department may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit; or to determine compliance with this permit. The permittee shall also furnish to the Department upon request, copies of records retained as a requirement of this permit.

2. **Duty to Reapply**

   The permittee shall apply for a re-issuance of this permit, if an activity regulated by this permit is to be continued after the expiration date of this permit. The application shall be submitted at least 180 days before the expiration of this permit on an application form supplied by the Department, as set forth in NDEQ Titles 119, Chapter 5 002.

3. **Signatory Requirements**

   All reports and applications required by this permit or submitted to maintain compliance with this permit, shall be signed and certified as set forth in this section.

   a. Permit applications shall be signed by a cognizant official who meets the following criteria:
      i) for a corporation: by a principal executive officer of at least the level of vice-president,
      ii) for a partnership or sole proprietorship: by a general partner or the proprietor, respectively, or
      iii) for a municipality, state, federal or other public facility: by either a principal executive officer or highest ranking elected official.
   b. Discharge monitoring reports and other information shall be signed by the **cognizant official** or by an **authorized representative**.
   c. The cognizant official designates an authorized representative. The authorized representative is responsible for the overall operation of the facility (i.e., the WWTF Operator, the City Manager, the Public Utilities Superintendent or similar person).
   d. Any change in the signatories shall be submitted to the Department, in writing, within 30 days after the change.
   e. Certification. All applications, reports and information submitted as a requirement of this permit, shall contain the following certification statement:

"I certify, under penalty of law, that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gathered and evaluated the information submitted. Based on my inquiry of the person or persons who manage the system or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate and complete. I am aware that there are significant penalties for submitting false information including the possibility of fine and imprisonment for knowing violations."

C. Monitoring and Records

1. **Representative Sampling**

   Samples and measurements taken as required within this permit shall be representative of the discharge. All samples shall be taken at the monitoring points specified in this permit and, unless otherwise specified, before the effluent joins or is diluted by any other waste stream, body of water or substance. Monitoring points shall not be changed without notification to the Department and with the written approval of the Director.

   a. Composite sampling shall be conducted in one of the following manners:
      i) continuous discharge - a minimum of one discrete aliquot collected every three hours,
      ii) less than 24 hours - a minimum of hourly discrete aliquots or a continuously drawn sample shall be collected during the discharge, or
      iii) batch discharge - a minimum of three discrete aliquots shall be collected during each discharge.

b. Composite samples shall be collected in one of the following manners:
   i) the volume of each aliquot must be proportional to either the waste stream flow at the time of sampling or the total waste stream flow since collection of the previous aliquot,
   ii) a number of equal volume aliquots taken at varying time intervals in proportion to flow,
   iii) a sample continuously collected in proportion to flow, and
   iv) where flow proportional sampling is infeasible or nonrepresentative of the pollutant loadings, the Department may approve the use of time composite samples.

c. Grab samples shall consist of a single aliquot collected over a time period not exceeding 15 minutes.

d. All sample preservation techniques shall conform to the methods adopted in NDEQ Title 119, Chapter 21, 006 unless:
   i) in the case of sludge samples, alternative techniques are specified in the 40 CFR, Part 503, or
   ii) other procedures are specified in this permit.

2. Flow Measurements

Appropriate flow measurement devices and methods consistent with accepted scientific practices shall be used to insure the accuracy and reliability of measurements. The devices shall be installed, calibrated and maintained to insure that the accuracy of the measurements. The accepted capability shall be consistent with the type of that device. Devices selected shall be capable of measuring flows with a maximum deviation of +/- 10%. The amount of deviation shall be from the true discharge rates throughout the range of expected discharge volumes. Guidance can be obtained from the following references for the selection, installation, calibration and operation of acceptable flow measurement devices:

a. "Water Management Manual," U. S. Department of Interior, Bureau of Reclamation, Second Edition, Revised Reprint, 2001, 327 pp. Available from the National Technical Information Services (NTIS)

b. "NPDES Compliance Inspection Manual," U. S. Environmental Protection Agency, Office of Enforcement and Compliance Assurance, Publication EPA 300-B-94-014 September 1994. This document is available from the National Technical Information Services (NTIS).

3. Test Procedures

Test procedures used for monitoring required by this permit shall conform to the methods adopted in NDEQ Title 119, Chapter 21, 006 unless:

a. in the case of sludge samples, alternative techniques are specified in the 40 CFR, Part 503, or

b. other procedures are specified in this permit.

4. Averaging of Measurements

Averages shall be calculated as an arithmetic mean except:

a. bacterial counts which shall be calculated as a geometric mean, or

b. where otherwise specified by the Department.

5. **Retention of Records**

The permittee shall retain records of all monitoring activities for a period of at least three years (except five years for biosolids data) as set forth in NDEQ Titles 119, Chapter 14 001.02. The types of records that must be retained include, but are not limited to:

a. calibration and maintenance records,
b. original strip chart recordings,
c. copies of all reports required by this permit,
d. monitoring records and information, and
e. electronically readable data.

The permittee shall retain records of monitoring required by this permit that are related to biosolids use and disposal for a period of five years or longer, as required in NDEQ Titles 119, Chapter 14.

6. **Record Contents**

As set forth in NDEQ Title 119, Chapter 14, records of sampling or monitoring information shall include:

a. the date(s), exact place, time and methods of sampling or measurements,
b. the name(s) of the individual(s) who performed the sampling or measurements,
c. the date(s) the analyses were performed,
d. the individual(s) who performed the analyses,
e. the analytical techniques or methods used,
f. the results of such analyses, and
g. laboratory data, bench sheets and other required information.

D. Reporting Requirements

1. **Immediate Notification**

a. NPP permittees shall report immediately to the publicly owned treatment works (POTW), any discharge to the POTW that may result in a violation of NDEQ Title 119, Chapter 26.
b. All permittees shall report immediately to the NDEQ:
   i) discharges of oil or hazardous substances which threaten waters of the state or public health and welfare, and
   ii) discharges causing in-stream toxicity (i.e., a fish kill) or an immediate threat to human health.

Initial notification may be verbal. A written noncompliance notification shall be submitted as set forth in Section D. 3 of this Appendix.

2. **Test Procedures**

Test procedures used for monitoring required by this permit, shall conform to the methods adopted in NDEQ Title 119, Chapter 27 unless:

a. In the case of biosolids samples, alternative techniques are specified in the NDEQ Title 119, Chapter 14; or
b. Other procedures are specified in this permit.

3. **24-Hour Reporting**

As set forth in NDEQ Title 119, Chapter 14 the permittee shall report to the NDEQ, within 24 hours of becoming aware of:

a. any noncompliance which may endanger the environment or human health or welfare,
b. any unanticipated bypass,
c. all upsets,
d. any discharge to a POTW that causes a violation of the prohibited discharge standards, or
e. any noncompliance of an effluent limitation in this permit.

Initial notification may be verbal. A written noncompliance notification shall be submitted as set forth in Section D. 3 of this permit.

As set forth in NDEQ Title 119, Chapter 26, if sampling performed by an industrial user (NPP permittee) indicates a permit effluent violation, the permittee shall notify the Department and the city within 24 hours of becoming aware of the violation. The permittee shall resample and have it analyzed. The results of the resampling analysis shall be submitted to the Department and the city within 30 days after becoming aware of the violation.

4. Written Noncompliance Notification

a. The permittee shall submit a written noncompliance report to the NDEQ:
   i) within five days of becoming aware of any noncompliance with the:
      (a) NPP effluent limitations or requirements set forth in this permit, or
      (b) NPDES toxic pollutant effluent limitations or requirements set forth in this permit.
   ii) within seven days of becoming aware of any other noncompliance with the NPDES requirements and/or effluent limitations set forth in this permit.
b. The written notification shall be submitted on a noncompliance form supplied by the Department and shall include:
   i) a description of the discharge and cause of noncompliance,
   ii) the period of noncompliance, including exact dates and times, or if not corrected, the anticipated time the noncompliance is expected to continue, and
   iii) the steps taken to reduce, eliminate and prevent the reoccurrence of the noncompliance.

The submittal of a written noncompliance report does not relieve the permittee of any liability from enforcement proceedings that may result from the violation of permit or regulatory requirements.

5. Quarterly Discharge Monitoring Reports (DMRs)

The permittee shall report the monitoring results required by this permit on a DMR form supplied or approved by the Department. Monitoring results shall be submitted on a quarterly basis using the reporting schedule set forth below, unless otherwise specified in this permit or by the Department.

Monitoring Quarters	DMR Reporting Deadlines
January - March	April 28
April - June	July 28
July - September	October 28
October - December	January 28

If the permittee monitors any pollutant more frequently than required by this permit, using procedures specified in this permit, the results of this monitoring shall be included in the calculation and reporting of the data submitted on the DMR. The frequency of the analysis shall also be reported on the DMR.

6. **Changes in Discharge**

   Any facility expansion, production increases or process modifications which will result in new or substantially increased discharges of pollutants or a change in the nature of the discharge of pollutants must be reported by the permittee 180 days prior to the expansion, increases or modifications, either by amending his original application or by submitting a new application. This permit may be modified or revoked and reissued as a result of this notification to maintain compliance with applicable state or federal regulations.

7. **Changes in Toxic Discharges from Manufacturing, Commercial, Mining and Silvicultural Facilities**

   Permittees discharging from manufacturing, commercial, mining and silvicultural facilities shall report to the Department:

   a. if any toxic pollutant not limited in this permit is discharged from any NPDES outfall as a result of any activity that will or has occurred and results in its routine or frequent discharge. The Department shall be informed if that discharge exceeds the following notification levels:
      i) 100 micrograms per liter (0.1 mg/L) for any toxic pollutant,
      ii) 200 micrograms per liter for acrolein and acrylonitrile (0.2 mg/L),
      iii) 500 micrograms per liter for 2,4-dinitrophenol and for 2-methyl-4, 6-dinitrophenol (0.5 mg/L),
      iv) 1000 micrograms per liter for antimony (1 mg/L),
      v) five times the maximum concentration value reported for that pollutant in the permit application or
      vi) an alternative level established by the Director, and
   b. if any toxic pollutant not limited in this permit is discharged from an NPDES outfall as a result of any activity that will or has occurred and results in its nonroutine discharge. The Department shall be informed if that discharge exceeds the following notification levels:
      i) 500 micrograms per liter (0.5 mg/L) for any toxic pollutant,
      ii) 1000 micrograms for antimony (1 mg/L),
      iii) ten times the maximum concentration value reported for that pollutant in the permit application, or
      iv) an alternative level established by the Director.

8. **Changes in Sludge Quality**

   The permittee shall provide written notice to the Department of any alteration or addition that results in a significant change in the permittee's sludge use or disposal practices. This permit may be modified or revoked and reissued as a result of this notification to maintain compliance with applicable state or federal regulations.

9. **Changes of Loadings to Publicly Owned Treatment Work (POTW)**

   POTW's shall notify the Department of the following:

   a. any new introduction of pollutants from dischargers subject to the categorical pretreatment discharge limitations set forth in NDEQ Title 119, Chapter 27, and
   b. any substantial change in the volume or character of pollutants being introduced into the POTW.

   Notification shall be made 180 days in advance whenever possible. Information on the quantity and quality of new discharges and their anticipated impact on the POTW shall be included.

10. Transfers

The permittee shall notify the Department at least 30 days prior to the proposed transfer of ownership of this permit or the permitted facility to another party. The Department may modify or revoke and reissue this permit as set forth in NDEQ Title 119, Chapter 24.

11. Compliance Schedules

The permittee shall submit a written report of compliance or noncompliance with any compliance schedule established in this permit. The written report shall be submitted within 14 days following all deadlines established in the compliance schedule. If compliance has not been achieved, the report shall include an alternative completion date, an explanation of the cause of the noncompliance and an explanation of the steps being taken to ensure future compliance. The submission of this report does not ensure the Department's acceptance of alternative compliance dates nor does it preclude the Department from initiating enforcement proceedings based upon the reported noncompliance.

E. Operation and Maintenance

1. Proper Operation and Maintenance

The permittee shall, at all times, maintain in good working order and operate as efficiently as possible, any facilities or systems of control installed by the permittee in order to achieve compliance with the terms and conditions of this permit. This would include, but not be limited to, effective performance based on designed facility removals, effective management, adequate operator staffing and training, adequate laboratory and process controls, and adequate funding which reflects proper user fee schedules.

2. Treatment System Failure and Upset

An upset is an affirmative defense to an enforcement action brought for noncompliance with technology-based permit effluent limitations if the permittee can demonstrate, through properly signed, operating logs or other relevant evidence, that:

a. an upset occurred and the specific cause was identified,

b. that the facility was properly operated and maintained at such time,

c. the Department was notified within 24 hours of the permittee becoming aware of the upset, and

d. the permittee took action to reduce, eliminate and prevent a reoccurrence of upset, including minimizing adverse impact to waters of the state.

3. Bypassing

Any diversion from or bypass of the treatment facilities is prohibited, unless:

a. It is unavoidable to prevent loss of life, personal injury or severe property damage;
   i) No feasible alternative exists, i.e., auxiliary treatment facilities, retention of untreated wastes or maintenance during normal periods of equipment downtime;
   ii) The permittee submits notice to the Department within 24 hours of becoming aware of the bypass or if the bypass is anticipated or should have been anticipated, the Department is notified at least ten days prior to the bypass; and
   iii) The bypass is conducted under conditions determined to be necessary by the Director to minimize any adverse effects.

b. If the bypass is needed for regular preventative maintenance for which back-up equipment should be provided, the bypass will not be allowed. When a bypass occurs, the burden is on the permittee to demonstrate compliance with items "a" through "d" above.

c. Additionally, NPP permittees shall report any bypasses to the POTW. Unanticipated bypasses shall be reported immediately and anticipated bypasses shall be reported at least ten days in advance.

d. All NPDES permittees shall notify the general public that a bypass of the treatment system is occurring. The public notification shall include:
   i) Location of the bypass;
   ii) The date the bypass started;
   iii) Anticipated length of time the bypass will occur; and
   iv) An estimate of the total volume of wastewater bypassed.

4. Removed Substances

Solids, sludge, filter backwash or other pollutants removed in the course of treatment or control of wastewater shall be disposed of at a site and in a manner approved by the Nebraska Department of Environmental Quality. The disposal of nonhazardous industrial sludges shall conform to the standards established in or to the regulations established pursuant to 40 CFR, Part 257. The disposal of sludge shall conform to the standards established in or to the regulations established pursuant to 40 CFR, Part 503. If solids are disposed of in a licensed sanitary landfill, the disposal of solids shall conform to the standards established in NDEQ Title 132. Publicly owned treatment works shall dispose of sewage sludge in a manner that protects public health and the environment from any adverse effects which may occur from toxic pollutants as defined in Section 307 of the Clean Water Act. This permit may be modified or revoked and reissued to incorporate regulatory limitations established pursuant to 40 CFR, Part 503.

F. Definitions

Administrator: The Administrator of the USEPA.

Aliquot: An individual sample having a minimum volume of 100 milliliters that is collected either manually or in an automatic sampling device.

Biweekly: Once every other week.

Bimonthly: Once every other month.

Bypass: The intentional diversion of wastes from any portion of a treatment facility.

Daily Average: An effluent limitation that cannot be exceeded and is calculated by averaging the monitoring results for any given pollutant parameter obtained during a 24-hour day.

Department: Nebraska Department of Environmental Quality.

Director: The Director of the Nebraska Department of Environmental Quality.

Industrial Discharge: Wastewater that originates from an industrial process and / or is noncontact cooling water and / or is boiler blowdown.

Industrial User: A source of indirect discharge (a pretreatment facility).

Monthly Average: Is an effluent limitation that cannot be exceeded. It is calculated by averaging any given pollutant parameter monitoring results obtained during a calendar month.

Passive Discharge: A discharge from a POTW that occurs in the absence of an affirmative action and is not authorized by the NPDES permit (e.g. discharges due to a leaking valve, discharges from an overflow structure) and / or is a discharge from an overflow structure not designed as part of the POTW (e.g. discharges resulting from lagoon berm / dike breaches).

Publicly Owned Treatment Works (POTW): A treatment works as defined by Section 212 of the Clean Water Act (Public Law 100-4) which is owned by the state or municipality, excluding any sewers or other conveyances not leading to a facility providing treatment.

Semiannually: Twice every year

Significant Industrial Use (SIU): All industrial users subject to Categorical Pretreatment Standards or any industrial user that, unless exempted under Chapter 1, Section 115 of NDEQ Title 119, discharges an average of 25,000 gallons per day or more of process water; or contributes a process waste stream which makes up 5 percent or more of the average dry weather hydraulic or organic capacity of the POTW; or is designated as such by the Director on the basis that the industrial user has a reasonable potential for adversely affecting the POTW's operation or for violating any National Pretreatment Standard or requirement.

30-Day Average: Is an effluent limitation that cannot be exceeded. It is calculated by averaging any given pollutant parameter monitoring results obtained during a calendar month.

Total Toxic Organics (TTO): The summation of all quantifiable values greater than 0.01 milligrams per liter (mg/l) for toxic organic compounds that may be identified elsewhere in this permit. (If this term has application in this permit, the list of toxic organic compounds will be identified, typically in the Limitations and Monitoring Section(s) and/or in an additional Appendix to this permit.)

Toxic Pollutant: Those pollutants or combination of pollutants, including disease causing agents, after discharge and upon exposure, ingestion, inhalation or assimilation into an organism, either directly from the environment or indirectly by ingestion through food chains will, on the basis of information available to the administrator, cause death, disease, behavioral abnormalities, cancer, genetic mutations, physiological malfunction (including malfunctions in reproduction) or physical deformations, in such organisms or their offspring.

Upset: An exceptional incident in which there is unintentional and temporary noncompliance with technology based permit effluent limitations because of factors beyond the reasonable control of the permittee, excluding such factors as operational error, improperly designed or inadequate treatment facilities or improper operation and maintenance or lack thereof.

Volatile Organic Compounds (VOC): The summation of all quantifiable values greater than 0.01 milligrams per liter (mg/l) for volatile, toxic organic compounds that may be identified elsewhere in this permit. (See the definition for Total Toxic Organics above. In many instances, VOCs are defined as the volatile fraction of the TTO parameter. If the term "VOC" has application in this permit, the list of toxic organic compounds will be identified, typically in the Limitations and Monitoring Section(s) and/or in an additional Appendix to this permit.)

Weekly Average: Is an effluent limitation that cannot be exceeded. It is calculated by averaging any given pollutant parameter monitoring results obtained during a fixed calendar week. The permittee may start their week on any weekday but the weekday must remain fixed. The Department approval is required for any change of the starting day.

"X" Day Average: An effluent limitation defined as the maximum allowable "X" day average of consecutive monitoring results during any monitoring period where "X" is a number in the range of one to seven days.

G. Abbreviations

CFR: Code of Federal Regulations
kg/Day: Kilograms per Day
MGD: Million Gallons per Day
mg/L: Milligrams per Liter
NOI: Notice of Intent
NDEQ: Nebraska Department of Environmental Quality
NDEQ Title 115: *Rules of Practice and Procedure*
NDEQ Title 117: *Nebraska Surface Water Quality Standards*
NDEQ Title 118: *Ground Water Quality Standards and Use Classification*
NDEQ Title 119: *Rules and Regulations Pertaining to the Issuance of Permits under the National Pollutant Discharge Elimination System*
NDEQ Title 126: *Rules and Regulations Pertaining to the Management of Wastes*
NDEQ Title 132: *Integrated Solid Waste Management Regulations*
NPDES: National Pollutant Discharge Elimination System
NPP: Nebraska Pretreatment Program
POTW: Publicly Owned Treatment Works
µg/L: Micrograms per Liter
WWTF: Wastewater Treatment Facility

Nebraska Water Pollution Control Council
State Certification for
Federally Licensed Facilities or Activities

The Nebraska Water Pollution Control Council hereby issues a state certification to: The Nebraska Public Power District

for the purpose of conducting the following described activity: Circulation Of Missouri River Water Through A Condenser To Cool And Condense Steam From A Turbo-Generator, Warming Such Water A Maximum of 18 Degrees Fahrenheit At Point of Discharge

which may result in the following type or types of discharges: Missouri River Water Warmed A Maximum of 18°F At Point Of Discharge

into the following named navigable water flowing through or bordering the State of Nebraska The Missouri River (Near Missouri River Mile 532.5)

This activity shall be conducted at Brownville in the County of Nemaha in the State of Nebraska.

The issuance of this certification to the above named entity signifies that the Nebraska Water Pollution Control Council determined that there is reasonable assurance that the above described activity will be conducted in a manner which will not violate the water quality standards of the State of Nebraska.

CHAIRMAN, Nebraska Water Pollution Control Council

ATTEST:

EXECUTIVE SECRETARY,
Nebraska Water Pollution Control Council

June 11, 1971
Date

NWPCC 51-1970

Nebraska Public Power District
"Always there when you need us"

K. Michael Krumland
Environmental Protection Supvr.
PH: 402-563-5329

Mr. John Bender
Nebraska Department of
Environmental Quality
P.O. Box 98922
Lincoln, NE 68509-8922

RE: Nebraska Public Power District – Cooper Nuclear Station
Clean Water Act Section 401 Certification – License Renewal

Dear Mr. Bender:

This is a quick note to confirm our conversation regarding the license renewal application the District plans to file later this year to extend the Cooper Nuclear Station operating term for another twenty years. Specifically, as we discussed, the existing Section 401 certification that the state previously issued on July 11, 1971, would remain effective throughout the renewed term of plant operation should the U.S. Nuclear Regulatory Commission grant the application. I have attached the existing certification to this letter.

Sincerely,

Kevin M. Krumland
Environmental Protection Supervisor

Att.

cc: J. L. Citta, Jr. w/att.
L. M. McFarland w/att.

bc: R. Buckley/Entergy w/att.
K. M. Sutton/Morgan, Lewis & Bockius LLP w/att.
J. Lagace/Entergy w/att.

D. W. Bremer w/att.
File: ENV-705.0350

Nebraska Water Pollution Control Council
State Certification for
Federally Licensed Facilities or Activities

The Nebraska Water Pollution Control Council hereby issues a state certification to: The Nebraska Public Power District

for the purpose of conducting the following described activity: Circulation Of Missouri River Water Through A Condenser To Cool And Condense Steam From A Turbo-Generator, Warming Such Water A Maximum of 18 Degrees Fahrenheit At Point of Discharge

which may result in the following type or types of discharges: Missouri River Water Warmed A Maximum of 18°F At Point Of Discharge

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CHAIRMAN, Nebraska Water Pollution Control Council

ATTEST:

EXECUTIVE SECRETARY,
Nebraska Water Pollution Control Council

June 11, 1971
Date

NWPCC 51-1970

Attachment D

Miscellaneous Agency Correspondence

- J.L. Citta, Jr., NPPD, to D. Childers, Missouri Department of Natural Resources, January 15, 2008.
- J.L. Citta, Jr., NPPD, to M. Linder, Nebraska Department of Environmental Quality, March 6, 2008.
- J.L. Citta, Jr., NPPD, to A. Salomon Bleed, Nebraska Department of Natural Resources, March 6, 2008.
- S. McMaster, Nebraska Department of Natural Resources to J.L. Citta, Jr., NPPD, March 12, 2008.
- J.L. Citta, Jr., NPPD, to Colonel D.C. Press, U.S. Army Corps of Engineers, Omaha District, January 15, 2008.
- L.D. Janis, U.S. Army Corps of Engineers, Omaha District, to J.L. Citta, Jr., NPPD, February 11, 2008.
- J.L. Citta, Jr., NPPD, to Colonel R.A. Wilson, Jr., U.S. Army Corps of Engineers, Kansas City District, January 15, 2008.
- M.D. Frazier, U.S. Army Corps of Engineers, Kansas City District, to J.L. Citta, Jr., NPPD, February 8, 2008.

Nebraska Public Power District
"Always there when you need us"

Joe L. Citta, Jr.
Corporate Environmental Mgr.
PH: 402-563-5355

January 15, 2008

Mr. Doyle Childers, Director
Missouri Department of Natural Resources
P.O. Box 176
Jefferson City, MO 65102

RE: Nebraska Public Power District
Cooper Nuclear Station

Dear Mr. Childers:

Nebraska Public Power District (NPPD) is preparing an application to the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for the Cooper Nuclear Station (CNS). The current 30-year operating license for the station expires in 2014. If the NRC approves the application, NPPD will have the option to continue operating CNS until 2034.

CNS is located in Nemaha County, Nebraska, on the west bank of the Missouri River at river mile 532.5 (Figure 1). Coordinates for the station are 40°21'43" North latitude and 95°38'29" West longitude. CNS is located on approximately 55 acres of a 1,351-acre site that includes 205 acres located on the east bank of the Missouri River in Atchison County, Missouri. Approximately 150 miles of transmission lines were constructed to connect the station to the regional electric power grid.

As part of the license renewal process, the NRC requires that the applicant assess the impact of the proposed license renewal action. This assessment, which is contained in the Environmental Report, addresses specific environmental issues related to the continued operation of the station. NPPD is confident that the operation of CNS will continue to have no significant environmental impacts.

There are no plans to alter current operations during the 20-year license renewal period. Any maintenance activities necessary to support continued operation of CNS will be limited to currently developed areas of the site. No expansion of existing facilities is planned and no additional land disturbance is anticipated in support of license renewal.

General Office
1414 15th Street / P.O. Box 499 / Columbus, NE 68602-0499
***Telephone:** (402) 564-8561 / **Fax:** (402) 563-5551*
www.nppd.com

To ensure that impacts are adequately addressed, we are requesting from your office pertinent information regarding concerns, if any, that you may have regarding potential environmental impacts from the continued operation of CNS.

After your review, we would appreciate your office responding by letter detailing any concerns you may have or confirmation that no concerns exist.

If you have any questions or need additional information, please feel free to contact me at (402) 563-5355.

Thank you,

Joe L. Citta, Jr.
Corporate Environmental Manager

Att.: Maps & Photographs

cc: Rick Buckley (Entergy Nuclear) w/att.

Nebraska Public Power District
"Always there when you need us"

Joe L. Citta, Jr.
Environmental Manager
PH: 402-563-5355

March 6, 2008

Mr. Mike Linder, Director
Nebraska Department of Environmental Quality
P.O. Box 98922
Lincoln, NE 68509-8922

RE: Nebraska Public Power District
Cooper Nuclear Station

Dear Mr. Linder:

Nebraska Public Power District (NPPD) is preparing an application to the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for the Cooper Nuclear Station (CNS). The current 30-year operating license for the station expires in 2014. If the NRC approves the application, NPPD will have the option to continue operating CNS until 2034.

CNS is located in Nemaha County, Nebraska, on the west bank of the Missouri River at river mile 532.5 (Figure 1). Coordinates for the station are 40°21'43" North latitude and 95°38'29" West longitude. CNS is located on approximately 55 acres of a 1,351-acre site that includes 205 acres located on the east bank of the Missouri River in Atchison County, Missouri. Approximately 150 miles of transmission lines were constructed to connect the station to the regional electric power grid.

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To ensure that impacts are adequately addressed, we are requesting from your office pertinent information regarding concerns, if any, that you may have regarding potential environmental impacts from the continued operation of CNS.

After your review, we would appreciate your office responding by letter detailing any concerns you may have or confirmation that no concerns exist. If you have any questions or need additional information, please feel free to contact me at (402) 563-5355.

Thank you,

Joe L. Citta, Jr.
Corporate Environmental Manager

Att.: Maps & Photographs

cc: Rick Buckley (Entergy Nuclear) w/att.

bc: J. C. McClure w/o att.
R. L. Beilke w/o att.
K. M. Krumland w/o att.
D. W. Bremer w/o att.
L. D. Linder w/o att.
C. O. Stipp w/o att.
L. M. McFarland w/o att.
ENV-705-0350 / E40 w/att.

Nebraska Public Power District
"Always there when you need us"

Joe L. Citta, Jr.
Environmental Manager
PH: 402-563-5355

March 6, 2008

Ms. Ann Salomon Bleed, Director
Nebraska Department of Natural Resources
301 Centennial Mall South
P.O. Box 94676
Lincoln, NE 68509-4676

RE: Nebraska Public Power District
Cooper Nuclear Station

Dear Ms. Bleed:

Nebraska Public Power District (NPPD) is preparing an application to the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for the Cooper Nuclear Station (CNS). The current 30-year operating license for the station expires in 2014. If the NRC approves the application, NPPD will have the option to continue operating CNS until 2034.

CNS is located in Nemaha County, Nebraska, on the west bank of the Missouri River at river mile 532.5 (Figure 1). Coordinates for the station are 40°21'43" North latitude and 95°38'29" West longitude. CNS is located on approximately 55 acres of a 1,351-acre site that includes 205 acres located on the east bank of the Missouri River in Atchison County, Missouri. Approximately 150 miles of transmission lines were constructed to connect the station to the regional electric power grid.

As part of the license renewal process, the NRC requires that the applicant assess the impact of the proposed license renewal action. This assessment, which is contained in the Environmental Report, addresses specific environmental issues related to the continued operation of the station. NPPD is confident that the operation of CNS will continue to have no significant environmental impacts.

There are no plans to alter current operations during the 20-year license renewal period. Any maintenance activities necessary to support continued operation of CNS will be limited to currently developed areas of the site. No expansion of existing facilities is planned and no additional land disturbance is anticipated in support of license renewal.

To ensure that impacts are adequately addressed, we are requesting from your office pertinent information regarding concerns, if any, that you may have regarding potential environmental impacts from the continued operation of CNS.

After your review, we would appreciate your office responding by letter detailing any concerns you may have or confirmation that no concerns exist. If you have any questions or need additional information, please feel free to contact me at (402) 563-5355.

Thank you,

Joe L. Citta, Jr.
Corporate Environmental Manager

Att.: Maps & Photographs

cc: Rick Buckley (Entergy Nuclear) w/att.

bc: J. C. McClure w/o att.
R. L. Beilke w/o att.
K. M. Krumland w/o att.
D. W. Bremer w/o att.
L. D. Linder w/o att.
C. O. Stipp w/o att.
L. M. McFarland w/o att.
ENV-705-0350 / E40 w/att.

NOTE: Same attachments as NDEQ's letter.

STATE OF NEBRASKA

Dave Heineman
Governor

DEPARTMENT OF NATURAL RESOURCES
Ann Bleed
Director

March 12, 2008

IN REPLY TO:

Joe Citta, Jr.
NPPD
1414 15th Street
PO Box 499
Columbus, NE 68602-0499

RE: Cooper Nuclear Station

Dear Mr. Citta:

By itself, a license renewal does not constitute an action which would trigger a review for resources under NDNR's review authority: floodplain management, surface water, and ground water. In addition, since your letter states that no new ground will be disturbed and no new water resources will be developed or changed, this means that the Nebraska Department of Natural Resources has no comment.

If you have any questions about this letter, please call me at (402) 471-3957.

Sincerely,

Steve McMaster
Natural Resources Planner Coordinator

RECEIVED
MAR 13 2008

Dam Safety-Flood Plain/McMaster

301 Centennial Mall South, 4th Floor • P.O. Box 94676 • Lincoln, Nebraska 68509-4676 • Phone (402) 471-2363 • Telefax (402) 471-2900

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Joe L. Citta, Jr.
Corporate Environmental Mgr.
PH: 402-563-5355

January 15, 2008

Colonel David C. Press, Commander
U.S. Army Corps of Engineers
Omaha District
106 South 15th Street
Omaha, NE 68102-1618

RE: Nebraska Public Power District
Cooper Nuclear Station

Dear Colonel Press:

Nebraska Public Power District (NPPD) is preparing an application to the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for the Cooper Nuclear Station (CNS). The current 30-year operating license for the station expires in 2014. If the application is approved by the NRC, NPPD will have the option to continue operating CNS until 2034.

CNS is located in Nemaha County, Nebraska, on the west bank of the Missouri River at river mile 532.5, an area referred to by the Corps of Engineers as the Lower Brownville Bend. Coordinates for the station are 40°21'43" North latitude and 95°38'29" West longitude. CNS is located on approximately 55 acres of a 1,351-acre site, which includes 205 acres located on the east bank of the Missouri River in Atchison County, Missouri. Approximately 150 miles of transmission lines were constructed to connect the station to the regional electric power grid.

As part of the license renewal process, the NRC requires that the applicant assess the impact of the proposed license renewal action. This assessment, which is contained in the Environmental Report, addresses specific environmental issues related to the continued operation of the station. NPPD is confident that the continued operation of CNS will have no significant environmental impacts.

There are no plans to alter current operations during the 20-year license renewal period. Any maintenance activities necessary to support continued operation of CNS will be limited to currently developed areas of the site. No expansion of existing facilities is planned and no additional land disturbance is anticipated in support of license renewal.

General Office
1414 15th Street / P.O. Box 499 / Columbus, NE 68602-0499
***Telephone:** (402) 564-8561 / **Fax:** (402) 563-5551*
www.nppd.com

To ensure that potential impacts are adequately addressed, we are requesting from the Omaha and Kansas City Districts pertinent information regarding any concerns or issues, if any, that you may have about potential impacts from the continued operation of CNS, and information regarding any proposed changes in the future operation and maintenance of the Missouri River that could affect the CNS facility.

After your review, we would appreciate your office responding by letter detailing any concerns you may have or confirmation that no concerns exist.

If you have any questions or need additional information, please feel free to contact me at (402) 563-5355.

Thank you,

Joe L. Citta, Jr.
Corporate Environmental Manager

Att.: Maps & Photographs

cc: Randal K. Petersen (ACOE) w/att.
Rick Buckley (Entergy Nuclear) w/att.

DEPARTMENT OF THE ARMY
CORPS OF ENGINEERS, OMAHA DISTRICT
106 SOUTH 15TH STREET
OMAHA NE 68102-1618

REPLY TO
ATTENTION OF

February 11, 2008

RECEIVED
FEB 14 2008

Planning, Programs, and Project Management Division

Mr. Joe Citta
Nebraska Public Power District
P.O. Box 499
Columbus, Nebraska 68602-0499

Dear Mr. Citta:

The U.S. Army Corps of Engineers, Omaha District (Corps) has reviewed your letter dated January 15, 2008 regarding the renewal of the operating license for the Cooper Nuclear Station. The Corps offers the following comments:

There are no flood plain or environmental comments regarding the above mentioned license renewal, however if your plans include additional construction you should coordinate with the U.S. Environmental Protection Agency, which is currently involved in a program to protect ground water resources. In addition, it would be recommended that you consult with the U.S. Fish and Wildlife Service, Nebraska Game and Parks Commission, Iowa Department of Natural Resources, Kansas Department of Wildlife and Parks, and the Missouri Department of Conservation regarding fish and wildlife resources if new construction is to take place.

