Keith J. Polson
Vice President-Nine Mile Point

P.O. Box 63
Lycoming, New York 13093
315.349.5200
315.349.1321 Fax

Constellation Energy
Nine Mile Point Nuclear Station

October 24, 2007

U. S. Nuclear Regulatory Commission
Washington, DC 20555-0001

ATTENTION: Document Control Desk

SUBJECT: Nine Mile Point Nuclear Station
Unit No. 1; Docket No. 50-220

Submittal of Revision 20 to the Final Safety Analysis Report (Updated), 10 CFR 50.59 Evaluation Summary Report, and Technical Specifications Bases Changes

Pursuant to the requirements of 10 CFR 50.71(e), 10 CFR 50.59(d)(2), and the Nine Mile Point Unit 1 (NMP1) Technical Specifications (TS) Bases Control Program (TS 6.5.6), Nine Mile Point Nuclear Station, LLC (NMPNS) hereby submits the following:

- Revision 20 to the NMP1 Final Safety Analysis Report (Updated) (UFSAR)
- The NMP1 10 CFR 50.59 Evaluation Summary Report, and
- NMP1 Technical Specifications Bases Changes.

One copy of the UFSAR Revision 20 pages is contained in Attachment 1. The UFSAR revision contains changes made since the submittal of Revision 19 in October 2005. The revision reflects all changes up to and including April 18, 2007. Attachment 2, 10 CFR 50.59 Evaluation Summary Report, covering the same time interval as the UFSAR revision, contains a brief description of changes, tests, and experiments, and includes summaries of the associated 10 CFR 50.59 evaluations. None of the 10 CFR 50.59 evaluations involved obtaining a license amendment as defined in 10 CFR 50.59(c)(1).

One copy of revised Technical Specifications Bases pages (Attachment 3) is also enclosed, which incorporates changes made since April 6, 2005. The corresponding summaries of the changes to this document are provided in Attachment 4.

A053
NRR

Should you have any questions regarding the information in this submittal, please contact T. F. Syrell, Licensing Director, at (315) 349-5219.

Very truly yours,

KJP/LWB

Attachments:
1. Final Safety Analysis Report (Updated) Pages
2. 10 CFR 50.59 Evaluation Summary Report
3. Revised Technical Specifications Bases Pages
4. Technical Specifications Bases Changes Summary

cc: S. J. Collins, NRC
M. J. David, NRR Project Manager
Resident Inspector, NRC

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of	)	
	)	
Nine Mile Point Nuclear	)	
Station, LLC	)	Docket No. 50-220
	)	
(Nine Mile Point Nuclear	)	
Station Unit 1)	)	

CERTIFICATION

I, Keith J. Polson, being duly sworn, state that I am Vice President-Nine Mile Point; and that I am duly authorized to execute and file this certification on behalf of Nine Mile Point Nuclear Station, LLC. In accordance with 10 C.F.R. §50.71(e)(2), to the best of my knowledge and belief, I certify that the information contained in the attached letter and the Final Safety Analysis Report (Updated) accurately presents changes made since the previous submittal necessary to reflect information and analyses submitted to the Commission or prepared pursuant to Commission requirements and contains an identification of changes made under the provisions of §50.59 but not previously submitted to the Commission.

By: Keith J. Polson
Keith J. Polson
Vice President-Nine Mile Point

Subscribed and sworn to before me this 24th day of October, 2007.

Notary Public in and for Oswego County, New York

My Commission Expires: 10-25-09

SANDRA A. OSWALD
Notary Public, State of New York
No. 01OS6032276
Qualified in Oswego County
Commission Expires 10-25-09

bcc: L. S. Larragoite
C. W. Fleming, Esquire
K. J. Polson
D. R. Bauder
T. F. Syrell
J. L. Lyon

NMP1L 2171

COMMITMENTS IDENTIFIED IN THIS CORRESPONDENCE:

- None

Posting Requirements for Responses -- NOV/Order **No**

ATTACHMENT 1

FINAL SAFETY ANALYSIS REPORT (UPDATED) PAGES

Nine Mile Point Nuclear Station, LLC
October 24, 2007

ATTACHMENT 2

10 CFR 50.59 EVALUATION SUMMARY REPORT

Nine Mile Point Nuclear Station, LLC
October 24, 2007

50.59 Evaluation No.: 2000-016

Implementation Document No.: Temporary Mod. 00-021

UFSAR Affected Pages: N/A

System: RAGEMS

Title of Change: RAGEMS Functionality and Reliability

Description of Change:

This temporary modification implemented a compensatory measure as an interim step until final corrective action is complete in accordance with Generic Letter 91-18. This temporary modification restored the capability of RAGEMS to a functional status that is more reliable/available for post-accident stack gaseous effluent monitoring/sampling. RAGEMS was not operational in its present automatic configuration because of failed obsolete process and computer equipment that was no longer available or supported by Canberra (isotopic equipment manufacturer), DEC (PDP 11/34 computer manufacturer), or SAI (system supplier). RAGEMS is controlled by a DEC PDP 11/34 computer that is obsolete with source programming that is not available from the vendor. RAGEMS is considered to be the primary system to be utilized for stack gaseous effluent post-accident monitoring. RAGEMS was currently INOP because it was unable to perform its original intended design functions. RAGEMS was initially installed in the early 1980s to provide post-accident gaseous effluent monitoring in conformance with station commitments to Regulatory Guide (RG) 1.97, Rev. 2, and NUREG-0737. The temporary modifications were necessary to simplify the design of RAGEMS and to make it available for high-range post-accident monitoring.

Improved reliability was accomplished by simplifying and reconfiguring the system such that unnecessary and obsolete system functions and equipment that are not required for RAGEMS to be in compliance with RG 1.97/NUREG-0737 per station commitments were eliminated. However, the NMPC commitment for isotopic analysis and the RG 1.97 lower limit of detection (LLD) 1E-6 uCi/ml detection requirement were not met.

50.59 Evaluation Summary:

The proposed temporary modification of RAGEMS does not require a Technical Specification change, as it is an interim compensatory measure in accordance with Generic Letter 91-18, and the system will not be made operable. Per discussion with the gross count radiation detector vendor, Tennelec, the best possible LLD would be approximately 5E-4 uCi/ml. Technical Specification Table 4.6.15-2 requires that the LLD for the noble gas monitor be 1E-6 uCi/ml. The Technical Specification is being

50.59 Evaluation No.: 2000-016 (cont'd.)

50.59 Evaluation Summary: (cont'd.)

complied with in that it allows for a 1E-4 uCi/ml LLD when RAGEMS is inoperable. The compensatory action itself (not the degraded condition) does not impact other aspects of the facility as described in the UFSAR.

The possible effects of the RAGEMS after the temporary modification on operating equipment and systems are no different than those prior to the temporary modification. For the duration of this temporary modification, OGESMS will be the normal operating system. OGESMS currently performs a Hi-Hi radiation isolation function. This isolation function is unaffected by this temporary modification. RAGEMS will only be activated under administrative control as required to provide high-range monitoring during accident situations in compliance with NUREG-0737, and only after drywell and suppression chamber vent and purge isolation has been verified. RAGEMS operating procedures will be revised to transfer from OGESMS to RAGEMS only after drywell and suppression chamber vent and purge isolation has been verified. RAGEMS has no other connections with any plant system or component other than 1E power source, output to the plant computer, Control Room recorder, and the selector valve in OGESMS that is transferred to RAGEMS during an accident.

Based on the evaluation performed, it is concluded that these changes do not require prior NRC approval.

ATTACHMENT 3

REVISED TECHNICAL SPECIFICATIONS BASES PAGES

Nine Mile Point Nuclear Station, LLC
October 24, 2007

INSERTION INSTRUCTIONS

TECHNICAL SPECIFICATIONS BASES

The following instructions are for the insertion of revised Bases pages into the Nine Mile Point Unit 1 Technical Specifications Bases.

Remove pages, tables, and/or figures listed in the REMOVE column and replace them with the pages, tables, and/or figures listed in the INSERT column. Dashes (---) in either column indicate no action required.

REMOVE	INSERT
LEP-1 through LEP-4	LEP-1 through LEP-4
27b	27b
27c	27c
27d	27d
27e	27e
---	27f
58	58
71	71
72	72
---	72a
73	73
75	75
129	129
130	130
273	273

NMP1 FACILITY OPERATING LICENSE (FOL) AND
TECHNICAL SPECIFICATIONS (TS)

LIST OF EFFECTIVE PAGES

Page No. (1)	Amend. No. (A) or Rev. No. (R)	Page No. (1)	Amend. No. (A) or Rev. No. (R)
FOL Page 1	Renewed	27a	A182
FOL Page 2	Renewed	27b (B)	R17
FOL Page 3	A193	27c (B)	R17
FOL Page 4	Renewed	27d (B)	R17
FOL Page 5	Renewed	27e (B)	R17
FOL Page 6	Renewed	27f (B)	R17
FOL Page 7	Renewed	28	A142
FOL Page 8	Renewed	29	A180
		29a	A180
Forward	A172	30	A180
		31	A180
i	A182	31a	A180
ii	A173	32	A178
iii	A176	33	A193
iv	A176	34	A193
v	A189	35	A142
vi	A181	36	A180
		37 (B)	R5
1	A142	37a (B)	R5
2	A143	37b (B)	R5
3	A142	37c (B)	R5
4	A187	38 (B)	A142
5	A142	39 (B)	R4
6	A176	40 (B)	A142
7	A176	41 (B)	R4
8	A181	42 (B)	A142
9	A168	43 (B)	R5
10	A168	44	A142
11	A181	45	A166
12	A168	46	A142
13 (B)	A142	47	A142
14 (B)	A168	48 (B)	A166
15 (B)	A142	49 (B)	A142
16 (B)	A142	50	A142
17 (B)	A168	51	A142
18 (B)	A168	52 (B)	June 2, 1994
19 (B)	A168	53 (B)	A142
20 (B)	A153	54	A142
21 (B)	A153	55	A192
22 (B)	A168	56	A142
23	A152	57 (B)	A142
24 (B)	A142	58 (B)	R16
25 (B)	A152	59 (B)	A142
26 (B)	A168	60	A142
27	A182	61 (B)	A142

(1) (B) denotes Bases page.

NMP1 FACILITY OPERATING LICENSE (FOL) AND
TECHNICAL SPECIFICATIONS (TS)

LIST OF EFFECTIVE PAGES

Page No. [1]	Amend. No. (A) or Rev. No. (R)	Page No. [1]	Amend. No. (A) or Rev. No. (R)
62	A142	101	A142
63	A142	102	A142
64 (B)	A142	103 (B)	A142
65	A143	104 (B)	A142
66	A193	105	A173
67	A143	106	A173
68	A142	107 (B)	R2
69	A142	108	A181
70	A142	109	A142
70a	A153	110	A145
71 (B)	R18	111 through 114	Not Used
72 (B)	R18	115 (B)	R6
72a (B)	R18	116	A142
73 (B)	R18	117	A154
74 (B)	A153	118	A152
75 (B)	R18	119 (B)	A152
76	A142	120	A142
77	A142	121	A142
78 (B)	A142	122 (B)	R1
79 (B)	A142	123	A170
80	A142	124	A185
81	A142	125	A185
82 (B)	A142	126 (B)	R11
83	A184	127	A170
84	A184	128	A142
85	A183	129 (B)	R14
86	A183	130 (B)	R14
87	A183	131	A182
88	A183	132	A159
89	A183	133	A159
90	A183	134 through 139	Deleted
91	A183	140 (B)	A142
92	A183	141 (B)	A159
93	A183	142 (B)	R8
94	A183	143	A170
94a	A183	144	A142
94b through 94d	Deleted	145	A145
95 (B)	R12	146 through 149	Not Used
96	A169	150 (B)	R12
97	A169	150a (B)	R12
97a	A163	151	A170
98 (B)	A172	152	A142
98a (B)	A169	153	A142
99	A170	154	A142
100 (B)	A170	155	A142

[1] (B) denotes Bases page.

LIST OF EFFECTIVE PAGES

Page No. [(1)]	Amend. No. (A) or Rev. No. (R)	Page No. [(1)]	Amend. No. (A) or Rev. No. (R)
156	A142	201	A149
157 (B)	A142	202	A186
158 (B)	A142	203	A186
159	A170	204	A142
160	A142	205	A142
161	A190	206	A153
162 (B)	A142	207	A142
163 (B)	A142	208	A142
164	A170	209	A149
165	A170	210	A177
166	A142	211	A142
167 (B)	A156	212	A142
168	A170	213	A153
169 (B)	A142	214	A142
170	A170	215	A142
171	A170	216	A142
172 (B)	A170	217	A142
173	A179	218	A142
174	A171	219	A142
175	A142	220	A142
176 (B)	A171	221	A142
177 (B)	A142	222	A142
178	A179	223	A142
179	A171	224	A142
180 (B)	A171	225	A142
181 (B)	A142	226	A186
182	A142	227	A153
183	A142	228	A186
184	A142	229	A186
185 (B)	A142	230	A186
186	A142	231	A186
187 (B)	A142	232	A186
188	A142	233	A186
189	A142	234	A142
190 (B)	A142	235	A142
191	A176	236	A142
192	A176	237	A142
193 (B)	A142	238	A148
194	A142	239	A142
195	A143	240	A142
196	A176	241	A142
197	A143	242	A142
198	A142	243	A142
199	A153	244	A142
200	A153		

(1) (B) denotes Bases page.