If future construction activities will involve any work in waters of the United States, a Section 404 permit may be required. For a detailed review of permit requirements, preliminary and final project plans should be sent to:

For Iowa:
U.S. Army Corps of Engineers
Rock Island District
Attention: Regulatory Branch
P.O. Box 2004
Clock Tower Building
Rock Island, Illinois 61204-2004

For Kansas and Missouri:
U.S. Army Corps of Engineers
Kansas City District
Attention: CENWK-OD-R
700 Federal Building
601 East 12th Street
Kansas City, MO 64106-2896

For Nebraska:
U.S. Army Corps of Engineers
Wehrspann Regulatory Office
Attention: CENWO-OD-R-NE/Moeschen
8901 South 154th Street
Omaha, Nebraska 68138-3621

If you have any questions, please contact Mr. Dave Crane of my staff at (402) 221-4882.

Sincerely,

Larry D. Janis, Chief
Environmental, Economics, and
Cultural Resources Section
Planning Branch

Nebraska Public Power District
"Always there when you need us"

Joe L. Citta, Jr.
Corporate Environmental Mgr.
PH: 402-563-5355

January 15, 2008

Colonel Roger A. Wilson, Jr., Commander
U. S. Army Corps of Engineers
Kansas City District
601 E. 12th St., Rm. 736
Kansas City, MO 64106

RE: Nebraska Public Power District
Cooper Nuclear Station

Dear Colonel Wilson:

Nebraska Public Power District (NPPD) is preparing an application to the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for the Cooper Nuclear Station (CNS). The current 30-year operating license for the station expires in 2014. If the application is approved by the NRC, NPPD will have the option to continue operating CNS until 2034.

CNS is located in Nemaha County, Nebraska, on the west bank of the Missouri River at river mile 532.5, an area referred to by the Corps of Engineers as the Lower Brownville Bend. Coordinates for the station are 40°21'43" North latitude and 95°38'29" West longitude. CNS is located on approximately 55 acres of a 1,351-acre site, which includes 205 acres located on the east bank of the Missouri River in Atchison County, Missouri. Approximately 150 miles of transmission lines were constructed to connect the station to the regional electric power grid.

As part of the license renewal process, the NRC requires that the applicant assess the impact of the proposed license renewal action. This assessment, which is contained in the Environmental Report, addresses specific environmental issues related to the continued operation of the station. NPPD is confident that the continued operation of CNS will have no significant environmental impacts.

There are no plans to alter current operations during the 20-year license renewal period. Any maintenance activities necessary to support continued operation of CNS will be limited to currently developed areas of the site. No expansion of existing facilities is planned and no additional land disturbance is anticipated in support of license renewal.

To ensure that potential impacts are adequately addressed, we are requesting from the Omaha and Kansas City Districts pertinent information regarding any concerns or issues, if any, that you may have about potential impacts from the continued operation of CNS, and information regarding any proposed changes in the future operation and maintenance of the Missouri River that could affect the CNS facility.

After your review, we would appreciate your office responding by letter detailing any concerns you may have or confirmation that no concerns exist.

If you have any questions or need additional information, please feel free to contact me at (402) 563-5355.

Thank you,

Joe L. Citta, Jr.
NPPD Corporate Environmental Manager

Att.: Maps & Photographs

cc: Scott Young (ACOE) w/att.
Rick Buckley (Entergy Nuclear) w/att.

DEPARTMENT OF THE ARMY
KANSAS CITY DISTRICT, CORPS OF ENGINEERS
700 FEDERAL BUILDING
KANSAS CITY, MISSOURI 64106-2896

February 8, 2008

RECEIVED
FEB 11 2008

REPLY TO
ATTENTION OF:

Regulatory Branch
(Project 2008-00155)

Joe L. Citta, Jr., Environmental Manager
Nebraska Public Power District
P.O. Box 499
Columbus, Nebraska 68602-0449

Dear Mr. Citta:

This is in response to your letter dated January 15, 2008, concerning your renewal application with the U.S. Nuclear Regulatory Commission for operation of your Cooper Nuclear Station located adjacent to the Missouri River (River mile 532.5) in Nemaha County, Nebraska.

This portion of the Missouri River navigation channel is within the Omaha District's area of review. To address any current environmental issues, identified in your Environmental Report, or for review of any future activities you should contact Mr. Stephen Earl, Omaha District, at 402-221-7325. In addition, for any future activities involving the discharge of dredged or fill material into waters of the United States, including wetlands, you should contact the Omaha District, Regulatory Branch at 402-896-0896 and/or for activities in the State of Missouri please contact the Kansas City District, Regulatory Branch at 816-389-3990.

We have reviewed the information provided and we have contacted the Omaha District, regarding this request, and at this time the Corps of Engineers has no issues or concerns with your application for continued operations at the Cooper Nuclear Station. We have provided a copy of this letter to the Omaha District for their records.

If you have any questions concerning this matter, please feel free to write me or call Mr. Douglas R. Berka, Regulatory Project Manager, at 816-389-3657.

Sincerely,

Mark D. Frazier
Chief, Regulatory Branch
Operations Division

Attachment E

Severe Accident Mitigation Alternatives Analysis

Attachment E contains the following sections.

E.1 – Evaluation of CNS PSA Model

E.2 – Evaluation of CNS SAMA Candidates

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LIST OF ACRONYMS

Acronym	Definition
AC	Alternating Current
ADS	Automatic Depressurization System
AOV	Air Operated Valve
ASDS	Alternate Shutdown System
ATWS	Anticipated Transient Without Scram
BOC	Break Outside of Containment
BWR	Boiling Water Reactor
BWROG	Boiling Water Reactor Owners Group
CB	Control Building
CCF	Common Cause Failure
CDF	Core Damage Frequency
CET	Containment Event Tree
CNS	Cooper Nuclear Station
CRD	Control Rod Drive
CS	Core Spray
CST	Condensate Storage Tank
DC	Direct Current
DFP	Diesel Fire Pump
DG	Diesel Generator
DHR	Decay Heat Removal
ECCS	Emergency Core Cooling System
ECST	Emergency Condensate Storage Tank
EDG	Emergency Diesel Generator

Acronym	Definition
EOP	Emergency Operating Procedure
EPG	Emergency Procedure Guidelines
FIVE	Fire Induced Vulnerability Evaluation
FPS	Fire Protection System
HCLPF	High Confidence Low Probability of Failure
HPCI	High Pressure Coolant Injection
HVAC	Heating Ventilation and Air Conditioning
IPE	Individual Plant Examination
IPEEE	Individual Plant Examination of External Events
ISLOCA	Interfacing Systems Loss of Coolant Accident
LERF	Large Early Release Frequency
LOCA	Loss of Coolant Accident
LOOP	Loss of Off-site Power
LPCI	Low Pressure Coolant Injection
MAAP	Modular Accident Analysis Program
MACCS2	Melcor Accident Consequences Code System 2
MCC	Motor Control Center
MSIV	Main Steam Isolation Valve
NBPP	No Break Power Panel
NPSH	Net Positive Suction Head
NRC	Nuclear Regulatory Commission
OECR	Off-site Economic Cost Risk
OSP	Off-site Power
PCPL	Primary Containment Pressure Limit
PDR	Population Dose Risk
PDS	Plant Damage State

Acronym	Definition
PSA	Probabilistic Safety Assessment
RCIC	Reactor Core Isolation Cooling
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RHRSW	Residual Heat Removal Service Water
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
RWCU	Reactor Water Clean Up
SAMA	Severe Accident Mitigation Alternative
SAMG	Severe Accident Management Guidance
SBO	Station Blackout
SLC	Standby Liquid Control
SMA	Seismic Margin Assessment
SORV	Stuck Open Relief Valve
SPC	Suppression Pool Cooling
SQUG	Seismic Qualification Utility Group
SRV	Safety Relief Valve
SW	Service Water
SWBP	Service Water Booster Pump
TAF	Top of Active Fuel
TBCCW	Turbine Building Closed Cooling Water
TEC	Turbine Equipment Cooling
THPV	Torus Hard Pipe Vent
WW	Wetwell

ATTACHMENT E.1

EVALUATION OF CNS PSA MODEL

E.1 EVALUATION OF CNS PROBABILISTIC SAFETY ANALYSIS MODEL

The severe accident risk was estimated using the Probabilistic Safety Analysis (PSA) model and a Level 3 model developed using the most recent version (version 1.13.1) of the MELCOR Accident Consequences Code System version 2 (MACCS2 code). The CAFTA code was used to develop the CNS PSA Level 1 and Level 2 models. This section provides the description of CNS PSA levels 1, 2, and 3 analyses, Core Damage Frequency (CDF) uncertainty, Individual Plant Examination of External Events (IPEEE) analyses, and PSA model peer review.

E.1.1 PSA Model—Level 1 Analysis

The PSA model (Level 1 and Level 2) used for the SAMA analysis was the most recent internal events risk model for CNS (2007TM model, Rev. 1). This model is an updated version of the model used in the IPE and reflects the CNS configuration and design as of December 2007. It uses component failure and unavailability data as of March 2006. The CNS model adopts the small-event-tree / large-fault-tree approach and uses the CAFTA code for quantifying CDF.

The PSA model has had five major revisions since the IPE due to the following.

- Equipment performance: as data collection progresses, estimated failure rates and system unavailability data change.
- Plant configuration changes: plant configuration changes are incorporated into the PSA model.
- Modeling changes: the PSA model is refined to incorporate the latest state of knowledge and recommendations from internal and industry peer reviews.

The PSA model contains the major initiators leading to core damage with baseline CDFs listed in Table E.1-1. A separate breakdown of the top flood scenarios is given in Table E.1-2.

The CNS 2007TM model, Rev. 1, was reviewed to identify those potential risk contributors that made a significant contribution to CDF. CDF-based Risk Reduction Worth (RRW) rankings were reviewed down to 1.005. Events below this point would influence the CDF by less than 0.5% and are judged to be highly unlikely contributors for the identification of cost-beneficial enhancements. These basic events, including component failures, operator actions, and initiating events, were reviewed to determine if additional SAMA actions may need to be considered.

Table E.1-3 provides a correlation between the Level 1 RRW risk significant events (component failures, operator actions, and initiating events) down to 1.005 identified from the CNS PSA model and the SAMAs evaluated in Section E.2.

Table E.1-1
CNS PSA Model CDF Results by Major Initiators

Initiating Event Group	CDF (/ry)	% of Total CDF
Inadvertent ADS	4.48E-10	0.00
LOCA	1.37E-06	14.79
Internal Flood	2.62E-07	2.82
Interfacing System LOCA	5.14E-08	0.55
Loss of Offsite Power	6.52E-07	7.03
Transients	3.01E-06	32.44
Loss of AC Buses	2.62E-07	2.83
Loss of DC Power	2.06E-06	22.24
Loss of Feedwater	1.00E-06	10.83
Loss of Service Water	6.00E-07	6.47
Total CDF	**9.27E-06**	**100.00**
Total ATWS(1)	2.59E-07	2.79
Total SBO(1)	2.58E-07	2.78

1. Because SBO and ATWS may occur following multiple initiators, their contributions to CDF are listed separately.

Table E.1-2
Level 1 Flooding Contributions

Flooding Event	CDF (/ry)	% of Total Flood CDF	Description
%FLSWCB7AM	1.32E-07	50.41	Moderate SW pipe rupture in the control building basement (comp 7a)
%FLSWRBM	5.43E-08	20.74	Moderate SW rupture (RB-859' or above)
%FLSWCB7AL	2.57E-08	9.82	Large SW pipe rupture in the control building basement (comp 7a)
%FLSWRBL	9.71E-09	3.71	Large SW rupture (RB-859' or above)
%FLCWTB11L	9.34E-09	3.57	Large CW pipe rupture in turbine building basement (loss of FW, cond, MC)
%FLFPCB8DM	8.75E-09	3.34	Moderate fire water pipe rupture in control building ground floor corridor (CB-903')
%FLFPCB7AL	4.05E-09	1.55	Large fire water pipe rupture in the control building basement
%FLECRBM	2.97E-09	1.13	Moderate ECCS rupture (RB-859' or above)
%FLFPCB8DL	2.83E-09	1.08	Large fire water pipe rupture in control building ground floor corridor (CB-903')
%FLFPRBL	2.44E-09	0.93	Large fire water pipe rupture (RB-859' or above)
%FLECRB1DM	2.29E-09	0.87	Moderate ECCS rupture in quad 1D/1E (SW)
%FLFPCB7AM	2.26E-09	0.86	Moderate fire water pipe rupture in the control building basement
Other	5.19E-09	1.98	
Total	2.62E-07	100.00	

Table E.1-3
Correlation of Level 1 Risk-Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
%TDCA	5.25E-04	1.19	Loss of 125 VDC A	This term represents an initiating event caused by loss of 125V DC bus A. Phase II SAMAs 1, 2, 3, 13, 14, 15, 19, and 21, for enhancing DC system availability and reliability, were evaluated.
EDC-XHE-FO-RSTRA	7.10E-01	1.19	Failure to restore DC power within 30 min. (data based)	This term represents operator failure to restore DC power in train A within 30 min. when DC power has been lost. Phase II SAMAs 1, 2, 3, 13, 14, 15, 19, and 21, for enhancing DC system availability and reliability, were evaluated.
%TF	1.35E-01	1.121	Loss of feedwater	This term represents the initiating event for loss of feedwater. A modification to significantly reduce the potential for loss of feedwater by upgrading to a digital feedwater control system has already been installed. Phase II SAMAs 33, 34, and 75, to further reduce the potential for loss of feedwater, were evaluated.
DEP-XHE-FO-ERLY3	2.51E-06	1.11	Operator fails to initiate ADS & fails to initiate ECCS & RHR (early)	This term represents the combination of human failure events ADS-XHE-FO-COND, ECS-XHE-FO-TRANS, and RHR-XHE-FO-RHRE to account for dependencies. These three events represent operator failure to initiate ADS following failure of ECCS initiation, failure to initiate ECCS, and failure to initiate early suppression pool cooling. Phase II SAMAs 28, 29, 46, 47, 52, 71, 73, and 77, to improve the probability of successful injection and depressurization, to improve reliability of ECCS auto-start features, and to improve suppression pool cooling were evaluated.
%TC	1.16E-01	1.102	Loss of condenser vacuum	This term represents the loss of condenser vacuum initiator. Phase II SAMAs 75 and 76, to reduce initiating event frequencies by implementing generation risk assessment and to prevent inadvertent MSIV closure, were evaluated.

Table E.1-3 (Continued)
Correlation of Level 1 Risk-Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
%S2-WA	3.59E-03	1.102	Small break LOCA, below core inside drywell	This term represents an initiating event caused by a small break LOCA below the core inside of the drywell. Phase II SAMAs 22, 23, 24, 25, 28, 32, 67, and 78, to enhance high or low pressure injection systems and reduce the core damage frequency contribution from a LOCA, were evaluated.
SWS-XHE-FO-WNDML	1.00E+00	1.102	Operator does not use RHRSW without a SWBP (windmilling)	This term represents operator failure to use the RHRSW without a SWBP even though it has this capability. Phase II SAMA 79, to modify procedures to enhance the probability that the operator will use RHRSW without a SWBP, was evaluated.
FPS-XHE-FO-RHR25A	1.00E+00	1.095	Operator fails to manually open RHR-MO-25A locally	This term represents operator failure to manually open RHR-MO-25A which leads to a failure of fire water for RPV injection. Phase II SAMA 78, to improve training on alternate injection via the fire water system, was evaluated.
%MS	1.44E+00	1.086	Manual shutdown	This term represents the manual shutdown initiating event. Phase II SAMA 75, to reduce initiating event frequencies by implementing generation risk assessment, was evaluated.
ADS-XHE-FO-TRANS	3.90E-04	1.078	Operator failure to depressurize with SRVs	This term represents operator failure to depressurize with the safety relief valves following a transient. Phase I SAMAs to improve plant procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 26, 27, 43, and 44, to improve SRV availability and reliability, were evaluated.
EAC-ACB-CF-1F&G	2.64E-07	1.077	Common cause failure of 4160V AC buses 1F & 1G	This term represents common cause failure of 4160V AC buses 1F and 1G. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.

Table E.1-3 (Continued)
Correlation of Level 1 Risk-Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
%LOOP	1.86E-02	1.076	Loss of offsite power	This term represents the loss of offsite power initiating event. Phase I SAMAs to improve station blackout procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
NBI-PIS-TM-PS52D	8.47E-03	1.071	Test or maintenance of PS-52D	This term represents pressure switch PS-52D unavailable due to testing or maintenance, impacting initiation of core spray and RHR. Phase II SAMAs 28, 29 and 47, to enhance low pressure system availability and reliability, were evaluated.
%TSW	2.08E-04	1.069	Loss of service water	This term represents the initiating event of a complete loss of the service water system. Enhancements to prevent or mitigate loss of service water system components were evaluated in Phase II SAMAs 30 and 31. Phase II SAMA 75, to reduce initiating event frequencies by implementing generation risk assessment, was also evaluated.
%TT	7.30E-01	1.066	Turbine trip	This term represents the turbine trip initiating event. Phase II SAMA 75, to reduce initiating event frequencies by implementing generation risk assessment, was evaluated.
NBI-PIS-TM-P52B	7.32E-03	1.06	Test or maintenance of PS-52B (6.2CSCS.303)	This term represents pressure switch PS-52B unavailable due to testing or maintenance, impacting initiation of core spray and RHR. Phase II SAMAs 28, 29 and 47, to enhance low pressure system availability and reliability, were evaluated.

Table E.1-3 (Continued)
Correlation of Level 1 Risk-Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
PCI-CNT-FF-PREEX	2.70E-03	1.056	Pre-existing containment failure	This term represents a pre-existing containment failure leading to loss of NPSH to the ECCS pumps. Phase II SAMAs 22, 28, 46, and 47, providing independent or passive high and low pressure systems, were evaluated.
OSP-SYS-LP-LOCA	2.40E-02	1.054	Conditional probability of LOOP (LOCA signal)	This term represents the conditional probability that offsite power is lost as the result of a transient which also causes ECCS actuation. Phase I SAMAs to improve station blackout procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
SPC-XHE-FO-RCVR	4.80E-01	1.054	Failure to recover/repair SPC before vent (transient/ IORV)	This term represents failure to recover suppression pool cooling before venting during a transient. Phase II SAMAs 30, 46, 71, and 73 to improve suppression pool cooling, were evaluated.
FPS-XHE-FO-RPVIN	1.00E-01	1.049	Operator fails to align fire protection system for RHR loop A injection	This term represents operator failure to align the fire protection system for RHR loop A injection. Phase II SAMA 78, to improve training on alternate injection via the fire water system, was evaluated.
SWS-XHE-FO-SWBPS	7.70E-03	1.049	Human error failure to manually initiate service water booster pump system	This term represents human failure to manually initiate the service water booster pump system. Phase II SAMA 79, to modify procedures to enhance the probability that the operator will use RHRSW without a SWBP, was evaluated.

Table E.1-3 (Continued)
Correlation of Level 1 Risk-Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
%TIA	8.84E-03	1.048	Loss of instrument air	This term represents an initiating event caused by loss of the instrument air system. Phase II SAMAs 41, 42, 45, to improve the availability and reliability of the instrument air system, were evaluated. Phase II SAMA 75, to reduce initiating event frequencies by implementing generation risk assessment, was also evaluated.
DEP-XHE-FO-ERLY7	2.20E-05	1.046	Operator fails to initiate ADS & bypass HPCI high temperature trip	This term represents the combination of human failure events ADS-XHE-FO-TRANS and HCI-XHE-FO-BYPTP to account for dependencies. These basic events represent operator failure to depressurize with the safety relief valves following a transient and failure to bypass the HPCI high temperature trip. Phase II SAMAs 22, 23, 26, 27, 43, and 44, to improve SRV availability and reliability and to provide additional high pressure injection, were evaluated.
NBI-XHE-CF-PS52	8.00E-05	1.046	Common cause failure to restore PS52A2 and PIS52B or PS52C2 and PIS52D	This term represents common cause failure to restore PS52A2 and PIS52B or PS52C2 and PIS52D, impacting initiation of core spray and RHR. Phase II SAMAs 28, 29 and 47, to enhance low pressure system availability and reliability, were evaluated.
ADS-XHE-FO-COND	1.40E-01	1.045	Conditional probability of moderate dependence between injection initiation & depressurization	This term represents the probability of moderate dependence between injection initiation failure and operator failure to initiate ADS. Phase II SAMAs 28, 29, 47, 52, and 77, to improve the probability of successful injection and depressurization, were evaluated.
%TDC	7.88E-07	1.044	Loss of both DC buses	This term represents the loss of both DC buses initiating event. Phase II SAMAs 1, 2, 3, 13, 14, 15, 19, and 21 for enhancing DC system availability and reliability were evaluated.

Table E.1-3 (Continued)
Correlation of Level 1 Risk-Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
EDC-XHE-FO-RSTR	5.00E-01	1.044	Failure to restore a single DC bus within 30 min. (data based)	This term represents operator failure to restore a single DC bus within 30 minutes when both DC buses fail. Phase II SAMAs 1, 2, 3, 13, 14, 15, 19, and 21 for enhancing DC system availability and reliability were evaluated.
LOOP-IE-SW	2.10E-01	1.043	Conditional probability due to weather related LOOP event	This term represents the conditional probability of a weather related LOOP event. Phase I SAMAs to improve station blackout procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
HCI-TDP-SS-TP	1.30E-02	1.038	Standby turbine driven pump HPCI-P-MP fails to start	This term represents random failure of the standby turbine driven pump to start. Phase II SAMAs 22, 23, 67, and 77, to enhance high pressure injection, were evaluated.
PCV-XHE-FO-233MV	1.00E-01	1.035	Operator fails to manually open PC-MOV-233MV on loss of electrical power	This term represents operator failure to manually open torus vent valve PC-MOV-233MV on loss of electrical power. Phase II SAMA 20, to provide redundant power to the direct torus vent valves, was evaluated.
EAC-XHE-FO-MCCRA	1.00E+00	1.035	Operator fails to switch MCC-RA to alternate power source	This term represents operator failure to switch MCC-RA to an alternate power source. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
HVC-PHE-FF-CB7A	1.00E+00	1.034	Phenomenological requirement for CB7A HVAC	This term represents the phenomenological HVAC requirement for CB7A which affects the SW booster pumps. Phase II SAMA 35, to provide a redundant train of ventilation, was evaluated.

Table E.1-3 (Continued)
Correlation of Level 1 Risk-Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
HVC-XHE-FO-CB7A	2.40E-02	1.034	Operator fails to provide alternative cooling to CB basement (RHRSWBP)	This term represents operator failure to provide alternative cooling to the control building basement which affects the SW booster pumps. Phase II SAMA 35, to provide a redundant train of ventilation, was evaluated.
EAC-DGN-TM-DG2	1.97E-02	1.034	Diesel generator DG2 unavailable due to maintenance	This term represents diesel generator DG2 being unavailable due to maintenance. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
EAC-TRN-TM-SU	6.30E-03	1.034	Test or maintenance unavailability of startup service transformer	This term represents the startup service transformer unavailable due to testing or maintenance. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
OSPR30MIN-GR	8.25E-01	1.031	Failure to recover OSP within 30 minutes (grid related LOOP event)	This term represents operator failure to recover a grid related LOOP event within 30 minutes. Phase I SAMAs to improve station blackout procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
RCI-TDP-SS-TP	1.30E-02	1.031	Standby turbine driven pump RCIC-P-MP fails to start	This term represents random failure of the standby turbine driven RCIC pump to start. Phase II SAMAs 22, 23, 24, 25, 67, and 77, to enhance high pressure injection, were evaluated.

Table E.1-3 (Continued)
Correlation of Level 1 Risk-Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
HCI-SYS-TM-HPCI	1.15E-02	1.03	HPCI unavailable due to test and maintenance	This term represents HPCI unavailability during testing or maintenance. Phase I SAMAs to improve availability and reliability of the HPCI system that have already been implemented include raising backpressure trip set points and proceduralizing intermittent operation. Additional improvements for the HPCI system were evaluated in Phase II SAMAs 22, 23, 67, and 77.
DFP-FAIL-NOT	7.50E-01	1.029	DFP successful	This term represents successful injection via the diesel fire pump. Sequences containing this event fail due to loss of DC power. Phase II SAMAs 1, 2, 3, 13, 14, 15, 19, and 21, for enhancing DC system availability and reliability, were evaluated.
DEP-XHE-FO-ERLY4	2.10E-05	1.029	Operator fails to initiate ADS & control HPCI to prevent level 8 trip	This term represents the combination of human failure events ADS-XHE-FO-TRANS and HCI-XHE-FO-LVL8 to account for dependencies. These basic events represent operator failure to depressurize with the safety relief valves following a transient and failure to control HPCI to prevent reaching the high level trip. Phase II SAMAs 22, 23, 26, 27, 43, and 44, to improve SRV availability and reliability and to provide additional high pressure injection, were evaluated.
%TM	3.46E-02	1.028	MSIV closure	This term represents an initiating event caused by MSIV closure. A Phase I SAMA to develop procedures to re-open MSIVs is already in place. Phase II SAMAs 27, 44, and 75, to improve SRV and MSIV availability and reliability and to reduce initiating event frequencies by implementing generation risk assessment, were evaluated.
RHR-MDP-TM-RHRD	7.38E-03	1.027	Test or maintenance unavailability: RHR pump D	This term represents unavailability of RHR pump D due to testing and maintenance. Phase II SAMAs 30, 46, and 73, to improve suppression pool cooling, were evaluated.

Table E.1-3 (Continued)
Correlation of Level 1 Risk-Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
RPS-SYS-CF-MECH	2.10E-06	1.027	CCF of RPS mechanical scram components	This term represents common cause failure of RPS mechanical scram components, which leads to failure to scram. Phase II SAMA 44, to improve SRV and MSIV availability and reliability, was evaluated.
RCI-SYS-TM-RCIC	1.25E-02	1.026	RCIC unavailable due to test or maintenance	This term represents RCIC unavailable due to testing or maintenance. Phase I SAMAs to improve availability and reliability of the RCIC system that have already been implemented include proceduralizing intermittent operation and manual initiation of HPCI and RCIC given auto initiation failure. Additional improvements for the RCIC system were evaluated in Phase II SAMAs 22, 23, 24, 25, 67 and 77.
SWS-MDP-TM-SWPB	1.62E-02	1.026	Test or maintenance unavailability: SW pump B	This term represents the unavailability of SW pump B due to testing or maintenance. Enhancements to prevent or mitigate loss of service water system components were evaluated in Phase II SAMAs 30 and 31.
SWS-MDP-TM-SWPD	1.62E-02	1.026	Test or maintenance unavailability: SW pump D	This term represents the unavailability of SW pump D due to testing or maintenance. Enhancements to prevent or mitigate loss of service water system components were evaluated in Phase II SAMAs 30 and 31.
ECS-XHE-FO-TRANS	3.30E-04	1.025	Manual ECCS initiation with a transient	This term represents operator failure to manually initiate ECCS following a transient and ECCS auto-start failure. Phase II SAMA 77, to improve reliability of ECCS auto-start features, was evaluated.
EAC-DGN-TM-DG1	1.45E-02	1.022	Diesel generator DG1 unavailable due to maintenance	This term represents EDG DG-1 unavailable due to maintenance. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.

Table E.1-3 (Continued)
Correlation of Level 1 Risk-Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
DEP-XHE-FO-SPTDV	5.00E-07	1.021	Operating staff fails to initiate both SPC and torus drywell vent	This term represents operator failure to initiate both SPC and the torus drywell vent. Phase II SAMAs 46, 52, and 73, providing independent suppression pool cooling and passive overpressure relief and maintaining a lower normal suppression pool temperature, were evaluated.
%TDCB	5.25E-04	1.02	Loss of 125 VDC B	This term represents an initiating event caused by loss of 125VDC bus B. Phase II SAMAs 1, 2, 3, 13, 14, 15, 19, and 21 for enhancing DC system availability and reliability were evaluated.
EDC-XHE-FO-RSTRB	7.10E-01	1.02	Failure to restore DC power within 30 min. (data based)	This term represents operator failure to restore DC power in train B within 30 min. when DC power has been lost. Phase II SAMAs 1, 2, 3, 13, 14, 15, 19, and 21 for enhancing DC system availability and reliability were evaluated.
NBI-XHE-MC-P52B	1.70E-03	1.02	Human error: miscalibration of pressure switch PS-52B	This term represents miscalibration of pressure switch PS-52B, impacting initiation of core spray and RHR. Phase II SAMAs 28, 29 and 47, to enhance low pressure system availability and reliability, were evaluated.
NBI-XHE-MC-P52D	1.70E-03	1.02	Human error: miscalibration of pressure switch PS-52D	This term represents miscalibration of pressure switch PS-52D, impacting initiation of core spray and RHR. Phase II SAMAs 28, 29 and 47, to enhance low pressure system availability and reliability, were evaluated.

Table E.1-3 (Continued)
Correlation of Level 1 Risk-Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
NBI-ACT-TM-RCIC	8.20E-03	1.019	Test or maintenance unavailability: RCIC actuation relays	This term represents RCIC actuation relays unavailable due to testing or maintenance which prevents RCIC initiation. Phase I SAMAs to improve availability and reliability of the RCIC system that have already been implemented include proceduralizing intermittent operation and manual initiation of HPCI and RCIC given auto initiation failure. Additional improvements for the RCIC system were evaluated in Phase II SAMAs 22, 23 and 77.
OSPR65HR-SW	2.93E-01	1.019	Failure to recover OSP within 6.5 hrs (weather related LOOP event)	This term represents operator failure to recover a weather related LOOP event within 6.5 hours. Phase I SAMAs to improve station blackout procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
%TACF	1.28E-03	1.019	Loss of 4160 VAC F	This term represents an initiating event caused by loss of 4160V AC bus 1F. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
OSPR65HR-GR	7.08E-02	1.018	Failure to recover OSP within 6.5 hrs (grid related LOOP event)	This term represents operator failure to recover a grid related LOOP event within 6.5 hours. Phase I SAMAs to improve station blackout procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.

Table E.1-3 (Continued)
Correlation of Level 1 Risk-Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
ACP-XHE-FO-11HR	2.26E-01	1.017	Onsite AC power not recovered within 11.5 hrs (data based)	This term represents failure to recover onsite AC power within 11.5 hours. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
ADS-SRV-CF-ADSRV	7.40E-05	1.017	Common cause failure of a sufficient number of safety relief valves	This term represents common cause failure of a sufficient number of SRVs to cause failure of the ADS system. Phase II SAMAs 26, 43, and 44, to improve SRV availability and reliability, were evaluated.
EAC-TRN-TM-E	1.00E-02	1.017	Test or maintenance unavailability of emergency service transformer	This term represents the emergency service transformer being in testing or maintenance. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
%S2-ST	2.88E-03	1.016	Small break LOCA, above core inside drywell	This term represents an initiating event caused by a small break LOCA above the core inside the drywell. Phase II SAMAs 22, 23, 24, 25, 28, 32, 67, and 78, to enhance high or low pressure injection systems and reduce the core damage frequency contribution from a LOCA, were evaluated.
PCS-MDP-CF-TRIP	1.00E-02	1.016	Common cause trip of circulating water pumps	This term represents common cause trip of the circulating water pumps, resulting in failure to remove heat from the reactor. SAMAs that improve suppression pool cooling will help mitigate this event. Phase II SAMAs 46, 71, and 73, to improve suppression pool cooling, were evaluated.

Table E.1-3 (Continued)
Correlation of Level 1 Risk-Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
OSPR11HR-SW	2.03E-01	1.016	Failure to recover OSP within 11 hrs (weather related loop event)	This term represents operator failure to recover a weather related LOOP event within 11 hours. Phase I SAMAs to improve station blackout procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
ACP-XHE-FO-65HR	3.53E-01	1.016	Onsite AC power not recovered within 6.5 hrs (data based)	This term represents failure to recover onsite AC power within 6.5 hours. Phase I SAMAs to improve station blackout procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
HVC-PHE-FF-RHRQD	1.00E+00	1.015	Phenomenological room cooling requirement for quads	This term represents the phenomenological room cooling requirement for the quads. Phase II SAMA 35, to provide a redundant train of ventilation, was evaluated.
HVC-XHE-FO-ALTQC	4.30E-03	1.015	Operator fails to initiate alternate room cooling	This term represents operator failure to initiate alternate room cooling to the quads when needed. Phase II SAMA 35, to provide a redundant train of ventilation, was evaluated.
RPT-PIP-RP-SEALL	5.00E-02	1.015	Conditional probability of large recirc seal LOCA given SBO	This term represents the conditional probability of a large recirc seal LOCA given that a SBO has occurred. Phase II SAMAs 24 and 25, to extend HPCI/RCIC operation, were evaluated.
RHR-XHE-FO-RHRE	4.50E-03	1.015	Operator action: initiate SPC (early)	This term represents failure to initiate early suppression pool cooling. Phase II SAMAs 30, 46, 71, and 73, to improve suppression pool cooling, were evaluated.

Table E.1-3 (Continued)
Correlation of Level 1 Risk-Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
LOOP-IE-GR	2.93E-01	1.015	Conditional probability LOOP due to grid related event	This term represents the conditional probability of a grid related LOOP event. Phase I SAMAs to improve station blackout procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
%FLSWCB7AM	5.06E-05	1.014	Moderate SW pipe rupture in the control bldg. basement (comp 7A)	This term represents the moderate SW pipe rupture in the control building basement initiator. Phase II SAMA 62, to improve internal flooding procedures, was evaluated along with SAMA 30 to help mitigate loss of service water.
ACP-XHE-FO-NONE	1.00E+00	1.014	No onsite AC power recovery	This term represents no onsite AC power recovery. This basic event is used to keep on-site AC power recoveries from being applied to cutsets when there is an EDG available. Since this term does not represent a component failure, no Phase II SAMAs were evaluated.
OSPR11HR-GR	2.22E-02	1.014	Failure to recover OSP within 11 hrs (grid related loop event)	This term represents operator failure to recover a grid related LOOP event within 11 hours. Phase I SAMAs to improve station blackout procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
HCI-HOV-CC-HO10	4.86E-03	1.013	Normally closed hydraulic operated valve HO10 fails closed	This term represents random failure of normally closed hydraulic operated valve HO10 which causes a failure of the turbine driven pump. Phase II SAMAs 22 and 23 were evaluated to add additional high pressure injection systems.