NMP1 FACILITY OPERATING LICENSE (FOL) AND
TECHNICAL SPECIFICATIONS (TS)

LIST OF EFFECTIVE PAGES

Page No. [(1)]	Amend. No. (A) or Rev. No. (R)	Page No. [(1)]	Amend. No. (A) or Rev. No. (R)
245	A142	296 (B)	A176
246	A161	297	A176
247	A161	298 through 338 (B)	Deleted
247a	A161	339	A142
248 (B)	A142	340	A142
249 (B)	A142	341 (B)	R5
250 (B)	R10	342	A189
250a (B)	R10	343	A172
251 (B)	R13	344	A142
251a (B)	R13	345	A189
252 (B)	R13	346	A189
253 (B)	R13	347	A181
254 (B)	R13	348	A181
255	A142	349	A181
256	A179	350	A181
257	A142	351	A182
258 (B)	A142	352	A181
259	A175	353	A182
260	A175	354	A182
261	A175	355	A182
262	A142	356	A188
263	A142	357	A188
263a	A182	358	A184
264 (B)	R3	359	A181
265	A142	360	A181
266	A142	361	A181
267 (B)	A142	362	A181
268	A142	363	A181
269	A191	364	A181
270	A142	365	A176
271	A142	366	A181
272	A191	367	A181
273 (B)	R15	368	A181
274	A142	369	A176
275	A142	370	A181
276 (B)	A142	371	A181
277	A155	371a	A181
278	A155	371b	A181
279	A155	372	A181
280	A142	372a	A181
281 (B)	A155	373	A181
282	A176	374	A181
283 through 294 (B)	Deleted	375	A181
295	A176	376	A181

[(1)] (B) denotes Bases page.

3.0.1 Specification 3.0.1 delineates what additional conditions must be satisfied to permit operation to continue, consistent with the specifications for power sources, when a normal or emergency power source is not operable. It specifically prohibits operation when one division is inoperable because its normal or emergency power source is inoperable and a system, subsystem, train, component, or device in another division is inoperable for another reason.

The provisions of this specification permit the specifications associated with individual systems, subsystems, trains, components or devices to be consistent with the specifications of the associated electrical power source. It allows operation to be governed by the time limits of the specification for the normal or emergency power source, not the individual specification for each system, subsystem, train, component, or device that is determined to be inoperable solely because of the inoperability of its normal or emergency power source. The provisions of Specification 3.0.1 permit the time limits for continued operation to be consistent with the specification for the inoperable normal or emergency power source instead, provided the other specific conditions are satisfied. If the other specified conditions are not satisfied, actions are required consistent with the applicable individual specification(s).

For example, Specification 3.6.3.a requires, in part, that two diesel generator power systems be available. Specification 3.6.3.c provides for a 14 day out-of-service time when one diesel generator power system is not operable. If the definition of Operable were applied without consideration of Specification 3.0.1, all systems, subsystems, trains, components, and devices supplied by the inoperable diesel generator would also be inoperable. This would dictate invoking the applicable specifications for each of the applicable LCOs. However, the provisions of Specification 3.0.1 permit the time limits for continued operation to be consistent with the specification for the inoperable diesel generator system instead, provided the other specified conditions are satisfied. In this case, this would mean that the corresponding normal power source must be operable, and all redundant systems, subsystems, trains, components, and devices must be operable, or otherwise satisfy Specification 3.0.1 (i.e., be capable of performing their design function and have at least one normal power source or diesel generator operable). If the other specified conditions are not satisfied, the plant is required to be placed in the condition stated in the applicable individual specification(s).

As a further example, Specification 3.6.3.a requires, in part, that two 115 kv external lines be available. Specification 3.6.3.e(2) provides a 24 hour out-of-service time when both required offsite circuits are not available. If the definition of Operable were applied without consideration of Specification 3.0.1, all systems, subsystems, trains, components, and devices supplied by the inoperable normal power sources (i.e., both of the 115 kv external lines) would also be inoperable. This would dictate invoking the applicable specifications for each of the applicable LCOs. However, the provisions of Specification 3.0.1 permit the time limits for continued operation to be consistent with the specification for the inoperable normal power source instead, provided the other specified conditions are satisfied. In this case, this would mean that for one division the diesel generator power system must be operable (as must be the components supplied by the diesel generator power system) and the diesel generator must be running. In addition, all of the redundant systems, subsystems, trains, components, and devices in the other division must be operable, or likewise satisfy Specification 3.0.1 (i.e., be capable of performing their design functions and have the diesel generator power system operable, but with the diesel generator not running). In other words, both diesel generator power systems must be operable, with one diesel generator running, and all redundant systems, subsystems, trains, components, and devices in both divisions must also be operable. If these conditions are not satisfied, the plant is required to be placed in the condition stated in the applicable individual specification(s).

Additionally, Specification 3.0.1 delineates the action to be taken for circumstances not directly provided for in the specification condition statements, and whose occurrences would violate the intent of the specification. For example, certain specifications call for both subsystems in a two subsystem design to be operable and provide explicit action requirements if one (1) subsystem is inoperable. Under the terms of Specification 3.0.1, if both of the required subsystems are inoperable, the plant is required to take actions consistent with the specification. It is assumed that the plant is to be in at least the required operational condition within the required times by promptly initiating and carrying out the appropriate action statement.

Specifications 4.0.1 through 4.0.3 establish general requirements applicable to all specifications in Sections 4.1 through 4.7 and apply at all times, unless otherwise stated.

4.0.1 Specification 4.0.1 establishes the requirement that SRs must be met during the applicable reactor operating or other specified conditions for which the requirements of the LCO apply, unless otherwise specified in the individual SRs. This specification is to ensure that surveillances are performed to verify the operability of systems and components, and that variables are within specified limits. Failure to meet a surveillance within the specified frequency, in accordance with Specification 4.0.2, constitutes a failure to meet an LCO. Surveillances may be performed by means of any series of sequential, overlapping, or total steps provided the entire surveillance is performed within the specified frequency.

Systems and components are assumed to be operable when the associated SRs have been met. Nothing in this specification, however, is to be construed as implying that systems or components are operable when either:

a. The systems or components are known to be inoperable, although still meeting the SRs; or

b. The requirements of the surveillance(s) are known to be not met between required surveillance performances.

Surveillances do not have to be performed when the unit is in a reactor operating or other specified condition for which the requirements of the associated LCO are not applicable, unless otherwise specified. The SRs associated with a special test exception LCO are only applicable when the special test exception LCO is used as an allowable exception to the requirements of a specification.

Unplanned events may satisfy the requirements (including applicable acceptance criteria) for a given SR. In this case, the unplanned event may be credited as fulfilling the performance of the SR. This allowance includes those SRs whose performance is normally precluded in a given reactor operating or other specified condition.

Surveillances, including surveillances invoked by LCO actions, do not have to be performed on inoperable equipment because the applicable individual specifications define the remedial measures that apply. Surveillances have to be met and performed in accordance with Specification 4.0.2, prior to returning equipment to operable status.

Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment operable. This includes ensuring applicable surveillances are not failed and their most recent performance is in accordance with Specification 4.0.2. Post maintenance testing may not be possible in the current reactor operating or other specified conditions in the LCO due to the necessary unit parameters not having been established. In these situations, the equipment may be considered operable provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to a reactor operating or other specified condition where other necessary post maintenance tests can be completed.

4.0.2 Specification 4.0.2 establishes the limit for which the specified time interval for SRs may be extended. It permits an allowable extension of the surveillance interval to facilitate surveillance scheduling and consideration of plant operating conditions that may not be suitable for conducting the surveillance; e.g., transient conditions or other ongoing surveillance or maintenance activities. It also provides flexibility to accommodate the length of a fuel cycle for surveillances that are performed at each refueling outage and are specified with a 24 month surveillance interval. It is not intended that this provision be used repeatedly as a convenience to extend surveillance intervals beyond that specified for surveillances that are not performed during refueling outages. The limitation of Specification 4.0.2 is based on engineering judgment and the recognition that the most probable result of any particular surveillance being performed is the verification of conformance with the SRs. This provision is sufficient to ensure that the reliability ensured through surveillance activities is not significantly degraded beyond that obtained from the specified surveillance interval.

4.0.3 Specification 4.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a surveillance has not been completed within the specified frequency. A delay period of up to 24 hours or up to the limit of the specified frequency, whichever is greater, applies from the point in time it is discovered that the surveillance has not been performed in accordance with Specification 4.0.2, and not at the time that the specified frequency was not met. This delay period permits the completion of a surveillance before complying with LCO actions or other remedial measures that might preclude completion of the surveillance.

The basis for this delay period includes consideration of unit conditions, adequate planning, availability of personnel, the time required to perform the surveillance, the safety significance of the delay in completing the required surveillance, and the recognition that the most probable result of any particular surveillance being performed is the verification of conformance with the requirements.

When a surveillance with a frequency based not on time intervals, but upon specified unit conditions, operating situations, or requirements of regulations (e.g., prior to power operation, or in accordance with the 10 CFR 50 Appendix J Testing Program Plan, etc.) is discovered to not have been performed when specified, Specification 4.0.3 allows for the full delay period of up to the specified frequency to perform the surveillance. However, since there is not a time interval specified, the missed surveillance should be performed at the first reasonable opportunity.

Specification 4.0.3 provides a time limit for, and allowances for the performance of, surveillances that become applicable as a consequence of operating condition changes imposed by LCO actions.

Failure to comply with specified frequencies for surveillance requirements is expected to be an infrequent occurrence. Use of the delay period established by Specification 4.0.3 is a flexibility which is not intended to be used as an operational convenience to extend surveillance intervals. While up to 24 hours or the limit of the specified frequency is provided to perform the missed surveillance, it is expected that the missed surveillance will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the surveillance as well as any plant configuration changes required or shutting the plant down to perform the surveillance) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of personnel, and the time required to perform the surveillance. The risk impact should be managed through the program in place to implement 10 CFR 50.65(a)(4) and its implementation guidance, NRC Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants." This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determines the risk management action thresholds, and risk management action up to and including plant shutdown. The missed surveillance should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. Missed surveillances for important components should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All missed surveillances will be placed in the Corrective Action Program.

If a surveillance is not completed within the allowed delay period, then the equipment is considered inoperable or the variable then is considered outside the specified limits and entry into the applicable LCO actions begin immediately upon expiration of the delay period. If a surveillance is failed within the delay period, then the equipment is inoperable, or the variable is outside the specified limits and entry into the applicable LCO actions begin immediately upon failure of the surveillance.

Completion of the surveillance within the delay period allowed by this specification, or within the times allowed by LCO actions, restores compliance with Specification 4.0.1.

The testing specified for each major refueling outage will demonstrate component response upon automatic system initiation. For example, pump set starting (low-low level or high drywell pressure) and valve opening (low-low level or high drywell pressure and low reactor pressure) must function, under simulated conditions, in the same manner as the systems are required to operate under actual conditions. The only differences will be that demineralized water rather than suppression chamber water will be pumped to the reactor vessel and the reactor will be at atmospheric pressure. The core spray systems are designed such that demineralized water is available to the suction of one set of pumps in each system (Section VII-Figure VII-1)*.

The system test interval between operating cycles results in a system failure probability of 1.1×10^{-6} (Fifth Supplement, page 115) and is consistent with practical considerations. The more frequent component testing results in a more reliable system.

At quarterly intervals, startup of core spray pumps will demonstrate pump starting and operability. No flow will take place to the reactor vessel due to the lack of a low-pressure permissive signal required for opening of the blocking valves. A flow restricting device has been provided in the test loop which will create a low pressure loss for testing of the system. In addition, the normally closed power operated blocking valves will be manually opened and re-closed to demonstrate operability.

The intent of Specification 3.1.4i is to allow core spray operability at the time that the suppression chamber is dewatered which will allow normal refueling activities to be performed. With a core spray pump taking suction from the CST, sufficient time is available to manually initiate one of the two raw water pumps that provide an alternate core spray supply using lake water. Both raw water pumps shall be operable in the event the suppression chamber was dewatered.

---

*FSAR

Average Planar Linear Heat Generation Rate (APLHGR)

This specification assures that the peak cladding temperature and the peak local cladding oxidation following the postulated design basis loss-of-coolant accident will not exceed the limits specified in 10CFR50, Appendix K.

The peak cladding temperature following a postulated loss-of-coolant accident is primarily a function of the average heat generation rate of all the rods of a fuel assembly at any axial location and is only dependent secondarily on the rod-to-rod power distribution within an assembly. Since expected local variations in power distribution within a fuel assembly affect the calculated peak clad temperature by less than ±20°F relative to the peak temperature for a typical fuel design, the limit on the average linear heat generation rate is sufficient to assure that calculated temperatures are within the 10CFR50, Appendix K limit. The limiting value for APLHGR is provided in the Core Operating Limits Report. The APLHGR curves in the Core Operating Limits Report are based on calculations using the models described in Reference 15.

The LOCA analyses are sensitive to minimum critical power ratio (MCPR). In the Reference 15 analysis, an MCPR value of 1.30 was assumed. If future transient analyses should yield a MCPR limit below this value, the Reference 15 LOCA analysis MCPR value would become limiting. The current MCPR limit is provided in the Core Operating Limits Report.

Linear Heat Generation Rate (LHGR)

This specification assures that the linear heat generation rate in any rod is less than the design linear heat generation even if fuel pellet densification is postulated (Reference 12). The LHGR shall be checked daily during reactor operation at ≥25% power to determine if fuel burnup or control rod movement has caused changes in power distribution.

Minimum Critical Power Ratio (MCPR)

At core thermal power levels less than or equal to 25%, the reactor will be operating at a minimum recirculation pump speed and the moderator void content will be very small. For all designated control rod patterns which may be employed at this point, operating plant experience and thermal-hydraulic analysis indicated that the resulting MCPR value is in excess of requirements by a considerable margin. With this low void content, any inadvertent core flow increase would only place operation in a more conservative mode relative to MCPR. During initial startup testing of the plant, an MCPR evaluation will be made at the 25% thermal power level with minimum recirculation pump speed. The MCPR margin will thus be demonstrated such that future MCPR evaluations below this power level will be shown to be unnecessary. The daily requirement for calculating MCPR above 25% rated thermal power is sufficient since power distribution shifts are very slow when there have not been significant power or control rod changes. The requirement for calculating MCPR when a limiting control rod pattern is approached ensures that MCPR will be known following a change in power or power shape (regardless of magnitude) that could place operation at a thermal limit.

MCPR limits during operation at other than rated conditions are provided in the Core Operating Limits Report. For the case of automatic flow control, the K_f factor is determined such that any automatic increase in power (due to flow control) will always result in arriving at the nominal required MCPR at 100% power. For manual flow control, the K_f is determined such that an inadvertent increase in core flow (i.e., operator error or recirculation pump speed controller failure) would result in arriving at the 99.9% limit MCPR when core flow reaches the maximum possible core flow corresponding to a particular setting of the recirculation pump MG set scoop tube maximum speed control limiting set screws. These screws are to be calibrated and set to a particular value and whenever the plant is operating in manual flow control, the K_f defined by that setting of the screws is to be used in the determination of required MCPR. This will assure that the reduction in MCPR associated with an inadvertent flow increase always satisfies the 99.9% requirement. Irrespective of the scoop tube setting, the required MCPR is never allowed to be less than the nominal MCPR (i.e., K_f is never less than unity).

Because the transient analysis takes credit for conservatism in the scram speed performance, it must be demonstrated that the specific scram speed distribution is consistent with that used in the transient analysis. SR 4.1.1(c) determines the actual scram speed distribution which is compared to the assumed distribution. The MCPR operating limit is then determined based either on the applicable limit associated with the scram times of TS 3.1.1(c) or the actual scram times. The MCPR operating limit must be determined once within 72 hours after each set of scram time tests required by SR 4.1.1(c) because the effective scram speed distribution may change during the cycle or after maintenance that could affect scram times. The 72 hour Completion Time is acceptable due to the relatively minor changes in scram speed expected during the fuel cycle.

Power/Flow Relationship

The power/flow curve is the locus of critical power as a function of flow from which the occurrence of abnormal operating transients will yield results within defined plant safety limits. Each transient and postulated accident applicable to operation of the plant was analyzed along the power/flow line. The analysis [7, 8, 12, 14] justifies the operating envelope bounded by the power/flow curve as long as other operating limits are satisfied. Operation under the power/flow line is designed to enable the direct ascension to full power within the design basis for the plant.

Partial Loop Operation

The requirements of Specification 3.1.7e for partial loop operation in which the idle loop is isolated, precludes the inadvertent startup of a recirculation pump with a cold leg. However, if these conditions cannot be met, power level is restricted to 90.5 percent power based on current transient analysis (Reference 9). For three loop operation, power level is restricted to 90 percent power based on the Reference 13 and 15 LOCA analyses.

The results of the ECCS calculation are affected by one or more recirculation loops being unisolated and out of service. This is due to the fact that credit is taken for extended nucleate boiling caused by flow coastdown in the unbroken loops. The reduced core flow coastdown following the break results in higher peak clad temperature due to an earlier boiling transition time. The results of the ECCS calculations are also affected by one or more recirculation loops being isolated and out of service. The mass of water in the isolated loops unavailable during blowdown results in an earlier uncovery time for the hot node. This results in an increase in the peak clad temperature.

For fuel bundles analyzed with the methodology used in Reference 15, MAPLHGR shall be reduced as required in the Core Operating Limits Report for 4 and 3 loop operation.

Partial loop operation and its effect on lower plenum flow distribution is summarized in Reference 11. Since the lower plenum hydraulic design in a non-jet pump reactor is virtually identical to a jet pump reactor, application of these results is justified. Additionally, non-jet pump plants contain a cylindrical baffle plate which surrounds the guide tubes and distributes the impinging water jet and forces flow in a circumferential direction around the outside of the baffle.

Recirculation Loops

Requiring the suction and discharge for at least two (2) recirculation loops to be fully open assures that an adequate flow path exists from the annular region between the pressure vessel wall and the core shroud, to the core region. This provides for communication between those areas, thus assuring that reactor water level instrument readings are indicative of the water level in the core region.

When the reactor vessel is flooded to the level of the main steam nozzle, communication between the core region and annulus exists above the core to ensure that indicative water level monitoring in the core region exists. When the steam separators and dryer are removed, safety limit 2.1.1d and e requires water level to be higher than 9 feet below minimum normal water level (Elevation 302'9"). This level is above the core shroud elevation which would ensure communication between the core region and annulus thus ensuring indicative water level monitoring in the core region. Therefore, maintaining a recirculation loop in the full open position in these two instances is not necessary to ensure indicative water level monitoring

References (1) through (6) intentionally deleted.

(7) "Nine Mile Point Nuclear Power Station Unit 1, Load Line Limit Analysis," NEDO-24012.

(8) Licensing Topical Report GE Boiling Water Reactor Generic Reload Fuel Application, NEDE-24011-P-A, August 1978.

(9) Final Safety Analysis Report, Nine Mile Point Nuclear Station, Niagara Mohawk Power Corporation, June 1967.

(10) NRC Safety Evaluation, Amendment No. 24 to DPR-63 contained in letter from G. Lear, NRC, to D. P. Dise dated May 15, 1978.

(11) "Core Flow Distribution in a GE Boiling Water Reactor as Measured in Quad Cities Unit 1," NEDO-10722A.

(12) Nine Mile Point Nuclear Power Station Unit 1, Extended Load Line Limit Analysis, License Amendment Submittal (Cycle 6), NEDO-24185, April 1979.

(13) (Not Used)

(14) GE Boiling Water Reactor Extended Load Line Limit Analysis for Nine Mile Point Unit 1 Cycle 9, NEDC-31126, February 1986.

(15) UFSAR Section XV-C.2.0

(16) (Not Used)

(17) Communication: R. E. Engel (GE) to T. A. Ippolito (NRC) - "End-of-Cycle Coastdown Analyzed with ODYN/TASC," dated September 1, 1981.

(18) Amendment No. 7 to GESTAR, NEDE-24011-P-A-7-US, dated August 1985.

BASES FOR 3.3.2 AND 4.3.2 PRESSURE SUPPRESSION SYSTEM PRESSURE AND SUPPRESSION CHAMBER WATER TEMPERATURE AND LEVEL

The combination of three and one-half foot downcomer submergence, 85°F suppression chamber water temperature at lake water temperature defined by specification 3.3.7/4.3.7 will maintain post-accident system temperature and pressure within FSAR design limits (FSAR Section VI, XV, XVI).

The three and one-half foot minimum and the four and one-quarter foot maximum submergence are a result of Suppression Chamber Heat-up Analysis and the Mark I Containment Program respectively. The minimum submergence provides sufficient water to meet the Suppression Chamber Heat-up Analysis post LOCA. The maximum submergence limits the torus levels to be consistent with the Mark I Plant Unique Analysis. The NMP1 vent header geometry allows the accumulation of water in the spherical junctions. Since NMP1 has no drains in the junctions, the effect of this accumulated water has been analyzed and included in the Mark I load definition. The increase in torus water level, due to the presence of water accumulated in the vent header spherical junctions, has a negligible impact on the containment load definitions (Mark I Plant Unique Analysis) and does not alter the required operational torus water levels.

The 215°F limit for the reactor is specified, since below this temperature the containment can tolerate a blowdown without exceeding the 35 psig design pressure of the suppression chamber without condensation.

Actually, for reactor temperatures up to 312°F the containment can tolerate a blowdown without exceeding the 35 psig design pressure of the suppression chamber, without condensation.

Some experimental data suggests that excessive steam condensing loads might be encountered if the bulk temperature of the suppression pool exceeds 160°F during any period of relief valve operation with sonic conditions at the discharge exit. This can result in local pool temperatures in the vicinity of the quencher of 200°F. Specifications have been placed on the envelope of reactor operating conditions so that the reactor can be depressurized in a timely manner to avoid the regime of potentially high suppression chamber loadings.

In addition to the limits on temperature of the suppression chamber pool water, operating procedures define the action to be taken in the event of a relief valve inadvertently opens or sticks open. As a minimum, this action would include: (1) use of all available means to close the valve, (2) initiate suppression pool water cooling heat exchangers, (3) initiate reactor shutdown, and (4) if other relief valves are used to depressurize the reactor, their discharge shall be separated from that of the stuck-open relief valve to assure mixing and uniformity of energy insertion to the pool.

BASES FOR 3.3.2 AND 4.3.2 PRESSURE SUPPRESSION SYSTEM PRESSURE AND SUPPRESSION CHAMBER WATER TEMPERATURE AND LEVEL

Because of the large volume and thermal capacity of the suppression pool, the volume and temperature normally changes very slowly and monitoring these parameters daily is sufficient to establish any temperature trends. By requiring the suppression pool temperature to be continually monitored and frequently logged during periods of significant heat addition, the temperature trends will be closely followed so that appropriate action can be taken. The requirement for an external visual examination following any event where potentially high loadings could occur provides assurance that no significant damage was encountered. Particular attention should be focused on structural discontinuities in the vicinity of the relief valve discharge since these are expected to be the points of highest stress.

Continuous monitoring of suppression chamber water level and temperature and pressure suppression system pressure is provided in the control room. Alarms for these parameters are also provided in the control room.

To determine the status of the pressure suppression system, inspections of the suppression chamber interior surfaces at each major refueling outage with water at its normal elevation will be made. This will assure that gross defects are not developing.

Accident monitoring instrumentation ensures that sufficient information is available on selected plant parameters to monitor and assess these variables during and following an accident. This capability is consistent with the recommendations of NUREG-0578, "TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations," NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980, NUREG-0661, "Safety Evaluation Report Mark I Containment Long Term Program," and the NRC Final Rule, "Combustible Gas Control in Containment," made effective October 16, 2003 (68 FR 54123).

Specified surveillance intervals and surveillance and maintenance outage times have been determined in accordance with GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-Of-Service Times for Selected Instrumentation Technical Specifications," as approved by the NRC and documented in the SER (letter to R. D. Binz IV from C. E. Rossi dated July 21, 1992).

ATTACHMENT 4

TECHNICAL SPECIFICATIONS BASES CHANGES SUMMARY

Nine Mile Point Nuclear Station, LLC
October 24, 2007

Technical Specifications Bases
Change Summary Report

Revision 14	Bases for Sections 3.3.2 and 4.3.2 (Pages 129 and 130) were revised to reflect the fact that the condition of accumulated water in the vent header spherical junctions located in the torus was determined to be acceptable. Bases for Section 3.6.11 and 4.6.11 (Page 273) were revised to reflect the deletion of the allowable setpoint deviation statement for the suppression chamber water level instrumentation.
Revision 15	Bases for Section 3.6.11 and 4.6.11 (Page 273) were revised to reflect License Amendment 191. License Amendment 191 revised the Technical Specifications (TS) to remove references to containment hydrogen monitors (accident monitoring instrumentation) consistent with the Consolidated Line Item Improvement Process (TSTF-447).
Revision 16	Bases for Section 3.1.4 and 4.1.4 (Page 58) were revised to reflect License Amendment 192. License Amendment 192 relocated the periodic checking, calibration, and testing requirements for the core spray header differential pressure instrumentation to the Updated Final Safety Analysis Report (UFSAR).
Revision 17	Bases (Pages 27b, 27c, 27d, 27e, and 27f) were created for Section 3.0. Basis data is consistent with NRC Generic Letter 80-30 and Nine Mile Point Unit 1 License Amendment No. 55.
Revision 18	Bases for Section 3.1.7 and 4.1.7 (Pages 71, 72, 72a, 73, and 75) were revised to reflect License Amendment 193 to include associated information from Nine Mile Point Unit 1 Reload 19 Cycle 18 core design.

U.S. NUCLEAR REGULATORY
COMMISSION
DOCKET 50-220
LICENSE DPR-63

NINE MILE POINT NUCLEAR STATION UNIT 1

FINAL SAFETY ANALYSIS REPORT (UPDATED)

OCTOBER 2007

REVISION 20

INSERTION INSTRUCTIONS

The following instructions are for the insertion of the current revision into the Nine Mile Point Unit 1 FSAR (Updated).

Remove pages listed in the REMOVE column and replace them with the pages listed in the INSERT column. Dashes (---) in either column indicate no action required.

Vertical bars have been placed in the margins of inserted pages and tables to indicate revision locations.