Table E.1-3 (Continued)
Correlation of Level 1 Risk-Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
IAS-XHE-FO-COOL	1.60E-01	1.013	Human error failure to align emergency compressor cooling	This term represents human error failure to align emergency air compressor cooling. Phase II SAMAs 42 and 45, to upgrade air compressors and to add a portable air compressor, were evaluated.
ADS-SRV-OO-RECLF	1.50E-01	1.012	SRVs fail to re-close on reduced pressure	This term represents failure of the SRVs to re-close on reduced pressure. Phase II SAMA 44, to improve SRV and MSIV pneumatic components, was evaluated.
PCV-XHE-FO-AOV	1.00E-01	1.012	Human error: fail to locally open HPV AOVs, PC-AOV-237AV and PC-AOV-32AV.	This term represents failure to locally open hard pipe vent AOVs, PC-AOV-237AV and PC-AOV-32AV, which results in failure to depressurize. Phase II SAMAs 41, 42, and 45, to improve the availability and reliability of the instrument air system, and Phase II SAMA 20, to provide redundant power to the hard pipe vent valves, were evaluated.
IAS-XHE-FO-CST	3.10E-01	1.012	Operator fails to isolate CST from the hotwell	This term represents operator failure to isolate the CST from the hotwell which allows the CST to drain to the hotwell. Phase II SAMA 72, to prevent drain-down of the CST to the hotwell, was evaluated.
FPS-XHE-FO-DFPAL	1.00E-01	1.012	Crew fails to align DFP under SBO conditions (> 2 hrs. available)	This term represents operator failure to align the DFP under SBO conditions for injection when greater than 2 hours is available. Phase II SAMA 78, to improve training on alternate injection via the fire water system, was evaluated.
LOOP-IE-SWYD	4.03E-01	1.012	Conditional probability LOOP due to switchyard event	This term represents the conditional probability of a switchyard centered LOOP event. Phase I SAMAs to improve station blackout procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.

Table E.1-3 (Continued)
Correlation of Level 1 Risk-Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
RHR-HTX-TM-HXB	8.12E-03	1.011	Test or maintenance unavailability: RHR heat exchanger B	This term represents unavailability of RHR heat exchanger B due to testing or maintenance. Phase II SAMAs 30, 46, and 73, to improve suppression pool cooling, were evaluated.
RHR-MDP-TM-RHRA	9.49E-03	1.011	Test or maintenance unavailability: RHR pump A	This term represents unavailability of RHR pump A due to testing or maintenance. Phase II SAMAs 30, 46, and 73, to improve suppression pool cooling, were evaluated.
%TRLA	2.24E-03	1.011	Reactor water reference leg 3A line break	This term represents a reactor water reference leg 3A line break initiating event. Phase II SAMA 80, to install additional instrumentation to assist in identifying a reference leg leak-down, was evaluated.
FPS-XHE-FO-RBENV	1.00E+00	1.011	RB local access for alignment unavailable	This term represents the probability that reactor building local access for alignment of injection from the fire water system is unavailable due to adverse conditions. Phase II SAMAs 22, 23, 24, 25, 28, 32, 67, and 78, to enhance high or low pressure injection systems, were evaluated.
NBI-XHE-MC-P52C2	1.70E-03	1.01	Human error miscalibration of pressure switch PS-52C2	This term represents miscalibration of pressure switch PS-52C2, impacting initiation of core spray and RHR. Phase II SAMAs 28, 29 and 47, to enhance low pressure system availability and reliability, were evaluated.
NBI-PIS-TM-P52A2	7.32E-03	1.01	Test or maintenance of PS-52A2 (6.1CSCS.303)	This term represents pressure switch PS-52A2 unavailable due to testing or maintenance, impacting initiation of core spray and RHR. Phase II SAMAs 28, 29 and 47, to enhance low pressure system availability and reliability, were evaluated.
NBI-PIS-TM-P52C2	7.32E-03	1.01	Test or maintenance of PS-52C2 (6.1CSCS.303)	This term represents pressure switch PS-52C2 unavailable due to testing or maintenance, impacting initiation of core spray and RHR. Phase II SAMAs 28, 29 and 47, to enhance low pressure system availability and reliability, were evaluated.

Table E.1-3 (Continued)
Correlation of Level 1 Risk-Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
NBI-LIS-TM-101A	8.20E-03	1.009	Test or maintenance of reactor level switch NBI-LIS-101A (6.1RPS.307)	This term represents reactor level switch NBI-LIS-101A unavailable due to testing or maintenance. This causes failure of RCIC to trip on high reactor water level. Phase I SAMAs to improve availability and reliability of the RCIC system that have already been implemented include proceduralizing intermittent operation and manual initiation of HPCI and RCIC given auto initiation failure. Additional improvements were evaluated in Phase II SAMAs 22 and 23.
NBI-LIS-TM-101C	8.20E-03	1.009	Test or maintenance of reactor level switch NBI-LIS-101C (6.1RPS.307)	This term represents reactor level switch NBI-LIS-101C unavailable due to testing or maintenance. This causes failure of RCIC to trip on high reactor water level. Phase I SAMAs to improve availability and reliability of the RCIC system that have already been implemented include proceduralizing intermittent operation and manual initiation of HPCI and RCIC given auto initiation failure. Additional improvements were evaluated in Phase II SAMAs 22 and 23.
SPC-SYS-TM-TRNB	8.95E-03	1.009	Test or maintenance of SPC train B equipment	This term represents test or maintenance of the SPC train B equipment. Phase II SAMAs 30, 46, 71, and 73, to improve suppression pool cooling, were evaluated.
DEP-XHE-FO-ERLYA	7.85E-06	1.009	Operator fails to initiate ADS, ECCS, RHR (early) and control HPCI to prevent level 8 trip	This term represents the combination of human failure events ADS-XHE-FO-COND, ECS-XHE-FO-TRANS and HCI-XHE-FO-LVL8 to account for dependencies. These three events represent operator failure to initiate ADS following failure of ECCS initiation, failure to initiate ECCS, and failure to control HPCI to prevent reaching the high level trip. Phase II SAMAs 22, 23, 28, 29, 47, 52, and 77, to improve the probability of successful injection and depressurization, to improve reliability of ECCS auto-start features, and to provide additional high pressure injection, were evaluated.

Table E.1-3 (Continued)
Correlation of Level 1 Risk-Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
PCS-SYS-RP-DWFAIL	4.30E-01	1.009	Large drywell containment failure causes loss of injection	This term represents a large drywell containment failure causing a loss of injection. Phase II SAMAs 22, 23, 28, and 46, to improve the probability of successful injection and depressurization, were evaluated.
NBI-XHE-MC-P52A2	1.70E-03	1.009	Human error miscalibration of pressure switch PS-52A2	This term represents miscalibration of pressure switch PS-52A2, impacting initiation of core spray and RHR. Phase II SAMAs 28, 29 and 47, to enhance low pressure system availability and reliability, were evaluated.
FPS-XHE-FO-DISEL	1.90E-02	1.009	No fuel oil makeup provided within 8 hours	This term represents operator failure to make-up fuel oil to diesel fire pump 1D within 8 hours. Phase II SAMA 78, to improve training on alternate injection via the fire water system, was evaluated.
ADS-SRV-CO-ISOL	5.40E-02	1.009	Probability of SORV for isolation initiators	This term represents the probability of a stuck open relief valve following a loss of offsite power or a non-turbine trip transient initiator. Phase II SAMA 44, to improve SRV and MSIV pneumatic components, was evaluated.
RCI-TDP-SR-TP24	4.25E-03	1.009	Standby turbine driven pump RCIC-P-MP fails to continue running (24 hrs)	This term represents random failure of the standby turbine driven RCIC pump to continue to run. Phase II SAMAs 22, 23, 24, 25, and 67, to enhance high pressure injection, were evaluated.
HCI-TDP-SR-TP24	4.25E-03	1.008	Standby turbine driven pump HPCI-P-MP fails to continue running (24 hrs)	This term represents random failure of the standby turbine driven pump to continue to run. Phase II SAMAs 22, 23, and 67, to enhance high pressure injection, were evaluated.
HVC-ACU-FS-DG_1C	2.63E-03	1.008	DG1 room air cooling unit HV-DG-1C fails to start	This term represents random failure of DG1 room air cooling unit HV-DG-1C. Phase II SAMAs 36, 38, 39, and 40, to enhance diesel room HVAC, were evaluated.

Table E.1-3 (Continued)
Correlation of Level 1 Risk-Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
NBI-LIS-TM-101B	6.71E-03	1.008	Test or maintenance of reactor level switch NBI-LIS-101B (6.2RPS.307)	This term represents the reactor level sensor NBI-LIS-101B unavailable due to testing or maintenance. This leads to failure of HPCI to trip on high reactor water level. Phase I SAMAs to improve availability and reliability of the HPCI system that have already been implemented include proceduralizing intermittent operation and manual initiation of HPCI and RCIC given auto initiation failure. Additional improvements were evaluated in Phase II SAMAs 22 and 23.
NBI-LIS-TM-101D	6.71E-03	1.008	Test or maintenance of reactor level switch NBI-LIS-101D (6.2RPS.307)	This term represents the reactor level sensor NBI-LIS-101D unavailable due to testing or maintenance. This leads to failure of HPCI to trip on high reactor water level. Phase I SAMAs to improve availability and reliability of the HPCI system that have already been implemented include proceduralizing intermittent operation and manual initiation of HPCI and RCIC given auto initiation failure. Additional improvements were evaluated in Phase II SAMAs 22 and 23.
EAC-CRB-CC-1FS	2.55E-03	1.008	Normally closed circuit breaker 1FS fails to open	This term represents failure of circuit breaker 1FS to open. This leads to no power to bus 1F from diesel generator DG1. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
SLC-SYS-FF-SUCCE	7.32E-01	1.007	Early SLC success	This term represents early SLC success. Phase II SAMA 58, 59, 60, and 61 for enhancing ATWS mitigation capabilities, were evaluated.
HVC-ACU-FS-DG_1D	2.63E-03	1.007	DG2 room air cooling unit HV-DG-1D fails to start	This term represents random failure of DG2 room air cooling unit HV-DG-1D. Phase II SAMAs 36, 38, 39, and 40, to enhance diesel room HVAC, were evaluated.

Table E.1-3 (Continued)
Correlation of Level 1 Risk-Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
EDC-DCB-LP-125A	9.19E-06	1.007	125V DC bus 1A failure	This term represents loss of 125V DC bus 1A. Phase II SAMAs 1, 2, 3, 13, 14, 15, 19, and 21 for enhancing DC system availability and reliability were evaluated.
EAC-CRB-CC-1GS	2.55E-03	1.007	Normally closed circuit breaker 1GS fails to open	This term represents failure of circuit breaker 1GS to open. This leads to no power to bus 1G from diesel generator DG2. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
ADS-XHE-FO-3ALEG	9.50E-03	1.007	Failure of cognitive recognition of leakdown	This term represents the failure of cognitive recognition of leakdown after a reference leg break. Phase II SAMA 80, to install additional instrumentation to assist in identifying a reference leg leak-down, was evaluated.
OSP-SYS-LP-TRANS	2.40E-03	1.006	Transient induced LOOP	This term represents the transient induced LOOP event. Phase I SAMAs to improve station blackout procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21 for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
%S1-WA	1.77E-04	1.006	Other medium break LOCA, below core	This term represents an initiating event caused by a medium break LOCA below the core but not in the LPCI line or drywell. Phase II SAMAs 22, 23, 24, 25, 28, 32, 67 and 78, to enhance high or low pressure injection systems and reduce the core damage frequency contribution from a LOCA, were evaluated.

Table E.1-3 (Continued)
Correlation of Level 1 Risk-Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
HCI-XHE-FO-BYPTP	5.40E-03	1.006	Failure to bypass HPCI high temperature trip	This term represents failure to bypass the HPCI high temperature trip. Phase II SAMAs 22 and 23, to provide additional high pressure injection, were evaluated.
%TACG	1.28E-03	1.006	Loss of 4160 VAC G	This term represents the loss of 4160 VAC bus G initiating event. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
ADS-XHE-FO-S2W	4.70E-04	1.006	Operator failure to depressurize with SRVs (small water LOCA)	This term represents operator failure to depressurize with the SRVs following a small break LOCA below the core inside of the drywell. Phase I SAMAs to improve plant procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 26, 27, and 43, to improve SRV availability and reliability, were evaluated.
ALT-PHE-FF-BOCIN	1.00E+00	1.006	Alternate low pressure injection unavailable	This term represents unavailability of the alternate low pressure injection system (not including CS/LPCI). Phase II SAMAs 28, 29, 30, 32, and 78, to enhance alternate injection methods, were evaluated.
RHR-XHE-MC-TRIPD	1.70E-03	1.006	Miscalibration failure of position switches causes RHR pump D to trip	This term represents miscalibration of position switches causing RHR pump D to trip. Phase II SAMAs 30, 46, and 73, to improve suppression pool cooling, were evaluated.
%S1-LP	1.52E-04	1.006	Medium break LOCA, below core in LPCI line	This term represents an initiating event caused by a medium break LOCA below the core in the LPCI line. Phase II SAMAs 22, 23, 24, 25, 28, 32, 67, and 78, to enhance high or low pressure injection systems and reduce the core damage frequency contribution from a LOCA, were evaluated.

Table E.1-3 (Continued)
Correlation of Level 1 Risk-Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
SWS-XHE-FO-SWPS	1.40E-02	1.006	Operator fails to start SW pump following LOSP	This term represents operator failure to start the SW pump following a LOSP. Phase II SAMAs 9 and 12, were evaluated to reduce the likelihood of a LOSP.
%FLSWRBM	1.43E-04	1.006	Moderate SW rupture (RB-859' or above)	This term represents the moderate SW pipe rupture in the RB 859' or above initiating event. Phase II SAMA 62, to improve internal flooding procedures was evaluated, along with SAMA 30 to help mitigate loss of service water.
LCS-XHE-FO-BOCL8	2.00E-01	1.006	Operator controls level given a BOC	This term represents operator failure to control level given a break outside containment. Phase II SAMA 28, to add a diverse low pressure injection system, was evaluated.
EAC-DGN-FR-DG1	1.91E-03	1.006	Diesel generator DG1 fails to continue running	This term represents random failure of emergency diesel generator DG-1 to continue to run. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
ADS-XHE-FO-ADSHP	4.90E-02	1.005	Failure to inhibit ADS with HPCI injecting	This term represents operator failure to inhibit ADS when HPCI is injecting. Phase II SAMA 44, to improve SRV and MSIV pneumatic components to reduce the likelihood of a stuck-open relief valve, was evaluated.
ADS-XHE-FO-RFLEG	3.50E-02	1.005	Failure of cognitive recognition of the leakdown given both	This term represents operator failure to recognize that both reactor water reference legs have failed. Phase II SAMA 80, to install additional instrumentation to assist in identifying a reference leg leak-down, was evaluated.

Table E.1-3 (Continued)
Correlation of Level 1 Risk-Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
%A-ST	1.60E-05	1.005	Large break LOCA, above top of the active fuel	This term represents the initiating event of a large break LOCA above the top of the active fuel. Phase II SAMA 66, to install a digital large break LOCA protection system, was evaluated.
RHR-XHE-FO-ISRPF	9.50E-01	1.005	Operator fails to isolate ISLOCA (pipe rupture)	This term represents operator failure to isolate the ISLOCA pipe rupture. Phase II SAMAs 54, 56, and 57, to improve ISLOCA identification and mitigation, were evaluated.
HVC-FAN-FS-DG_1A	1.79E-03	1.005	DG1 room exhaust fan EF-DG-1A fails to start	This term represents random failure of the DG1 room exhaust fan EF-DG-1A which leads to a failure of DG1. Phase II SAMAs 36, 38, 39, and 40, to enhance diesel room HVAC, were evaluated.
PCV-SYS-TM-VENT	2.43E-03	1.005	Test or maintenance of hard pipe vent system	This term represents unavailability of the hard pipe vent system due to testing or maintenance. Phase II SAMAs 50, 52 and 53 were evaluated for the hard pipe vent system.
SLC-XHE-FO-SLC1P	3.00E-02	1.005	Operator fails to initiate SLC with one pump in required time	This term represents operator failure to initiate SLC with one pump in the required time. Phase II SAMAs 58, 59, 60, and 61, for enhancing ATWS mitigation capabilities, were evaluated.
OSPR30MIN-SWYD	5.95E-01	1.005	Failure to recover OSP within 30 min. (switchyard centered event)	This term represents operator failure to recover a switchyard centered LOOP event within 30 minutes. Phase I SAMAs to improve station blackout procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21 for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.

Table E.1-3 (Continued)
Correlation of Level 1 Risk-Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
EAC-CRB-CF-1FLS	6.00E-03	1.005	4160V bus 1F load shed breaker independent failures (12 bkrs.)	This term represents 4160V bus 1F load shed breaker failure. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
EAC-DGN-FR-DG2	1.91E-03	1.005	Diesel generator DG2 fails to continue running	This term represents random failure of emergency diesel generator DG-2 to continue to run. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
ADS-XHE-FO-S2S	4.70E-04	1.005	Operator failure to depressurize with SRVs (small steam LOCA)	This term represents operator failure to depressurize with the SRVs following a small break LOCA above the core inside the drywell. Phase I SAMAs to improve plant procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 26, 27, and 43, to improve SRV availability and reliability, were evaluated.
EAC-CRB-CC-1AN	2.55E-03	1.005	Normally closed circuit breaker 1AN fails to open	This term represents random failure of circuit breaker 1AN to open. This leads to failure of fast transfer for division I power and loss of power from the startup service transformer. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
PCV-XHE-FO-HPV	1.90E-03	1.005	Operator fails to operate primary containment hard pipe vent system	This term represents operator failure to operate the primary containment hard pipe vent system. Phase II SAMAs 52 and 53 were evaluated for the hard pipe vent system.

Table E.1-3 (Continued)
Correlation of Level 1 Risk-Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
EAC-DGN-CF-DGR	5.39E-05	1.005	Common cause failure to run for diesel generators	This term represents common cause failure of both EDGs to continue to run. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 12, 13, 14, 15, 17, 18, 19, 20, and 21 for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
EDC-CHG-CF-125V	1.71E-06	1.005	Common cause failure of 125V DC chargers	This term represents common cause failure of the 125V DC chargers. Phase II SAMAs 1, 2, 3, 13, 14, 15, 19, and 21 for enhancing DC system availability and reliability were evaluated.
HVC-FAN-FS-DG_1B	1.79E-03	1.005	DG2 room exhaust fan EF-DG-1B fails to start	This term represents random failure of the DG2 room exhaust fan EF-DG-1B which leads to a failure of DG2. Phase II SAMAs 36, 38, 39, and 40, to enhance diesel room HVAC, were evaluated.
EAC-CRB-CF-1GLS	6.00E-03	1.005	4160V bus 1G load shed breaker independent failures (12 bkrs.)	This term represents 4160V bus 1G load shed breaker failure. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.

CDF Uncertainty

The uncertainty associated with CDF was estimated from the 2007TM model, Rev. 1. The ratio of the 95th percentile CDF to the mean is about 1.86. An uncertainty factor of 3 was conservatively selected to determine the "internal and external benefit with uncertainty" described in Section 4.21.5.4.

E.1.2 PSA Model – Level 2 Analysis

E.1.2.1 Containment Performance Analysis

The CNS Level 2 PSA model used for the SAMA analysis (2007TM model, Rev. 1) is the most recent internal events risk model, which is an updated version of the model used in the IPE. The Level 2 PSA model used for the SAMA analysis reflects the CNS operating configuration and design as of December 2007.

The CNS Level 2 model includes two types of considerations: (1) a deterministic analysis of the physical processes for a spectrum of severe accident progressions, and (2) a probabilistic analysis component in which the likelihood of the various outcomes are assessed. The deterministic analysis examines the response of the containment to the physical processes during a severe accident. This response is performed by

- utilization of the Modular Accident Analysis Program MAAP 4.0.5 code to simulate severe accidents that have been identified as dominant contributors to core damage in the Level 1 analysis, and

- reference calculation of several hydrodynamic and heat transfer phenomena that occur during the progression of severe accidents. Examples include debris coolability, pressure spikes due to ex-vessel steam explosions, scoping calculation of direct containment heating, molten debris filling the pedestal sump and flowing over the drywell floor, containment bypass, deflagration and detonation of hydrogen, thrust forces at reactor vessel failure, liner melt-through, and thermal attack of containment penetrations.

The Level 2 analysis examined the dominant accident sequences and the resulting plant damage states (PDS) defined in Level 1. The Level 1 analysis involves the assessment of those scenarios that could lead to core damage.

A full Level 2 model was developed for the 2007TM model and completed at the same time as the Level 1 model. The Level 2 model consists of containment event trees (CETs) with functional nodes that represent phenomenological events and containment protection system status. The nodes were quantified using subordinate trees and logic rules. A list of the CET functional nodes and descriptions, used for the Level 2 analysis is presented in Table E.1-4.

The Large Early Release Frequency (LERF) is an indicator of containment performance from the Level 2 results because the magnitude and timing of these releases provide the greatest potential for early health effects to the public. The frequency calculated is approximately 2.44E-6/ry. Figure E.1-1 and Figure E.1-2 summarize the Level 2 results.

LERF represents a fraction (~21%) of all release end states. Table E.1-5 provides a correlation between the Level 2 RRW risk significant events (severe accident phenomenon, initiating events, component failures and operator actions) down to 1.005 identified from the CNS 2007TM Revision 1 PSA LERF model and the SAMAs evaluated in Section E.2.

Table E.1-4
Notation and Definitions for CNS CET Functional Nodes Description

CET Functional Node	Success Criteria	Parameter Monitored for Success Determination
Containment Isolation (IS)	The success of the containment isolation node (IS) is satisfied if the containment penetrations that communicate between the drywell (or wetwell) atmosphere and the reactor building (or environment) are "closed and isolated." The criteria used to satisfy this requirement of "closed or isolated" is that no line, hatch, or penetration has an opening greater than 2 inches in diameter that communicates with the atmosphere outside of containment. This implies that all containment penetrations are adequately sealed and isolated during the entire accident progression until either (1) a safe stable state is reached, or (2) the accident conditions exceed the ultimate capability of containment as determined in the plant specific evaluation.	Failure size (> 2-inch dia.)
RPV Depressurization (OP)	This function questions whether the RPV is depressurized after core damage but before vessel breach. Success of this action would allow low pressure injection, if available, and would minimize the challenge to containment due to a high pressure RPV rupture. The functional success criterion for this node is defined as having the RPV depressurized (i.e., less than 100 psig) until core melt is arrested in-vessel or until the RPV is breached by debris attack. The success of the depressurization function for the RPV is similar to the criterion established in the Level 1 analysis, i.e., prior to core damage. However, there are additional phenomena (i.e., non-condensible gas generation contributing to a high containment pressure that prevents SRV operation, and potentially very high containment temperatures which could fail electrical and mechanical components of the SRVs) which can occur during the accident progression beyond core damage and pose further challenge to the operator's ability to depressurize the RPV.	RPV Pressure (< 100 psig)

Table E.1-4 (Continued)
Notation and Definitions for CNS CET Functional Nodes Description

CET Functional Node	Success Criteria	Parameter Monitored for Success Determination
RPV Depressurization (OP) (cont'd)	The success criterion is to depressurize the RPV to less than 100 psig. The success criteria, in terms of systems, is the following: • any single SRV(1) is opened, or • failure of the primary system due to high temperature during core melt progression,(2) or • a large or medium LOCA (NEDO-24708A). Other alternatives(3) may be available but are not credited in this analysis.	
Arrest Core Melt Progression In-vessel (RX)	In-vessel recovery or arrest of core melt progression addresses the ability of the operating staff to restore adequate core cooling from the time the end state of the Level 1 PRA occurs (i.e., core nodal temperature > 1800°F) until restoration of water injection make-up cannot prevent the breach of the RPV bottom head by debris. As part of the definition of success, it is also useful to define what constitutes failure to maintain the RPV intact. The two primary failure modes that have been identified in the literature include: • Local penetration seal failure due to debris heat up and local failure at welds • Creep rupture failure of the entire bottom head.	> 1/2 core relocation calculated by MAAP.

Table E.1-4 (Continued)
Notation and Definitions for CNS CET Functional Nodes Description

CET Functional Node	Success Criteria	Parameter Monitored for Success Determination
Arrest Core Melt Progression In-vessel (RX) (cont'd)	Preventing the core melt from progressing outside the reactor pressure vessel requires the timely introduction of water onto the debris and intact fuel assemblies. Both timing and system requirements must be defined as part of the success criteria. There are differences in-core melt progression models regarding the ability to recover adequate cooling under different circumstances. These vary from no credit for retention of debris in-vessel after core melting has begun (MAAP), to substantial credit for recovery even after debris has accumulated in the bottom head (MARCH). The best estimate success criteria used in this evaluation are based on the time available from the initiation of core degradation until just before substantial core relocation occurs. This typically is on the order of 30-40 minutes. This basis is documented in the success criteria discussion of the RX node in Appendix C. In terms of system requirements, coolant injection is assumed necessary to re-flood the RPV to above 1/3 core height. It is judged, based on deterministic calculations, that this can be accomplished using makeup systems (identified in the EOPs) with capability greater than approximately 1000 gpm.(4)	
Combustible Gas Venting (GV Node)	The functional success criterion at this node is that the containment vent and purge lines are opened to allow combustible gas mixtures to be removed from containment. The downward path of GV in the CET implies that combustible gas venting has not been initiated. Therefore, on the downward path either of two conditions may exist: • the containment is inerted,(5) or • a combustible gas mixture is present.	Vent opened.

Table E.1-4 (Continued)
Notation and Definitions for CNS CET Functional Nodes Description

CET Functional Node	Success Criteria	Parameter Monitored for Success Determination
Combustible Gas Venting (GV Node) (cont'd)	The probabilistic evaluation of these two states on the downward branch is treated in the Containment Remains Intact Early (CZ) node. Hydrogen combustion that could lead to containment failure is prevented by either of the following: • deinerted operation with no oxygen intrusion during the accident, or • combustible gas purging and venting through the purge and vent lines. If both of these success paths fail, the hydrogen deflagration or detonation is assumed to occur, resulting in containment failure. The location of the failure is assumed to be in the drywell head region and is classified as a large failure. <u>Failure</u> • Radionuclide release: Assumed High magnitude (conservative) • Containment Failure Location: Assumed DW Head (conservative) <u>Success</u> Radionuclide Release: Same as Drywell Vent	
Containment Remains Intact (CZ)	The functional success criteria for the containment intact node are that the containment retains its pressure capability and that no early containment failure modes compromise the containment integrity. The early containment failures modeled by the CZ node are characterized by phenomenological events (e.g., steam explosions, missile generation, direct containment heating) that are estimated to challenge containment integrity relatively quickly following core melt. Late containment failures, modeled in subsequent nodes, are characterized by extreme pressure and temperature conditions that develop slowly over the course of the accident due to inadequate	No energetic containment failure pressure < 178 psig.

Table E.1-4 (Continued)
Notation and Definitions for CNS CET Functional Nodes Description

CET Functional Node	Success Criteria	Parameter Monitored for Success Determination
Containment Remains Intact (CZ) (cont'd)	containment heat removal. Note that successful prevention of early containment failure does not necessarily preclude late containment failure. Therefore, successful prevention of early containment failure requires the following. • No direct containment heating (direct containment heating is precluded if the RPV is already depressurized). • No ex-vessel steam explosion. • No failure of vapor suppression (i.e., the suppression pool is not bypassed and no more than 1 drywell-to-wetwell vacuum breaker fails open). • No in-vessel steam explosion (in-vessel steam explosions are precluded if either the RPV is at high pressure, e.g., greater than 100 psig, or the core does not fragment into fine particles before dropping onto the bottom head). • No high pressure spike sufficient to cause containment failure occurs at the time of vessel melt-through (extreme pressure spikes are precluded if the RPV bottom head penetration fails locally or the RPV remains at low pressure). • No hydrogen deflagration or detonation (if the containment remains inert or effective combustible gas vent was operated successfully, then hydrogen detonation or deflagration is guaranteed not to occur). • No RPV blowdown from high pressure with the suppression pool temperature above 260°F. • No recriticality due to an unusual core configuration that may be achieved during the melt progression.	

Table E.1-4 (Continued)
Notation and Definitions for CNS CET Functional Nodes Description

CET Functional Node	Success Criteria	Parameter Monitored for Success Determination
Containment Remains Intact (CZ) (cont'd)	If these failure modes cannot be prevented, containment failure is assumed to occur. The failure location is assumed to be in the drywell head region and is classified as a large failure with no Reactor Building effectiveness.	
Injection Established to RPV or Drywell (SI)	Success at this node requires that water is available (greater than 1000 gpm) to the core debris at the time of vessel failure. Continuous water injection either directed into the failed RPV or into the drywell will provide for the following: • reduced likelihood for drywell shell failure, • mitigation of high drywell gas temperatures, • water overburden to scrub fission products resulting from possible core concrete interaction, and • potential for debris coolability. These are considered substantially mitigated if on a best estimate basis a continuous water supply is available to the debris with a flow rate of greater than 1000 gpm. The two active mitigation methods that may provide coolant injection to the debris bed include continued make-up to the RPV and initiation of drywell sprays. These effects would influence the integrity of containment. Note that inadequate water injection will be modeled for the purposes of consequence evaluation as inducing a drywell failure high in the containment.	Flow > 1000 gpm to the debris

Table E.1-4 (Continued)
Notation and Definitions for CNS CET Functional Nodes Description

CET Functional Node	Success Criteria	Parameter Monitored for Success Determination
Injection Established to RPV or Drywell (SI) (cont'd)	However, there are some models that indicate that concrete attack and non-condensible gas generation will not be terminated even if substantial water injection is available to the debris. The temperatures in the drywell will be acceptable, but continued non-condensible gas generation will occur. MAAP sensitivity analyses with minimum heat transfer between debris and water indicate this is not a LERF contributor. In addition, shell failure can occur relatively quickly (i.e., minutes) following RPV failure if water is not available to cool the core debris. It is assumed in the model that the core debris will come in contact with and fail the drywell shell if water is not available.	
Containment Flooding Initiated (FC)	Success at this node implies that the containment flooding contingency procedure has been initiated by the operating staff and that a system of adequate flow capacity from external sources is available to implement the procedure. In addition to these two requirements, the instrumentation must be available to initiate the flood operation. This node evaluates the possibility that the operator suspends containment flooding because the staff is unable to maintain containment conditions within prescribed limits described in the SAMGs. Success at FC includes drywell venting. Since it is presumed that containment pressurization will occur during the latter stage of flooding as a result of a diminishing drywell volume, the operator will be required to establish a drywell vent path (i.e., > 4 inch equivalent diameter).	External flow > 1000 gpm Vent > 6 inch dia.

Table E.1-4 (Continued)
Notation and Definitions for CNS CET Functional Nodes Description

CET Functional Node	Success Criteria	Parameter Monitored for Success Determination
Containment Flooding Initiated (FC) (cont'd)	Drywell venting can have varying degrees of releases associated with it depending on the following: • when in the containment flood process drywell venting is required, and • whether success of RHR suppression pool cooling and injection is effective in controlling containment pressure. Success at this juncture in the model is defined as the continuation of the flooding evolution with containment conditions remaining within the limits of the Primary Containment Pressure Limit (PCPL). MAAP calculations indicate that containment flooding through the RPV or drywell sprays results in a low radionuclide release [MAAP CN060504, CN060515, CN060527, CN060528 for transient and large LOCAs.].	
Containment Pressure Control (see node descriptions HR and VC below)	Successful containment pressure control is achieved if either of two functional nodes are successfully satisfied: 1. RHR containment heat removal, or 2. containment venting. Because these have different potential impacts on the radionuclide releases they are treated in separate nodes.	1. Cont. pressure < 178 psig 2. Cont. pressure < 62 psig

Table E.1-4 (Continued)
Notation and Definitions for CNS CET Functional Nodes Description

CET Functional Node	Success Criteria	Parameter Monitored for Success Determination
1. RHR Containment Heat Removal (HR)	Successful containment pressure control is unattainable using RHR[6] suppression pool cooling if either of the following conditions occur: • No debris cooling (in-vessel or ex-vessel) • Early containment failure modes RHR has the capability to remove heat from containment through the RHR heat exchangers. This capability requires • a flow path from the suppression pool, • one RHR pump, • one RHR pump heat exchanger, • SW to cool the heat exchanger, • a return flow path to ▸ The suppression pool ▸ The RPV ▸ The drywell spray (wetwell spray flow rate is considered too low) • bypass of the low RPV water level (2/3 core height) interlock if not using RPV return. Failure at this juncture in the sequence implies insufficient containment heat rejection to the environment and that the continued decay heat generation could subject the containment to continued pressurization. This condition may eventually cause structural failure, which could subsequently threaten continued successful core coolant injection.	

Table E.1-4 (Continued)
Notation and Definitions for CNS CET Functional Nodes Description

CET Functional Node	Success Criteria	Parameter Monitored for Success Determination
1. RHR Containment Heat Removal (HR) (cont'd)	Note that RHR success is a moot point if adequate injection to the core or debris has failed. This is because of high temperatures from debris radiative heating or high pressure from non-condensable gases will cause drywell failure.	
2. Containment Venting (VC)	The capability to vent the containment is a valuable supplement to the containment pressure control systems. As pressure and temperature increase, there is decreasing confidence in the ability to maintain the integrity of the containment pressure boundary. By instituting a controlled vent of the containment atmosphere, it is possible to maintain long-term containment integrity by providing a viable means of containment pressure control and heat removal. Venting also constitutes a viable mitigative action to minimize the source term released to the environment. Containment venting is successful if it can remove the excess heat and non-condensable gases from the containment and, thereby, maintain the containment pressure within acceptable limits. Adequate pressure control can be obtained by containment venting if the following conditions are satisfied: • reactivity control exists, • no "early" containment failure modes occur, • containment flooding does not eliminate the venting pathways, • vent pathways can be opened and controlled.	Cont. Press < 62 psig

Table E.1-4 (Continued)
Notation and Definitions for CNS CET Functional Nodes Description

CET Functional Node	Success Criteria	Parameter Monitored for Success Determination
2. Containment Venting (VC) (cont'd)	Based upon deterministic calculations, a containment vent of approximately 8 inches in diameter will provide sufficient vent capability to prevent containment failure for sequences involving the loss of containment heat removal or severe accidents. Currently, no vent capability is considered successful for unmitigated failure to scram events.	
No Suppression Pool Bypass (SP)	This node in the CET is used to characterize the magnitude of radionuclides that may escape the containment if wetwell failure or venting occurs. Success means that radionuclides are directed through the suppression pool. Subsequent headings address specific release paths. Success in preventing suppression pool bypass requires that • vacuum breakers remain closed; • the suppression pool water level remains above the bottom of the downcomers; and • the downcomers do not rupture or fail due to debris attack.	Bypass path < 6 inch dia.