INSERTION INSTRUCTIONS

LIST OF EFFECTIVE PAGES

REMOVE	INSERT
EP i	EP i
EP 1-1	EP 1-1
EP 2-1	EP 2-1
EP 3-1	EP 3-1
EP 4-1	EP 4-1
EP 5-1	EP 5-1
EP 6-1	EP 6-1
EP 7-1	EP 7-1
EP 8-1 thru EP 8-2	EP 8-1 thru EP 8-2
EP 9-1	EP 9-1
EP 10-1 thru EP 10-6	EP 10-1 thru EP 10-6
EP 11-1	EP 11-1
EP 12-1	EP 12-1
EP 13-1	EP 13-1
EP 14-1	EP 14-1
EP 15-1 thru EP 15-3	EP 15-1 thru EP 15-3
EP 16-1 thru EP 16-3	EP 16-1 thru EP 16-3
EP 17-1 thru EP 17-2	EP 17-1 thru EP 17-2
EP 18-1	EP 18-1
EP A-1	EP A-1
EP B-1 thru EP B-2	EP B-1
---	EP C-1

INSERTION INSTRUCTIONS

VOLUME 1

REMOVE	INSERT
i/ii	i/ii
---	iia/iib
ix/x	ix/x
xa/xb	xa/xb
xi/xii	xi/xii
xiii/xiv	xiii/xiv
xv/xvi	xv/xvi
xvii/xviia	xvii/xviia
xviib/xviii	xviib/xviii
xxi/xxii	xxi/xxii
xxv/xxvi	xxv/xxvi
xxvia/xxvib	xxvia/xxvib
xxix/xxx	xxix/xxixa
---	xxixb/xxx
xxxiii/xxxiv	xxxiii/xxxiv
I-21/-	I-21/-
T I-2 Sh 1 thru 5	T I-2 Sh 1 thru 7
F I-1	F I-1
III-3/4	III-3/4
---	III-4a/4b
F III-1	F III-1
F III-3	F III-3
F III-4	F III-4
F III-5	F III-5
F III-7	F III-7
IV-25/26	IV-25/25a
---	IV-25b/26
IV-31/32	IV-31/32
IV-33/-	IV-33/-
V-5/6	V-5/6
V-6a/6b	V-6a/6b
V-21/-	V-21/-

INSERTION INSTRUCTIONS

VOLUME 2

REMOVE	INSERT
i/ii	i/ii
---	iia/iib
ix/x	ix/x
xa/xb	xa/xb
xi/xii	xi/xii
xiii/xiv	xiii/xiv
xv/xvi	xv/xvi
xvii/xviia	xvii/xviia
xviib/xviii	xviib/xviii
xxi/xxii	xxi/xxii
xxv/xxvi	xxv/xxvi
xxvia/xxvib	xxvia/xxvib
xxix/xxx	xxix/xxixa
---	xxixb/xxx
xxxiii/xxxiv	xxxiii/xxxiv
VI-19/20	VI-19/20
VI-21/21a	VI-21/21a
T VI-3a Sh 4	T VI-3a Sh 4
VII-7/8	VII-7/7a
---	VII-7b/8
VII-11/12	VII-11/12
---	VII-12a/12b
VII-13/14	VII-13/14
VII-14a/14b	VII-14a/14b
VII-14c/14d	VII-14c/14d
VII-14e/14f	VII-14e/14f
VII-14g/14h	VII-14g/14h
VII-41/42	VII-41/42
VII-42a/42b	VII-42a/42b
VII-43/44	VII-43/44
VIII-17/18	VIII-17/18
VIII-19/20	VIII-19/20
---	VIII-20a/20b
VIII-31/32	VIII-31/32
VIII-33/34	VIII-33/34
VIII-34a/34b	VIII-34a/34b
VIII-55/-	VIII-55/56
T VIII-3 Sh 1 thru 5	T VIII-3 Sh 1 thru 5
T VIII-3 Sh 10a/-	T VIII-3 Sh 10a/10b
F VIII-2	F VIII-2
F VIII-6	F VIII-6
F VIII-8	F VIII-8
F VIII-12	F VIII-12
F VIII-26a	F VIII-26a

INSERTION INSTRUCTIONS

VOLUME 2 (Cont'd.)

REMOVE	INSERT
IX-1/2	IX-1/2
---	IX-2a/2b
IX-25/26	IX-25/26
IX-27/28	IX-27/28
---	IX-28a/28b
T IX-1 Sh 1/2	T IX-1 Sh 1/2
F IX-1	F IX-1
F IX-6	F IX-6

INSERTION INSTRUCTIONS

VOLUME 3

REMOVE	INSERT
i/ii	i/ii
---	iia/iib
ix/x	ix/x
xa/xb	xa/xb
xi/xii	xi/xii
xiii/xiv	xiii/xiv
xv/xvi	xv/xvi
xvii/xviia	xvii/xviia
xviib/xviii	xviib/xviii
xxi/xxii	xxi/xxii
xxv/xxvi	xxv/xxvi
xxvia/xxvib	xxvia/xxvib
xxix/xxx	xxix/xxixa
---	xxixb/xxx
xxxiii/xxxiv	xxxiii/xxxiv
X-17/18	X-17/18
X-19/20	X-19/20
---	X-20a/20b
X-21/22	X-21/22
X-23/24	X-23/23a
---	X-23b/24
X-25/26	X-25/26
X-27/28	X-27/28
X-29/30	X-29/30
X-31/32	X-31/32
X-33/34	X-33/34
X-35/36	X-35/36
X-37/38	X-37/38
X-43/44	X-43/44
X-47/48	X-47/48
X-51/52	X-51/52
---	X-52a/52b
F X-5	F X-5
10A-i/ii	10A-i/ii
10A-iii/iv	10A-iii/iv
10A-v/vi	10A-v/vi
---	10A-via/vib
10A-18a/18b	10A-18a/18b
---	10A-18c/18d
---	10A-18e/18f
10A-19/20	10A-19/20
10A-23/24	10A-23/24
10A-25/25a	10A-25/25a
10A-41/42	10A-41/42
10A-43/44	10A-43/44

INSERTION INSTRUCTIONS

VOLUME 3 (Cont'd.)

REMOVE	INSERT
10A-44a/44b	10A-44a/44b
10A-51/52	10A-51/52
---	10A-52a/52b
10A-53/54	10A-53/54
10A-57/58	10A-57/58
10A-59/60	10A-59/60
---	10A-60a/60b
10A-69/70	10A-69/70
10A-71/72	10A-71/72
10A-73/74	10A-73/74
---	10A-74a/74b
10A-83/84	10A-83/84
10A-87/-	10A-87/-
---	10A-87a
10B-iii/-	10B-iii/-
10B-9/10	10B-9/9a
---	10B-9b/10
10B-33/-	10B-33/-
---	10B-33a/-
10B-43/-	10B-43/-
10B-44/-	10B-44/-
10B-45/-	10B-45/-
10B-46/-	10B-46/-
10B-47/-	10B-47/-
10B-48/-	10B-48/-
---	10B-48a/-
10B-51/52	10B-51/52
10B-53/54	10B-53/54
10B-72/-	10B-72/-
10B-77/78	10B-77/78
10B-79/80	10B-79/79a
---	10B-79b/-
10B-81/-	10B-81/-
10B-87/-	10B-87/-
10B-93/-	10B-93/-
10B-100/-	10B-100/-
10B-103/104	10B-103/104
---	10B-104a/104b
10B-106/-	10B-106/-
10B-113/-	10B-113/-
10B-118/-	10B-118/-
10B-123/-	10B-123/-
10B-128/-	10B-128/-
10B-133/-	10B-133/-
10B-138/-	10B-138/-
10B-143/-	10B-143/-

INSERTION INSTRUCTIONS

VOLUME 3 (Cont'd.)

REMOVE	INSERT
10B-148/-	10B-148/-
10B-153/-	10B-153/-
10B-161/162	10B-161/162
---	10B-162a/162b
10B-164/-	10B-164/-
10B-169/-	10B-169/-
10B-177/178	10B-177/178
10B-183/184	10B-183/184
10B-189/190	10B-189/190
10B-199/200	10B-199/200
10B-201/202	10B-201/202
---	10B-202a/202b
10B-207/-	10B-207/-
---	10B-207a/-
XI-9/9a	XI-9/9a
XI-9b/10	XI-9b/10
XI-11b/12	XI-11b/12
XI-13/14	XI-13/14
XI-15/16	XI-15/16
F XI-3	F XI-3
F XI-5	F XI-5
XII-1/2	XII-1/2
XII-3/4	XII-3/4
---	XII-4a/4b
XII-5/6	XII-5/6
XII-9/9a	XII-9/9a
XII-9b/10	XII-9b/10
XII-27/28	XII-27/28
T XII-2 Sh 2	T XII-2 Sh 2
T XII-3/T XII-4	T XII-3/T XII-4
T XII-8 Sh 1/2	T XII-8 Sh 1/2
T XII-8 Sh 3/-	T XII-8 Sh 3/-
F XII-1	F XII-1
XIII-1/2	XIII-1/2
XIII-5/6	XIII-5/6
XIII-7/8	XIII-7/8
XIII-9/10	XIII-9/10
XIII-11/12	XIII-11/12
XIII-19/20	XIII-19/20
XIII-23/24	XIII-23/24
XIII-25/26	XIII-25/26
F XIII-5	F XIII-5

INSERTION INSTRUCTIONS

VOLUME 4

REMOVE	INSERT
i/ii	i/ii
---	iia/iib
ix/x	ix/x
xa/xb	xa/xb
xi/xii	xi/xii
xiii/xiv	xiii/xiv
xv/xvi	xv/xvi
xvii/xviia	xvii/xviia
xviib/xviii	xviib/xviii
xxi/xxii	xxi/xxii
xxv/xxvi	xxv/xxvi
xxvia/xxvib	xxvia/xxvib
xxix/xxx	xxix/xxixa
---	xxixb/xxx
xxxiii/xxxiv	xxxiii/xxxiv
XV-61/61a	XV-61/61a
XV-61b/62	XV-61b/62
XV-63/64	XV-63/64
XV-65/66	XV-65/65a
---	XV-65b/66
XV-79/80	XV-79/79a
---	XV-79b/80
XV-81/82	XV-81/82
T XV-32a Sh 1/2	T XV-32a Sh ½
F XV-60a	F XV-60a
F XV-60b	F XV-60b
XVI-21/21a	XVI-21/21a
XVI-45/46	XVI-45/45a
---	XVI-45b/46
XVI-51/52	XVI-51/52
XVI-52a/52b	XVI-52a/52b
XVI-55/55a	XVI-55/55a
XVI-55b/56	XVI-55b/56
T XVI-9a Sh 1/2	T XVI-9a Sh 1/2
T XVI-26	T XVI-26 Sh 1/2
All Appendix B Pages	B-1/-
---	C-i/ii thru C-iii/iv
---	C.0-1/2
---	C.1-1/2 thru C.1-27/28
---	C.2-1/2 thru C.2-13/-
---	C.3-1/-
---	C.4-1/2
---	T C-1 Sh 1 thru 10

U.S. NUCLEAR REGULATORY COMMISSION
DOCKET 50-220
LICENSE DPR-63

NINE MILE POINT NUCLEAR STATION UNIT 1

FINAL SAFETY ANALYSIS REPORT (UPDATED)

OCTOBER 2007

REVISION 20

LIST OF EFFECTIVE PAGES

GENERAL TABLE OF CONTENTS

Page Number	Revision Number	Page Number	Revision Number
i	17	xxxi	16
ii	20	xxxii	16
iia	20	xxxiii	20
iib	20	xxxiv	18
iii	16	xxxiva	19
iv	16	xxxivb	17
v	17	xxxv	19
vi	16	xxxvi	16
vii	19	xxxvii	16
viii	17	xxxviii	16
ix	20	xxxix	16
x	20	xl	16
xa	20	xli	16
xb	17	xlii	16
xi	20	xliii	16
xii	18	xliv	19
xiii	16	xlv	19
xiv	20	xlvi	17
xv	20	xlvii	18
xvi	20	xlviia	18
xvii	20	xlviib	17
xviia	20	xlviii	16
xviib	20	xlix	16
xviii	20	l	16
xix	19	li	16
xx	19	lii	16
xxa	19	liii	16
xxb	17	liv	16
xxi	20	lv	16
xxii	16	lvi	16
xxiii	16		
xxiv	16		
xxv	19		
xxvi	20		
xxvia	20		
xxvib	18		
xxvii	19		
xxviii	16		
xxix	20		
xxixa	20		
xxixb	20		
xxx	16		

LIST OF EFFECTIVE PAGES

SECTION I

Page Number	Revision Number	Page Number	Revision Number
I-1	18		
I-2	18		
I-3	17		
I-4	17		
I-5	17		
I-6	17		
I-7	18		
I-8	17		
I-9	17		
I-10	17		
I-11	17		
I-12	17		
I-13	17		
I-14	17		
I-15	18		
I-16	18		
I-17	17		
I-18	17		
I-19	18		
I-20	17		
I-21	20		
T I-1	17		
T I-2 Sh 1	20		
T I-2 Sh 2	20		
T I-2 Sh 3	20		
T I-2 Sh 4	20		
T I-2 Sh 5	20		
T I-2 Sh 6	20		
T I-2 Sh 7	20		
F I-1	20		

LIST OF EFFECTIVE PAGES

SECTION II

Page Number	Revision Number	Page Number	Revision Number
II-1	18		
II-2	18		
II-3	15		
II-4	15		
II-5	18		
II-6	15		
II-7	15		
II-8	18		
II-9	18		
T II-1	15		
T II-2	15		
T II-3	15		
T II-4	15		
T II-5	15		
T II-6	18		
T II-7	15		
T II-8 Sh 1	15		
T II-8 Sh 2	15		
F II-1	14		
F II-2	14		
F II-3	14		
F II-4	14		
F II-5	14		
F II-6	14		

LIST OF EFFECTIVE PAGES

SECTION III

Page Number	Revision Number	Page Number	Revision Number
III-1	15	III-39	17
III-2	15	III-40	15
III-3	15	III-41	15
III-4	20	III-42	19
III-4a	20	III-43	19
III-4b	20	III-44	19
III-5	16	III-45	16
III-6	17	F III-1	20
III-7	17	F III-2	16
III-8	16	F III-3	20
III-9	19	F III-4	20
III-10	19	F III-5	20
III-11	19	F III-6	16
III-12	19	F III-7	20
III-12a	19	F III-8	16
III-12b	16	F III-9	16
III-13	19	F III-10	14
III-14	15	F III-11	14
III-15	16	F III-12	17
III-16	16	F III-13	18
III-17	17	F III-14	18
III-18	16	F III-15	17
III-19	15	F III-16	18
III-20	17	F III-17	16
III-21	15	F III-18	14
III-22	15	F III-19	14
III-23	16	F III-20	14
III-24	17	F III-21	17
III-25	16	F III-22	14
III-26	15	F III-23	14
III-27	17		
III-28	17		
III-29	17		
III-30	17		
III-31	16		
III-32	15		
III-33	15		
III-34	15		
III-35	15		
III-36	15		
III-37	15		
III-38	15		

LIST OF EFFECTIVE PAGES

SECTION IV

Page Number	Revision Number
IV-1	15
IV-2	15
IV-3	15
IV-4	15
IV-5	17
IV-6	15
IV-7	18
IV-8	15
IV-9	15
IV-10	15
IV-11	18
IV-12	17
IV-13	16
IV-14	18
IV-15	18
IV-16	15
IV-17	15
IV-18	17
IV-18a	17
IV-18b	17
IV-19	18
IV-19a	16
IV-19b	16
IV-20	15
IV-21	16
IV-22	15
IV-23	16
IV-24	17
IV-25	20
IV-25a	20
IV-25b	20
IV-26	16
IV-27	16
IV-28	16
IV-29	16
IV-30	16
IV-31	16
IV-32	20
IV-33	20
F IV-1	14
F IV-2	14
F IV-3	14
F IV-4	15
F IV-4a	15
F IV-5	14
F IV-6	14
F IV-7	16
F IV-7a	16
F IV-8	14
F IV-9	14

LIST OF EFFECTIVE PAGES

SECTION V

LIST OF EFFECTIVE PAGES

SECTION VI

Page Number	Revision Number	Page Number	Revision Number
VI-1	17	T VI-1 Sh 2	15
VI-2	15	T VI-2	15
VI-3	15	T VI-3a Sh 1	18
VI-4	15	T VI-3a Sh 2	18
VI-5	15	T VI-3a Sh 3	18
VI-6	15	T VI-3a Sh 4	20
VI-7	17	T VI-3b Sh 1	17
VI-8	17	T VI-3b Sh 2	18
VI-9	17	T VI-3b Sh 3	18
VI-10	17	T VI-3b Sh 4	18
VI-10a	17	T VI-4	17
VI-10b	17	T VI-5 Sh 1	15
VI-11	15	T VI-5 Sh 2	15
VI-12	15	F VI-1	14
VI-13	16	F VI-2	14
VI-14	16	F VI-3	14
VI-15	17	F VI-4	14
VI-16	17	F VI-4a	14
VI-17	19	F VI-5	14
VI-18	19	F VI-6	14
VI-19	15	F VI-7	14
VI-20	20	F VI-8	14
VI-21	20	F VI-9	14
VI-21a	20	F VI-10	14
VI-21b	16	F VI-11	14
VI-22	15	F VI-12	14
VI-23	17	F VI-13	14
VI-23a	17	F VI-14	14
VI-23b	17	F VI-15	14
VI-24	16	F VI-16	14
VI-25	17	F VI-17	14
VI-26	17	F VI-18	14
VI-27	19	F VI-19	14
VI-27a	17	F VI-20	17
VI-27b	17	F VI-21	14
VI-28	15	F VI-22	17
VI-29	15	F VI-23	16
VI-30	15	F VI-24	18
VI-31	15		
VI-32	15		
VI-33	16		
T VI-1 Sh 1	15		

LIST OF EFFECTIVE PAGES

SECTION VII

Page Number	Revision Number	Page Number	Revision Number
VII-1	15	VII-29	15
VII-2	17	VII-30	15
VII-2a	17	VII-31	15
VII-2b	17	VII-32	15
VII-3	17	VII-33	15
VII-4	17	VII-34	18
VII-5	19	VII-35	19
VII-6	19	VII-36	17
VII-7	20	VII-37	18
VII-7a	20	VII-38	18
VII-7b	20	VII-39	18
VII-8	18	VII-40	18
VII-9	17	VII-41	20
VII-10	17	VII-42	20
VII-11	18	VII-42a	20
VII-12	20	VII-42b	17
VII-12a	20	VII-43	15
VII-12b	20	VII-44	20
VII-13	20	T VII-1	15
VII-14	20	F VII-1	17
VII-14a	20	F VII-2	17
VII-14b	20	F VII-3	18
VII-14c	20	F VII-4	14
VII-14d	20	F VII-5	14
VII-14e	20	F VII-6	16
VII-14f	20	F VII-7	14
VII-14g	20	F VII-8	14
VII-14h	20	F VII-9	14
VII-15	15	F VII-10	16
VII-16	16	F VII-11	14
VII-17	16	F VII-12	17
VII-18	16	F VII-13	17
VII-19	16	F VII-14	19
VII-20	15	F VII-15	19
VII-21	15	F VII-16	19
VII-22	15	F VII-17	14
VII-23	17		
VII-24	16		
VII-25	15		
VII-26	16		
VII-27	16		
VII-28	16		

LIST OF EFFECTIVE PAGES

SECTION VIII

Page Number	Revision Number	Page Number	Revision Number
VIII-1	16	VIII-35	18
VIII-2	16	VIII-36	17
VIII-3	19	VIII-37	16
VIII-3a	19	VIII-38	18
VIII-3b	19	VIII-38a	18
VIII-4	19	VIII-38b	18
VIII-5	16	VIII-39	18
VIII-6	16	VIII-40	15
VIII-7	16	VIII-41	15
VIII-8	17	VIII-42	18
VIII-9	18	VIII-42a	18
VIII-9a	16	VIII-42b	18
VIII-9b	16	VIII-43	18
VIII-10	17	VIII-44	18
VIII-11	15	VIII-45	18
VIII-12	16	VIII-46	18
VIII-13	17	VIII-47	16
VIII-14	18	VIII-48	16
VIII-15	15	VIII-49	18
VIII-16	17	VIII-50	16
VIII-17	20	VIII-51	16
VIII-18	20	VIII-52	17
VIII-19	20	VIII-53	15
VIII-20	20	VIII-54	15
VIII-20a	20	VIII-55	20
VIII-20b	20	VIII-56	20
VIII-21	15	T VIII-1	16
VIII-22	15	T VIII-2	15
VIII-23	15	T VIII-3 Sh 1	20
VIII-24	16	T VIII-3 Sh 2	20
VIII-25	17	T VIII-3 Sh 3	20
VIII-26	17	T VIII-3 Sh 4	20
VIII-27	17	T VIII-3 Sh 5	20
VIII-28	15	T VIII-3 Sh 6	15
VIII-29	16	T VIII-3 Sh 7	19
VIII-30	19	T VIII-3 Sh 8	19
VIII-31	15	T VIII-3 Sh 9	19
VIII-32	20	T VIII-3 Sh 10	19
VIII-33	20	T VIII-3 Sh 10a	20
VIII-34	20	T VIII-3 Sh 10b	20
VIII-34a	20	T VIII-4 Sh 1	17
VIII-34b	20	T VIII-4 Sh 2	19

LIST OF EFFECTIVE PAGES

SECTION VIII (Cont'd.)

Page Number	Revision Number	Page Number	Revision Number
T VIII-4 Sh 3	17		
T VIII-5 Sh 1	19		
T VIII-5 Sh 2	19		
F VIII-1	16		
F VIII-2	20		
F VIII-3	17		
F VIII-4	17		
F VIII-5	14		
F VIII-6	20		
F VIII-7	14		
F VIII-8	20		
F VIII-9	14		
F VIII-10	14		
F VIII-11	14		
F VIII-12	20		
F VIII-13	17		
F VIII-14	17		
F VIII-15	14		
F VIII-16	14		
F VIII-17	14		
F VIII-18	16		
F VIII-19	14		
F VIII-20	14		
F VIII-21	16		
F VIII-22	17		
F VIII-23	14		
F VIII-24	17		
F VIII-25	14		
F VIII-26	17		
F VIII-26a	20		
F VIII-26b	17		
F VIII-27	14		
F VIII-28	18		
F VIII-29	17		

LIST OF EFFECTIVE PAGES

SECTION IX

Page Number	Revision Number
IX-1	15
IX-2	20
IX-2a	20
IX-2b	20
IX-3	18
IX-4	17
IX-5	15
IX-6	15
IX-7	15
IX-8	19
IX-9	19
IX-10	19
IX-11	19
IX-11a	19
IX-11b	19
IX-12	15
IX-13	16
IX-14	16
IX-15	17
IX-16	15
IX-17	17
IX-17a	18
IX-17b	17
IX-18	17
IX-19	15
IX-20	15
IX-21	15
IX-22	17
IX-23	17
IX-24	17
IX-25	18
IX-26	20
IX-27	20
IX-28	20
IX-28a	20
IX-28b	20
IX-29	15
T IX-1 Sh 1	20
T IX-1 Sh 2	17
F IX-1	20
F IX-2	14
F IX-3	14
F IX-4	14
F IX-5	14
F IX-6	20
F IX-7	14
F IX-8	17

LIST OF EFFECTIVE PAGES

SECTION X

Page Number	Revision Number	Page Number	Revision Number
X-1	17	X-35	20
X-1a	17	X-36	20
X-1b	17	X-37	20
X-2	16	X-38	20
X-3	19	X-39	19
X-4	17	X-40	19
X-5	17	X-40a	19
X-5a	17	X-40b	17
X-5b	17	X-41	17
X-6	18	X-42	16
X-7	19	X-43	17
X-8	19	X-44	20
X-9	19	X-45	16
X-10	19	X-46	16
X-11	17	X-47	20
X-12	17	X-48	20
X-13	17	X-49	16
X-14	17	X-50	16
X-15	17	X-51	20
X-16	16	X-52	20
X-17	20	X-52a	20
X-18	20	X-52b	20
X-19	20	X-53	17
X-20	20	X-54	17
X-20a	20	X-55	17
X-20b	20	X-56	17
X-21	20	F X-1	14
X-22	20	F X-2	17
X-23	20	F X-3	16
X-23a	20	F X-4	17
X-23b	20	F X-5	20
X-24	19	F X-6	14
X-25	20	F X-7	17
X-26	20	F X-8	17
X-27	16	F X-9	15
X-28	20	F X-10	14
X-29	20	F X-11	14
X-30	20		
X-31	20	10A	16
X-32	20	10A-i	20
X-33	20	10A-ii	20
X-34	20	10A-iii	20

LIST OF EFFECTIVE PAGES

SECTION X (Cont'd.)

Page Number	Revision Number
10A-iv	20
10A-v	20
10A-vi	20
10A-via	20
10A-vib	20
10A-vii	16
10A-viii	16
10A-ix	16
10A-1	18
10A-2	16
10A-3	16
10A-4	16
10A-5	16
10A-6	16
10A-7	16
10A-8	18
10A-8a	18
10A-8b	18
10A-9	18
10A-10	19
10A-11	18
10A-12	18
10A-13	17
10A-14	16
10A-15	16
10A-16	16
10A-17	16
10A-18	18
10A-18a	20
10A-18b	20
10A-18c	20
10A-18d	20
10A-18e	20
10A-18f	20
10A-19	20
10A-20	16
10A-21	18
10A-22	19
10A-23	19
10A-24	20
10A-25	20
10A-25a	20

Page Number		Revision Number
10A-25b		17
10A-26		16
10A-27		19
10A-28		16
10A-29		16
10A-30		18
10A-31		18
10A-32	T 2.5.1.1-1	16
10A-33	T 2.5.1.1-2	16
10A-34	T 2.5.1.1-3	16
10A-35	T 2.5.1.1-4	16
10A-36	T 2.5.1.1-5	19
10A-37	T 2.5.1.1-6	16
10A-38	T 2.5.1.1-7	16
10A-39		16
10A-40		17
10A-41		17
10A-42		20
10A-43		20
10A-44		20
10A-44a		20
10A-44b		17
10A-45		19
10A-46		17
10A-47		17
10A-48	T 2.5.3.4-1	16
10A-49	T 2.5.3.4-1	16
10A-50		19
10A-51		19
10A-52		20
10A-52a		20
10A-52b		20
10A-53		20
10A-54		17
10A-55		16
10A-56		16
10A-57		20
10A-58		20
10A-59		20
10A-60		20
10A-60a		20
10A-60b		20

LIST OF EFFECTIVE PAGES

SECTION X (Cont'd.)