Table E.1-4 (Continued)
Notation and Definitions for CNS CET Functional Nodes Description

CET Functional Node	Success Criteria	Parameter Monitored for Success Determination
No Large Containment Failure (NC)	This event examines the size of containment leakage that may be induced by extreme pressure and temperature conditions. The downward path at this event tree node is defined as large leakage or failure, while the upward path depicts either no leakage or the existence of drywell leak paths that prevent further containment pressurization. Any failure of the containment structure greater than 1 ft^2 is considered to be a large containment failure and is modeled as a 2 ft^2 break in the MAAP runs. A small break is assumed to be 1 ft^2 or less in size, and is modeled in MAAP with a leak size of 27 in^2. A small containment breach may be characterized by any of the following breach of containment: • electrical penetration leak, • hatch seal leak, • bellows seal leak, or • drywell head seal leak: ▸ thermal degradation ▸ inadequate pre-load Leak sizes up to 3 in^2 equivalent area are assumed to present a negligible impact on the course of the accident. The downward branch of the "No Large Containment Failure" node is probabilistically based on the plant-specific structure analysis. However, there are certain cases in which failure (i.e., large break) is guaranteed. These cases include the following: • failure to scram sequences with continued injection and no effective SLC, • No Injection to containment, causing high temperature induced failure,	Break <1 $ft.^2$

Table E.1-4 (Continued)
Notation and Definitions for CNS CET Functional Nodes Description

CET Functional Node	Success Criteria	Parameter Monitored for Success Determination
No Large Containment Failure (NC) (cont'd)	• Any early containment failure (e.g., steam explosion, etc.), or • LOCAs plus failure of vapor suppression.	
Coolant Makeup Remains Available Post Containment Failure (MU)	This event node is used to examine the availability of water injection to the drywell and RPV following containment failure. Failure of coolant makeup to the debris results in delayed fission product release due to heat up and revaporization of fission products on the RPV internals and containment structures. Releases are reduced if coolant injection can be maintained. The success of coolant makeup following containment failure may be compromised by any of the following: • harsh environment in reactor building, • steam binding of pumps, • disruption of injection pathways due to catastrophic containment failure. The same success criteria established for accomplishing the ex-vessel debris coolability (node "SI") influence the analysis of whether functional success is achieved at this node. Alignment of the following injection sources external to the reactor building may be used to achieve success (these systems are not hindered by steam binding or harsh conditions in the reactor building). • condensate • fire protection (not credited) • LPCI/CS from CST (not credited) • SW cross tie	Flow > 1000 gpm

Table E.1-4 (Continued)
Notation and Definitions for CNS CET Functional Nodes Description

CET Functional Node	Success Criteria	Parameter Monitored for Success Determination
Drywell Intact (DI)	Containment failure has already been asked in the CET. If containment failure has not occurred, this node is bypassed. If containment failure is determined to have occurred, then, the "DI" node is included to distinguish whether the failure occurred in the drywell (downward branch) or wetwell (upward branch). The probabilistic determination of the location of the failure is determined based on the Quad Cities structural analysis for slow overpressure events. Additional guidance is also provided for other accident scenarios as follows: • high temperature induced failures result in drywell failures, • rapid or energetic failure modes are assumed to occur in the drywell (e.g., steam explosions, etc.).	No DW release path > 2-inch diameter

Table E.1-4 (Continued)
Notation and Definitions for CNS CET Functional Nodes Description

CET Functional Node	Success Criteria	Parameter Monitored for Success Determination
Wetwell Airspace Failure (WW) (Scrubbed Release)	This node appears after the Drywell Intact (DI) node. If the DI node determines that the containment failure occurred in the drywell this node is bypassed. If containment failure occurred in the wetwell, this node distinguishes whether the wetwell failure occurred above or below the wetwell water line. As in the previous node, successfully avoiding a large containment failure requires successful containment heat removal. The probabilistic determination of the location of the failure is determined based on the plant specific structural analysis for slow overpressurization events.	No WW water release path > 2-inch diameter
Reactor Building Effectiveness (RB)	The reactor building provides a substantial capability to remove particulate fission products from the release pathway for scenarios where the containment has failed. Success of the reactor building to provide a substantial radionuclide reduction (i.e., a factor of 5 to 10 reduction in the radionuclide release magnitude) is based upon any of the following: • very small containment failures (i.e., 6 inch equivalent diameter) for which the reactor building remains substantially intact; • primary containment failures low in the reactor building for which the release pathway consists of a tortuous route through the reactor building and no other failures are induced due to hydrogen combustion; • cases in which substantial fire protection spray is occurring during the release (not credited due to limited area coverage by the fire sprays in the Reactor Building, i.e., cable trays only). The RB node is not currently credited in the CNS calculation of radionuclide release frequency.	Not used.

1. A plant-specific assessment of the CNS response to a high pressure core melt with a single ADS valve opened when the RPV level reaches TAF supports this criterion. This was illustrated in MAAP Case CN060501.
2. Primary system failure may be induced by very high internal temperatures generated by molten debris in an uncooled state within the RPV. Such high temperatures coincident with high RPV pressures may lead to localized failures at weak points high within the RPV.
3. Opening MSIVs and the use of HPCI steam line are not credited because no calculations are available to demonstrate sufficient capacity to lead to depressurization.
4. The 1000 gpm criterion is an approximation. There is a comparatively large degree of uncertainty surrounding this issue. However, ORNL and GE calculations seem to indicate that an injection rate close to 1000 gpm initiated at thirty minutes may be sufficient.
5. For this situation, the containment remains inerted and venting would not have been required. Therefore, in this case, the down branch is not considered as a failure of combustible gas venting but as a continuation of the sequence.
6. Other modes of containment heat removal are not considered effective because of interlocks or procedural restrictions under severe accident conditions. (e.g., RWCU, Main Condenser).

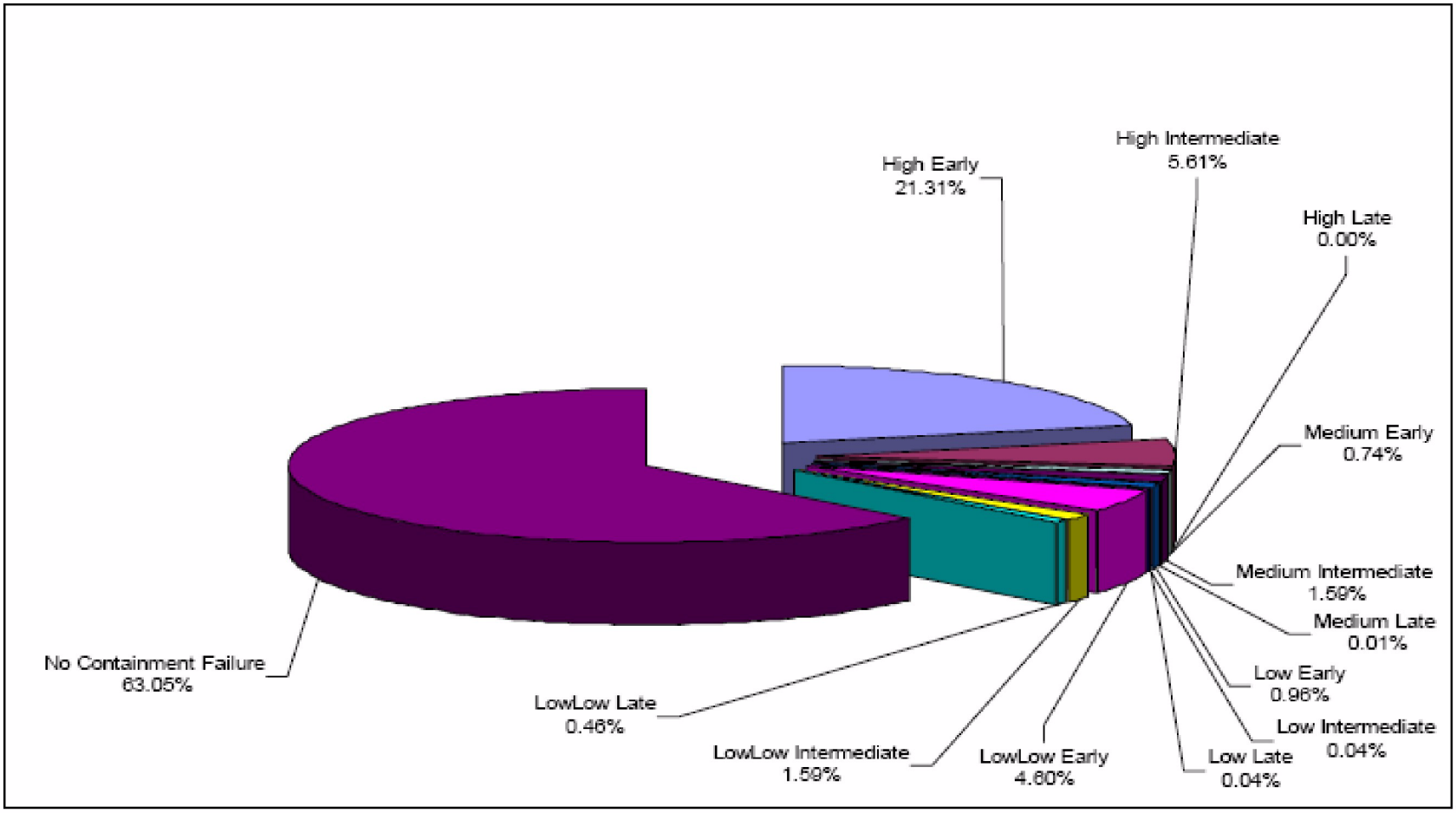
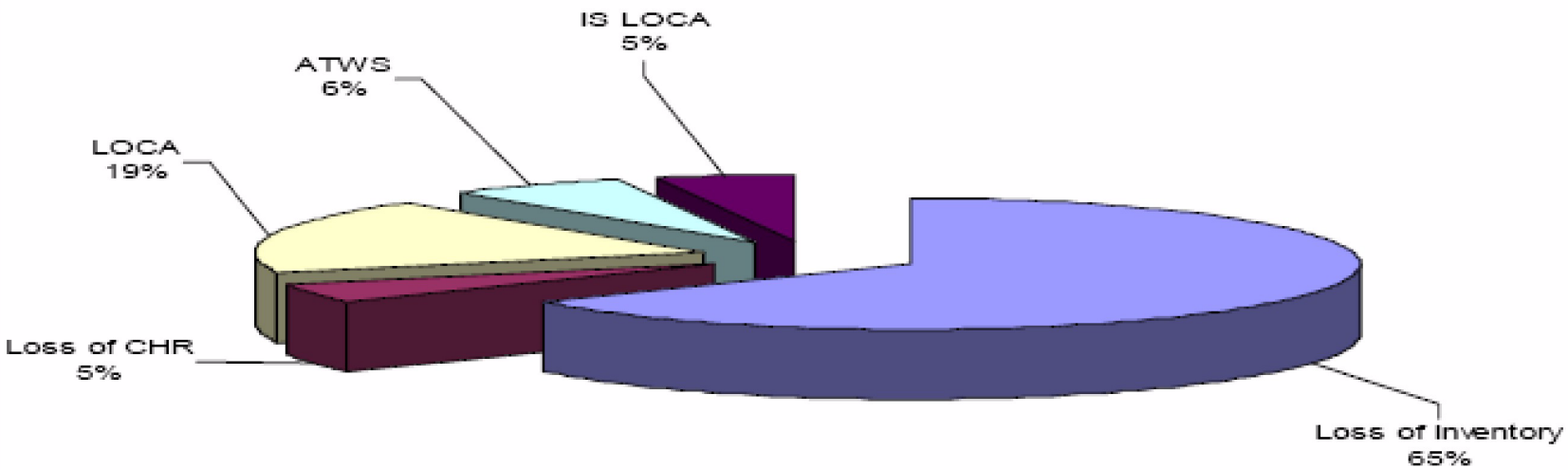


Figure E.1-1
CNS Radionuclide Release Category Summary



Note: The contribution of SBO to LERF is 0.43%. SBO is not a unique LERF accident class, thus the contribution is listed separately.

Figure E.1-2
Accident Class Contributions to LERF

Table E.1-5
Correlation of Level 2 Risk-Significant Terms to Evaluated SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
CGS-PHE-FF-INERT	9.90E-01	3.417	Containment inerted; venting not required	This term represents the containment being inerted when combustible gas venting fails or is not required and AC power is available. A Phase I SAMA to implement venting procedures with respect to timing, path selection, and technique has already been installed. Phase II SAMA 70, to install a curb to prevent debris from spreading across the floor and contacting the shell, was evaluated.
CNT-SMP-FF-MLTOF	1.00E+00	2.181	Melt overflows sump	This event models the possibility that even though water is present on the drywell floor the debris in the sump is not coolable. The likelihood of this occurring is relatively high considering the depth of the debris accumulated in the sump. Phase II SAMA 70, to install a curb to prevent debris from spreading across the floor and contacting the shell, was evaluated.
RPV-DWV-FO-BARIS	1.00E+00	2.181	Drywell barriers fail to prevent debris from contacting shell	This term represents the possibility that barriers are present to block the debris from reaching the steel shell. This event is a result of the proposed Mark I containment modification which suggested installing a curb to prevent debris from spreading across the floor and contacting the shell. Phase II SAMA 70, to install a curb to prevent debris from spreading across the floor and contacting the shell, was evaluated.
CNT-MDL-FF-WTRCV	9.00E-01	2.181	Failure to recover a water system	This term represents failure to recover a water system at time of RPV breach (~ 3 hours). No repairs are currently credited in the model due to potential adverse environmental conditions. Phase II SAMAs 22, 23, 24, 25, 28, 29, 67, 77, and 78 for enhancing reactor vessel injection during transients, small LOCA and SBO were evaluated.

Table E.1-5 (Continued)
Correlation of Level 2 Risk-Significant Terms to Evaluated SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
RPV-XHE-FO-L2REC	9.00E-01	1.814	Operator fails to recover injection before RPV melt	This term represents operator failure to recover an injection method before RPV melt. The failure probability for system recovery is assumed to be quite high. If failed systems have not been repaired or restored at this point in the accident, it is judged relatively unlikely that the system(s) will be restored before RPV melt-through. Phase II SAMAs 22, 23, 24, 25, 28, 29, 67, 77, and 78 for enhancing reactor vessel injection during transients, small LOCA and SBO were evaluated.
RPV-MDL-FF-RXFLS	1.00E+00	1.749	Failure of RX (Classes ID, IE (OP=F), II, IIIA, IIIC, IIID, IV)	This term represents the probability of core melt progression causing in-vessel fuel degradation, vessel failure, and the discharge of molten debris from the reactor vessel. Phase II SAMAs 22, 23, 24, 25, 28, 29, 67, 77, and 78 for enhancing reactor vessel injection during transients, small LOCA and SBO were evaluated.
RPV-MDL-SC-C1A1E	7.00E-01	1.335	Successful RPV depressurization (Class IA, IE)	This term represents RPV depressurization during accident sequences involving loss of inventory makeup in which the reactor pressure remains high. Phase II SAMAs 26, 27, 43, and 44, to enhance depressurization, were evaluated.
RPV-MDL-FF-HITMP	7.00E-01	1.29	High primary system temperature does not cause failure of RCS pressure boundary	This term represents a time when failure of RCS pressure boundary is not caused by high primary system temperature. Phase II SAMA 70, to install a curb to prevent debris from spreading across the floor and contacting the shell, was evaluated.
RPV-MDL-FF-TRPRS	8.00E-01	1.29	Pressure transient does not fail mechanical systems	This term represents the case where pressure transient does not fail mechanical systems. The main contributor to LERF during this sequence is failure of the AC buses. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21 for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.

Table E.1-5 (Continued)
Correlation of Level 2 Risk-Significant Terms to Evaluated SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
RPV-MDL-FO-ALTDP	1.00E+00	1.29	Alternate depressurization methods not credited	This term represents alternate methods of depressurization not being credited. Because the MSIVs are assumed to not be able to be re-opened in sufficient time in a severe accident and the HPCI and RCIC steam exhaust lines and the steam line drains do not have analyses to support their adequacy as the sole means to depressurize the RPV, it is concluded that these alternative methods of depressurization would not be effective under the extreme conditions of high radiation, low reactor water level, and elevated reactor pressure. Phase II SAMA 44, to improve SRV and MSIV pneumatic components, was evaluated.
RPV-SRV-FO-CSORV	5.50E-01	1.29	SRVs do not fail open during core melt progression	This term represents the SRVs not failing open during adverse conditions. This leads to a failure to depressurize. Phase II SAMAs 44 and 52, to improve SRV and MSIV pneumatic components and to provide passive overpressure relief, were evaluated.
CNT-MDL-FF-LVL1F	1.00E+00	1.187	Large containment failure given containment failed in level 1 (Class II, IIID, IV)	This term represents a large containment failure given the containment failed in level 1. Phase II SAMA 51, to install redundant vacuum breakers, was evaluated.
CNT-MDL-FF-SCTRM	1.00E+00	1.157	Reactor building ineffective in reducing source term	This term represents the failure of the reactor building to contain the event. Phase II SAMAs 48 and 49 were evaluated to improve fission product scrubbing during severe accidents.
RPV-MDL-SC-CLIII	1.00E+00	1.146	Successful RPV depressurization (Class III)	This term represents successful RPV depressurization. This basic event is driven by loss of the diesel generators and loss of offsite power. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21 for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.

Table E.1-5 (Continued)
Correlation of Level 2 Risk-Significant Terms to Evaluated SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
FPS-PHE-CF-FLOW	5.00E-01	1.127	In-vessel core melt arrest precluded by limited FPS flow	This term represents in-vessel core melt arrest precluded by limited FPS flow. Phase II SAMA 78 to improve training on alternate injection via the FPS was evaluated.
CNT-DWV-FF-MLTFL	1.00E+00	1.091	Drywell shell melt-through failure due to containment failure	This term represents drywell shell melt-through due to containment failure. Phase I SAMAs 121, 137, 138, 139, 141, 142, and 143 for enhancing containment integrity and cooling were investigated. Phase II SAMA 70, to install a curb to prevent debris from spreading across the floor and contacting the shell, was evaluated.
CNT-PHE-FO-HBFFS	1.00E+00	1.079	High pressure blowdown overwhelms vapor suppression	This term represents the high pressure blowdown overwhelming the vapor suppression. Phase II SAMAs 48, 49, and 51, to improve venting and fission product scrubbing, were evaluated.
CNT-DWV-SC-ATWSF	9.90E-01	1.066	Drywell intact for ATWS events (Class IV)	This term represents the drywell intact for ATWS events. Phase II SAMAs 58, 59, 60, and 61 for enhancing ATWS migration capabilities were evaluated.
CND-SYS-FF-LERF	1.00E+00	1.055	Conditional probability of a LERF (Class V)	This term represents the conditional probability of a LERF in an ISLOCA event. Phase II SAMAs 54, 56, and 57 were evaluated to reduce the risk from ISLOCAs.
PCV-WWV-FF-ATWSF	5.00E-01	1.051	WW water space fail. for ATWS events (Class IV)	This term represents a breach in the wetwell water space for ATWS events which may deplete the suppression pool water inventory and result in lowering the water level to below the downcomers. To successfully avoid a containment failure requires successful containment heat removal and containment pressure control. Phase II SAMAs 20 and 46 were evaluated to help mitigate failure of containment heat removal and increase vent capability.

Table E.1-5 (Continued)
Correlation of Level 2 Risk-Significant Terms to Evaluated SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
CGS-PHE-FF-STMIN	9.90E-01	1.049	Combustible gas venting not required (steam inerted - Class IIID)	This term represents combustible gas venting not required. Phase II SAMA 66 for installing digital large break LOCA protection was evaluated.
CNT-DWV-FF-NOVSS	1.00E+00	1.049	Drywell not intact for loss of vapor suppression (Class IIID)	This term represents the drywell not intact for loss of vapor suppression. This sequence is initiated by a LOCA thus Phase II SAMA 66 for installing digital large break LOCA protection was evaluated.
RPV-MDL-SC-CLSII	9.00E-01	1.044	Successful RPV depressurization (Class II)	This term represents successful RPV depressurization during Class II sequences. This term represents RPV depressurization during accident sequences involving loss of inventory makeup in which the reactor pressure remains high. This basic event is driven by loss of power to the hard pipe vent valves. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21 for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
RPV-MDL-SC-CLSIV	8.00E-01	1.038	Successful RPV depressurization (Class IV)	This term represents successful RPV depressurization. Improvements to the SLC system help mitigate this event. Phase II SAMAs 58, 59, and 60, to enhance boron injection, were evaluated.
CNT-DWV-SC-NODHR	5.50E-01	1.027	Drywell intact for loss of DHR events (Class II)	This term represents the drywell intact for loss of DHR events. Electrical power to the torus hard pipe vent system is very important in this sequence thus Phase II SAMA 20, to provide redundant power to the direct torus vent valves, helps mitigate this event.
CNT-DWV-FF-NODHR	4.50E-01	1.023	Drywell not intact for loss of DHR events (Class II)	This term represents failure of the drywell for decay heat removal events. Phase II SAMAs 46, 71, and 73, to enhance suppression pool cooling, were evaluated.

Table E.1-5 (Continued)
Correlation of Level 2 Risk-Significant Terms to Evaluated SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
PCV-WWV-SC-LOTMP	7.80E-01	1.021	WW air space failure at low drywell temperature (CL I, III without RPV failure and CL II)	This term represents wet well air space failure at low drywell temperature. Electrical power to the torus hard pipe vent system is very important in this sequence thus Phase II SAMA 20, to provide redundant power to the direct torus vent valves, helps mitigate this event.
RPV-PHE-FF-RBEAL	5.00E-01	1.019	Adverse Rx building environment conditions cause failure	This term represents adverse reactor building environment conditions causing a failure. The location of the SRV logic and power control centers is in the reactor building. Therefore, failures of the containment or failure of isolation may result in adverse reactor building environment that can cause failure of the depressurization function. Phase II SAMAs 20 and 52, to provide redundant power to the direct torus vent valves and to provide passive overpressure relief, were evaluated.
CGS-PHE-SC-INERT	1.00E-02	1.015	Containment not inerted; Venting required	This term represents the containment not inerted and venting is required. A Phase I SAMA to implement venting procedures with respect to timing, path selection, and technique has already been installed. Phase II SAMAs 48, 49, 50, and 52, to improve venting and fission product scrubbing and to provide passive overpressure relief, were evaluated.
L2-OSP-15H-SW	7.99E-01	1.014	Conditional probability of failure to restore AC in l2 within 15 hrs in node SI	This term represents conditional probability of failure to restore AC in L2 within 15 hours when injection has been established. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21 for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
RHR-XHE-CF-TRIP	8.00E-05	1.014	Human error CCF to restore limit switches or to align interlocks	This term represents human CCF to restore limit switches or to align interlocks for the RHR system. Phase II SAMAs 28 and 29 to improve the LPCI system were evaluated.

Table E.1-5 (Continued)
Correlation of Level 2 Risk-Significant Terms to Evaluated SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
CNT-PHE-FF-H2DFG	1.00E+00	1.014	Hydrogen deflagration occurs globally	This term represents the event in which hydrogen deflagration occurs globally. Phase II SAMA 49, to improve fission product scrubbing, was evaluated.
CNT-PHE-FF-O2DIN	1.00E-02	1.014	Operation deinerted or O2 introduced	This term represents the deinerting of containment. Phase II SAMA 49, to improve fission product scrubbing, was evaluated.
CNT-PHE-FF-STMIN	5.00E-01	1.014	Containment not steam inerted	This term represents the containment not being steam inerted. If the containment is steam inerted hydrogen deflagration will not occur. Phase II SAMA 49, to improve fission product scrubbing, was evaluated.
PCV-MDL-FF-CGVFL	1.00E+00	1.014	Combustible gas venting fails	This term represents failure of combustible gas venting. Phase II SAMA 49, to improve fission product scrubbing, was evaluated.
PCV-WWV-SC-ATWSF	5.00E-01	1.014	WW air space fails for ATWS events (Class IV)	This term represents a breach in the wetwell air space for ATWS events which may result in a release that passes through the suppression pool. To successfully avoid a containment failure requires successful containment heat removal and containment pressure control. Phase II SAMAs 20, 46, 71, and 73 were evaluated to help mitigate failure of containment heat removal and increase vent capability.
ADS-XHE-FF-RBENV	5.00E-01	1.013	Adverse reactor building environment conditions affect SRVs	This term represents the adverse reactor building environment conditions causing failure of the SRVs and depressurization. Phase II SAMAs 44 and 52, to improve SRV and MSIV pneumatic components and to provide passive overpressure relief, were evaluated.
%A-LP	1.01E-05	1.013	Large break LOCA, below TAF in LPCI line	This term represents a large break LOCA – below TAF in LPCI line. Phase II SAMA 66 to install a digital large break LOCA system was evaluated.

Table E.1-5 (Continued)
Correlation of Level 2 Risk-Significant Terms to Evaluated SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
%BOC-MS	1.06E-07	1.012	Main steam line BOC	This term represents a main steam line break outside of containment. Phase II SAMAs 22, 23, 28, and 47, to enhance injection, were evaluated.
FLD-XHE-FO-MSW7A	5.70E-04	1.011	Failure to isolate moderate flood late (terminate SW)	This term represents a failure to isolate a moderate pipe rupture in the control building basement. Phase II SAMA 62 to improve internal flooding procedures was evaluated along with SAMA 30 to help mitigate loss of service water.
SWS-PIP-BRK-TRNB	5.00E-01	1.01	Conditional probability That flood is in train B	This term represents the conditional probability that a flood is in train B rather than train A. No Phase II SAMAs were recommended.
%ISLOCA-HP	4.15E-06	1.009	ISLOCA initiator for HPCI injection line	This term represents the ISLOCA initiator for the HPCI injection line. Phase II SAMAs 54, 56, and 57 were evaluated to reduce the risk from ISLOCAs.
HPI-PIP-RP-ISLOC	5.52E-03	1.009	Pipe ruptures for HPCI injection line ISLOCA	This term represents the ISLOCA pipe rupture for the HPCI injection line. Phase II SAMAs 54, 56, and 57 were evaluated to reduce the risk from ISLOCAs.
FPS-DDP-TM-FPD	1.00E-02	1.009	Diesel-driven fire pump 1D unavailable due to test or maintenance	This term represents the diesel-driven fire pump 1D being unavailable due to testing or maintenance. Phase II SAMA 28, 29, and 47, to enhance injection, were evaluated.
%BOC-FW	8.06E-08	1.009	Feedwater line BOC	This term represents an unisolated feedwater line break outside of containment. Phase II SAMAs 22, 23, 28, and 47, to enhance injection, were evaluated.
SLC-EPV-CF-SQ14	1.40E-02	1.009	Common cause failure to open of squib valves SQ14A and SQ14B	This term represents the common cause failure to open of squib valves SQ14A and SQ14B. Phase II SAMAs 59 and 60, to provide alternate means of boron injection, were evaluated.

Table E.1-5 (Continued)
Correlation of Level 2 Risk-Significant Terms to Evaluated SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
LCI-SYS-TM-LOOPA	9.49E-03	1.009	Test or maintenance unavailability: RHR (LPCI mode) loop A	This term represents the LPCI mode of RHR loop A unavailable due to testing or maintenance. Phase II SAMA 28, to add a diverse low pressure injection system, was evaluated.
EDC-DCB-CF-125AB	2.84E-07	1.008	Common cause failure of 125V DC buses 1A and 1B	This term represents common cause failure of the 125V DC buses 1A and 1B. Phase II SAMAs 1, 2, 3, 13, 14, 15, 19, and 21 for enhancing DC system availability and reliability were evaluated.
SWS-XHE-FO-RPVIN	6.30E-02	1.008	Human error fail to operate RPV injection (level 1)	This term represents the human error fail to operate RPV injection (level 1). Phase II SAMAs 22, 23, 28, and 47, to enhance injection, were evaluated.
%A-CS	6.72E-06	1.008	Large break LOCA, above TAF in CS line	This term represents a large break LOCA above the TAF in the CS line. Phase II SAMA 66 to install a digital large break LOCA protection system was evaluated
%FLSWCB7AL	7.61E-06	1.008	Large SW pipe rupture in the control building basement	This term represents a large SW pipe rupture in the control building basement. Phase II SAMA 62 to improve internal flooding procedures was evaluated along with SAMA 30 to help mitigate loss of service water.
VSS-VAB-CO-NRV20	6.58E-03	1.008	Normally closed vacuum breaker NRV20 fails open	This term represents random failure of Vacuum breaker NRV20. Phase II SAMA 51, to install redundant vacuum breakers, was evaluated.
VSS-VAB-CO-NRV21	6.58E-03	1.008	Normally closed vacuum breaker NRV21 fails open	This term represents random failure of Vacuum breaker NRV21. Phase II SAMA 51, to install redundant vacuum breakers, was evaluated.
VSS-VAB-CO-NRV22	6.58E-03	1.008	Normally closed vacuum breaker NRV22 fails open	This term represents random failure of Vacuum breaker NRV22. Phase II SAMA 51, to install redundant vacuum breakers, was evaluated.

Table E.1-5 (Continued)
Correlation of Level 2 Risk-Significant Terms to Evaluated SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
VSS-VAB-CO-NRV23	6.58E-03	1.008	Normally closed vacuum breaker NRV23 fails open	This term represents random failure of Vacuum breaker NRV23. Phase II SAMA 51, to install redundant vacuum breakers, was evaluated.
VSS-VAB-CO-NRV24	6.58E-03	1.008	Normally closed vacuum breaker NRV24 fails open	This term represents random failure of Vacuum breaker NRV24. Phase II SAMA 51, to install redundant vacuum breakers, was evaluated.
VSS-VAB-CO-NRV25	6.58E-03	1.008	Normally closed vacuum breaker NRV25 fails open	This term represents random failure of Vacuum breaker NRV25. Phase II SAMA 51, to install redundant vacuum breakers, was evaluated.
VSS-VAB-CO-NRV26	6.58E-03	1.008	Normally closed vacuum breaker NRV26 fails open	This term represents random failure of Vacuum breaker NRV26. Phase II SAMA 51, to install redundant vacuum breakers, was evaluated.
VSS-VAB-CO-NRV27	6.58E-03	1.008	Normally closed vacuum breaker NRV27 fails open	This term represents random failure of Vacuum breaker NRV27. Phase II SAMA 51, to install redundant vacuum breakers, was evaluated.
VSS-VAB-CO-NRV28	6.58E-03	1.008	Normally closed vacuum breaker NRV28 fails open	This term represents random failure of Vacuum breaker NRV28. Phase II SAMA 51, to install redundant vacuum breakers, was evaluated.
VSS-VAB-CO-NRV29	6.58E-03	1.008	Normally closed vacuum breaker NRV29 fails open	This term represents random failure of Vacuum breaker NRV29. Phase II SAMA 51, to install redundant vacuum breakers, was evaluated.
VSS-VAB-CO-NRV30	6.58E-03	1.008	Normally closed vacuum breaker NRV30 fails open	This term represents random failure of Vacuum breaker NRV30. Phase II SAMA 51, to install redundant vacuum breakers, was evaluated.

Table E.1-5 (Continued)
Correlation of Level 2 Risk-Significant Terms to Evaluated SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
VSS-VAB-CO-NRV31	6.58E-03	1.008	Normally closed vacuum breaker NRV31 fails open	This term represents random failure of Vacuum breaker NRV31. Phase II SAMA 51, to install redundant vacuum breakers, was evaluated.
RPV-MDL-SC-CMS1A	8.70E-01	1.007	Core melt arrested in-vessel (OP = S, Class IA)	This term represents core melt being arrested in-vessel. Phase II SAMAs 22, 23, 24, 25, 28, 29, 67, 77, and 78 for enhancing reactor vessel injection during transients, small LOCA and SBO were evaluated.
L2-OSP-10H-SW	7.36E-01	1.007	Conditional probability of failure to restore AC in l2 within 10.5 hrs in node SI	This term represents the conditional probability of failure to restore AC in 12 to within 10.5 hrs in node SI. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21 for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
OSP65HR-SW	2.94E-01	1.007	Failure to recover OSP within 6.5 hours (severe weather loop event)	This term represents operator failure to recover a weather related LOOP event within 6.5 hours. Phase I SAMAs to improve station blackout procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21 for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
SLC-XHE-FO-SLC2E	2.30E-01	1.007	Operator fails to initiate SLC with 2 pumps in required time	This term represents the failure of an operator to initiate SLC within 2 pumps in the required time. Phase II SAMAs 58, 59, 60, and 61 for enhancements to the SLC system were evaluated.
EAC-CRB-CF-LS-FG	8.82E-05	1.007	4160V bus 1F and 1G load shed breaker common cause failure	This term represents common cause failure of the 4160V buses 1F and 1G load shed breaker failures. This impacts power for division I and division II. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21 for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.

Table E.1-5 (Continued)
Correlation of Level 2 Risk-Significant Terms to Evaluated SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
%A-WA	5.51E-06	1.007	Large break LOCA, below TAF	This term represents a large break LOCA below the TAF. Phase II SAMA 66 to install a digital large break LOCA protection system was evaluated.
EAC-DGN-FS-DG1	1.52E-03	1.006	Diesel generator DG1 fails to start	This term represents random failure to start of emergency diesel generator DG-1. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21 for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
%BOC-RW	4.97E-08	1.006	RWCU BOC	This term represents an unisolated RWCU break outside of containment. Phase II SAMAs 22, 23, 28, and 47, to enhance injection, were evaluated.
EAC-DGN-FS-DG2	1.52E-03	1.005	Diesel generator DG2 fails to start	This term represents random failure to start of emergency diesel generator DG-2. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21 for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
EAC-CRB-OO-EG1	1.29E-03	1.005	Normally open circuit breaker EG1 fails to close	This term represents random failure of normally open circuit breaker EG1. This causes no power to 4160V bus 1F from DG-1 Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21 for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
PCV-WWV-FF-LOTMP	2.20E-01	1.005	WW water space fails at low drywell temperature (CL I, III without RPV failure and CL II)	This term represents a WW water space fail at low drywell temperature. For this sequence to occur vessel injection must fail. Phase II SAMAs 22, 23, 24, 25, 28, 29, 67, 77, and 78 for enhancing reactor vessel injection during transients, small LOCA and SBO were evaluated.