Page Number		Revision Number	Page Number		Revision Number
10A-61		19	10A-99	T 3.10-1	16
10A-62		16	10A-100	T 3.10-1	16
10A-63		18	10A-101	T 3.1-1	16
10A-64		19	10A-102	T 3.1-1	16
10A-65		16	10A-103	T 3.1-1	16
10A-66		16	10A-104	T 3.1-1	18
10A-67		16	10A-105	T 3.1.1-1	18
10A-68		16	10A-106	T 3.1.1-1	18
10A-69		17	10A-107	T 3.1.1-1	18
10A-70		20	10A-108	T 3.1.1-1	18
10A-71		20	10A-108a	T 3.1.1-1	19
10A-72		20	10A-108b	T 3.1.1-1	18
10A-73		20	10A-109	T 3.1.1-2	18
10A-74		20	10A-110	T 3.1.1-2	19
10A-74a		20	10A-111	T 3.1.1-2	18
10A-74b		20	10A-112	T 3.1.1-2	18
10A-75		16	10A-113	T 3.1.1-2	18
10A-76		16	10A-114	T 3.1.1-2	18
10A-77		16	10A-114a	T 3.1.1-2	18
10A-78		16	10A-114b	T 3.1.1-2	18
10A-79		17	10A-115	T 3.1.1-3	18
10A-80		16	10A-116	T 3.1.1-4	18
10A-81		19	10A-117	T 3.1.1-4	18
10A-82		19	10A-118	T 3.1.1-5	18
10A-83		16	10A-119	T 3.1.1-6	19
10A-84		20	10A-120	T 3.1.1-6	18
10A-85	T 1.2.2	18	10A-121	T 3.1.1-7	18
10A-86	T 1.2.2	18	10A-122	T 3.1.1-8	18
10A-87	T 1.2.2	20	10A-123	T 3.1.1-8	18
10A-87a	T 1.2.2	20	10A-123a	T 3.1.1-8	18
10A-88	T 1.2.2	18	10A-124	T 3.1.1-9	18
10A-89	T 1.2.2	18	10A-125	T 3.1.1-9	18
10A-89a	T 1.2.2	18	10A-126	T 3.1.1-9	19
10A-90	T 3.2-1	17	10A-127	T 3.1.1-9	19
10A-91	T 3.3-1	16	10A-127a	T 3.1.1-9	19
10A-92	T 3.3-1	16	F 10A-1		16
10A-93	T 3.4-1	16	F 10A-2		16
10A-94	T 3.5-1	16	F 10A-2A		16
10A-95	T 3.6-1	16	F 10A-2B		16
10A-96	T 3.7-1	16	F 10A-2C		16
10A-97	T 3.8-1	16	F 10A-2D		16
10A-98	T 3.9-1	16	F 10A-3		18

LIST OF EFFECTIVE PAGES

SECTION X (Cont'd.)

Page Number	Revision Number	Page Number	Revision Number
F 10A-3A	18	10B-4	16
F 10A-3B	18	10B-5	16
F 10A-3C	18	10B-6	16
F 10A-3D	18	10B-7	16
F 10A-4	19	10B-8	16
F 10A-4A	17	10B-9	20
F 10A-4B	17	10B-9a	20
F 10A-4C	17	10B-9b	20
F 10A-4D	17	10B-10	18
F 10A-5	17	10B-11	16
F 10A-5A	17	10B-12	18
F 10A-5B	17	10B-13	18
F 10A-5C	17	10B-14	18
F 10A-5D	17	10B-14a	18
F 10A-6	16	10B-14b	17
F 10A-6A	16	10B-15	18
F 10A-6B	16	10B-16	16
F 10A-6C	16	10B-17	18
F 10A-6D	16	10B-18	18
F 10A-7	17	10B-18a	18
F 10A-7A	17	10B-18b	18
F 10A-7B	17	10B-19	16
F 10A-7C	17	10B-20	16
F 10A-7D	17	10B-21	16
F 10A-8	16	10B-22	16
F 10A-8A	16	10B-23	16
F 10A-8B	16	10B-24 T 1	17
F 10A-8C	16	10B-24a T 1	17
F 10A-8D	16	10B-25 T 1	17
F 10A-9	16	10B-26 T 1	17
F 10A-9A	16	10B-27 T 1	16
F 10A-9B	16	10B-28 T 1	17
F 10A-9C	16	10B-29 T 1	16
F 10A-9D	16	10B-30 T 1	17
		10B-30a T 1	17
10B	16	10B-31 T 1	17
10B-i	18	10B-31a T 1	17
10B-ii	18	10B-32 T 1	16
10B-iii	20	10B-33 T 1	20
10B-1	18	10B-33a T 1	20
10B-2	16	10B-34 T 1	16
10B-3	16	10B-35 T 1	16

LIST OF EFFECTIVE PAGES

SECTION X (Cont'd.)

Page Number		Revision Number	Page Number	Revision Number
10B-36		16	10B-76	16
10B-37		16	10B-77	20
10B-38		19	10B-78	20
10B-39		16	10B-79	20
10B-40		16	10B-79a	20
10B-41	T 2A	16	10B-79b	20
10B-42	T 2B	18	10B-80	16
10B-43	T 3	20	10B-81	20
10B-44	T 3	20	10B-82	16
10B-45	T 3	20	10B-83	16
10B-46	T 3	20	10B-84	16
10B-47	T 3	20	10B-85	16
10B-48	T 3	20	10B-86	16
10B-48a	T 3	20	10B-87	20
10B-49		16	10B-88	19
10B-50		16	10B-89	16
10B-51		20	10B-90	16
10B-52		20	10B-91	16
10B-53		20	10B-92	16
10B-54		18	10B-93	20
10B-55		18	10B-94	19
10B-56		16	10B-95	16
10B-57		16	10B-96	16
10B-57a		18	10B-97	16
10B-58		18	10B-98	16
10B-59		19	10B-99	16
10B-60		17	10B-100	20
10B-61		16	10B-101	19
10B-62		16	10B-102	16
10B-63		18	10B-103	16
10B-64		16	10B-104	20
10B-65		18	10B-104a	20
10B-66		16	10B-104b	20
10B-67		19	10B-105	16
10B-68		16	10B-106	20
10B-69		19	10B-107	19
10B-70		16	10B-108	16
10B-71		16	10B-109	16
10B-72		20	10B-110	16
10B-73		19	10B-111	18
10B-74		19	10B-112	16
10B-75		16	10B-113	20

LIST OF EFFECTIVE PAGES

SECTION X (Cont'd.)

Page Number	Revision Number	Page Number	Revision Number
10B-114	16	10B-156	16
10B-115	19	10B-157	16
10B-116	16	10B-158	16
10B-117	16	10B-159	16
10B-118	20	10B-160	19
10B-119	19	10B-161	16
10B-120	16	10B-162	20
10B-121	16	10B-162a	20
10B-122	16	10B-162b	20
10B-123	20	10B-163	16
10B-124	19	10B-164	20
10B-125	16	10B-165	19
10B-126	16	10B-166	16
10B-127	16	10B-167	16
10B-128	20	10B-168	16
10B-129	19	10B-169	20
10B-130	16	10B-170	19
10B-131	16	10B-171	16
10B-132	16	10B-172	16
10B-133	20	10B-173	16
10B-134	19	10B-174	16
10B-135	16	10B-175	19
10B-136	16	10B-176	16
10B-137	16	10B-177	20
10B-138	20	10B-178	20
10B-139	19	10B-179	16
10B-140	16	10B-180	16
10B-141	16	10B-181	19
10B-142	16	10B-182	16
10B-143	20	10B-183	20
10B-144	19	10B-184	20
10B-145	16	10B-185	16
10B-146	16	10B-186	16
10B-147	16	10B-187	19
10B-148	20	10B-188	16
10B-149	19	10B-189	20
10B-150	16	10B-190	20
10B-151	16	10B-191	16
10B-152	16	10B-192	16
10B-153	20	10B-193	19
10B-154	19	10B-194	18
10B-155	16	10B-195	18

LIST OF EFFECTIVE PAGES

SECTION X (Cont'd.)

Page Number	Revision Number	Page Number	Revision Number
10B-196	16		
10B-197	16		
10B-198	16		
10B-199	20		
10B-200	20		
10B-201	20		
10B-202	20		
10B-202a	20		
10B-202b	20		
10B-203	19		
10B-204	19		
10B-205	19		
10B-206	16		
10B-207	20		
10B-207a	20		
10B-208	16		
10B-209	16		
10B-210	16		
10B-211	16		
10B-212	16		
10B-213	16		
10B-214	16		
10B-215	16		
10B-216	18		
10B-217	18		
10B-218	16		
10B-219	16		
10B-220	16		
10B-221	16		
10B-222	16		
10B-223	17		

LIST OF EFFECTIVE PAGES

SECTION XI

Page Number	Revision Number	Page Number	Revision Number
XI-1	15		
XI-2	15		
XI-3	15		
XI-4	15		
XI-5	19		
XI-6	19		
XI-7	19		
XI-8	19		
XI-9	19		
XI-9a	20		
XI-9b	20		
XI-10	20		
XI-11	18		
XI-11a	18		
XI-11b	17		
XI-12	20		
XI-13	17		
XI-14	20		
XI-15	20		
XI-16	15		
F XI-1	17		
F XI-2	14		
F XI-3	20		
F XI-4	14		
F XI-5	20		
F XI-6	16		
F XI-7	18		

LIST OF EFFECTIVE PAGES

SECTION XII

Page Number	Revision Number
XII-1	18
XII-2	20
XII-3	20
XII-4	20
XII-4a	20
XII-4b	20
XII-5	20
XII-6	17
XII-7	17
XII-8	17
XII-9	20
XII-9a	20
XII-9b	18
XII-10	20
XII-11	17
XII-12	15
XII-13	15
XII-14	17
XII-14a	17
XII-14b	17
XII-15	15
XII-16	15
XII-17	18
XII-18	18
XII-19	18
XII-20	17
XII-21	19
XII-22	15
XII-23	17
XII-24	19
XII-25	19
XII-26	19
XII-27	20
XII-28	20
T XII-1	15
T XII-2 Sh 1	17
T XII-2 Sh 2	20
T XII-3	20
T XII-4	17
T XII-5	15
T XII-6	15
T XII-7	15
T XII-8 Sh 1	20
T XII-8 Sh 2	20
T XII-8 Sh 3	20
F XII-1	20

LIST OF EFFECTIVE PAGES

SECTION XIII

Page Number	Revision Number	Page Number	Revision Number
XIII-1	20		
XIII-2	19		
XIII-3	19		
XIII-4	19		
XIII-5	20		
XIII-6	20		
XIII-7	20		
XIII-8	20		
XIII-9	20		
XIII-10	20		
XIII-11	20		
XIII-12	19		
XIII-13	19		
XIII-14	19		
XIII-15	19		
XIII-16	19		
XIII-17	19		
XIII-18	19		
XIII-19	19		
XIII-20	20		
XIII-21	19		
XIII-22	19		
XIII-23	19		
XIII-24	20		
XIII-25	20		
XIII-26	20		
T XIII-1	19		
T XIII-2	19		
F XIII-1	19		
F XIII-2	19		
F XIII-3	19		
F XIII-4	19		
F XIII-4a Sh 1	19		
F XIII-4a Sh 2	19		
F XIII-4b	19		
F XIII-4c	19		
F XIII-5	20		

LIST OF EFFECTIVE PAGES

SECTION XIV

Page Number	Revision Number	Page Number	Revision Number
XIV-1	16		
XIV-2	15		
XIV-3	15		
XIV-4	15		
XIV-5	15		
XIV-6	15		
XIV-7	15		
XIV-8	15		
XIV-9	15		
XIV-10	16		
XIV-11	16		
XIV-12	16		
XIV-13	18		
XIV-14	18		

LIST OF EFFECTIVE PAGES

SECTION XV

Page Number	Revision Number	Page Number	Revision Number
XV-1	16	XV-41	16
XV-2	17	XV-42	16
XV-3	18	XV-43	16
XV-4	16	XV-44	19
XV-5	18	XV-45	19
XV-6	18	XV-46	19
XV-7	18	XV-47	19
XV-8	17	XV-48	19
XV-8a	17	XV-48a	19
XV-8b	17	XV-48b	19
XV-9	17	XV-49	16
XV-10	16	XV-50	16
XV-11	16	XV-51	16
XV-12	16	XV-52	16
XV-13	16	XV-53	16
XV-14	16	XV-54	16
XV-15	18	XV-55	16
XV-16	16	XV-56	16
XV-17	16	XV-57	16
XV-18	16	XV-58	16
XV-19	17	XV-59	18
XV-20	16	XV-60	16
XV-21	16	XV-61	18
XV-22	17	XV-61a	20
XV-23	16	XV-61b	20
XV-24	16	XV-62	20
XV-25	16	XV-63	20
XV-26	16	XV-64	20
XV-27	16	XV-65	20
XV-28	16	XV-65a	20
XV-29	16	XV-65b	20
XV-30	16	XV-66	20
XV-31	16	XV-67	17
XV-32	16	XV-68	18
XV-33	16	XV-69	16
XV-34	16	XV-70	16
XV-35	18	XV-71	16
XV-36	16	XV-72	16
XV-37	16	XV-73	16
XV-38	16	XV-74	16
XV-39	16	XV-75	16
XV-40	16	XV-76	16

LIST OF EFFECTIVE PAGES

SECTION XV (Cont'd.)