Table E.1-5 (Continued)
Correlation of Level 2 Risk-Significant Terms to Evaluated SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
ADS-SRV-CC-INDEP	7.71E-03	1.005	Independent failure to open (est.) (3 or more)	This term represents an independent failure to open three or more SRVs. Phases II SAMAs 44 and 52, to improve SRV and MSIV pneumatic components and to provide passive overpressure relief, were evaluated.
FLD-XHE-FO-LSW7A	1.40E-03	1.005	Failure to isolate large flood late (terminate SW)	This term represents failure to isolate the large flood in the control building basement. Phase II SAMA 62 to improve internal flooding procedures was evaluated along with SAMA 30 to help mitigate loss of service water.
%ISLOCA-CS	2.10E-06	1.005	ISLOCA initiator for core spray injection lines	This term represents the ISLOCA initiator for core spray injection lines. Phase II SAMAs 54, 56, and 57 were evaluated to reduce the risk from ISLOCAs.
%TI	1.93E-02	1.005	Inadvertently open relief valve	This term represents an inadvertently open relief valve initiating event. Phase II SAMAs 44 and 75, to improve SRV and MSIV pneumatic components and to implement trip/shutdown risk modeling, were evaluated.
EDC-DCB-LP-125B	9.19E-06	1.005	125V bus 1B failure	This term represents a 125V bus 1B failure. Phase II SAMAs 1, 2, 3, 13, 14, 15, 19, and 21 for enhancing DC system availability and reliability were evaluated
EAC-CRB-OO-EG2	1.29E-03	1.005	Normally open circuit breaker EG2 fails to close	This term represents normally open circuit breaker EG2 failure to close. This leads to no power to bus 1G from diesel generator DG-2. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21 for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.

Note: Basic events that are correlated in Table E.1-3 are not listed again in Table E.1-5.

E.1.2.2 Radionuclide Analysis

E.1.2.2.1 Introduction

A major feature of a Level 2 analysis is the estimation of the source term for every possible outcome of the CET. The CET end points represent the outcomes of possible in-containment accident progression sequences. These end points represent complete severe accident sequences from initiating event to release of radionuclides to the environment. The Level 1 and plant system information is passed through to the CET evaluation in discrete PDS. An atmospheric source term may be associated with each of these CET sequences. Because of the large number of postulated accident scenarios considered, mechanistic calculations (i.e., MAAP calculations) are not performed for every end-state in the CET. Rather, accident sequences produced by the CET are grouped or "binned" into a limited number of release categories each of which represents all postulated accident scenarios that would produce a similar fission product source term.

The criteria used to characterize the release are the estimated magnitude of total release and the timing of the first significant release of radionuclides. The predicted source term associated with each release category, including both the timing and magnitude of the release, is determined using the results of MAAP calculations.

E.1.2.2.2 Timing of Release

Timing completely governs the extent of radioactive decay of short-lived radioisotopes prior to an off-site release and, therefore, has a first-order influence on immediate health effects. CNS characterizes the release timing relative to the time at which the release begins, measured from the time of accident initiation. Three timing categories are used: early (less than 3.7 hours), intermediate (3.7 to 24 hours), and late (greater than 24 hours).

The definitions of the release timing categories are as follows.

- Early releases (E) are CET end-states involving containment failure less than 3.7 hours from declaration of a general emergency (i.e., prior to effective evacuation), for which minimal offsite protective measures have been observed to be performed in non-nuclear accidents.

- Intermediate releases (I) are CET end-states involving containment failure greater than or equal to 3.7 hours, but less than 24 hours from declaration of a general emergency, for which much of the offsite nuclear plant protective measures can be assured to be accomplished.

- Late releases (L) are CET end-states involving containment failure greater than or equal to 24 hours from declaration of a general emergency, for which offsite measures can be assumed to be fully effective.

E.1.2.2.3 Magnitude of Release

The CsI release fraction indicates the fraction of in-vessel radionuclides escaping to the environment. (Noble gas release levels are non-informative since release of the total core inventory of noble gases is essentially complete given containment failure).

The source terms were grouped into five distinct radionuclide release categories or bins according to release magnitude as follows.

(1) High (H): A radionuclide release of sufficient magnitude to have the potential to cause early fatalities. This implies a total integrated release of > 10% of the initial core inventory of CsI.

(2) Medium (M): A radionuclide release of sufficient magnitude to cause near-term health effects. This implies a total integrated release of between 1% and 10% of the initial core inventory of CsI.

(3) Low (L): A radionuclide release with the potential for latent health effects. This implies a total integrated release of between 0.1% and 1% of the initial core inventory of CsI.

(4) Low-Low (LL): A radionuclide release with undetectable or minor health effects. This implies a total integrated release of between 0% and 0.1% of the initial core inventory of CsI.

(5) Negligible (NCF): A radionuclide release that is less than or equal to the containment design base leakage.

The "total integrated release" as used in the above categories is defined as the integrated release within 36 hours after RPV failure. If no RPV failure occurs, then the "total integrated release" is defined as the integrated release within 36 hours after accident initiation.

E.1.2.2.4 Release Category Bin Assignments

Table E.1-6 summarizes the scheme used to bin sequences with respect to magnitude of release, based on the predicted CsI release fraction and release timing. The combination of release magnitude and timing produce seven distinct release categories for source terms. These are the representative release categories presented in Table E.1-7.

Table E.1-6
Release Severity and Timing Classification Scheme Summary

Release Severity		Release Timing	
Classification Category	**Cs Iodide % in Release**	**Classification Category**	**Time of Initial Release Relative to Time for General Emergency Declaration**
High (H)	Greater than 10	Late (L)	Greater than 24 hours
Medium or Moderate (M)	1 to 10	Intermediate (I)	3.7 to 24 hours
Low (L)	0.1 to 1	Early (E)	Less than 3.7 hours
Low-low (LL)	Less than 0.1		

Table E.1-7
CNS Release Categories

Time of Release	Magnitude of Release			
	H	**M**	**L**	**LL**
E	H/E	M/E	L/E	LL/E
I	H/I	M/I	L/I	LL/I
L	H/L	M/L	L/L	LL/L

E.1.2.2.5 Mapping of Level 1 Results into the Various Release Categories

PDS provide the interface between the Level 1 and Level 2 analyses (i.e., between core damage accident sequences and fission product release categories). In the PDS analysis, Level 1 results were grouped ("binned") according to plant characteristics that define the status of the reactor, containment, and core cooling systems at the time of core damage. This ensures that systems important to core damage in the Level 1 event trees, and the dependencies between containment and other systems are handled consistently in the Level 2 analysis. A PDS therefore represents a grouping of Level 1 sequences that defines a unique set of initial conditions that are likely to yield a similar accident progression through the Level 2 CETs and the attendant challenges to containment integrity.

From the perspective of the Level 2 assessment, PDS binning entails the transfer of specific information from the Level 1 to the Level 2 analyses.

- Equipment failures in Level 1. Equipment failures in support systems, accident prevention systems, and mitigation systems that have been noted in the Level 1 analysis are carried into the Level 2 analysis. In this latter analysis, the repair or recovery of failed

equipment is not allowed unless an explicit evaluation, including a consideration of adverse environments where appropriate, has been performed as part of the Level 2 analysis.

- RPV status. The RPV pressure condition is explicitly transferred from the Level 1 analysis to the CET.
- Containment status. The containment status is explicitly transferred from the Level 1 analysis to the CET. This includes recognition of whether the containment is bypassed or is intact at the onset of core damage.
- Differences in accident sequence timing are transferred with the Level 1 sequences. Timing affects such sequences as: SBO, internal flooding, and containment bypass (ISLOCA).

This transfer of information allows timing to be properly assessed in the Level 2 analysis.

Based on the above criteria, the Level 1 results were binned into PDS's. These PDS define important combinations of system states that can result in distinctly different accident progression pathways and therefore, different containment failure and source term characteristics. Table E.1-8 provides a description of the CNS PDS that are used to summarize the Level 1 results.

Table E.1-8
Summary of CNS Core Damage Accident Sequences Plant Damage States

Accident Class Designator	Subclass	Definition	CDF (/ry)
Class I	A	Accident sequences involving loss of inventory makeup in which the reactor pressure remains high.	IA 1.26E-6 IAL 2.35E-6
	B	Accident sequences involving a station blackout and loss of coolant inventory makeup.	IBE 2.26E-7 IBL 6.88E-7
	C	Accident sequences involving a loss of coolant inventory induced by an ATWS sequence with containment intact.	1.93E-8
	D	Accident sequences involving a loss of coolant inventory makeup in which reactor pressure has been successfully reduced to 200 psi.	ID 5.82E-7 IDL 1.30E-6
	E	Accident sequences involving loss of inventory makeup in which the reactor pressure remains high and DC power is unavailable.	5.11E-7

Table E.1-8 (Continued)
Summary of CNS Core Damage Accident Sequences Plant Damage States

Accident Class Designator	Subclass	Definition	CDF (/ry)
Class II	A	Accident sequences involving a loss of containment heat removal with the RPV initially intact; core damage; core damage induced post containment failure.	6.75E-7
	L	Accident sequences involving a loss of containment heat removal with the RPV breached but no initial core damage; core damage induced post containment failure.	5.43E-9
	V	Class IIA and III except that the vent operates as designed; loss of makeup occurs at some time following vent initiation. Suppression pool saturated but intact.	3.72E-8
Class III (LOCA)	A	Accident sequences leading to core damage conditions initiated by vessel rupture where the containment integrity is not breached in the initial time phase of the accident.	0
	B	Accident sequences initiated or resulting in small or medium LOCAs for which the reactor cannot be depressurized prior to core damage occurring.	3.97E-7
	C	Accident sequences initiated or resulting in medium or large LOCAs for which the reactor is a low pressure and no effective injection is available.	7.14E-7
	D	Accident sequences which are initiated by a LOCA or RPV failure and for which the vapor suppression system is inadequate, challenging the containment integrity with subsequent failure of makeup systems.	1.16E-7
Class IV (ATWS)	A	Accident sequences involving failure of adequate shutdown reactivity with the RPV initially intact; core damage induced post containment failure.	1.91E-7
	L	Accident sequences involving a failure of adequate shutdown reactivity with the RPV initially breached (e.g. LOCA or SORV); core damage induced post containment failure.	3.16E-8
Class V	---	Unisolated LOCA outside containment.	1.26E-7
		Total CDF	**9.23E-6**

Note: The total is not the same as the baseline CDF due to non-minimal cutsets created when quantifying at the sequence level.

E.1.2.2.6 Process Used to Group the Source Terms

The approach used to evaluate radionuclide releases and develop release categories is similar to that applied in the NUREG-1150 analysis [Reference E.1-17]. The objectives were to establish the timing of the first significant release of radionuclides and estimate the magnitude of the total release.

The CNS Level 3 analysis requires, as an input, the frequency, type, timing and amount of fission products released to the environment during the core damage accidents postulated by the CNS Level 2 PRA analyses. In order to simplify the large number of potential release scenarios, a representative set of release fractions was chosen for each containment event tree end state along with an end state frequency.

The PDS designators listed in Table E.1-8 represent the core damage end state categories from the Level 1 analysis that are grouped together as entry conditions for the Level 2 analysis. The Level 2 accident progression for each of the PDS is evaluated using a CET to determine the appropriate release category for each Level 2 sequence. Note, however, that since all the Level 2 sequences associated with each Level 1 plant damage state may not be assigned to the same release category, there is no direct link between a specific Level 1 core damage PDS and Level 2 release category. Rather, the sum of the Level 2 end state frequencies assigned to each release category determines the overall frequency of that release category.

The CNS Level 2 PSA Analysis describes which CNS specific MAAP analyses are representative of each CET end state. It also bins each CET sequence into one of the release categories depicted in Table E.1-7.

For each CET sequence, a value for each of the release-to-environment mass fractions was obtained from the representative MAAP calculation. These mass fractions were then weighed according to the contribution of that sequence to the sum of the sequences in the end state bin. The final mass fraction representing the end state bin was the sum of these individual weighed mass fractions for each species.

To evaluate the Level 2 model results in a manner that provided the above information, each Level 2 CET sequence was linked to its respective CET end state (H/E, H/I, H/L, etc.). The release fraction and timing data for all sequences associated with a particular CET end state was weighed according to the sequence weight for that end state and summed to obtain a representative release fraction and release timing for that end state.

Table E.1-9 summarizes the results of the CET quantification and identifies the total annual release frequency for each Level 2 release category.

Table E.1-9
Summary of Containment Event Tree Quantification
CNS 2007TM Model Revision 1

Release Category (Magnitude/Timing)	Release Frequency (/ry)
H/E	2.46E-06
H/I	6.48E-07
H/L	0.00
M/E	8.58E-08
M/I	1.83E-07
M/L	9.20E-10
L/E	1.11E-07
L/I	4.63E-09
L/L	4.12E-09
LL/E	5.31E-07
LL/I	1.84E-07
LL/L	5.37E-08
NCF	7.28E-06
Total	1.16E-05

Nomenclature

Timing (time between General Emergency Declaration and initial release):

Late (L): Greater than 24 hours
Intermediate (I): 3.7 to 24 hours
Early (E): Less than 3.7 hours

Magnitude

NCF (little to no release) - Much less than 0.1% CsI release fraction
Low-Low (LL) - Less than 0.1% CsI release fraction
Low (L) - 0.1% to 1% CsI release fraction
Medium (M) - 1% to 10% CsI release fraction
High (H) - Greater than 10% CsI release fraction

E.1.2.2.7 Consequence Analysis Source Terms

Input to the Level 3 CNS model from the Level 2 model is a combination of radionuclide release fractions, timing of radionuclide releases, and frequencies at which the releases occur. This combination of information is used in conjunction with CNS site characteristics in the Level 3 model to evaluate the off-site consequences of a core damage event.

Source terms were developed for the release categories identified in Table E.1-7. Table E.1-10 provides a summary of the Level 2 results that were used as Level 3 input for the CNS SAMA analysis (the baseline analysis case).

Consequences corresponding to each of the release categories are developed in the CNS Level 3 model, which is discussed in Section E.1.5.

E.1.2.2.8 Release Magnitude Calculations

The MAAP computer code is used to assign both the radionuclide release magnitude and timing based on the accident progression characterization. Specifically, MAAP provides the following information:

- containment pressure and temperature (time of containment failure is determined by comparing these values with the nominal containment capability);
- radionuclide release timing and magnitude for a large number of radioisotopes; and
- release fractions for radionuclide species.

Table E.1-10
CNS Release Category Source Terms

Release Mode (CET End State)	Frequency (/year)	Warning Time (sec)	Elevation (m)	Release Start (sec)	Release Duration (sec)	Release Energy (W)
H/E	2.46E-06	7.37E+03	35	1.63E+04	4.32E+04	1.30E+07
H/I	6.48E-07	9.20E+04	35	1.23E+05	1.12E+05	7.70E+06
H/L	0.00	N/A	N/A	N/A	N/A	N/A
M/E	8.58E-08	7.20E+03	35	7.20E+03	1.30E+05	1.30E+07
M/I	1.83E-07	4.03E+03	35	4.90E+04	1.10E+05	7.70E+06
M/L	9.20E-10	2.41E+03	35	9.00E+04	2.49E+04	2.50E+05
L/E	1.11E-07	2.90E+03	35	1.46E+04	3.76E+04	1.30E+07
L/I	4.63E-09	2.41E+03	35	8.78E+04	2.80E+03	7.70E+06
L/L	4.12E-09	2.41E+03	35	1.01E+05	3.25E+04	2.50E+05
LL/E	5.31E-07	2.41E+03	35	1.44E+04	9.96E+04	1.30E+07
LL/I	1.84E-07	2.41E+03	35	8.78E+04	2.64E+04	7.70E+06
LL/L	5.37E-08	2.41E+03	35	1.04E+05	2.63E+04	2.50E+05

Table E.1-10 (Continued)
CNS Release Category Source Terms

Release Mode (CET End State)	Release Fractions								
	NG	I	Cs	Te	Sr	Ru	La	Ce	Ba
H/E	8.83E-01	3.50E-01	3.50E-01	2.57E-01	9.21E-03	8.13E-03	3.25E-04	4.56E-03	1.24E-02
H/I	1.00E+00	3.46E-01	3.46E-01	2.35E-01	9.33E-03	1.34E-04	1.84E-04	4.91E-03	4.39E-03
H/L	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
M/E	1.00E+00	1.51E-01	1.51E-01	2.79E-05	6.42E-03	1.11E-02	3.55E-04	3.40E-03	1.36E-02
M/I	1.00E+00	1.00E-01	1.00E-01	9.46E-02	3.17E-03	3.30E-04	5.85E-05	1.28E-03	1.92E-03
M/L	1.00E+00	9.08E-02	9.08E-02	1.21E-01	1.03E-05	1.83E-07	1.25E-07	4.76E-06	7.78E-06
L/E	9.90E-01	6.05E-03	6.05E-03	3.25E-03	7.54E-04	2.32E-07	5.03E-06	2.11E-04	3.45E-04
L/I	1.00E+00	9.40E-03	9.40E-03	2.16E-02	1.62E-05	2.88E-07	1.23E-07	4.64E-06	8.05E-06
L/L	9.98E-01	6.17E-03	6.17E-03	1.82E-03	3.14E-04	5.40E-08	2.12E-06	8.82E-05	1.44E-04
LL/E	9.12E-01	1.70E-04	1.70E-04	3.55E-06	9.02E-09	5.51E-08	8.76E-10	1.05E-09	6.56E-08
LL/I	1.00E+00	6.44E-06	6.44E-06	5.73E-06	3.68E-07	2.39E-08	2.54E-09	4.95E-08	1.94E-07
LL/L	1.00E+00	5.65E-04	5.65E-04	5.25E-04	4.92E-04	1.28E-07	2.25E-06	6.54E-05	2.18E-04

E.1.3 IPEEE Analysis

E.1.3.1 Seismic Analysis

The seismic portion of the IPEEE was completed in conjunction with the SQUG program [References E.1-2 and E.1-3]. CNS performed a seismic margin assessment (SMA) following the guidance of NUREG-1407, *Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities*, June 1991 [Reference E.1-4], and EPRI NP-6041-SL, Revision 1, "A Methodology for Assessment of Nuclear Power Plant Seismic Margin," August 1991 [Reference E.1-5]. The SMA approach is a deterministic and conservative evaluation that does not calculate risk on a probabilistic basis. Therefore, its results should not be compared directly with the best-estimate internal events results.

The conclusions of the CNS IPEEE seismic margin analysis are as follows.

(1) The overall plant HCLPF (High Confidence Low Probability of Failure) capacity at CNS is 0.3g PGA. All major plant structures (e.g., primary containment, reactor building, control building, diesel generator building, turbine building superstructure, and intake structure) have seismic capacities in excess of the HCLPF.

(2) No unique decay heat removal vulnerabilities to seismic events were found.

(3) Seismic-induced flooding and fires do not pose major risks.

(4) No unique seismic-induced containment failure mechanisms were identified.

A number of plant improvements were identified as described in NUREG-1742, *Perspectives Gained from the IPEEE Program*, Final Report, April 2002 [Reference E.1-6]. These improvements were implemented or were evaluated as SAMAs. Phase II SAMA 69, "Upgrade the seismic capacity of the diesel fire pump fuel tank and water supply tank," was evaluated to reduce the seismic/fire interaction upon the diesel fire pump.

E.1.3.2 Fire Analysis

The CNS internal fire risk model was performed in 1996 as part of the IPEEE submittal report. The CNS fire analysis was performed using EPRI's Fire PRA Implementation Guide [Reference E.1-7]. The EPRI Fire Induced Vulnerability Evaluation method was used for the initial screening, for treatment of transient combustibles, and as the source of fire frequency data [Reference E.1-8].

Table E.1-11 presents the results of the current CNS IPEEE fire analysis. These values reflect the re-evaluation of the IPEEE fire CDF results to include responses to NRC questions regarding fire-modeling progression.

Two plant improvements were identified as described in NUREG-1742, *Perspectives Gained from the IPEEE Program*, Final Report, April 2002. It was determined that an improvement to install additional features to allow control of switchyard breakers remote from control room board C and vertical board F, or to have a pre-planned recovery/repair action for control of the switchyard breakers following a fire that completely disables the control room boards, would result in less than a 0.5% decrease in overall plant CDF. Therefore, this improvement was not implemented or evaluated as a SAMA. The improvement to provide the service water system with water supplies that are diverse from pumps in the service water pump room is evaluated under Phase II SAMA 68, "Proceduralize the ability to cross-connect the circulating water pumps and the service water going to the TEC heat exchangers." Also, Phase II SAMA 63, "Add automatic fire suppression systems to the dominant fire zones," and Phase II SAMA 65, "Upgrade the ASDS panel to include additional system controls for opposite division," were evaluated to reduce fire CDF in dominant fire zones without suppression and in the control room.

Generic conservatisms in the IPEEE fire analysis methods mentioned in NEI 05-01, "Severe Accident Mitigation Alternatives (SAMA) Analysis Guidance Document," that are applicable to the CNS fire analysis include the following.

- The frequency and severity of fires were generally conservatively overestimated. A revised NRC fire events database indicates a trend toward lower frequency and less severe fires. This trend reflects improved housekeeping, reduction in transient fire hazards, and other improved fire protection steps at utilities.

- There is little industry experience with crew actions following fires. This led to conservative characterization of crew actions in the IPEEE fire analysis. Because CDF is strongly correlated with crew actions, this conservatism has a profound effect on fire results.

- The peer review process for fire analyses is less well developed than for internal events PSAs. For example, no industry process, such as NEI 00-02, exists for the structured peer review of a fire PSA.

Plant-specific conservative assumptions in the CNS IPEEE fire analysis include the following.

- Cable failure due to fire damage was assumed to arise from open circuits, hot shorts circuits, and short circuits to ground. In damaging a cable, the fire was always assumed to induce the conductor failure mode of concern.

- Manual fire suppression was only credited in the control room and non-essential switchgear room evaluations.

- Generic fire frequencies were used.

- Hardware repair activities were not credited.

E.1.3.3 Other External Hazards

The CNS IPEEE submittal, in addition to the internal fires and seismic events, examined a number of other external hazards:

- high winds and tornadoes;
- external flooding; and
- ice, hazardous chemical, transportation, and nearby facility incidents.

The CNS Individual Plant Examination of External Events (IPEEE) concluded for high winds, floods, and other external events that no undue risks are present that might contribute to CDF with a predicted frequency in excess of 1E-06/ry except for the design-basis tornado and a lightning strike to the control building. As these events are not dominant contributors to external event risk and quantitative analysis of these events is not practical, they are considered negligible.

Table E.1-11
CNS Fire IPEEE
Five Phase 2 Screening Results

Fire Compartment	Fire Compartment Description	Total Compartment CDF (/ry)	Screened?
1A	RCIC & CS Room	9.05E-08	Y
1B/1G	CS and CRD Room	1.03E-07	Y
1C	RHR Pump 1A and 1C Room	5.74E-08	Y
1D/1E	RHR Pump 1B and 1D, and HPCI Room	8.40E-08	Y
1F	Suppression Pool Area	1.73E-07	Y
2A/2C	Reactor Building El. 903'-6" - CRD Units - North/South	8.16E-07	Y
2B	RHR Hx 1A Compartment	1.29E-08	Y
2D	RHR Hx 1B Compartment	1.30E-08	Y
2E	Steam Tunnel	4.88E-08	Y
3A	Swgr Room 1F	1.11E-06	N
3B	Swgr Room 1G	2.72E-06	N
3C/3D/3E	Reactor Building El. 932'-6" - REC	2.73E-07	Y
4A/4C/4D	Reactor Building El. 958'-3" - Fuel Pool Hx/ Lube Oil	5.37E-07	Y

Table E.1-11 (Continued)
CNS Fire IPEEE
Five Phase 2 Screening Results

Fire Compartment	Fire Compartment Description	Total Compartment CDF (/ry)	Screened?
5B	Reactor Building El. 976'-0" - RRMG Set	8.04E-08	Y
7A	RHRSW Booster and Service Air Compressor	5.58E-07	Y
7B	ECST Area	2.79E-08	Y
8A	Auxiliary Relay Room	3.66E-07	Y
8B	RPS Room 1B	7.30E-07	Y
8C	RPS Room 1A	6.52E-08	Y
8D	Seal Water Pump Area	4.86E-08	Y
8E	Battery Room 1A	1.77E-07	Y
8F	Battery Room 1B	6.73E-07	Y
8G	DC Swgr Room 1B	7.90E-07	Y
8H	DC Swgr Room 1A	3.36E-07	Y
9A	Cable Spreading Room	8.23E-07	Y
9B	Cable Expansion Room	3.45E-07	Y
10B	Control Room and SAS Corridor	3.73E-06	N
8-1	Condenser Pit Area	9.68E-07	Y
12D	Turbine Building Floor - North 903'-6" El.	1.41E-07	Y
13B	Non-Critical Swgr Room	3.32E-07	Y
13C	Electric Shop	4.19E-08	Y
13D	I&C Shop	4.36E-08	Y
14A	EDG 1A Room	6.08E-07	Y
14B	EDG 1B Room	6.08E-07	Y
14C	EDG 1A Day Tank Room	1.32E-08	Y
14D	EDG 1B Day Tank Room	1.32E-08	Y
20A	Service Water Pump Room	1.73E-06	N
		1.93E-05	

E.1.4 PSA Model Revisions and Peer Review Summary

The summary of the CNS PSA models CDF and LERF is presented in the table below.

Summary of Major PSA Models		
PSA Model	**CDF (/ry)**	**LERF (/ry)**
(IPE) 1995	7.97×10^{-5}	$< 1 \times 10^{-6}$
1996b	1.33×10^{-5}	(not updated)
2001a	1.25×10^{-5}	5.63×10^{-7}
2005TM	1.12×10^{-5}	(not updated)
2006TM	1.43×10^{-5}	(not updated)
2007TM (Rev. 1)	9.27×10^{-6}	2.44×10^{-6}

E.1.4.1 Major Differences between the 1996b PSA Model and the IPE Model

In the IPE model, the contributors in order of dominance were station blackout (35 percent), transient induced LOCAs (30 percent), loss of coolant injection (18 percent), loss of containment heat removal (11 percent), ATWS (5 percent), and LOCA (1 percent).

The 1996b model CDF (1.33×10^{-5}/ry) represents a reduction from the CDF determined from the IPE model (7.97×10^{-5}/ry).

In the 1996b model, the contributors in order of dominance were loss of offsite power (49 percent), loss of condenser (14 percent), reactor trip (6 percent), loss of instrument air (6 percent), inadvertent open relief valve (6 percent), loss of service water (5 percent), loss of DC bus (3 percent), loss of AC bus (2 percent), small LOCA (< 1 percent), recirculation pump seal LOCA (< 1 percent). From an accident contribution standpoint SBO contributes 41 percent, ATWS contributes 19 percent, and ISLOCA contributes < 1 percent.

The major changes in the 1996b model can be summarized as follows.

- Revised human reliability analysis to incorporate revisions to emergency operating procedures.
- Added newly installed torus hard pipe vent.
- Corrected conservative thermal hydraulic analysis of SRV flow.
- Improved loss of offsite power model.

E.1.4.2 Major Differences between the 2001a Model and the 1996b Model

The 2001a model CDF (1.25 x 10^{-5}/ry) represents a slight reduction from the CDF determined from the 1996b model (1.33 x 10^{-5}/ry).

In the 2001a model, the contributors in order of dominance were loss of offsite power (49 percent), loss of condenser (19 percent), LOCA (8 percent), reactor trip (6 percent), loss of instrument air (6 percent), inadvertent open relief valve (6 percent), loss of service water (5 percent), loss of DC bus (3 percent), and loss of AC bus (2 percent).

Changes in the 2001a model can be summarized as follows.

- Minor improvements stemming from the 9/97 peer review (see Section E.1.4.6 for more information on the peer review).
- Updated component failure and unavailability database.
- LERF model was developed to include the torus hard pipe vent, incorporate revisions to emergency operating procedures, and a LERF translation matrix from the Level 1 results was implemented.

E.1.4.3 Major Differences between the 2005TM Model and the 2001a Model

The 2005TM model CDF (1.12 x 10^{-5}/ry) represents a slight reduction from the CDF determined from the 2001a model (1.25 x 10^{-5}/ry).

In the 2005TM model, the contributors in order of dominance were loss of offsite power (28 percent), reactor trip (23 percent), loss of AC bus (15 percent), loss of condenser (11 percent), loss of service water (11 percent), inadvertent open relief valve (3 percent), loss of instrument air (2 percent), loss of DC bus (2 percent), loss of TBCCW (< 1 percent), and LOCA (< 1 percent).

Changes in the 2005TM model can be summarized as follows.

- Updated initiating event frequencies to reflect information in NUREG/CR-6890.

E.1.4.4 Major Differences between the 2006TM Model and the 2005TM Model

The 2006TM model CDF (1.43 x 10^{-5}/ry) represents an increase from the CDF determined from the 2005TM model (1.12 x 10^{-5}/ry).

In the 2006TM model, the contributors in order of dominance were loss of offsite power (34 percent), loss of condenser (20 percent), loss of service water (16 percent), loss of AC bus (11 percent), reactor trip (8 percent), loss of instrument air (3 percent), loss of DC bus (3 percent), loss of TBCCW (2 percent), inadvertent open relief valve (1 percent), and LOCA (< 1 percent).

Changes in the 2006TM model can be summarized as follows.

- Updated to support MSPI and maintenance rule update.

E.1.4.5 Major Differences between the 2007TM (Rev. 1) Model and the 2006TM Model

The 2007TM model Rev. 1 CDF (9.27 x 10^{-6}/ry) represents a decrease from the CDF determined from the 2006TM model (1.43 x 10^{-5}/ry). The 2007TM model Rev. 1 LERF (2.44 x 10^{-6}) represents an increase from the 2007TM model LERF (5.63 x 10^{-7}). [The 2007TM model (Rev. 0) was revised immediately after it was received to correct various inaccurate pipe break and EDG start and run frequencies that were significantly skewing the model results. The 2007TM model (Rev. 0) was never used and the "Rev. 1" was added strictly for tracking.]

In the 2007TM Rev. 1 model, the contributors in order of dominance are transients (32 percent), loss of DC power (22 percent), LOCA (15 percent), loss of feedwater (11 percent), loss of offsite power (7 percent), loss of service water (6 percent), loss of AC bus (3 percent), internal flood (3 percent), and ISLOCA (< 1 percent). There were no specific initiators for SBO but the percentage contributions due to SBO and ATWS are 2.78 percent and 2.79 percent respectively.

Changes in the 2007TM Rev. 1 model can be summarized as follows.

- Internal flooding was added to the Level 1 model.
- Operator action dependencies were accounted for.
- The treatment of common cause failures was expanded.
- A more detailed Containment Event Tree and new Level 2 fault trees were developed.
- New Level 1 system models were added including severe accident mitigation strategies such as firewater injection.
- The PRA data was updated.
- Initiator fault trees were developed and used to calculate some initiating event frequencies such as loss of TEC.

The 2007TM model Rev. 1 LERF represents an increase from the previous LERF value. This difference is attributed to the following.

- Contributors to plant damage states leading to LERF were changed by revisions to the Level 1 model mentioned above, especially addition of internal flooding and revision of initiating event fault trees and frequencies (particularly DC power initiating events).

- MAAP 4.0.5 deterministic calculations were used to provide more realistic success criteria and timings. These timings were used in the human reliability analysis (HRA) which was also revised to use the EPRI HRA Calculator.

- MAAP 4.0.5 radionuclide release calculations were used to replace fission product transport calculations using MAAP 3.0B.

E.1.4.6 PSA Model Peer Review

The 1996b model was peer reviewed in September 1997 using Boiling Water Reactor Owners Group process. Facts and Observation sheets documented the certification team's insights and potential level of significance. There were no Level A findings (for which immediate model changes would have been appropriate) from the peer review. Although a number of minor model corrections were made following the peer review, no significant changes were made to the model structure or underlying assumptions.

The model changes in the 2001a, 2005TM and 2006TM models were peer reviewed for accuracy and consistency by members of the CNS staff not directly involved in their implementation. In addition, cognizant departments (licensing, operations, maintenance, training, planning & scheduling, system engineering, and design engineering) were provided with the final results and insights derived from each study for an expert panel review.

The 2007TM model, Revision 1 was peer reviewed by members of the Boiling Water Reactor Owners Group in May 2008 using the NEI 05-04 [Reference E.1-18] process and the ASME PRA Standard [Reference E.1-19] along with the NRC clarifications provided in Regulatory Guide 1.200, Rev. 1 [Reference E.1-20]. The peer review was a full-scope review of all the technical elements of the internal events, at-power PRA. These elements are initiating events analysis, accident sequence analysis, success criteria, systems analysis, human reliability analysis, data analysis, internal flooding, quantification, and LERF analysis. The week-long peer review also addressed PRA configuration control.

The review team found that, of the 301 ASME PRA Standard supporting requirements applicable to CNS, approximately 94% are supportive of capability category II or greater. Nine best practices, 47 suggestions, and 33 findings were noted by the review team. The "best practices" identify PRA strengths, i.e., items that represent best industry practice. The "suggestions" identify changes desirable to maintain maximum flexibility for PRA applications and consistency with industry practices. Failing to resolve a suggestion should have no significant impact on the PRA results or the integrity of the PRA. "Findings" are observations that should be addressed to ensure the technical adequacy of the PRA relative to a capability category, the capability/ robustness of the PRA update process, or the process for evaluating the necessary capability of the PRA technical elements.

CNS review of the preliminary peer review findings determined that resolution of the findings would not result in significant impact on the PRA results. The areas considered "not met" or capability category I have negligible effect on the baseline CDF. In addition, with respect to this application, the issue regarding treatment of uncertainty on SAMA candidates is explicitly evaluated and reported. Therefore the "not met" characterization of the nine SRs related to uncertainty has limited impact. Generally the PRA model is documented extensively and peer review comments were related to thoroughness rather than specific deficiencies when assigning capability to each SR. It is anticipated that several of the findings will be revised or resolved prior to finalizing the peer review report. Therefore, use of the 2007TM model, Revision 1 for the SAMA analysis is appropriate.

No plant modifications or procedure changes have occurred since the freeze date of the 2007TM Revision 1 model that could have a significant impact on the results of the PSA or the SAMA analysis.

E.1.5 The MACCS2 Model – Level 3 Analysis

E.1.5.1 Introduction

SAMA evaluation relies on Level 3 PRA results to measure the effects of potential plant modifications. A Level 3 PRA model using version 1.13.1 of the MELCOR Accident Consequences Code System Version 2 (MACCS2) [Reference E.1-1] was created for CNS. This model, which requires detailed site-specific meteorological, population, and economic data, estimates the consequences in terms of population dose and offsite economic cost. Risks in terms of population dose risk (PDR) and offsite economic cost risk (OECR) were also estimated in this analysis. Risk is defined as the product of consequence and frequency of an accidental release.

This analysis considers a base case and two sensitivity cases to account for variations in data and assumptions for postulated internal events. The base case uses estimated time and speed for evacuation. Sensitivity case 1 is the base case with delayed evacuation. Sensitivity case 2 is the base case with lower evacuation speed.

PDR was estimated by summing over all releases the product of population dose and frequency for each accidental release. Similarly, OECR was estimated by summing over all releases the product of offsite economic cost and frequency for each accidental release. Offsite economic cost includes costs that could be incurred during the emergency response phase and costs that could be incurred through long-term protective actions.

E.1.5.2 Input

The following sections describe the site-specific input parameters used to obtain the off-site dose and economic impacts for cost-benefit analyses.

E.1.5.2.1 Projected Total Population by Spatial Element

The total population within a 50-mile radius of CNS was estimated for the year 2034, the end of the proposed license renewal period, for each spatial element by combining total resident population projections with transient populations. The 2034 permanent population values are based on the county-level projections obtained from the University of Nebraska Bureau of Business Research from 2000–2020, Woods & Poole Economics, Inc. for Iowa from 2000–2030, Darrel Eklund et al. for Kansas from 2000–2040, and the Missouri Census Data Center from 2000–2025 [References E.1-11, E.1-12, E.1-13 and E.1-14]. Regression methods were used to extrapolate population projections to 2034. For the counties with population in decline, the

population value for 2014 was used as the 2034 estimate. Table E.1-12 shows the estimated population distribution.

Table E.1-12
Estimated Population Distribution within a 50-mile Radius

Wind Direction	0 to 10 miles	11 to 20 miles	21 to 30 miles	31 to 40 miles	41 to 50 miles	Total
N	148	1,580	1,970	2,770	14,771	21,239
NNE	81	189	1,387	7,433	5,607	14,697
NE	231	248	975	1,047	6,803	9,304
ENE	1,498	2,100	588	1,481	1,974	7,641
E	103	816	272	4,580	9,984	15,755
ESE	51	255	471	1,240	2,455	4,472
SE	9	499	1,675	1,842	3,027	7,052
SSE	40	292	824	1,830	2,047	5,033
S	62	505	5,257	5,005	3,611	14,440
SSW	311	532	427	3,776	2,569	7,615
SW	237	638	1,192	897	2,532	5,496
WSW	108	230	646	1,391	837	3,212
W	90	2,021	2,615	709	1,951	7,386
WNW	104	2,646	1,308	1,641	3,654	9,353
NW	140	507	1,346	5,333	5,788	13,114
NNW	1,183	232	10,239	2,728	19,674	34,056
Totals	4,396	13,290	31,192	43,703	87,284	179,865

E.1.5.2.2 Land Fraction

The land fraction for each spatial element was estimated within the 50 mile radius area. The National Hydrography Dataset was used to estimate the extent of land and surface water coverage [Reference E.1-15].

E.1.5.2.3 Watershed Class

Watershed Index is defined by MACCS2 as areas drained by rivers (Class 1) or large water bodies (Class 2). No spatial elements were treated as large water bodies for CNS.

E.1.5.2.4 Regional Economic Data

Region Index

Each spatial element was assigned to an economic region, defined in this report as a county. Where a spatial element covers portions of more than one county, it was assigned to that county having the most area within the element.

Regional Economic Data

County level economic data were obtained from the US Department of Agriculture for 2002 [Reference E.1-16].

VALWF – Value of Farm Wealth

MACCS2 requires an average value of farm wealth (dollars/hectare) for the 50-mile radius area around CNS. The county-level farmland property value was used as a basis for deriving this value. VALWF is $3,701/hectare.

VALWNF– Value of Non-Farm Wealth

MACCS2 also requires an average value of non-farm wealth. The county-level non-farm property value was used as a basis for deriving this value. VALWNF is $104,504/person.

Other economic parameters and their values are shown below. The values were obtained by adjusting the economic data given in Reference E.1-1 with the consumer price index of 201.6, which is the average value for the year 2006, as appropriate.

Variable	Description	Value
EVACST	Daily cost for a person who has been evacuated ($/person-day)	49.7
POPCST	Population relocation cost ($/person)	9197
RELCST	Daily cost for a person who is relocated ($/person-day)	49.7
CDFRM0	Cost of farm decontamination for the various levels of decontamination ($/hectare)	1035 2299
CDNFRM	Cost of non-farm decontamination for the various levels of decontamination ($/person)	5518 14715
DLBCST	Average cost of decontamination labor ($/person-year)	64380

DPRATE	Property depreciation rate (per year)	0.2
DSRATE	Investment rate of return (per year)	0.12

E.1.5.2.5 Agriculture Data

The source of regional crop information is the 2002 Census of Agriculture [Reference E.1-16]. The crops listed for each county within the 50-mile area were summed and mapped into the seven MACCS2 crop categories.

E.1.5.2.6 Meteorological Data

The MACCS2 model requires meteorological data for wind speed, wind direction, atmospheric stability, accumulated precipitation, and atmospheric mixing heights. The required data was obtained from the CNS meteorological monitoring system and regional National Weather Service stations.

Site Specific Data

The CNS meteorological monitoring system includes both primary and backup systems. The primary meteorological system was the data source for the MACCS2 analysis. Based on a review of annual meteorological data collected at the site between 2002 and 2006, data from calendar years 2002 through 2006 were averaged for the MACCS2 input file. The data included 43,824 (one leap year) consecutive hourly values of wind speed, wind direction, precipitation, and temperature recorded at the CNS meteorological tower from January 2002 to December 2006. Missing data for parameters of interest were estimated using data substitution methods. These methods include substitution of missing data with valid data from the previous hour, removal of data from the average calculation, and substitution of valid data collected from other elevations on the meteorological tower.

Regional Mixing Height Data

Mixing height is defined as the height of the atmosphere above ground level within which a released contaminant will become mixed (from turbulence) within approximately one hour. Regional mixing heights were estimated using ground level and upper-air data collected at National Weather Service Station No. 94980 in Valley, NE (approximately 76 miles NNW of CNS) and Station No. 72553 in Falls City/Brenner, NE (approximately 19 miles S of CNS). These two weather stations were selected by staff meteorologists at the National Climatic Data Center to calculate seasonal mixing height values for the CNS area.

E.1.5.2.7 Emergency Response Assumptions

Detailed analysis of evacuation scenarios for the EPZ were addressed in the CNS evacuation travel time estimate studies for the Nebraska [Reference E.1-9] and Missouri [Reference E.1-10] portions of the EPZ. The Nebraska study, dated January 1992, was conducted by the Nebraska Civil Defense Agency in conjunction with the Civil Defense organizations in Nemaha and

Richardson Counties. The Missouri Study, dated August 1991, was conducted by the Missouri State Emergency Management Agency and the Nebraska Public Power District. The studies provide an analysis of the range and variation of public reaction to the evacuation notification process. They are the latest reports available and are still valid because the population in the 10-mile EPZ area has been in decline since the studies were conducted. The reports present conservative estimates of the time needed to evacuate the total population from the 10-mile EPZ.

Evacuation Delay Time

The elapsed time between the issuance of an evacuation notification and the beginning of the public evacuation is 2 hours and 15 minutes in Nebraska, 1 hour and 45 minutes in Missouri. The baseline delay time (2 hours) for an evacuation from the EPZ was calculated by averaging the delay times identified in both the Missouri and Nebraska evacuation time estimate studies. A sensitivity case that assumes 4.0 hours for evacuees to begin evacuation was considered in this study to evaluate consequence sensitivities due to uncertainties in delay time.

Evacuation Speed

Evacuation travel speed ranges from 23.8 miles/hour (10.6 meters/second) to 10.9 miles/hour (4.9 meters/second) in Nebraska. In Missouri the evacuation travel speed ranges from 28.6 miles/hour (12.8 meters/second) under normal conditions to 14.5 miles/hour (6.5 meters/second) under adverse conditions. The average evacuation speed was estimated to be approximately 19.5 miles/hour (8.7 meters/second). A sensitivity case that assumes a lower evacuation speed of 1.0 meter/second was considered in this study to evaluate consequence sensitivities due to uncertainties in evacuation speed.

E.1.5.2.8 Core Inventory

The estimated CNS core inventory (Table E.1-13) used in the MACCS2 input is based on a power level of 2429 MW(t). The core inventory was derived from isotope generation and depletion code ORIGEN2 for a bounding reload core immediately following shutdown. The core inventory values were calculated for an assumed power level of 2429 MWt (102% of the 2381 MWt licensed power level) to provide margin for possible Measurement Uncertainty Recapture (MUR) power uprate.

Table E.1-13
Estimated CNS Core Inventory (Becquerels)(1)

Nuclide	Inventory	Nuclide	Inventory
Co-58	1.38E+16	Te-131m	3.56E+17
Co-60	1.64E+16	Te-132	3.46E+18
Kr-85	3.29E+16	I-131	2.44E+18
Kr-85m	6.12E+17	I-132	3.53E+18

Table E.1-13 (Continued)
Estimated CNS Core Inventory (Becquerels)(1)

Nuclide	Inventory	Nuclide	Inventory
Kr-87	1.17E+18	I-133	4.95E+18
Kr-88	1.64E+18	I-134	5.43E+18
Rb-86	6.28E+15	I-135	4.64E+18
Sr-89	2.19E+18	Xe-133	4.73E+18
Sr-90	2.61E+17	Xe-135	1.67E+18
Sr-91	2.79E+18	Cs-134	6.07E+17
Sr-92	3.04E+18	Cs-136	1.94E+17
Y-90	2.70E+17	Cs-137	3.64E+17
Y-91	2.85E+18	Ba-139	4.40E+18
Y-92	3.05E+18	Ba-140	4.23E+18
Y-93	3.56E+18	La-140	4.38E+18
Zr-95	4.00E+18	La-141	4.01E+18
Zr-97	4.05E+18	La-142	3.86E+18
Nb-95	4.03E+18	Ce-141	4.02E+18
Mo-99	4.60E+18	Ce-143	3.69E+18
Tc-99m	4.06E+18	Ce-144	3.29E+18
Ru-103	3.86E+18	Pr-143	3.61E+18
Ru-105	2.72E+18	Nd-147	1.62E+18
Ru-106	1.56E+18	Np-239	5.27E+19
Rh-105	2.49E+18	Pu-238	1.15E+16
Sb-127	2.71E+17	Pu-239	1.16E+15
Sb-129	8.03E+17	Pu-240	1.59E+15
Te-127	2.74E+17	Pu-241	4.80E+17
Te-127m	3.65E+16	Am-241	6.17E+14
Te-129	7.90E+17	Cm-242	1.55E+17
Te-129m	1.17E+17	Cm-244	9.98E+15

1. From CNS specific data for a power level of 2429 MWth

E.1.5.2.9 Source Terms

Eleven release categories, corresponding to internal event sequences, were part of the MACCS2 input. The High Late (H/L) category has zero release frequency and is not considered. Section E.1.2.2.6 provides details of the source terms for postulated internal events. A linear release rate was assumed between the time the release started and the time the release ended.

E.1.5.3 Results

Risk estimates for one base case and two sensitivity cases were analyzed with MACCS2. The base case assumes 2.0 hours delay and 8.7 meter/sec speed of evacuation. Sensitivity case 1 is the base case with delayed evacuation of 4.0 hours. Sensitivity case 2 is the base case with an evacuation speed of 1.0 meter/sec. Table E.1-14 shows estimated base case mean risk values for each release mode. The estimated mean values of PDR and offsite OECR for CNS are 2.14 person-rem/yr and $7,010/yr, respectively.

Table E.1-14
Base Case Mean PDF and OECR Values

Release Mode	Frequency (/yr)	Population Dose (person-sv)(1)	Offsite Economic Cost ($)	Population Dose Risk (PDR) (person-rem/yr)	Offsite Economic Cost Risk (OECR) ($/yr)
H/E	2.46E-06	6.46E+03	2.13E+09	1.59E+00(2)	5.24E+03
H/I	6.48E-07	6.11E+03	2.10E+09	3.96E-01	1.36E+03
M/E	8.58E-08	4.51E+03	1.55E+09	3.87E-02	1.33E+02
M/I	1.83E-07	3.88E+03	1.33E+09	7.11E-02	2.44E+02
M/L	9.20E-10	3.59E+03	1.13E+09	3.30E-04	1.04E+00
L/E	1.11E-07	2.08E+03	2.26E+08	2.31E-02	2.51E+01
L/I	4.63E-09	1.33E+03	2.77E+08	6.15E-04	1.28E+00
L/L	4.12E-09	2.11E+03	1.77E+08	8.68E-04	7.29E-01
LL/E	5.31E-07	3.62E+02	3.51E+06	1.92E-02	1.86E+00
LL/I	1.84E-07	2.18E+01	4.16E+05	4.00E-04	7.64E-02
LL/L	5.37E-08	8.49E+02	2.04E+07	4.56E-03	1.09E+00
			Totals	2.14E+00	7.01E+03

1. 1 sv = 100 rem
2. 1.59E+00 (person-rem/yr) = 2.46E-06 (/yr) x 6.46E+03 (person-sv) x 100 (rem/sv)

Results of sensitivity analyses indicate that a delayed evacuation or a lower evacuation speed would not have any significant effects on the offsite consequences or risks determined in this study. Table E.1-15 summarizes offsite consequences in terms of population dose (person-sv) and offsite economic cost ($) for the base case and the sensitivity cases. Comparison of the consequences indicates that the maximal deviation is less than 2% between the base case population dose and the Sensitivity Case 1 population dose for release mode M/E.

Table E.1-15
Summary of Offsite Consequence Sensitivity Results

	Population Dose (person-sv)			Offsite Economic Cost ($)		
Release Mode	**Base Case**	**4-hr Delayed Evacuation**	**Lower Speed of Evacuation**	**Base Case**	**4 –hr Delayed Evacuation**	**Lower Speed of Evacuation**
H/E	6.46E+03	6.48E+03	6.53E+03	2.13E+09	2.13E+09	2.13E+09
H/I	6.11E+03	6.11E+03	6.11E+03	2.10E+09	2.10E+09	2.10E+09
M/E	4.51E+03	4.53E+03	4.56E+03	1.55E+09	1.55E+09	1.55E+09
M/I	3.88E+03	3.88E+03	3.88E+03	1.33E+09	1.33E+09	1.33E+09
M/L	3.59E+03	3.59E+03	3.59E+03	1.13E+09	1.13E+09	1.13E+09
L/E	2.08E+03	2.08E+03	2.08E+03	2.26E+08	2.26E+08	2.26E+08
L/I	1.33E+03	1.33E+03	1.33E+03	2.77E+08	2.77E+08	2.77E+08
L/L	2.11E+03	2.11E+03	2.11E+03	1.77E+08	1.77E+08	1.77E+08
LL/E	3.62E+02	3.62E+02	3.62E+02	3.51E+06	3.51E+06	3.51E+06
LL/I	2.18E+01	2.18E+01	2.18E+01	4.16E+05	4.16E+05	4.16E+05
LL/L	8.49E+02	8.49E+02	8.49E+02	2.04E+07	2.04E+07	2.04E+07

E.1.6 References

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E.1-4 United States Nuclear Regulatory Commission, NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities," June 1991.

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ATTACHMENT E.2

EVALUATION OF CNS SAMA CANDIDATES

E.2 EVALUATION OF CNS SAMA CANDIDATES

This section describes the generation of the initial list of potential SAMA candidates, screening methods, and the analysis of the remaining SAMA candidates.

E.2.1 SAMA List Compilation

A list of SAMA candidates was developed by reviewing industry documents and considering other plant-specific enhancements not identified in published industry documents. Since CNS is a BWR, considerable attention was paid to the SAMA candidates from SAMA analyses for other BWR plants. Industry documents reviewed include the following.

- NEI 05-01, Severe Accident Mitigation Alternatives Analysis [Reference E.2-1]
- James A. FitzPatrick Nuclear Power Plant SAMA Analysis [Reference E.2-2]
- Vermont Yankee Nuclear Power Station SAMA Analysis [Reference E.2-3]
- Pilgrim Nuclear Power Station SAMA Analysis [Reference E.2-4]
- Oyster Creek Nuclear Generating Station SAMA Analysis [Reference E.2-5]
- Monticello Nuclear Generating Plant SAMA Analysis [Reference E.2-6]
- Brunswick Steam Electric Plant, Units 1 and 2 SAMA Analysis [Reference E.2-7]
- NUREG-1742, *Perspectives Gained from the Individual Plant Examination of External Events (IPEEE) Program* [Reference E.2-8]

In addition to SAMA candidates from review of industry documents, additional SAMA candidates were obtained from plant-specific sources, such as the CNS IPE [Reference E.2-9] and the CNS IPEEE [Reference E.2-10]. In the IPE and IPEEE several enhancements related to severe accident insights were recommended. These enhancements are included in the comprehensive list of Phase I SAMA candidates. Table E.2-1 lists the IPE and IPEEE Phase I SAMA candidates for the SAMA analysis and indicates which have been implemented, which have been incorporated in the model used for the SAMA analysis, and which have been retained for further evaluation in Phase II of the SAMA analysis. The current CNS PSA levels 1 and 2 models were also used to identify plant-specific modifications for inclusion in the comprehensive list of SAMA candidates. The risk significant terms from the current PSA model were reviewed for similar failure modes and effects that could be addressed through a potential enhancement to the plant. The correlation between SAMAs and the risk significant events are listed in Tables E.1-3 and E.1-5.

The comprehensive list contained a total of 244 Phase I SAMA candidates and is available in onsite documentation.

E.2.2 Qualitative Screening of SAMA Candidates (Phase I)

The purpose of the preliminary SAMA screening was to identify the subset of candidate SAMAs that would reduce severe accident risk at CNS and would therefore warrant a detailed cost-benefit evaluation. Potential SAMA candidates were screened out if they modified features not applicable to CNS, if they had already been implemented at CNS, or if they were similar in nature and could be combined with another SAMA candidate to develop a more comprehensive or

plant-specific SAMA candidate. During this process, 49 of the Phase I SAMA candidates were screened out because they were not applicable to CNS, 24 of the Phase I SAMA candidates were screened out because they were similar in nature and could be combined with another SAMA candidate, and 91 of the Phase I SAMA candidates were screened out because they had already been implemented at CNS, leaving 80 SAMA candidates for further analysis. The final screening process involved identifying and eliminating those items whose implementation cost would exceed their benefit as described below. Table E.2-2 provides a description of each of the 80 Phase II SAMA candidates.

E.2.3 Final Screening and Cost Benefit Evaluation of SAMA Candidates (Phase II)

A cost/benefit analysis was performed on each of the remaining SAMA candidates. If the implementation cost of a SAMA candidate was determined to be greater than the potential benefit (i.e., there was a negative net value) the SAMA candidate was considered not to be cost beneficial and was not retained as a potential enhancement.

The expected cost of implementation of each SAMA was established from existing estimates of similar modifications. Most of the cost estimates were developed from similar modifications considered in previously performed SAMA. In particular, these cost-estimates were derived from the following sources.

- Pilgrim SAMA Analysis [Reference E.2-4]
- Vermont Yankee SAMA Analysis [Reference E.2-3]
- James A. FitzPatrick SAMA Analysis [Reference E.2-2]
- Peach Bottom SAMA Analysis [Reference E.2-12]
- Quad Cities SAMA Analysis [Reference E.2-13]
- Susquehanna Steam Electric Station SAMA Analysis [Reference E.2-14]
- Monticello SAMA Analysis [Reference E.2-6]
- Browns Ferry, Units 1, 2, and 3 SAMA Analysis [Reference E.2-15]
- Brunswick, Units 1 and 2 SAMA Analysis [Reference E.2-16]
- Oyster Creek SAMA Analysis [Reference E.2-5]
- Nine Mile Point, Units 1 and 2 SAMA Analysis [Reference E.2-17]

The cost estimates did not include the cost of replacement power during extended outages required to implement the modifications. Estimates based on modifications that were implemented or estimated in the past were presented in terms of dollar values at the time of implementation (or estimation) and were not adjusted to present-day dollars. Therefore, the cost estimates were conservative.

The benefit of implementing a SAMA candidate was estimated in terms of averted consequences. The benefit was estimated by calculating the arithmetic difference between the total estimated costs associated with the four impact areas for the baseline plant design and the total estimated impact area costs for the enhanced plant design (following implementation of the SAMA candidate).

Values for avoided public and occupational health risk were converted to a monetary equivalent (dollars) via application of the NUREG/BR-0184 [Reference E.2-11] conversion factor of $2,000 per person rem and discounted to present value. Values for avoided off-site economic costs were also discounted to present value.

As this analysis focuses on establishing the economic viability of potential plant enhancement when compared to attainable benefit, detailed cost estimates often were not required to make informed decisions regarding the economic viability of a particular modification. Several of the SAMA candidates were clearly in excess of the attainable benefit estimated from a particular analysis case.

For less clear cases, engineering judgment on the cost associated with procedural changes, engineering analysis, testing, training, and hardware modification was applied to determine if a more detailed cost estimate was necessary to formulate a conclusion regarding the economic viability of a particular SAMA. Cost input to the engineering judgment was obtained from project engineers experienced in performing design changes at the facility and these values were compared, where possible, to estimates developed and used at plants of similar design and vintage. Therefore, based on a review of previous SAMA evaluations and an evaluation of expected implementation costs at CNS, the following estimated costs for each potential element of the proposed SAMA implementation are used.

Type of Change	Estimated Cost Range
Procedural only	$25K-$50K
Procedural change with engineering required	$50K-$200K
Procedural change with engineering and testing/training required	$200K-$300K
Hardware modification	$100K to >$1000K

In most cases, more detailed cost estimates were not required, particularly if the SAMA called for the implementation of a hardware modification. Nonetheless, the cost of each unscreened SAMA candidate was conceptually estimated to the point where conclusions regarding the economic viability of the proposed modification could be adequately gauged. The cost benefit comparison and disposition of each of the 80 Phase II SAMA candidates is presented in Table E.2-2.

Bounding evaluations (or analysis cases) were performed to address specific SAMA candidates or groups of similar SAMA candidates. These analysis cases overestimated the benefit and thus were conservative calculations. For example, one SAMA candidate suggested installing digital large break LOCA protection; the bounding calculation estimated the benefit of this improvement by total elimination of risk due to large break LOCA (see analysis of Phase II SAMA 66 in Table E.2-2). This calculation obviously overestimated the benefit, but if the inflated benefit

indicated that the SAMA candidate was not cost beneficial, then the purpose of the analysis was satisfied.

A description of the analysis cases used in the evaluation follows.

Case 1: DC Power

This analysis case was used to evaluate the change in plant risk from plant modifications that would increase the availability of DC power (e.g., increasing battery capacity, portable power supplies, or using fuel cells). It was assumed that battery life could be extended to 24 hours to simulate additional battery capacity. This enhancement would extend HPCI and RCIC operability and allow more credit for AC power recovery. A bounding analysis was performed by changing the time available to recover offsite power before HPCI and RCIC are lost to 24 hours during station blackout scenarios in the level 1 PSA model. This resulted in an internal and external benefit (with uncertainty) of approximately $96,836. This analysis case was used to model the benefit of Phase II SAMAs 1, 2, 13, and 21.

Case 2: Improve Charger Reliability

This analysis case was used to evaluate the change in plant risk from improving DC battery charging reliability by adding an additional battery charger or by changing procedures to allow the charger high-voltage trip circuit to be disabled when the batteries are disconnected from the DC circuit, thereby preventing the trip and allowing the chargers to remain online. A bounding analysis was performed by setting the common cause failure contribution due to loss of DC battery chargers to zero in the level 1 PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $7,018. This analysis case was used to model the benefit of Phase II SAMAs 3 and 15.

Case 3: Add DC System Cross-ties

This analysis case was used to evaluate the change in plant risk from adding DC bus cross-ties to improve DC power availability and reliability. The 125V distribution panels and starter racks can be powered from either bus, thus the 125V buses are cross-tied. However, the 250V buses are not cross-tied. A bounding analysis was performed by setting the 250V DC buses to zero in the level 1 PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $0. This analysis case was used to model the benefit of Phase II SAMA 4.

Case 4: Improve Existing DC System Cross-ties

This analysis case was used to evaluate the change in plant risk from enhancing procedures to make use of the existing 125V DC bus cross-tie to improve DC power availability and reliability. A bounding analysis was performed by setting failure of the operator to use the 125V DC bus cross-tie to zero in the Level 1 PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $5,997. This analysis case was used to model the benefit of Phase II SAMA 19.

Case 5: Provide Backup DC Power to the 120 V Vital AC Bus

This analysis case was used to evaluate the change in plant risk from improving injection capability by auto-transfer of AC bus control power to a standby DC power source upon loss of the normal DC source. A bounding analysis was performed by eliminating failure of DC power to the no break power panel, which resulted in an internal and external benefit (with uncertainty) of approximately $1,395. This analysis case was used to model the benefit of Phase II SAMA 5.

Case 6: Increase Availability of the 120 V Vital AC Bus

This analysis case was used to evaluate the change in plant risk from improving injection capability by auto-transfer of AC bus control power to a standby power source upon loss of the normal power source. A bounding analysis was performed by setting failure to transfer the RPS panels to their alternate power source to zero in the level 1 PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $0. This analysis case was used to model the benefit of Phase II SAMA 6.

Case 7: Increase Availability of On-Site AC Power

This analysis case was used to evaluate the change in plant risk from improving the diversity of on-site AC power. A bounding analysis was performed by setting failure of the EDGs to zero in the level 1 PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $425,016. This analysis case was used to model the benefit of Phase II SAMAs 7 and 10.

Case 8: Provide Backup EDG SW Cooling

This analysis case was used to evaluate the change in plant risk from increasing EDG reliability by adding a backup source of diesel cooling. A bounding analysis was performed by eliminating failure of SW cooling to the EDGs, which resulted in an internal and external benefit (with uncertainty) of approximately $134,213. This analysis case was used to model the benefit of Phase II SAMA 11.

Case 9: Increase EDG Reliability

This analysis case was used to evaluate the change in plant risk from providing a portable EDG fuel oil transfer pump. A bounding analysis was performed by eliminating failure of the EDG fuel oil transfer pumps, which resulted in an internal and external benefit (with uncertainty) of approximately $18,687. This analysis case was used to model the benefit of Phase II SAMA 16.

Case 10: Improve AC Power

This analysis case was used to evaluate the change in plant risk from improving the 4.16-kV buses by adding cross-ties or by providing alternate feeds to essential loads directly from an alternate emergency bus. A bounding analysis was performed by eliminating the loss of the 4.16-kV buses, which resulted in an internal and external benefit (with uncertainty) of

approximately $106,470. This analysis case was used to model the benefit of Phase II SAMAs 8 and 17.

Case 11: Reduce Loss of Off-Site Power During Severe Weather

This analysis case was used to evaluate the change in plant risk from burying existing or additional power lines to reduce the probability of loss of off-site power during severe weather. A bounding analysis was performed by eliminating the weather centered loss of off-site power initiating event, which resulted in an internal and external benefit (with uncertainty) of approximately $129,710. This analysis case was used to model the benefit of Phase II SAMAs 9 and 12.

Case 12: Reduce Plant-Centered Loss of Off-Site Power

This analysis case was used to evaluate the change in plant risk from reducing the loss of off-site power by protecting the transformers from explosive failure. A bounding analysis was performed by eliminating the plant centered loss of offsite power initiating event, which resulted in an internal and external benefit (with uncertainty) of approximately $1,843. This analysis case was used to model the benefit of Phase II SAMA 18.

Case 13: Redundant Power to Torus Hard Pipe Vent (THPV) Valves

This analysis case was used to evaluate the change in plant risk from adding redundant power supplies to the hard pipe direct torus vent valve control circuits. A bounding analysis was performed by setting failure of power to the hard pipe torus vent valves to zero in the level 1 PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $232,320. This analysis case was used to model the benefit of Phase II SAMA 20.

Case 14: High Pressure Injection System

This analysis case was used to evaluate the change in plant risk from plant modifications that would increase the availability of high pressure injection (e.g., installing a high pressure injection system independent of AC power, passive high pressure injection system, or additional power to the HPCI system). The proposed modification for SAMA 14 includes using an available skid mounted portable AC generator and adding electrical wall penetrations in the control building. It would also require procedure revisions, training and maintenance of the portable generator to ensure availability. A bounding analysis was performed by setting the CDF contribution due to unavailability of the HPCI system to zero in the level 1 PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $905,481. This analysis case was used to model the benefit of Phase II SAMAs 14, 22, and 23.

Case 15: Extend RCIC Operation

This analysis case was used to evaluate the change in plant risk from raising or bypassing the RCIC backpressure trip set-point. A bounding analysis was performed by eliminating failures due to the RCIC backpressure trip, which resulted in an internal and external benefit (with

uncertainty) of approximately $86,079. This analysis case was used to model the benefit of Phase II SAMAs 24 and 25.

Case 16: Improve ADS System

This analysis case was used to evaluate the change in plant risk from adding larger accumulators to the ADS components to increase reliability during a SBO. A bounding analysis was performed by eliminating failure of the ADS accumulators, which resulted in an internal and external benefit (with uncertainty) of approximately $0. This analysis case was used to model the benefit of Phase II SAMA 26.

Case 17: Reliability of SRVs

This analysis case was used to evaluate the change in plant risk from installing additional signals to automatically open the SRVs in an MSIV closure transient. This improvement would reduce the likelihood of SRVs failing to open, thereby reducing the consequences of LOCAs. A bounding analysis was performed by setting the probability of SRVs failing to open when required by reactor pressure vessel overpressure conditions to zero in the level 1 PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $406,113. This analysis case was used to model the benefit of Phase II SAMA 27.

Case 18: Low Pressure Injection System

This analysis case was used to evaluate the change in plant risk from adding an additional low pressure injection system. A bounding analysis was performed by eliminating failure of the low pressure injection system, which resulted in an internal and external benefit (with uncertainty) of approximately $1,811,968. This analysis case was used to model the benefit of Phase II SAMA 28.

Case 19: ECCS Low Pressure Interlock

This analysis case was used to evaluate the change in plant risk from installing a bypass switch to allow operators to bypass the low reactor pressure interlock circuitry. A bounding analysis was performed by eliminating failure of the low pressure interlock circuitry in the level 1 PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $570,904. This analysis case was used to model the benefit of Phase II SAMA 29.

Case 20: Improve Reliability of HPCI and RCIC

This analysis case was used to evaluate the change in plant risk from improving the reliability of the HPCI and RCIC systems by upgrading their control systems. A bounding analysis was performed by eliminating failure of the HPCI and RCIC turbine driven pumps, which resulted in an internal and external benefit (with uncertainty) of approximately $125,987. This analysis case was used to model the benefit of Phase II SAMA 67.

Case 21: Main Condenser

This analysis case was used to evaluate the change in plant risk from improving steam tunnel HVAC reliability/redundancy to prevent inadvertent group 1 isolations. A bounding analysis was performed by eliminating failure of the condenser to remove heat and eliminating the group 1 isolation initiator, which resulted in an internal and external benefit (with uncertainty) of approximately $79,550. This analysis case was used to model the benefit of Phase II SAMA 76.

Case 22: Improve Reliability of ECCS Equipment

This analysis case was used to evaluate the change in plant risk from improving reliability of auto-start features for the ECCS equipment. A bounding analysis was performed by eliminating the failure of the auto-start features for the ECCS equipment, which resulted in an internal and external benefit (with uncertainty) of approximately $27,895. This analysis case was used to model the benefit of Phase II SAMA 77.

Case 23: Improve Injection Via Fire Water System

This analysis case was used to evaluate the change in plant risk from improving training on alternate injection via fire water system. A bounding analysis was performed by reducing operator actions that could be improved via training for alternate injection via the fire water system by a factor of 2, which resulted in an internal and external benefit (with uncertainty) of approximately $157,816. This analysis case was used to model the benefit of Phase II SAMA 78.

Case 24: RHR Heat Exchangers

This analysis case was used to evaluate the change in plant risk from revising procedures to allow manual alignment of the fire water system to RHR heat exchangers. A bounding analysis was performed by eliminating failure of the SW to provide cooling to the RHR heat exchangers, which resulted in an internal and external benefit (with uncertainty) of approximately $599,907. This analysis case was used to model the benefit of Phase II SAMA 30.

Case 25: Emergency Service Water System Reliability

This analysis case was used to evaluate the change in plant risk from installing an additional service water pump. A bounding analysis was performed by setting the events for the common cause contribution due to service water system pumps to zero in the level 1 PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $9,456. This analysis case was used to model the benefit of Phase II SAMA 31.

Case 26: Reduce Valve Failure, Fire Water System

This analysis case was used to evaluate the change in plant risk from enhancing alternate injection reliability by including the fire water cross-tie valves in the maintenance program. A bounding analysis was performed by eliminating the CDF contribution due to the fire water cross-

tie valves, which resulted in an internal and external benefit (with uncertainty) of approximately $1,073. This analysis case was used to model the benefit of Phase II SAMA 32.

Case 27: Alternate Water Supply for the TEC Heat Exchangers

This analysis case was used to evaluate the change in plant risk from proceduralizing the ability to cross-connect the circulating water pumps with the service water going to the turbine equipment cooling (TEC) heat exchangers. A bounding analysis was performed by eliminating failure of service water to provide cooling to the TEC heat exchangers, which resulted in an internal and external benefit (with uncertainty) of approximately $533,364. This analysis case was used to model the benefit of Phase II SAMA 68.

Case 28: Increase Availability of Feedwater and Condensate

This analysis case was used to evaluate installation of emergency connections of existing or alternate water sources to feedwater/condensate. A bounding analysis was performed by eliminating the CDF contribution due to failure of alternate injection from feedwater/condensate, which resulted in an internal and external benefit (with uncertainty) of approximately $1,295,174. This analysis case was used to model the benefit of Phase II SAMA 33.

Case 29: Main Feedwater System Reliability

This analysis case was used to evaluate the change in plant risk from installing a motor-driven feedwater pump. A bounding analysis was performed by setting failure of the feedwater turbine driven pumps to zero, which resulted in an internal and external benefit (with uncertainty) of approximately $267. This analysis case was used to model the benefit of Phase II SAMA 34.