Page Number	Revision Number	Page Number	Revision Number
XV-77	16	T XV-29c	16
XV-78	16	T XV-29d	16
XV-79	20	T XV-30	16
XV-79a	20	T XV-31	16
XV-79b	20	T XV-32	16
XV-80	19	T XV-32a Sh 1	20
XV-81	19	T XV-32a Sh 2	20
XV-82	20	T XV-33	16
T XV-1	17	T XV-34	16
T XV-2	17	T XV-35	16
T XV-3	16	T XV-36	16
T XV-4	16	F XV-1	17
T XV-5	16	F XV-2	14
T XV-6	16	F XV-3	14
T XV-7	16	F XV-4	14
T XV-8	16	F XV-5	14
T XV-9 Sh 1	16	F XV-6	14
T XV-9 Sh 2	16	F XV-7	14
T XV-9a	17	F XV-8	14
T XV-10	17	F XV-9	14
T XV-11	16	F XV-10	14
T XV-12	16	F XV-11	14
T XV-13	16	F XV-12	14
T XV-14	16	F XV-13	14
T XV-15	16	F XV-14	14
T XV-16	16	F XV-15	14
T XV-17	16	F XV-16	14
T XV-18	16	F XV-17	14
T XV-19	16	F XV-18	14
T XV-20	16	F XV-19	14
T XV-21	16	F XV-20	14
T XV-21a	16	F XV-21	14
T XV-22	16	F XV-22	14
T XV-23	16	F XV-23	14
T XV-24	16	F XV-24	14
T XV-25	16	F XV-25	14
T XV-26	16	F XV-26	14
T XV-27	16	F XV-27	14
T XV-28	16	F XV-28	14
T XV-29	16	F XV-29	14
T XV-29a	16	F XV-30	14
T XV-29b	16	F XV-31	14

LIST OF EFFECTIVE PAGES

SECTION XV (Cont'd.)

LIST OF EFFECTIVE PAGES

SECTION XVI

Page Number	Revision Number	Page Number	Revision Number
XVI-1	16	XVI-37	16
XVI-2	16	XVI-38	16
XVI-3	16	XVI-39	16
XVI-4	16	XVI-40	16
XVI-5	16	XVI-41	16
XVI-6	16	XVI-42	16
XVI-7	16	XVI-43	16
XVI-8	16	XVI-44	16
XVI-9	16	XVI-45	20
XVI-10	16	XVI-45a	20
XVI-11	16	XVI-45b	20
XVI-12	16	XVI-46	16
XVI-13	19	XVI-47	16
XVI-13a	19	XVI-48	16
XVI-13b	19	XVI-49	16
XVI-14	16	XVI-50	17
XVI-15	16	XVI-51	20
XVI-16	16	XVI-52	20
XVI-17	16	XVI-52a	20
XVI-18	16	XVI-52b	16
XVI-19	18	XVI-53	16
XVI-20	19	XVI-54	17
XVI-21	19	XVI-55	17
XVI-21a	20	XVI-55a	20
XVI-21b	16	XVI-55b	17
XVI-22	16	XVI-56	20
XVI-23	16	XVI-57	16
XVI-24	17	XVI-58	16
XVI-25	16	XVI-59	16
XVI-26	16	XVI-60	16
XVI-27	16	XVI-60a	17
XVI-28	16	XVI-60b	17
XVI-29	16	XVI-61	16
XVI-30	16	XVI-62	16
XVI-31	16	XVI-63	16
XVI-32	17	XVI-64	16
XVI-32a	17	XVI-65	17
XVI-32b	17	XVI-65a	17
XVI-33	16	XVI-65b	17
XVI-34	16	XVI-66	16
XVI-35	16	XVI-67	16
XVI-36	16	XVI-68	16

LIST OF EFFECTIVE PAGES

SECTION XVI (Cont'd.)

Page Number	Revision Number	Page Number	Revision Number
XVI-69	16	XVI-111	16
XVI-70	16	XVI-112	16
XVI-71	17	XVI-113	16
XVI-72	16	XVI-114	16
XVI-73	16	XVI-115	16
XVI-74	16	XVI-116	16
XVI-75	16	XVI-117	16
XVI-76	16	XVI-118	16
XVI-77	16	XVI-119	16
XVI-78	16	XVI-120	16
XVI-79	16	XVI-121	16
XVI-80	16	XVI-122	16
XVI-81	16	XVI-123	16
XVI-82	16	XVI-124	19
XVI-83	16	T XVI-1	16
XVI-84	16	T XVI-2 Sh 1	18
XVI-85	16	T XVI-2 Sh 2	17
XVI-86	16	T XVI-3	17
XVI-87	16	T XVI-4	16
XVI-88	16	T XVI-5	16
XVI-89	16	T XVI-6	16
XVI-90	16	T XVI-7	18
XVI-91	16	T XVI-8	16
XVI-92	16	T XVI-9	19
XVI-93	16	T XVI-9a Sh 1	16
XVI-94	16	T XVI-9a Sh 2	20
XVI-95	16	T XVI-10	16
XVI-96	16	T XVI-11	16
XVI-97	16	T XVI-12	16
XVI-98	16	T XVI-13	16
XVI-99	16	T XVI-14	16
XVI-100	16	T XVI-15	16
XVI-101	16	T XVI-16	16
XVI-102	16	T XVI-17	16
XVI-103	16	T XVI-18	16
XVI-104	16	T XVI-19	16
XVI-105	16	T XVI-20	16
XVI-106	16	T XVI-21	16
XVI-107	16	T XVI-22	16
XVI-108	16	T XVI-23	16
XVI-109	16	T XVI-24	16
XVI-110	16	T XVI-25	16

LIST OF EFFECTIVE PAGES

SECTION XVI (Cont'd.)

Page Number	Revision Number
T XVI-26 Sh 1	20
T XVI-26 Sh 2	20
T XVI-27 Sh 1	16
T XVI-27 Sh 2	16
T XVI-28	16
T XVI-29	16
T XVI-30	16
T XVI-31 Sh 1	16
T XVI-31 Sh 2	16
F XVI-1	14
F XVI-2	14
F XVI-3	14
F XVI-4	14
F XVI-5	14
F XVI-6	14
F XVI-7	14
F XVI-8	14
F XVI-9	14
F XVI-10	14
F XVI-11	14
F XVI-12	14
F XVI-12a	14
F XVI-12b	14
F XVI-12c	16
F XVI-12d	16
F XVI-13	14
F XVI-14	14
F XVI-15	14
F XVI-16	14
F XVI-17	16
F XVI-18	14
F XVI-19	14
F XVI-20	14
F XVI-21	14
F XVI-22	14
F XVI-23	14
F XVI-24	14
F XVI-25	14
F XVI-26	14
F XVI-27	14
F XVI-28	14
F XVI-29	14

Page Number	Revision Number
F XVI-30	14
F XVI-31	14
F XVI-32	14
F XVI-33	14
F XVI-34	14
F XVI-35	14
F XVI-36	14
F XVI-37	14
F XVI-38	14
F XVI-39	14
F XVI-40	14
F XVI-41	14
F XVI-42	14
F XVI-43	14
F XVI-44	14
F XVI-45	14
F XVI-46	14
F XVI-47	14
F XVI-48	14
F XVI-49	14
F XVI-50	14
F XVI-51	14
F XVI-52	14
F XVI-53	14
F XVI-54	14
F XVI-55	14
F XVI-56	14
F XVI-57	14
F XVI-58	14
F XVI-59	14
F XVI-60	14
F XVI-61	14

LIST OF EFFECTIVE PAGES

SECTION XVII

LIST OF EFFECTIVE PAGES

SECTION XVII (Cont'd.)

Page Number	Revision Number	Page Number	Revision Number
F XVII-20	15	F XVII-62	15
F XVII-21	15	F XVII-63	15
F XVII-22	15	F XVII-64	15
F XVII-23	15	F XVII-65	15
F XVII-24	15		
F XVII-25	15		
F XVII-26	15		
F XVII-27	15		
F XVII-28	15		
F XVII-29	15		
F XVII-30	15		
F XVII-31	15		
F XVII-32	15		
F XVII-33	15		
F XVII-34	15		
F XVII-35	15		
F XVII-36	15		
F XVII-37	15		
F XVII-38	15		
F XVII-39	15		
F XVII-40	15		
F XVII-41	15		
F XVII-42	15		
F XVII-43	15		
F XVII-44	15		
F XVII-45	15		
F XVII-46	15		
F XVII-47	15		
F XVII-48	15		
F XVII-49	15		
F XVII-50	15		
F XVII-51	15		
F XVII-52	15		
F XVII-53	15		
F XVII-54	15		
F XVII-55	15		
F XVII-56	15		
F XVII-57	15		
F XVII-58	15		
F XVII-59	15		
F XVII-60	15		
F XVII-61	15		

LIST OF EFFECTIVE PAGES

SECTION XVIII

Page Number	Revision Number	Page Number	Revision Number
XVIII-1	18		
XVIII-2	15		
XVIII-3	16		
XVIII-4	15		
XVIII-5	15		
XVIII-6	18		
XVIII-7	15		
XVIII-8	15		
XVIII-9	15		
XVIII-10	18		
XVIII-11	18		
XVIII-12	15		
XVIII-13	15		
XVIII-14	15		
XVIII-15	15		
XVIII-16	15		
T XVIII-1	18		

LIST OF EFFECTIVE PAGES

APPENDIX A

Page Number	Revision Number	Page Number	Revision Number
A-1	11		

LIST OF EFFECTIVE PAGES

APPENDIX B

Page Number	Revision Number	Page Number	Revision Number
B-1	20		

LIST OF EFFECTIVE PAGES

APPENDIX C

Page Number	Revision Number
C-i	20
C-ii	20
C-iii	20
C-iv	20
C.0-1	20
C.0-2	20
C.1-1	20
C.1-2	20
C.1-3	20
C.1-4	20
C.1-5	20
C.1-6	20
C.1-7	20
C.1-8	20
C.1-9	20
C.1-10	20
C.1-11	20
C.1-12	20
C.1-13	20
C.1-14	20
C.1-15	20
C.1-16	20
C.1-17	20
C.1-18	20
C.1-19	20
C.1-20	20
C.1-21	20
C.1-22	20
C.1-23	20
C.1-24	20
C.1-25	20
C.1-26	20
C.1-27	20
C.1-28	20
C.2-1	20
C.2-2	20
C.2-3	20
C.2-4	20
C.2-5	20
C.2-6	20
C.2-7	20
C.2-8	20
C.2-9	20
C.2-10	20
C.2-11	20
C.2-12	20
C.2-13	20
C.3-1	20
C.4-1	20
C.4-2	20
T C-1 Sh 1	20
T C-1 Sh 2	20
T C-1 Sh 3	20
T C-1 Sh 4	20
T C-1 Sh 5	20
T C-1 Sh 6	20
T C-1 Sh 7	20
T C-1 Sh 8	20
T C-1 Sh 9	20
T C-1 Sh 10	20

U.S. NUCLEAR REGULATORY COMMISSION
DOCKET 50-220
LICENSE DPR-63

NINE MILE POINT NUCLEAR STATION UNIT 1

FINAL SAFETY ANALYSIS REPORT (UPDATED)

VOLUME 1

OCTOBER 2007

REVISION 20

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

THIS PAGE INTENTIONALLY BLANK

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

THIS PAGE INTENTIONALLY BLANK

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

THIS PAGE INTENTIONALLY BLANK

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

THIS PAGE INTENTIONALLY BLANK

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

LIST OF TABLES

E. REFERENCES

1. USAEC Press Release H-252, "General Design Criteria for Nuclear Power Plant Construction Permits," November 22, 1965.

2. 0000-0053-5239-SRLR, Revision 0, "Supplemental Reload Licensing Report for NMP1, Reload 19, Cycle 18," December 2006.

3. GE Fuel Bundle Designs, General Electric Company Proprietary, NEDE-31152P, Revision 5, June 1996.

TABLE I-2

ABBREVIATIONS AND ACRONYMS USED IN UFSAR

ACI	American Concrete Institute
ADS	Automatic depressurization system
AISC	American Institute of Steel Construction
ALARA	As low as reasonably achievable
ALRA	Amended license renewal application
AMP	Aging Management Program
ANS	American Nuclear Society
ANSI	American National Standards Institute
AOV	Air-operated valve
APRM	Average power range monitor
ARI	Alternate rod injection
ARMS	Area radiation monitoring system
ART	Adjusted reference temperature
ASTM	American Society for Testing and Materials
ATWS	Anticipated transient without scram
BOC	Beginning of cycle
BOP	Balance of plant
BPWS	Banked position withdrawal sequence
BTP	Branch technical position
BWR	Boiling water reactor
BWROG	Boiling Water Reactor Owners' Group
BWRT	Backwash receiving tank
BWRVIP	Boiling Water Reactor Vessel and Internals Program
CAD	Containment atmosphere dilution (device)
CCCWS	Closed-cycle cooling water system
CEO	Chief Executive Officer
CFR	Code of Federal Regulations
CFS	Condensate filtration system
CGCS	Combustible gas control system
CHF	Critical heat flux
CIV	Combined intermediate valve
CND	Condensate demineralizer
CO_2	Carbon dioxide
COLR	Core Operating Limits Report
CPR	Critical power ratio
CRD	Control rod drive
CRDA	Control rod drop accident
CRDRL	Control rod drive return line

TABLE I-2 (Cont'd.)