Case 30: Increase Availability of the CST

This analysis case was used to evaluate the change in plant risk from providing a means of automatically preventing draindown of the CST to the hotwell during a SBO. A bounding analysis was performed by eliminating the CDF contribution from operator failure to prevent CST inventory drain-down to the hotwell, which resulted in an internal and external benefit (with uncertainty) of approximately $62,671. This analysis case was used to model the benefit of Phase II SAMA 72.

Case 31: Increase Availability of Room Cooling

This analysis case was used to evaluate the change in plant risk from providing a redundant means of ventilation to the CS pump rooms, RHR pump rooms, RHRSW booster pump rooms, SW pump rooms, or HPCI pump room. Room cooling to each of the rooms was eliminated individually. The RHRSW booster pump rooms had the largest benefit. Therefore, a bounding analysis was performed by eliminating failure of room cooling to the RHRSW booster pump rooms [basic event HVC-PHE-FF-CB7A was set to zero], which resulted in an internal and external benefit (with uncertainty) of approximately $115,493. This analysis case was used to model the benefit of Phase II SAMA 35.

Case 32: Increase Availability of the EDG System

This analysis case was used to evaluate the change in plant risk from installing a diverse set of fan actuation logic, installing an additional fan and louver pair, adding a diesel building high temperature alarm, or operator procedure revisions to provide additional space cooling to the EDG room. A bounding analysis was performed by eliminating failure of EDG HVAC, which resulted in an internal and external benefit (with uncertainty) of approximately $99,480. This analysis case was used to model the benefit of Phase II SAMAs 36, 38, 39, and 40.

Case 33: Improve Diagnosis of a Loss of Switchgear HVAC

This analysis case was used to evaluate the change in plant risk from adding a switchgear room high temperature alarm. A bounding analysis was performed by eliminating failure of room cooling to the critical switchgear rooms in the level 1 PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $0. This analysis case was used to model the benefit of Phase II SAMA 37.

Case 34: Increase Reliability of Instrument Air

This analysis case was used to evaluate the change in plant risk from improving the reliability of the instrument air system, by modifying procedures to allow alignment of diesel power to more air compressors, by replacing the compressors with more reliable models, or by using a portable compressor. A bounding analysis was performed by eliminating failure of the instrument air compressors in the level 1 PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $499,350. This analysis case was used to model the benefit of Phase II SAMAs 41, 42, and 45.

Case 35: Extend SRV Operation Time

This analysis case was used to evaluate the change in plant risk from installing nitrogen bottles as backup gas supply for safety relief valves. A bounding analysis was performed by eliminating the failure of loss of nitrogen and air to the SRVs, which resulted in an internal and external benefit (with uncertainty) of approximately $0. This analysis case was used to model the benefit of Phase II SAMA 43.

Case 36: Improve Availability of SRVs and MSIVs

This analysis case was used to evaluate the change in plant risk from improving SRV and MSIV pneumatic components. A bounding analysis was performed by eliminating failure of nitrogen, air, and accumulators for the SRVs and MSIVs, which resulted in an internal and external benefit (with uncertainty) of approximately $574,974. This analysis case was used to model the benefit of Phase II SAMA 44.

Case 37: Decay Heat Removal Capability, Torus Cooling

This analysis case was used to evaluate the change in plant risk from installing an additional decay heat removal system or upgrading the existing decay heat removal system for torus cooling. Enhancements of decay heat removal capability decrease the consequences of loss of containment heat removal. The system upgrade recommended in SAMA 71 would require new penetrations, piping, valves, heat exchanger, cooling capability and increased storage in the radwaste system. The additional means of suppression pool cooling recommended in SAMA 73 would involve installation of a chiller in the yard with piping and valves installed with penetrations through the reactor building. A heat exchanger would be required in the reactor building to transfer heat from the torus water to the chiller water. Pipe penetrations would be needed on the torus to allow for water circulation to the heat exchanger. A bounding analysis was performed by setting the events for loss of the torus cooling mode of the RHR and RHRSW systems to zero in the PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $1,122,355. This analysis case was used to model the benefit of Phase II SAMAs 46, 71, and 73.

Case 38: Decay Heat Removal Capability, Drywell Spray

This analysis case was used to evaluate the change in plant risk from installing an additional decay heat removal system for drywell sprays. Enhancements of decay heat removal capability decrease the probability of loss of containment heat removal. A bounding analysis was performed by setting the events for loss of the drywell sprays mode of the RHR and RHRSW systems to zero in the PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $957,021. This analysis case was used to model the benefit of Phase II SAMA 47.

Case 39: Filtered Vent

This analysis case was used to evaluate the change in plant risk from installing a filtered containment vent or to enhance the fire protection system/standby gas treatment system hardware and procedures to provide fission product scrubbing. A bounding analysis was performed by reducing the baseline accident progression source terms by a factor of 2 (excluding noble gases) to reflect the additional filtered capability. Reducing the releases from the vent path resulted in an internal and external benefit (with uncertainty) of approximately $267,367. This analysis case was used to model the benefit of Phase II SAMAs 48 and 49.

Case 40: Controlled Containment Venting

This analysis case was used to evaluate the change in plant risk from changing the containment venting procedure to establish a narrow pressure control band. This would prevent rapid containment depressurization when venting, thus avoiding adverse impact on the ability of the low pressure ECCS injection systems to take suction from the torus. A bounding analysis was performed by eliminating operator failure to control the venting evolution in the PSA model, which

resulted in an internal and external benefit (with uncertainty) of approximately $106. This analysis case was used to model the benefit of Phase II SAMA 50.

Case 41: Vacuum Breakers

This analysis case was used to evaluate the change in plant risk from improving the reliability of vacuum breakers by installing redundant valves in each line. A bounding analysis was performed by setting the vacuum breaker failure probability to zero in the PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $68,671. This analysis case was used to model the benefit of Phase II SAMA 51.

Case 42: Passive Containment Overpressure Relief

This analysis case was used to evaluate the change in plant risk from providing a passive containment overpressure relief pathway during severe accidents. This SAMA will prevent catastrophic failure of the containment by controlled relief through a selected vent path, which has a greater potential for reducing the release of radioactive material than through a random break. A bounding analysis was performed by eliminating hard pipe vent failure in the PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $383,762. This analysis case was used to model the benefit of Phase II SAMAs 52 and 53.

Case 43: Barriers to Block Debris from Reaching the Steel Shell

This analysis case was used to evaluate the change in plant risk from installing a curb to prevent debris from spreading across the floor and contacting the shell. A bounding analysis was performed by eliminating the CDF contribution due to failure of the DW barriers to prevent debris from contacting the shell, which resulted in an internal and external benefit (with uncertainty) of approximately $682,341. This analysis case was used to model the benefit of Phase II SAMA 70.

Case 44: ISLOCA

This analysis case was used to evaluate the change in plant risk from reducing the probability of an ISLOCA by increasing the frequency of valve leak testing or improving ISLOCA identification or coping. A bounding analysis was performed by setting the ISLOCA initiators to zero in the PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $25,669. This analysis case was used to model the benefit of Phase II SAMAs 54, 56, and 57.

Case 45: MSIV Design

This analysis case was used to evaluate the change in plant risk from improving MSIV design to decrease the likelihood of containment bypass scenarios. A bounding analysis was performed by eliminating failure of the MSIVs to close or remain closed, which resulted in an internal and external benefit (with uncertainty) of approximately $8,169. This analysis case was used to model the benefit of Phase II SAMA 55.

Case 46: SLC System

This analysis case was used to evaluate the change in plant risk from increasing boron concentration in the SLC system. A bounding analysis was performed by eliminating the contribution due to failure to initiate SLC and failures due to the boron concentration being too low in the PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $37,086. This analysis case was used to model the benefit of Phase II SAMA 58.

Case 47: Improve Availability of Boron Injection

This analysis case was used to evaluate the change in plant risk from providing an additional method of boron injection (e.g., add an independent boron injection system or use CRD for alternate boron injection). A bounding analysis was performed by eliminating failure of the SLC system in the PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $67,455. This analysis case was used to model the benefit of Phase II SAMAs 59 and 60.

Case 48: SRV Reseat

This analysis case was used to evaluate the change in plant risk from improving the reliability of the SRVs to reseat to address the risk associated with boron dilution. A bounding analysis was performed by setting failure of the SRVs to reseat to zero in the PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $32,202. This analysis case was used to model the benefit of Phase II SAMA 61.

Case 49: Internal Flooding

This analysis case was used to evaluate the change in plant risk from improving internal flooding procedures. A bounding analysis was performed by eliminating operator failures related to flood mitigation in the PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $51,711. This analysis case was used to model the benefit of Phase II SAMA 62.

Case 50: Fire Water Pipe Break

This analysis case was used to evaluate the change in plant risk from providing flow diversion to help mitigate the fire water pipe break in the control building ground floor corridor. A bounding analysis was performed by eliminating failure to isolate the large and medium fire water pipe breaks in the control building ground floor corridor, which resulted in an internal and external benefit (with uncertainty) of approximately $6,108. This analysis case was used to model the benefit of Phase II SAMA 74.

Case 51: Increase Reliability of the Fire Water System

This analysis case was used to evaluate the change in plant risk from upgrading the seismic capacity of the diesel fire pump fuel tank and water supply tank or proceduralizing the use of a

fire pumper truck to pressurize the fire water system. A bounding analysis was performed by eliminating failure of the diesel-driven fire pump in the PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $82,395. This analysis case was used to model the benefit of Phase II SAMAs 64 and 69.

Case 52: Add Fire Suppression

This analysis case was used to evaluate the change in plant risk from adding automatic fire suppression systems to the dominant fire zones. The dominant fire zones reported in the IPEEE for CNS are the control room, switchgear rooms, and SW pump room. The control room has no automatic suppression system. The switchgear rooms have no automatic suppression system. The SW pump room has an automatic suppression system which is a total flooding halon system.

For the main control room, an automatic suppression system would not provide a significant safety benefit. The sensing devices used for fires include both fuse elements that melt given high temperature and smoke detectors. These types of actuation devices would only actuate after the fire has progressed to a point that would cause evacuation of the control room. Even if the auto suppression system actuated prior to evacuation, the consequences of actuation would require evacuation. Halon or CO_2 systems would asphyxiate any personnel remaining in the main control room and water would damage the control equipment. Given that the main control room fire risk is dominated by failure to shut down the reactor from outside the control room, extremely limited benefit is judged to exist for auto suppression systems in the main control room.

A bounding analysis was performed as described below, which resulted in an internal and external benefit (with uncertainty) of approximately $347,908. This analysis case was used to model the benefit of Phase II SAMA 63.

SAMA analysis case 52 (adding automatic fire suppression systems to the critical switchgear rooms) is an external events SAMA, which would not mitigate internal event risk. A bounding analysis was performed by assuming the SAMA would eliminate the contribution to fire CDF from fires in the critical switchgear rooms. Since the total fire CDF is 1.93E-05/yr [Table E.1-11] and the critical switchgear rooms fire CDF is 1.11E-06 + 2.72E-06 = 3.83E-06/yr, fires in the critical switchgear rooms contribute 19.84% of the total fire CDF.

The internal events model cannot be used to assess the benefit from this external event SAMA. However, the consequences resulting from fire-induced core damage and internal event-induced core damage would be comparable. Since we have already estimated the maximum benefit from removing all internal event risk, the maximum benefit of removing all fire risk was estimated by reducing the maximum internal event benefit by the ratio of the total fire CDF to the internal event CDF. Since SAMA analysis case 52 would eliminate 19.84% of the total fire risk, the benefit for SAMA analysis case 52 was estimated to be 19.84% of the total fire benefit as shown below.

Given,

Maximum internal benefit is $351,319

Total fire CDF = 1.93E-05/rx-yr [Table E.1-11]

Internal events CDF = 1.16E-05/rx-yr

Maximum fire benefit = Maximum internal benefit x Total fire CDF/Internal events CDF

Maximum fire benefit = $351,319(1.93E-5/1.16E-5)

SAMA case 52 benefit = 19.84% x (Maximum fire benefit) = 0.1984 x $351,319(1.93E-5/1.16E-5)

SAMA case 52 benefit = $115,969

Applying the uncertainty factor of 3,

SAMA case 52 benefit with uncertainty = $115,969 x 3 = $347,908.

Case 53: Reduce Risk from Fires that Require Control Room Evacuation

This analysis case was used to evaluate the change in plant risk from upgrading the ASDS panel to include additional system controls for division I equipment. A bounding analysis was performed as described below, which resulted in an internal and external benefit (with uncertainty) of approximately $338,964. This analysis case was used to model the benefit of Phase II SAMA 65.

SAMA analysis case 53 (Reduce Risk from Fires that Require Control Room Evacuation) is an external events SAMA, which would not mitigate internal event risk. A bounding analysis was performed by assuming the SAMA would eliminate the contribution to fire CDF from fires in the control room. Since the total fire CDF is 1.93E-05/yr [Table E.1-11] and the control room fire CDF is 3.73E-06, fires in the control room contribute 19.33% of the total fire CDF.

The internal events model cannot be used to assess the benefit from this external event SAMA. However, the consequences resulting from fire-induced core damage and internal event-induced core damage would be comparable. Since we have already estimated the maximum benefit from removing all internal event risk, the maximum benefit of removing all fire risk was estimated by reducing the maximum internal event benefit by the ratio of the total fire CDF to the internal event CDF. Since SAMA analysis case 53 would eliminate 19.33% of the total fire risk, the benefit for SAMA analysis case 53 was estimated to be 19.33% of the total fire benefit as shown below.

Given,

Maximum internal benefit is $351,319

Total fire CDF = 1.93E-05/rx-yr [Table E.1-11]

Internal events CDF = 1.16E-05/rx-yr

Maximum fire benefit = Maximum internal benefit x Total fire CDF/Internal events CDF

Maximum fire benefit = $351,319(1.93E-5/1.16E-5)

SAMA case 53 benefit = 19.33% x (Maximum fire benefit) = 0.1933 x $351,319(1.93E-5/1.16E-5)

SAMA case 53 benefit = $112,988

Applying the uncertainty factor of 3,

SAMA case 53 benefit with uncertainty = $112,988 x 3 = $338,964

Case 54: Large Break LOCA

This analysis case was used to evaluate the change in plant risk from installing a digital large break LOCA (LBLOCA) protection system. A bounding analysis was performed by setting the LBLOCA initiators to zero in the PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $57,704. This analysis case was used to model the benefit of Phase II SAMA 66.

Case 55: Trip/Shutdown Risk

This analysis case was used to evaluate the change in plant risk from including Generation Risk Assessment (trip and shutdown risk modeling) in plant activities. It is assumed that this would reduce the frequency of plant trips and shutdowns. A bounding analysis was performed by reducing all initiating events except pipe breaks, floods, and LOOP by a factor of 2, which resulted in an internal and external benefit (with uncertainty) of approximately $1,183,332. This analysis case was used to model the benefit of Phase II SAMA 75.

Case 56: Improve RHRSW System

This analysis case was used to evaluate the change in plant risk from modifying procedures to allow use of the RHRSW system without a SWBP. A bounding analysis was performed by eliminating failure to use the RHRSW system without a SWBP, which resulted in an internal and external benefit (with uncertainty) of approximately $331,699. This analysis case was used to model the benefit of Phase II SAMA 79.

Case 57: Improve Plant Identification of Reference Leg Leakdowns

This analysis case was used to evaluate the change in plant risk from installing additional instrumentation to assist in identifying a reference leg leakdown. A bounding analysis was performed by eliminating failure of cognitive recognition of a leakdown of the reference legs in the PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $15,917. This analysis case was used to model the benefit of Phase II SAMA 80.

E.2.4 Sensitivity Analyses

Two sensitivity analyses were conducted to gauge the impact of assumptions upon the analysis. The benefits estimated for each of these sensitivities are presented in Table E.2-3.

A description of each sensitivity case follows.

Sensitivity Case 1: Years Remaining Until End of Plant Life

The purpose of this sensitivity case was to investigate the sensitivity of assuming a 26-year period for remaining plant life (i.e., six years on the original plant license plus the 20-year license renewal period), rather than the 20-year license renewal period used in the base case. Changing this assumption does not cause additional SAMAs to be cost-beneficial.

Sensitivity Case 2: Conservative Discount Rate

The purpose of this sensitivity case was to investigate the sensitivity of each analysis case to the discount rate. The discount rate of 7.0% used in the base case analyses is conservative relative to corporate practices. Nonetheless, a lower discount rate of 3.0% was assumed in this case to investigate the impact on each analysis case. Changing this assumption does not cause additional SAMAs to be cost-beneficial.

E.2.5 References

E.2-1 NEI 05-01, "Severe Accident Mitigation Alternatives (SAMA) Analysis Guidance Document," Revision A, November 2005.

E.2-2 NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding James A. FitzPatrick Nuclear Power Plant,* Supplement 31, Final Report, January 2008.

E.2-3 NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding Vermont Yankee Nuclear Power Station*, Supplement 30, Final Report, August 2007.

E.2-4 NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding Pilgrim Nuclear Power Station*, Supplement 29, Final Report, July 2007.

E.2-5 NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding Oyster Creek Nuclear Generating Station*, Supplement 28, Final Report, January 2007.

E.2-6 NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding Monticello Nuclear Generating Plant*, Supplement 26, Final Report, August 2006.

E.2-7 NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding Brunswick Steam Electric Plant, Units 1 and 2*, Supplement 25, Final Report, April 2006.

E.2-8 U.S. Nuclear Regulatory Commission, NUREG-1742, *Perspectives Gained From the Individual Plant Examination of External Events (IPEEE) Program*, Volumes 1 & 2, Final Report, April 2002.

E.2-9 "Cooper Nuclear Station Probabilistic Risk Assessment (IPE) Level 1 and Level 2," March 1993.

E.2-10 Nebraska Public Power District, "Cooper Nuclear Station Individual Plant Examination for External Events," October 1996, Revision 0.

E.2-11 U.S. Nuclear Regulatory Commission, NUREG/BR-0184, *Regulatory Analysis Technical Evaluation Handbook*, January 1997.

E.2-12 NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding Peach Bottom Atomic Power Station, Units 2 and 3*, Supplement 10, Final Report, January 2003.

E.2-13 NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants Supplement 16 Regarding Quad Cities Nuclear Power Station, Units 1 and 2*, Supplement 16, June 2004.

E.2-14 Attachment E, Severe Accident Mitigation Alternatives Analysis Submittal Related to Licensing Renewal for the Susquehanna Steam Electric Station, September 2006.

E.2-15 NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding Browns Ferry Nuclear Plant, Units 1, 2, and 3*, Supplement 21, Final Report, June 2005.

E.2-16 Appendix F, Severe Accident Mitigation Alternatives Analysis Submittal Related to Licensing Renewal for the Brunswick Steam Electric Plant, October 2004.

E.2-17 NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding Nine Mile Point Nuclear Station, Units 1 and 2*, Supplement 24, Final Report, May 2006.

Table E.2-1
Phase I SAMAs Related to IPE and IPEEE Insights

Phase I SAMA ID number	SAMA Title	Result of Potential Enhancement	Screening Results	SAMA Disposition
61	Modify automatic depressurization system components to improve reliability.	Reduced frequency of high pressure core damage sequences.	Retain (Phase II SAMA 26)	The CNS SRVs use an electro-pneumatic control system for automatic depressurization. Two redundant 125 VDC power supplies power a solenoid-operated pilot valve that controls pneumatic pressure to an activator valve, which in turn operates the SRV. Each SRV has a dedicated accumulator tank sized for approximately five actuations of its associated SRV against atmospheric pressure or two actuations against 70 percent of drywell design pressure. This SAMA is being retained to add larger accumulators, thus increasing reliability during SBOs.
67	Provide capability for alternate injection via diesel-driven fire pump.	Improved injection capability.	Already installed	The CNS diesel-driven fire pump can be used for alternate injection.
120	Cross-tie open cycle cooling system to enhance drywell spray system.	Increased availability of containment heat removal.	Already installed	CNS has an RHR/RHRSW crosstie that can be aligned for vessel injection flow and for drywell spray header flow. This would use the untreated water from the RHRSW loops.
123	Install a passive drywell spray system.	Improved drywell spray capability.	Retain (Phase II SAMA 47)	CNS does not contain a passive drywell spray system.

Table E.2-1 (Continued)
Phase I SAMAs Related to IPE and IPEEE Insights

Phase I SAMA ID number	SAMA Title	Result of Potential Enhancement	Screening Results	SAMA Disposition
124	Use the fire water system as a backup source for the drywell spray system.	Improved drywell spray capability.	Already installed	This operator action is taken in the event that containment heat removal via the RHR system (suppression pool cooling and drywell spray) is unavailable.
182	Modify safety-related condensate storage tanks	Improved availability of ECSTs following a seismic event and reduced potential for flooding from ECSTs following a seismic event.	Already installed	Emergency condensate storage tanks (CM-TK-ECSA, B) were evaluated and determined to be acceptable for the 0.3g RLE, without modification.
203	Increase training and operating experience feedback to improve operator response.	Improved likelihood of success of operator actions taken in response to abnormal conditions.	Already installed	Operator response has been a focus at CNS over the past decade. Training has been improved and training reference materials and procedures have been updated in an ongoing effort to improve operator reliability.
206	Develop a procedure outlining improved battery loading schemes associated with a load study demonstrating potential extended battery life.	Improved availability of DC power system.	Already installed	DC load-shedding procedures are in place to increase the probability of successful load shed under SBO conditions.
207	Develop a procedure to bypass the AC solenoid valve on the nitrogen supply to the SRVs.	Reduced failure to depressurize during station blackout scenarios.	Already installed	Actions to bypass the AC solenoid valve on the nitrogen supply to the SRVs have been implemented in procedure 2.3_9.3.1 page 45.

Table E.2-1 (Continued)
Phase I SAMAs Related to IPE and IPEEE Insights

Phase I SAMA ID number	SAMA Title	Result of Potential Enhancement	Screening Results	SAMA Disposition
208	Improve the reliability of the HPCI and RCIC systems by upgrading their control systems.	Improved reliability of HPCI and RCIC systems.	Retain (Phase II SAMA 67)	A sensitivity study using the 1997 PSA model showed a 16% decrease in both CDF and LERF. Improvement was not implemented because existing risk estimates did not present an outlier in the industry and no associated vulnerability was identified.
209	Enhance the reactor pressure vessel depressurization system reliability.	Reduced frequency of high pressure core damage sequences.	N/A	A sensitivity study using the 1997 PSA model showed a CDF reduction of 1% and the LERF was unaffected. Due to the low CDF contribution this SAMA has been determined not to be cost beneficial.
210	Provide a backup for the service water pumps via equipment modifications and procedure changes.	Continued use of the power conversion system after service water is lost.	Similar item is addressed under other proposed SAMAs	See Phase I SAMA 212 (Phase II SAMA 68).
211	Provide a low pressure source of cooling water (i.e., diesel fire water pump) which is not dependent on AC power.	Extended recovery time during station blackout scenarios.	Already Installed	The CNS diesel-driven 3000 gpm fire pump can be used for alternate injection.
212	Proceduralize the ability to cross-connect the circulating water pumps and the service water going to the turbine equipment cooling (TEC) heat exchangers.	Continued use of the power conversion system after service water is lost.	Retain (Phase II SAMA 68)	A sensitivity study using the 1997 PSA model showed a 3% decrease for CDF and no change in LERF.

Table E.2-1 (Continued)
Phase I SAMAs Related to IPE and IPEEE Insights

Phase I SAMA ID number	SAMA Title	Result of Potential Enhancement	Screening Results	SAMA Disposition
213	Provide an alternate water supply for the drywell spray.	Increased availability of containment heat removal.	Similar item is addressed under other proposed SAMAs	A sensitivity study using the 1997 PSA model showed a LERF reduction of 19%, but this impact was considered to be significantly reduced by the EOP revisions in Phase I SAMA 215 since the latest EPGs have added cues to increase the probability that drywell sprays will be actuated for the mitigation of core melt progression. See Phase II SAMA 47.
214	Provide alternate cooling in the HPCI quad room.	Increased availability of the HPCI system.	Similar item is addressed under other proposed SAMAs	See Phase I SAMA 101 (Phase II SAMA 35).
215	Upgrade emergency operating procedures (EOP's) to the latest revision of the Boiling Water Reactor Owners Group Emergency Procedure Guidelines (EPG's).	Improved likelihood of success of operator actions taken in response to abnormal conditions.	Already installed	The CNS EOP's incorporated Rev. 4 of the EPG's around the time the IPE was being performed. CNS has also incorporated the latest revision of the EPG's and reviews every new revision of the EPG's.
216	Implement emergency procedures and training.	Improved likelihood of success of operator actions taken in response to abnormal conditions.	Already Installed	See Phase I SAMA 215.
217	Upgrade relays identified as outliers in the A-46 program.	Increased reliability of relays that may chatter at low seismic levels.	N/A	The ten relays identified as potential outliers in the A-46 program were resolved analytically.

Table E.2-1 (Continued)
Phase I SAMAs Related to IPE and IPEEE Insights

Phase I SAMA ID number	SAMA Title	Result of Potential Enhancement	Screening Results	SAMA Disposition
218	Relocate or upgrade anchorage for equipment located adjacent to control room panels.	Increased availability of control room panels following a seismic event.	Already installed	Control room ceiling diffusers were secured to the supporting grid using plastic ties. Procedure 7.2.79, Securing Control Room Ceiling Diffuser Panels, ensures the ties are replaced when ceiling panels are removed for periodic maintenance. Outlier cabinets, a table, and a copier were resolved by increasing anchorage or by removing the items.
219	Eliminate the interaction hazard vulnerability caused by the concrete beam and hanging lights near 480V control switchgear 1G.	Increased reliability of essential relays in 480V control switchgear 1G.	Already installed	Outliers were resolved by attaching a brace between the switchgear and the concrete beam to prevent pounding, and relocating the lights.
220	Remove potential seismic interaction hazards from transformers EE-XFMR-RPS1A and B.	Improved reliability of EE-XFMR-RPS1A and B during a seismic event.	N/A	Outlier resolved analytically. Further evaluation determined that these transformers are not required to achieve and maintain hot shutdown for 72 hours. Thus, they were removed from the safe shutdown equipment list.
221	Eliminate the interaction hazard with adjacent rack posed on jet pump instrument rack A (LRP-PNL-{25-51}).	Improved reliability of jet pump instrument rack A during a seismic event.	N/A	Outlier resolved analytically. Further evaluation showed that the gap between the jet pump instrument rack and the adjacent rack is sufficient to preclude interaction.

Table E.2-1 (Continued)
Phase I SAMAs Related to IPE and IPEEE Insights

Phase I SAMA ID number	SAMA Title	Result of Potential Enhancement	Screening Results	SAMA Disposition
222	Eliminate the interaction hazard vulnerability of the auxiliary relay room panels (LRP-PNL-9-32, 33, 41, 42, 45) which contain a significant number of essential (chatter-sensitive) relays.	Improved reliability of auxiliary relay room panels LRP-PNL-9-32, 33, 41, 42, and 45 during a seismic event.	Already installed	Outlier resolved by upgrading anchorage of auxiliary relay room panels LRP-PNL-9-32, 33, 41, 42, and 45.
223	Upgrade the braced Unistrut trapeze frame (hanger 89) in the NE corner of elevation 903' of the reactor building (suspended from elevation 931')	Improved reliability of hanger 89 during a seismic event.	Already installed	Outlier was resolved by upgrading hanger 89 anchorage and evaluating the surrounding similar hangers.
224	Upgrade seismic capacity of the SE and NE quad recirculation fans (HV-FAN-FC-R-1E and F).	Improved availability of the vibration-isolated air handling systems following a seismic event.	N/A	Outlier resolved analytically. Further evaluation determined that HV-FAN-FC-1E and F are not required to achieve and maintain hot shutdown for 72 hours. Thus, they were removed from the safe shutdown equipment list.
225	Upgrade seismic capacity of service water pump B&D strainer control panel (LRP-PNL-S192) by tightening loose bolt securing one corner of interior panel.	Improved seismic capacity of service water pump B&D strainer control panel (LRP-PNL-S192).	Already installed	Minor maintenance item was resolved by tightening the loose bolt securing one corner of the service water pump B&D strainer control panel.
226	Upgrade seismic capacity of hanger 144 in the cable spreading room which has cross pieces overstressed in dead weight.	Improved seismic capacity of hanger 144.	N/A	Outlier resolved analytically. Further evaluation determined that gross failure of the hanger will not occur following a seismic event.

Table E.2-1 (Continued)
Phase I SAMAs Related to IPE and IPEEE Insights

Phase I SAMA ID number	SAMA Title	Result of Potential Enhancement	Screening Results	SAMA Disposition
227	Upgrade seismic capacity of the recirculation pump motor generator set lube oil cooler heat exchangers.	Reduced potential for release of combustible fluid following a seismic event.	N/A	Outlier resolved analytically. The Fire IPEEE considered this source of oil in its evaluation of the fire area. The fire area screened with a fire CDF of < 1E-6/yr. Therefore, the benefit from this improvement is not considered adequate to justify the cost of potential modifications.
228	Upgrade the seismic capacity of the diesel fire pump fuel tank and water supply tank.	Improved availability of water-based fire protection following a seismic event.	Retain (Phase II SAMA 69)	The water-based fire protection systems are vulnerable to a seismic event because the electric fire pumps are dependent on offsite power and the diesel fire pump is dependent on its fuel tank and water supply tank, both of which have seismic vulnerability. Upgrading the seismic capacity of the tanks would decrease the vulnerability.
229	Install additional features to allow control of switchyard breakers remote from control room board C and vertical board F, or have a pre-planned recovery/repair action for control of the switchyard breakers following a fire that completely disables the control room boards.	Allows for control of switchyard breakers following a control room fire that completely disables board C and vertical board F.	N/A	Further evaluation concluded that this improvement would result in less than a 0.5% decrease in overall plant CDF. The minor reduction in overall plant CDF is not considered adequate to justify the cost of potential modifications.

Table E.2-1 (Continued)
Phase I SAMAs Related to IPE and IPEEE Insights

Phase I SAMA ID number	SAMA Title	Result of Potential Enhancement	Screening Results	SAMA Disposition
230	Provide the service water system with water supplies that are diverse from pumps in the service water pump room.	Improved availability of the service water system following a fire in the pump house that disables all the service water pumps.	Similar item is addressed under other proposed SAMAs	See Phase I SAMAs 210 and 212 (Phase II SAMA 68).
231	Reduce the potential vulnerability of the control building to a lightning induced loss of offsite power that also affects the station batteries.	Reduced probability of a lightning induced non-recoverable loss of offsite power.	N/A	Further evaluation concluded that the control building is not vulnerable to a lightning induced loss of offsite power that also affects the station batteries.
232	Protect the diesel generator exhaust system from postulated tornado-generated missiles.	Improved availability of the EDG system.	Already installed	A modification completed in 1998 removed the diesel generator muffler bypass valves, thereby eliminating the failure mode and significantly improving protection of the diesel generator exhaust system from tornado generated missiles.

Table E.2-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
DC Power	Changed the time available to recover offsite power before HPCI and RCIC are lost to 24 hours during station blackout scenarios in the level 1 PSA model.	3.14%	2.80%	3.00%	$32,279	$96,836		
1 - Provide additional DC battery capacity.	The cost for implementing this SAMA was specifically estimated for Pilgrim and FitzPatrick.						$500,000	Not cost effective
2 - Replace lead-acid batteries with fuel cells.	The cost for implementing this SAMA was specifically estimated for Peach Bottom.						$1,000,000	Not cost effective
13 - Portable generator for DC power to supply the battery chargers.	The cost for implementing this SAMA was specifically estimated for Susquehanna.						$203,000	Not cost effective
21-Modify plant procedures to allow use of a portable power supply for battery chargers.	Part of SAMA 13						Part of SAMA 13 cost estimate	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Improve Charger Reliability	The common cause failure contribution due to loss of DC battery chargers to zero in the level 1 PSA model.	0.34%	0.00%	0.00%	$2,339	$7,018		
3 - Add battery charger to existing DC system.	The cost for implementing this SAMA was specifically estimated for FitzPatrick.						$90,000	Not cost effective
15 - Proceduralize battery charger high-voltage shutdown circuit inhibit.	The cost for implementing this SAMA was specifically estimated for Brunswick.						$50,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Add DC System Cross-ties	The 250V DC buses were set to zero in the level 1 PSA model.	0.00%	0.00%	0.00%	$0	$0		
4 - Provide DC bus cross-ties [The 125V distribution panels and starter racks can be powered from either bus, thus the 125V buses are cross-tied. However the 250V buses are not cross-tied].	The cost for implementing this SAMA was specifically estimated for FitzPatrick.						$300,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Improve Existing DC System Cross-ties	The failure of the 125V DC bus cross-tie was set to zero in the level one PSA model.	0.29%	0.00%	0.00%	$1,999	$5,997		
19 - Modify plant procedures to use DC bus cross-ties [This SAMA will enhance procedures to use the existing 125V DC bus cross-ties].	The cost for implementing this SAMA was specifically estimated for Pilgrim.						$25,000	Not cost effective
Provide Backup DC Power to the 120 V Vital AC Bus	Eliminate the failure of DC power to the NBPP.	0.07%	0.00%	0.00%	$465	$1,395		
5 - Provide additional DC power to the 120/240V vital AC system.	The cost for implementing this SAMA was specifically estimated for CNS.						> 100k	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Increase Availability of the 120 V Vital AC Bus	The time available to recover offsite power before HPCI and RCIC are lost was changed to 24 hours during station blackout scenarios in the level 1PSA model.	0.00%	0.00%	0.00%	$0	$0		
6 - Add an automatic feature to transfer the 120V vital AC bus from normal to standby power.	The cost for implementing this SAMA was specifically estimated for Pilgrim, Vermont Yankee, and FitzPatrick.						$500,000	Not cost effective
Increase Availability of On-Site AC Power	The contribution of the EDGs was set to zero in the level 1 PSA model.	13.06%	14.02%	14.27%	$141,672	$425,016		
7 - Provide an additional diesel generator.	The cost for implementing this SAMA was specifically estimated for Monticello.						$20,000,000	Not cost effective
10 - Install a gas turbine generator.	The cost for implementing this SAMA was specifically estimated for Vermont Yankee.						$2,000,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Provide Backup EDG SW Cooling	Eliminate failure of SW cooling to the EDGs.	4.71%	3.27%	3.42%	$44,738	$134,213		
11 - Add a new backup source of diesel cooling.	The cost for implementing this SAMA was specifically estimated for Browns Ferry.						$2,000,000	Not cost effective
Increase EDG Reliability	Eliminate failure of the EDG fuel oil transfer pumps.	0.58%	0.47%	0.71%	$6,229	$18,687		
16 - Provide a portable EDG fuel oil transfer pump.	The cost for implementing this SAMA was specifically estimated for Brunswick.						$100,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Improve AC Power	Eliminate the loss of the 4.16-kV buses.	2.62%	4.67%	4.85%	$35,490	$106,470		
8 - Improve 4.16-kV bus cross-tie ability.	The cost for implementing this SAMA was specifically estimated for Susquehanna.						$656,000	Not cost effective
17 - Provide alternate feeds to essential loads directly from an alternate emergency bus.	The cost for implementing this SAMA was specifically estimated for Brunswick.						$217,388	Not cost effective
Reduce Loss of Off-Site Power During Severe Weather	Eliminate the weather centered loss of off-site power initiating event.	4.26%	3.74%	3.85%	$43,237	$129,710		
9 - Install an additional, buried off-site power source.	The cost for implementing this SAMA was specifically estimated for CNS.						$2,485,000	Not cost effective
12 - Bury off-site power lines.	The cost for implementing this SAMA was specifically estimated for CNS.						$1,140,000,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Reduce Plant-Centered Loss of Off-Site Power	Eliminate the plant centered loss of offsite power initiating event.	0.09%	0.00%	0.00%	$614	$1,843		
18 - Protect transformers from failure.	The cost for implementing this SAMA was specifically estimated for Oyster Creek.						$780,000	Not cost effective
Redundant Power to Torus Hard Pipe Vent (THPV) Valves	Set failure of power to the hard pipe torus vent valves to zero in the PSA model.	4.16%	13.08%	13.55%	$77,440	$232,320		
20 - Provide redundant power to direct torus hard pipe vent valves to improve the reliability of the direct torus vent valves and enhance the containment heat removal capability.	The cost for implementing this SAMA was specifically estimated for CNS.						$714,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
High Pressure Injection System	Set the CDF contribution due to unavailability of the HPCI system to zero in the level 1 PSA model.	31.93%	22.43%	22.40%	$301,827	$905,481		
14 - Portable generator for DC power to supply the individual panels.	The cost for implementing this SAMA was specifically estimated for CNS.						$714,000	Retain
22 - Install an independent active or passive high pressure injection system.	The cost for implementing this SAMA was specifically estimated for Peach Bottom.						$1,000,000	Not cost effective
23 - Provide an additional high pressure injection pump with independent diesel.	The cost for implementing this SAMA was specifically estimated for Peach Bottom.						$1,000,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Extend RCIC Operation	Eliminate failures due to the RCIC backpressure trip.	3.93%	0.47%	0.43%	$28,693	$86,079		
24 - Raise HPCI/ RCIC backpressure trip set points [HPCI backpressure trip setpoint has already been raised. This SAMA will evaluate raising the RCIC backpressure trip set point].	The cost for implementing this SAMA was specifically estimated for CNS.						>200K	Not cost effective
25 - Revise procedure to allow bypass of RCIC turbine exhaust pressure trip [This SAMA will revise EOP 5.8.20 to give direction to allow bypass of RCIC turbine exhaust pressure trip].	The cost for implementing this SAMA was specifically estimated for CNS.						$25,000	Retain

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Improve ADS System	Eliminate failure of the ADS accumulators.	0.00%	0.00%	0.00%	$0	$0		
26 - Modify automatic depressurization system components to improve reliability [This SAMA will add larger accumulators thus increasing reliability during SBOs].	The cost for implementing this SAMA was specifically estimated for CNS.						> 100k	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Reliability of SRVs	Set the probability of SRVs failing to open when required by reactor pressure vessel overpressure conditions to zero in the level 1 PSA model.	19.17%	0.93%	0.86%	$135,371	$406,113		
27 - Add signals to open safety relief valves automatically in an MSIV closure transient.	The cost for implementing this SAMA was specifically estimated for Pilgrim and Vermont Yankee.						$1,500,000	Not cost effective
Low Pressure Injection System	Eliminate failure of the low pressure injection.	54.58%	62.66%	62.34%	$603,989	$1,811,968		
28 - Add a diverse low pressure injection system.	The cost for implementing this SAMA was specifically estimated for Monticello.						$8,800,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
ECCS Low Pressure Interlock	Eliminate failure of the low pressure interlock circuitry in the level 1 PSA model.	24.47%	6.07%	5.85%	$190,301	$570,904		
29 - Install a bypass switch to allow operators to bypass the low reactor pressure interlock circuitry.	The cost for implementing this SAMA was specifically estimated for Pilgrim and Vermont Yankee.						$1,000,000	Not cost effective
Improve Reliability of HPCI and RCIC	Eliminate failure of the HPCI and RCIC turbine driven pumps.	5.95%	0.00%	0.43%	$41,996	$125,987		
67 - Improve the reliability of the HPCI and RCIC systems by upgrading their control systems.	The cost for implementing this SAMA was specifically estimated for Brunswick.						$434,775	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Main Condenser	Eliminate failure of the steam tunnel HVAC.	2.96%	1.40%	1.85%	$26,517	$79,550		
76 - Improve steam tunnel HVAC reliability/ redundancy to prevent inadvertent group 1 isolations.	The cost for implementing this SAMA was specifically estimated for CNS.						> 100k	Not cost effective
Improve Reliability of ECCS Equipment	Eliminate the failure of the auto-start features for the ECCS equipment.	1.35%	0.00%	0.00%	$9,298	$27,895		
77 - Improve reliability of auto-start features for the ECCS equipment.	The cost for implementing this SAMA was specifically estimated for CNS.						> 100k	Not cost effective
Improve Injection Via Fire Water System	Reduce operator actions that could be improved via training for alternate injection via the FPS by a factor of 2.	5.29%	4.21%	4.56%	$52,605	$157,816		
78 - Improve training on alternate injection via FPS.	The cost for implementing this SAMA was specifically estimated for CNS.						$25,000	Retain

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
RHR Heat Exchangers	Eliminate failure of the SW to provide cooling to the RHR heat exchangers.	20.62%	15.89%	15.83%	$199,969	$599,907		
30 - Revise procedures to allow manual alignment of the fire water system to RHR heat exchangers.	The cost for implementing this SAMA was specifically estimated for CNS.						$25,000	Retain
Emergency Service Water System Reliability	Set the events for the common cause contribution due to service water system pumps to zero in the level 1 PSA model.	0.36%	0.00%	0.29%	$3,152	$9,456		
31 - Add a service water pump to reduce the impact of common cause failures on the SW system.	The cost for implementing this SAMA was specifically estimated for Quad Cities.						$5,900,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Reduce Valve Failure – Fire Water System	Eliminate the CDF contribution due to the fire service water cross-tie valves that are not contained in the maintenance program.	0.05%	0.00%	0.00%	$358	$1,073		
32 - Enhance alternate injection reliability by including the residual heat removal service water and fire water cross-tie valves in the maintenance program.	The cost for implementing this SAMA was specifically estimated for Monticello.						$50,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Alternate Water Supply for the TEC Heat Exchangers	Eliminate failure of the service water to provide cooling to the TEC heat exchangers.	15.39%	19.63%	19.69%	$177,788	$533,364		
68 - Proceduralize the ability to cross-connect the circulating water pumps and the service water going to the TEC heat exchangers.	The cost for implementing this SAMA was specifically estimated for Browns Ferry.						$50,000	Retain

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Increase Availability of Feedwater and Condensate	Eliminate the CDF contribution due to loss of the feedwater and condensate systems as alternate injection paths in the PSA model.	38.31%	45.79%	46.08%	$431,725	$1,295,174		
33 - Create ability for emergency connection of existing or new water sources to feedwater and condensate systems.	The cost for implementing this SAMA was specifically estimated for CNS.						$25,000	Retain

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Main Feedwater System Reliability	Set the events for failure of the feedwater turbine driven pumps to zero in the level 1 PSA model.	0.01%	0.00%	0.00%	$89	$267		
34 - Add a motor-driven feed water pump to increase the availability of injection subsequent to MSIV closure.	The cost for implementing this SAMA was specifically estimated for FitzPatrick.						$1,650,000	Not cost effective
Increase Availability of the CST	Eliminate the CDF contribution from operator failure to prevent CST inventory drain-down to the hotwell.	2.00%	1.87%	2.00%	$20,890	$62,671		
72 - Provide a means of automatically preventing draindown of CST to hotwell during a SBO.	The cost for implementing this SAMA was specifically estimated for Monticello.						$230,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Increase Availability of Room Cooling	Eliminate failure of room cooling to the RHRSW booster pump rooms.	4.04%	2.80%	3.00%	$38,498	$115,493		
35 - Provide a redundant train or means of ventilation.	The cost for implementing this SAMA was specifically estimated for Vermont Yankee.						$2,202,725	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Increase Availability of the EDG System	Eliminate failure of the EDG HVAC.	2.94%	3.27%	3.71%	$33,160	$99,480		
36 - Add a diesel building high temperature alarm or redundant louver and thermostat.	The cost for implementing this SAMA was specifically estimated for Vermont Yankee.						$1,304,700	Not cost effective
38 - Diverse EDG HVAC logic.	The cost for implementing this SAMA was specifically estimated for Brunswick.						$100,000	Not cost effective
39 - Install additional fan and louver pair for EDG heating, ventilation, and air conditioning.	The cost for implementing this SAMA was specifically estimated for Browns Ferry.						$6,000,000	Not cost effective
40 - Operator procedure revisions to provide additional space cooling to the EDG room via the use of portable equipment.	The cost for implementing this SAMA was specifically estimated for CNS.						$25,000	Retain

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Improve Diagnosis of a Loss of Switchgear HVAC	Eliminate failure of room cooling to the critical switchgear rooms in the level 1 PSA model.	0.00%	0.00%	0.00%	$0	$0		
37 - Add a switchgear room high temperature alarm.	The cost for implementing this SAMA was specifically estimated for Browns Ferry.						$400,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Increase Reliability of Instrument Air	Eliminate failure of the instrument air compressors in the level 1 PSA model.	16.79%	13.55%	14.12%	$166,450	$499,350		
41 - Modify procedure to provide ability to align diesel power to more air compressors.	The cost for implementing this SAMA was specifically estimated for FitzPatrick.						$1,200,000	Not cost effective
42 - Replace service and instrument air compressors with more reliable compressors which have self-contained air cooling by shaft driven fans.	The cost for implementing this SAMA was specifically estimated for CNS.						$1,394,598	Not cost effective
45 - Provide an alternate means of supplying the instrument air header.	The cost for implementing this SAMA was specifically estimated for CNS.						$100,000	Retain

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Extend SRV Operation Time	Eliminate the failure of loss of nitrogen and air to the SRVs.	0.00%	0.00%	0.00%	$0	$0		
43 - Install nitrogen bottles as backup gas supply for safety relief valves.	The cost for implementing this SAMA was specifically estimated for CNS.						> 100k	Not cost effective
Improve Availability of SRVs and MSIVs	Eliminate failure of nitrogen/air/accumulators for the SRVs and MSIVs.	16.89%	20.56%	20.68%	$191,658	$574,974		
44 - Improve SRV and MSIV pneumatic components.	The cost for implementing this SAMA was specifically estimated for Pilgrim.						$1,500,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Decay Heat Removal Capability – Torus Cooling	Set the events for loss of the torus cooling mode of the RHR and RHRSW systems to zero in the PSA model.	34.64%	36.92%	37.23%	$374,118	$1,122,355		
46 - Install an independent method of suppression pool cooling.	The cost for implementing this SAMA was specifically estimated for Quad Cities.						$5,800,000	Not cost effective
71 - Upgrade existing equipment to transfer water from the torus to radwaste.	The cost for implementing this SAMA was specifically estimated for CNS.						$11,118,000	Not cost effective
73 - Provide ability to maintain suppression pool temperature lower.	The cost for implementing this SAMA was specifically estimated for CNS.						$1,275,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Decay Heat Removal Capability, Drywell Spray	Set the events for loss of the drywell sprays mode of the RHR and RHRSW systems to zero in the PSA model.	16.83%	55.05%	56.06%	$319,007	$957,021		
47 - Install a passive drywell spray system to provide a redundant drywell spray method.	The cost for implementing this SAMA was specifically estimated for FitzPatrick.						$5,800,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Filtered Vent	Reduce the baseline accident progression source terms by a factor of 2 (excluding noble gases) to reflect the additional filtered capability.	0.00%	24.77%	24.25%	$89,122	$267,367		
48 - Install a filtered containment vent to provide fission product scrubbing.	The cost for implementing this SAMA was specifically estimated for Peach Bottom.						$1,500,000	Not cost effective
49 - Enhance fire protection system and/or standby gas treatment system hardware and procedures.	The cost for implementing this SAMA was specifically estimated for Vermont Yankee.						$2,500,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Controlled Containment Venting	Eliminate operator failure to control the venting evolution in the PSA model.	0.01%	0.00%	0.00%	$35	$106		
50 - Control containment venting within a narrow band of pressure to prevent rapid containment depressurization when venting is implemented thus avoiding adverse impact on the low pressure ECCS injection systems taking suction from the torus.	The cost for implementing this SAMA was specifically estimated for Vermont Yankee.						$250,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Vacuum Breakers	Set the vacuum breaker failure probability to zero in the PSA model.	1.31%	3.74%	3.85%	$22,890	$68,671		
51 - Install improved vacuum breakers (redundant valves in each line).	The cost for implementing this SAMA was specifically estimated for Peach Bottom.						$500,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Passive Containment Overpressure Relief	Eliminate the hard pipe vent failure in the PSA model.	6.80%	21.50%	22.68%	$127,921	$383,762		
52 - Provide passive overpressure relief by changing the containment vent valves to fail open and improving the strength of the rupture disk.	The cost for implementing this SAMA was specifically estimated for Oyster Creek.						$1,000,000	Not cost effective
53 - Install alternate path to the torus hard pipe vent via the wet well using a rupture disk.	The cost for implementing this SAMA was specifically estimated for Susquehanna.						$5,700,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Barriers to Block Debris from Reaching the Steel Shell	Eliminate the CDF contribution due to failure of the DW barriers to prevent debris from contacting the shell.	11.59%	40.19%	40.66%	$227,447	$682,341		
70 - Install a curb to prevent debris from spreading across the floor and contacting the shell.	The cost for implementing this SAMA was specifically estimated for CNS.						$844,000	Not cost effective
ISLOCA	Set the ISLOCA initiator to zero in the PSA model.	0.44%	1.40%	1.57%	$8,556	$25,669		
54 - Increase frequency of valve leak testing to reduce ISLOCA frequency.	The cost for implementing this SAMA was specifically estimated for Vermont Yankee.						$100,000	Not cost effective
56 - Revise EOPs to improve ISLOCA identification.	The cost for implementing this SAMA was specifically estimated for Brunswick.						$50,000	Not cost effective
57 - Improve operator training on ISLOCA coping.	The cost for implementing this SAMA was specifically estimated for CNS.						$112,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
MSIV Design	Eliminate failure of the MSIVs to close or remain closed.	0.25%	0.00%	0.43%	$2,723	$8,169		
55 - Improve MSIV design to decrease the likelihood of containment bypass scenarios.	The cost for implementing this SAMA was specifically estimated for Peach Bottom.						$1,000,000	Not cost effective
SLC System	Eliminate the contribution due to failure to initiate SLC along with the boron concentration being too low in the PSA model.	0.72%	1.87%	2.14%	$12,362	$37,086		
58 - Increase boron concentration in the SLC system [Reduced time required to achieve shutdown provides increased margin in the accident timeline for successful initiation of SLC].	The cost for implementing this SAMA was specifically estimated for CNS.						>50k	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Improve Availability of Boron Injection	Eliminate failure of the SLC system in the PSA model.	1.25%	3.74%	3.85%	$22,485	$67,455		
59 - Add an independent boron injection system.	The cost for implementing this SAMA was specifically estimated for CNS.						> 100k	Not cost effective
60 - Provide ability to use control rod drive (CRD) for alternate boron injection.	The cost for implementing this SAMA was specifically estimated for Nine Mile Point.						$150,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
SRV Reseat	Set the failure of the SRVs to reseat to zero in the PSA model.	1.32%	0.47%	0.43%	$10,734	$32,202		
61 - Increase safety relief valve (SRV) reseat reliability to address the risk associated with dilution of boron caused by the failure of the SRVs to reseat after standby liquid control (SLC) injection.	The cost for implementing this SAMA was specifically estimated for FitzPatrick.						$2,200,000	Not cost effective
Internal Flooding	Eliminate operator failures related to flood mitigation in the PSA model.	1.52%	1.87%	1.85%	$17,237	$51,711		
62 - Improve internal flooding procedures.	The cost for implementing this SAMA was specifically estimated for CNS.						$460,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Fire Water Pipe Break	Eliminate failure to isolate the large and medium fire water pipe breaks in the control building ground floor corridor.	0.20%	0.00%	0.29%	$2,036	$6,108		
74 - Provide flow diversion to help mitigate the fire water pipe break in the control building ground floor corridor.	The cost for implementing this SAMA was specifically estimated for CNS.						> 100k	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Increase Reliability of the Fire Water System	Eliminate failure of the diesel-driven fire pump in the PSA model.	2.67%	2.34%	2.57%	$27,465	$82,395		
64 - Proceduralize the use of a fire pumper truck to pressurize the fire water system.	The cost for implementing this SAMA was specifically estimated for Monticello.						$50,000	Retain
69 - Upgrade the seismic capacity of the diesel fire pump fuel tank and water supply tank.	The cost for implementing this SAMA was specifically estimated for CNS.						> 100k	Not cost effective
Add Fire Suppression[1]	Eliminate fire CDF from the critical switchgear rooms.	n/a	n/a	n/a	$115,969	$347,908		
63 - Add automatic fire suppression systems to the dominant fire zones.	The cost for implementing this SAMA was specifically estimated for Brunswick.						$375,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Reduce Risk from Fires that Require Control Room Evacuation[1]	Eliminate fire CDF from the main control room.	n/a	n/a	n/a	112,988	$338,964		
65 - Upgrade the ASDS panel to include additional system controls for opposite division.	The cost for implementing this SAMA was specifically estimated for Monticello.						$786,991	Not cost effective
Large Break LOCA	Set the LBLOCA initiators to zero in the PSA model.	1.01%	3.27%	3.42%	$19,235	$57,704		
66 - Provide digital large break LOCA protection to identify symptoms/ precursors of a large break LOCA (a leak before break).	The cost for implementing this SAMA was specifically estimated for Pilgrim.						$100,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Trip/Shutdown Risk	Reduce the initiating events that could be improved by the GRA by a factor of 2.	38.76%	34.58%	35.09%	$394,444	$1,183,332		
75 - Generation Risk Assessment implementation into plant activities.	The cost for implementing this SAMA was specifically estimated for CNS.						$500,000	Retain
Improve RHRSW System	Eliminate failure to use the RHRSW system without a SWBP.	10.75%	9.81%	10.13%	$110,566	$331,699		
79 - Modify procedures to allow use of the RHRSW system without a SWBP.	The cost for implementing this SAMA was specifically estimated for CNS.						$25,000	Retain

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Improve Plant Identification of Reference Leg Leakdowns	Eliminate failure of cognitive recognition of a leakdown of the reference legs in the PSA model.	0.77%	0.00%	0.00%	$5,306	$15,917		
80 - Install additional instrumentation to assist in identifying a reference leg leakdown.	The cost for implementing this SAMA was specifically estimated for CNS.						> 100k	Not cost effective

1. These analysis cases only impact external events and have been evaluated differently as shown in Section E.2.3 (analysis cases 52 and 53).

Table E.2-3
Sensitivity Analysis Results

Analysis Case (Bold) SAMA Number and Title	Internal and External Benefit, 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1, 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2, 20 yrs Remaining, 3% Discount Rate	CNS Cost Estimate ($)
DC Power	$32,279	$39,487	$39,221	
1 - Provide additional DC battery capacity.				$500,000
2 - Replace lead-acid batteries with fuel cells.				$1,000,000
13 - Portable generator for DC power to supply the battery chargers.				$203,000
21-Modify plant procedures to allow use of a portable power supply for battery chargers.				Part of SAMA 13 cost estimate
Improve Charger Reliability	$2,339	$2,988	$2,631	
3 - Add battery charger to existing DC system.				$90,000
15 - Proceduralize battery charger high-voltage shutdown circuit inhibit.				$50,000
Add DC System Cross-ties	$0	$0	$0	
4 - Provide DC bus cross-ties [The 125V distribution panels and starter racks can be powered from either bus, thus the 125V buses are cross-tied. However the 250V buses are not cross-tied].				$300,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Analysis Case (Bold) SAMA Number and Title	Internal and External Benefit, 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1, 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2, 20 yrs Remaining, 3% Discount Rate	CNS Cost Estimate ($)
Improve Existing DC System Cross-ties	$1,999	$2,554	$2,249	
19 - Modify plant procedures to use DC bus cross-ties [This SAMA will enhance procedures to use the existing 125V DC bus cross-ties].				$25,000
Provide Backup DC Power to the 120 V Vital AC Bus	$465	$593	$523	
5 - Provide additional DC power to the 120/240V vital AC system.				> 100k
Increase Availability of the 120 V Vital AC Bus	$0	$0	$0	
6 - Add an automatic feature to transfer the 120V vital AC bus from normal to standby power.				$500,000
Increase Availability of On-Site AC Power	$141,672	$172,502	$173,475	
7 - Provide an additional diesel generator.				$20,000,000
10 - Install a gas turbine generator.				$2,000,000
Provide Backup EDG SW Cooling	$44,738	$55,143	$53,680	
11 - Add a new backup source of diesel cooling.				$2,000,000
Increase EDG Reliability	$6,229	$7,585	$7,623	
16 - Provide a portable EDG fuel oil transfer pump.				$100,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Analysis Case (Bold) SAMA Number and Title	Internal and External Benefit, 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1, 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2, 20 yrs Remaining, 3% Discount Rate	CNS Cost Estimate ($)
Improve AC Power	$35,490	$42,467	$44,679	
8 - Improve 4.16-kV bus cross-tie ability.				$656,000
17 - Provide alternate feeds to essential loads directly from an alternate emergency bus.				$217,388
Reduce Loss of Off-Site Power During Severe Weather	$43,237	$52,957	$52,430	
9 - Install an additional, buried off-site power source.				$2,485,000
12 - Bury off-site power lines.				$1,140,000,000
Reduce Plant-Centered Loss of Off-Site Power	$614	$784	$690	
18 - Protect transformers from failure.				$780,000
Redundant Power to Torus Hard Pipe Vent (THPV) Valves	$77,440	$90,889	$100,406	
20 - Provide redundant power to direct torus hard pipe vent valves to improve the reliability of the direct torus vent valves and enhance the containment heat removal capability.				$714,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Analysis Case (Bold) SAMA Number and Title	Internal and External Benefit, 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1, 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2, 20 yrs Remaining, 3% Discount Rate	CNS Cost Estimate ($)
High Pressure Injection System	$301,827	$372,216	$361,864	
14 - Portable generator for DC power to supply the individual panels.				$714,000
22 - Install an independent active or passive high pressure injection system.				$1,000,000
23 - Provide an additional high pressure injection pump with independent diesel.				$1,000,000
Extend RCIC Operation	$28,693	$36,403	$32,726	
24 - Raise HPCI/RCIC backpressure trip set points [HPCI backpressure trip setpoint has already been raised. This SAMA will evaluate raising the RCIC backpressure trip set point].				> 200K
25 - Revise procedure to allow bypass of RCIC turbine exhaust pressure trip [This SAMA will revise EOP 5.8.20 to give direction to allow bypass of RCIC turbine exhaust pressure trip].				$25,000
Improve ADS System	$0	$0	$0	
26 - Modify automatic depressurization system components to improve reliability [This SAMA will add larger accumulators thus increasing reliability during SBOs].				> 100k

Table E.2-3 (Continued)
Sensitivity Analysis Results

Analysis Case (Bold) SAMA Number and Title	Internal and External Benefit, 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1, 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2, 20 yrs Remaining, 3% Discount Rate	CNS Cost Estimate ($)
Reliability of SRVs	$135,371	$172,481	$153,207	
27 - Add signals to open safety relief valves automatically in an MSIV closure transient.				$1,500,000
Low Pressure Injection System	$603,989	$734,195	$741,607	
28 - Add a diverse low pressure injection system.				$8,800,000
ECCS Low Pressure Interlock	$190,301	$239,635	$220,027	
29 - Install a bypass switch to allow operators to bypass the low reactor pressure interlock circuitry.				$1,000,000
Improve Reliability of HPCI and RCIC	$41,996	$53,513	$47,519	
67 - Improve the reliability of the HPCI and RCIC systems by upgrading their control systems.				$434,775
Main Condenser	$26,517	$32,872	$31,507	
76 - Improve steam tunnel HVAC reliability/ redundancy to prevent inadvertent group 1 isolations.				> 100k
Improve Reliability of ECCS Equipment	$9,298	$11,883	$10,462	
77 - Improve reliability of auto-start features for the ECCS equipment.				> 100k

Table E.2-3 (Continued)
Sensitivity Analysis Results

Analysis Case (Bold) SAMA Number and Title	Internal and External Benefit, 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1, 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2, 20 yrs Remaining, 3% Discount Rate	CNS Cost Estimate ($)
Improve Injection Via Fire Water System	$52,605	$64,556	$63,587	
78 - Improve training on alternate injection via FPS.				$25,000
RHR Heat Exchangers	$199,969	$245,994	$240,745	
30 - Revise procedures to allow manual alignment of the fire water system to RHR heat exchangers.				$25,000
Emergency Service Water System Reliability	$3,152	$3,920	$3,722	
31 - Add a service water pump to reduce the impact of common cause failures on the SW system.				$5,900,000
Reduce Valve Failure – Fire Water System	$358	$456	$402	
32 - Enhance alternate injection reliability by including the residual heat removal service water and fire water cross-tie valves in the maintenance program [The residual heat removal service water cross-tie valves (CNS-1-SW-MOV-36MV and CNS-2-SW-MOV-37MV) are essential and in the maintenance rule program. The fire water cross-tie valves are not in the maintenance program. This SAMA will evaluate including the fire water cross-tie valves].				$50,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Analysis Case (Bold) SAMA Number and Title	Internal and External Benefit, 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1, 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2, 20 yrs Remaining, 3% Discount Rate	CNS Cost Estimate ($)
Alternate Water Supply for the TEC Heat Exchangers	$177,788	$215,342	$219,563	
68 - Proceduralize the ability to cross-connect the circulating water pumps and the service water going to the turbine equipment cooling (TEC) heat exchangers.				$50,000
Increase Availability of Feedwater and Condensate	$431,725	$523,994	$531,403	
33 - Create ability for emergency connection of existing or new water sources to feedwater and condensate systems.				$25,000
Main Feedwater System Reliability	$89	$113	$99	
34 - Add a motor-driven feed water pump to increase the availability of injection subsequent to MSIV closure.				$1,650,000
Increase Availability of the CST	$20,890	$25,520	$25,439	
72 - Provide a means of automatically preventing draindown of CST to hotwell during a SBO.				$230,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Analysis Case (Bold) SAMA Number and Title	Internal and External Benefit, 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1, 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2, 20 yrs Remaining, 3% Discount Rate	CNS Cost Estimate ($)
Increase Availability of Room Cooling	$38,498	$47,436	$46,219	
35 - Provide a redundant train or means of ventilation [This SAMA examines implementing a redundant means of ventilation to the CS pump rooms, RHR pump rooms, RHRSW booster pump rooms, SW pump rooms, and HPCI pump room].				$2,202,725
Increase Availability of the EDG System	$33,160	$40,239	$40,827	
36 - Add a diesel building high temperature alarm or redundant louver and thermostat.				$1,304,700
38 - Diverse EDG HVAC logic.				$100,000
39 - Install additional fan and louver pair for EDG heating, ventilation, and air conditioning.				$6,000,000
40 - Operator procedure revisions to provide additional space cooling to the EDG room via the use of portable equipment.				$25,000
Improve Diagnosis of a Loss of Switchgear HVAC	$0	$0	$0	
37 - Add a switchgear room high temperature alarm.				$400,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Analysis Case (Bold) SAMA Number and Title	Internal and External Benefit, 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1, 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2, 20 yrs Remaining, 3% Discount Rate	CNS Cost Estimate ($)
Increase Reliability of Instrument Air	$166,450	$204,331	$201,094	
41 - Modify procedure to provide ability to align diesel power to more air compressors.				$1,200,000
42 - Replace service and instrument air compressors with more reliable compressors which have self-contained air cooling by shaft driven fans.				$1,394,598
45 - Provide an alternate means of supplying the instrument air header.				$100,000
Extend SRV Operation Time	$0	$0	$0	
43 - Install nitrogen bottles as backup gas supply for safety relief valves.				> 100k
Improve Availability of SRVs and MSIVs	$191,658	$232,481	$236,137	
44 - Improve SRV and MSIV pneumatic components.				$1,500,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Analysis Case (Bold) SAMA Number and Title	Internal and External Benefit, 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1, 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2, 20 yrs Remaining, 3% Discount Rate	CNS Cost Estimate ($)
Decay Heat Removal Capability – Torus Cooling	$374,118	$455,722	$457,795	
46 - Install an independent method of suppression pool cooling.				$5,800,000
71 - Upgrade existing equipment to transfer water from the torus to radwaste.				$11,118,000
73 - Provide ability to maintain suppression pool temperature lower.				$1,275,000
Decay Heat Removal Capability – Drywell Spray	$319,007	$374,060	$414,194	
47 - Install a passive drywell spray system to provide a redundant drywell spray method.				$5,800,000
Filtered Vent	$89,122	$99,126	$124,533	
48 - Install a filtered containment vent to provide fission product scrubbing.				$1,500,000
49 - Enhance fire protection system and/or standby gas treatment system hardware and procedures.				$2,500,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Analysis Case (Bold) SAMA Number and Title	Internal and External Benefit, 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1, 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2, 20 yrs Remaining, 3% Discount Rate	CNS Cost Estimate ($)
Controlled Containment Venting	$35	$44	$39	
50 - Control containment venting within a narrow band of pressure to prevent rapid containment depressurization when venting is implemented thus avoiding adverse impact on the low pressure ECCS injection systems taking suction from the torus.				$250,000
Vacuum Breakers	$22,890	$26,952	$29,534	
51 - Install improved vacuum breakers (redundant valves in each line).				$500,000
Passive Containment Overpressure Relief	$127,921	$150,053	$165,996	
52 - Provide passive overpressure relief by changing the containment vent valves to fail open and improving the strength of the rupture disk.				$1,000,000
53 - Install alternate path to the torus hard pipe vent via the wet well using a rupture disk.				$5,700,000
Barriers to Block Debris from Reaching the Steel Shell	$227,447	$266,226	$296,088	
70 - Install a curb to prevent debris from spreading across the floor and contacting the shell.				$844,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Analysis Case (Bold) SAMA Number and Title	Internal and External Benefit, 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1, 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2, 20 yrs Remaining, 3% Discount Rate	CNS Cost Estimate ($)
ISLOCA	$8,556	$10,024	$11,121	
54 - Increase frequency of valve leak testing to reduce ISLOCA frequency.				$100,000
56 - Revise EOPs to improve ISLOCA identification.				$50,000
57 - Improve operator training on ISLOCA coping.				$112,000
MSIV Design	$2,723	$3,318	$3,327	
55 - Improve MSIV design to decrease the likelihood of containment bypass scenarios.				$1,000,000
SLC System	$12,362	$14,567	$15,930	
58 - Increase boron concentration in the SLC system [Reduced time required to achieve shutdown provides increased margin in the accident timeline for successful initiation of SLC].				> 50k
Improve Availability of Boron Injection	$22,485	$26,433	$29,078	
59 - Add an independent boron injection system.				> 100k
60 - Provide ability to use control rod drive (CRD) for alternate boron injection.				$150,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Analysis Case (Bold) SAMA Number and Title	Internal and External Benefit, 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1, 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2, 20 yrs Remaining, 3% Discount Rate	CNS Cost Estimate ($)
SRV Reseat	$10,734	$13,450	$12,517	
61 - Increase safety relief valve (SRV) reseat reliability to address the risk associated with dilution of boron caused by the failure of the SRVs to reseat after standby liquid control (SLC) injection.				$2,200,000
Internal Flooding	$17,237	$20,905	21,240	
62 - Improve internal flooding procedures.				$460,000
Fire Water Pipe Break	$2,036	$2,494	$2,466	
74 - Provide flow diversion to help mitigate the fire water pipe break in the control building ground floor corridor.				> 100k
Increase Reliability of the Fire Water System	$27,465	$33,602	$33,365	
64 - Proceduralize the use of a fire pumper truck to pressurize the fire water system.				$50,000
69 - Upgrade the seismic capacity of the diesel fire pump fuel tank and water supply tank.				> 100k

Table E.2-3 (Continued)
Sensitivity Analysis Results

Analysis Case (Bold) SAMA Number and Title	Internal and External Benefit, 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1, 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2, 20 yrs Remaining, 3% Discount Rate	CNS Cost Estimate ($)
Add Fire Suppression[1]	N/A	N/A	N/A	
63 - Add automatic fire suppression systems to the dominant fire zones.				$375,000
Reduce Risk from Fires that Require Control Room Evacuation[1]	N/A	N/A	N/A	
65 - Upgrade the ASDS panel to include additional system controls for opposite division.				$786,991
Large Break LOCA	$19,235	$22,547	$24,982	
66 - Provide digital large break LOCA protection to identify symptoms/precursors of a large break LOCA (a leak before break).				$100,000
Trip/Shutdown Risk	$394,444	$483,039	$478,471	
75 - Generation Risk Assessment implementation into plant activities (trip/shutdown risk modeling).				$500,000
Improve RHRSW System	$110,566	$135,263	$134,344	
79 - Modify procedures to allow use of the RHRSW system without a SWBP.				$25,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Analysis Case (Bold) SAMA Number and Title	Internal and External Benefit, 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1, 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2, 20 yrs Remaining, 3% Discount Rate	CNS Cost Estimate ($)
Improve Plant Identification of Reference Leg Leakdowns	$5,306	$6,780	$5,969	
80 - Install additional instrumentation to assist in identifying a reference leg leakdown.				> 100k

1. These analysis cases only impact external events and have been evaluated differently as shown in Section E.2.3 (analysis cases 52 and 53).