CRPI	Control rod position indication
CRS	Control Room Supervisor
CRT	Cathode ray tube
CSO	Chief Shift Operator
CST	Condensate storage tank
CUF	Cumulative usage factor
CWT	Concentrated waste tank
DAC	Dominant area of concern
DBA	Design basis accident
DBE	Design basis earthquake
DCRDR	Detailed control room design review
DEC	Department of Environmental Conservation
DER	Deviation/Event Report
DER	Double-ended rupture
DG	Diesel generator
DOP	Dioctylphthalate
DOT	Department of Transportation
ECCS	Emergency core cooling system
ECP	Electrochemical corrosion potential
EDG	Emergency diesel generator
EFPY	Effective full-power years
EIC	Energy Information Center
EOC	End of cycle
EOF	Emergency Operations Facility
EOL	End of life
EOP	Emergency operating procedure
EPA	Environmental Protection Agency
EPDM	Ethylene-propylene-diene-monomer
EPG	Emergency procedure guideline
EPRI	Electric Power Research Institute
EQ	Environmental qualification
ESF	Engineered safety feature
ESW	Emergency service water
FA	Fire area
FAC	Flow-accelerated corrosion
FCV	Flow control valve
FHA	Fire Hazards Analysis
FMEA	Failure modes and effects analysis
FMP	Fatigue Monitoring Program
FSA	Fire subarea

TABLE I-2 (Cont'd.)

FSAR	Final Safety Analysis Report
FZ	Fire zone
GALL	Generic aging lessons learned
GDC	General Design Criterion
GE	General Electric Company
GL	Generic Letter
GSI	Generic Safety Issue
HAZ	Heat-affected zone
HCU	Hydraulic control unit
HEM	Homogeneous equilibrium model
HEO	Human engineering observation
HEPA	High-efficiency particulate air/absolute (filter)
HPCI	High-pressure coolant injection
HVAC	Heating, ventilating, and air conditioning
HWC	Hydrogen water chemistry
HX	Heat exchanger
I&C	Instrumentation & control
ID	Inner diameter
IGSCC	Intergranular stress corrosion cracking
ILRT	Integrated leakage rate test
INPO	Institute of Nuclear Power Operations
ISEG	Independent Safety Engineering Group
ISI	Inservice inspection
ISP	Integrated Surveillance Program
IST	Inservice testing
LCO	Limiting condition of operation
LHGR	Linear heat generation rate
LLD	Lower limit of detection
LLL	Low-low limit
LOCA	Loss-of-coolant accident
LOFW	Loss of feedwater
LOOP	Loss of offsite power
LPCS	Low-pressure core spray
LPRM	Local power range monitor
LPSP	Low power setpoint
LPZ	Low population zone
LRA	License renewal application
LSSS	Limiting safety system setting
LTC	Load tap changer

TABLE I-2 (Cont'd.)

M&TE	Measuring and testing equipment
MAPLHGR	Maximum average planar linear heat generation rate
MCC	Motor control center
MCPR	Minimum critical power ratio
MG	Motor generator
MLHGR	Maximum linear heat generation rate
MOV	Motor-operated valve
MSIV	Main steam isolation valve
MSL	Main steam line
MSLB	Main steam line break
NDT	Nil ductility transition
NDT	Nondestructive testing
NDTT	Nil ductility transition temperature
NEIL	Nuclear Electric Insurance Limited
NFPA	National Fire Protection Association
NMPC	Niagara Mohawk Power Corporation
NPSH	Net positive suction head
NRC	Nuclear Regulatory Commission
NRV	Nonreturn valve
NSRB	Nuclear Safety Review Board
NSSS	Nuclear steam supply system
NVLAP	National Voluntary Laboratory Accreditation Program
NYPA	New York Power Authority
NYPP	New York Power Pool
OBE	Operating basis earthquake
OCCWS	Open-cycle cooling water system
OEA	Operating experience assessment
OL	Operating license
OLNC	On-Line NobleChem
OOS	Out of service
OSC	Operational Support Center
OT	Operational transient
PA	Public address (system)
PASS	Post-accident sampling system
PCI	Pellet-cladding interaction
PCT	Peak cladding temperature
p.f.	Power factor
P&ID	Piping and instrumentation diagram

TABLE I-2 (Cont'd.)

PM	Preventive maintenance
PORC	Plant Operations Review Committee
PP/PA	Page party/public address (system)
PSAR	Preliminary Safety Analysis Report
PSTG	Plant-specific technical guideline
P-T	Pressure-temperature
PVC	Polyvinyl chloride
QA	Quality assurance
QATR	Quality Assurance Topical Report
RBCLCW	Reactor building closed loop cooling water
RBM	Rod block monitor
RCA	Radiologically-controlled area
RCPB	Reactor coolant pressure boundary
RCS	Reactor coolant system
RG	Regulatory Guide
RIP	Reactor internals protection
RMS	Radiation monitoring system
RO	Reactor Operator
RPIS	Rod position information system
RPS	Reactor protection (trip) system
RPT	Recirculation pump trip
RPV	Reactor pressure vessel
RSP	Remote shutdown panel
RSS	Remote shutdown system
RTD	Resistance temperature detector
RT_{NDT}	Reference temperature nil ductility transition
RWCU	Reactor water cleanup
RWE	Rod withdrawal error
RWM	Rod worth minimizer
RWP	Radiation work permit
SAP	Severe accident procedure
SAR	Safety analysis report
SAS	Secondary alarm system
SBO	Station blackout
SCBA	Self-contained breathing apparatus
SCC	Stress corrosion cracking
SDM	Shutdown margin
SDV	Scram discharge volume
SER	Safety Evaluation Report
SFC	Spent fuel pool cooling and cleanup

TABLE I-2 (Cont'd.)

SIL	Service Information Letter
SJAE	Steam jet air ejector
SM	Shift Manager
SNM	Special nuclear material
SOE	Sequence of events
SOP	Special operating procedure
SORC	Station Operations Review Committee
SOV	Solenoid-operated valve
SPDS	Safety parameter display system
SR	Surveillance requirement
SRAB	Safety Review and Audit Board
SRLR	Supplemental Reload Licensing Report
SRM	Source range monitor
SRO	Senior Reactor Operator
SRP	Standard Review Plan
SRV	Safety/relief valve
SRVDL	Safety/relief valve discharge line
SSA	Safe Shutdown Analysis
SSC	Structures, systems and components
SWEC	Stone & Webster Engineering Corporation
SWP	Service water system
TAF	Top of active fuel
TBCLCW	Turbine building closed loop cooling water
TCV	Turbine control valve
TDH	Total developed head
TIP	Traversing in-core probe
TLAA	Time-Limited Aging Analyses
TLD	Thermoluminescence dosimeter
TMI	Three Mile Island
TSC	Technical Support Center
TSVC	Turbine stop valve closure
TVD	Test, vent and drain
UBC	Uniform Building Code
UFSAR	Updated Final Safety Analysis Report
UHS	Ultimate heat sink
UL	Underwriters' Laboratories Inc.
Unit 1	Nine Mile Point Nuclear Station - Unit 1
Unit 2	Nine Mile Point Nuclear Station - Unit 2
UPS	Uninterruptible power supply
URC	Ultrasonic resin cleaning
U.S.	United States

TABLE I-2 (Cont'd.)

USBM	U.S. Bureau of Mines
USE	Upper-shelf energy
USLS	U.S. Land Survey
UT	Ultrasonic testing
VWO	Valve wide open
WNT	Waste neutralizer tank
WSLR	Within scope of license renewal

PIPING, INSTRUMENT AND EQUIPMENT SYMBOLS

INSTRUMENT FUNCTION / MEASURED VARIABLE		CONTROLLING: RECORDING	CONTROLLING: INDICATING	CONTROLLING: NON-INDICATING	CONTROLLING: CONTROL VALVES	CONTROLLING: SAFETY-RELIEF VALVES	CONTROLLING: ORIFICE RESTRICTING	CONTROLLING	MEASURING: HIGH PRESS. CONN.	MEASURING: LOW PRESS. CONN.	MEASURING: RECORDING	MEASURING: INDICATING	MEASURING: OBSERVATION GLASS	MEASURING: PRIMARY ELEMENT	MEASURING: TEST POINT OR WELL
		-RC	-IC	-C	-CV	-SV	O_R				-R	-I	-G	-E	-X
CONDUCTIVITY	C	CRC	CIC								CR	CI		CE	CX
DIFF. PRESS.	DP	DPRC	DPIC	DPC							DPR	DPI			
FLOW	F	FRC	FIC	FC	FCV		FO_R		K1	K2	FR	FI	FG	FE	FX
HUMIDITY	H	HRC	HIC								HR	HI		HE	HX
PH	PH	PHRC	PHIC	PHC							pHR	pHI		pHE	pHX
LEVEL	L	LRC	LIC	LC	LCV						LR	LI	LG	LE	
PRESSURE	P	PRC	PIC	PC	PCV	PSV	PO_R				PR	PI			PX
POSITION	P_O										P_OR	P_OI			
RADIATION	R				RCV						RR	RI		RE	RX
TEMPERATURE	T	TRC	TIC	TC	TCV						TR	TI		TE	TX
VIBRATION	V_B										V_BR				
VACUUM	V_C	V_CRC	V_CIC	V_CC		V_CSV						V_CI			
VISCOSITY	V_I														
SAMPLE	S														SX
SPEC. GRAVITY	S_G	S_GRC													
NEUTRON FLUX	N		NIC								NR	NI		NE	NX
OXYGEN	O_2										O_2R	O_2I		O_2E	
SPEED	S_P	S_PRC	S_PIC	S_PC							S_PR	S_PI		S_PE	
DENSITY	D			DC										DE	
HYDROGEN	H_2	H_2RC												H_2E	
FREON	F_{12}										$F_{12}R$			$F_{12}E$	

MEASURED VARIABLE	MEASURING: SET POINT	MEASURING: TRANSMITTER	MEASURING: INTEGRATOR	MEASURING: AMPLIFIER	MEASURING: SAMPLER	MEASURING	SWITCH: INDICATING	SWITCH: NON-INDICATING	SWITCH: ELECTRONIC	ALARMS: OPEN	ALARMS: CLOSED	ALARMS: ALARM	ALARMS: ALARM HIGH	ALARMS: ALARM LOW	POWER SUPPLY
		-T	-O	$-A_M$	$-S_M$		-IS	-S	$-S_E$	$-A_O$	$-A_C$	-A	$-A_H$	$-A_L$	$-P_W$
CONDUCTIVITY					CS_M		CIS	CS				CA	CA_H	CA_L	
DIFF. PRESS.		DPT					DPIS	DPS				DPA	DPA_H	DPA_L	
FLOW		FT	FO				FIS	FS				FA	FA_H	FA_L	
HUMIDITY															
PH				pHA_M	pHS_M							pHA	pHA_H	pHA_L	
LEVEL		LT					LIS	LS	LS_E			LA	LA_H	LA_L	
PRESSURE		PT					PIS	PS	PS_E			PA	PA_H	PA_L	
POSITION		P_OT					POIS	POS		P A	P A				
RADIATION				RA_M	RS_M			RS				RA	RA_H		RP_W
TEMPERATURE		TT					TIS	TS				TA	TA_H	TA_L	
VIBRATION		V_BT		V_BA_M				V_BS				V_BA			
VACUUM		V_CT						V_CS				V_CA	V_CA_H	V_CAL	
VISCOSITY															
SAMPLE					SS_M										
SPEC. GRAVITY															
NEUTRON FLUX		NT	NO	NA_M			NIS	NS				NA	NA_H	NA_L	NP_W
OXYGEN															
SPEED															
DENSITY	DSP	DT													
HYDROGEN												H_2A			
FREON															

SUFFIX SUB 'H' OR 'L' (HIGH, LOW)
SUFFIX SUB 'O' OR 'C' (OPEN, CLOSED)

VALVE SYMBOLS

- BALL
- GATE
- GLOBE
- CHECK (USUALLY SWING TYPE)
- LIFT CHECK
- STOP CHECK
- BUTTERFLY (CLOSE)
- BUTTERFLY (OPEN)
- ANGLE
- SAFETY OR RELIEF
- THREE WAY
- FOUR WAY
- 2 PORT COCK, PLUG OR BALL VALVE
- THREE-PORT COCK
- FOUR-PORT COCK
- FLOW CHECK VALVE
- SAUNDERS TYPE
- HISTORIC SYMBOL FOR GLOBE
- AIR VENT VALVE

LINE SYMBOLS

- PRIMARY FLOW
- SECONDARY FLOW
- INSTRUMENT PROCESS AIR
- INSTRUMENT CONTROL AIR
- INSTRUMENT ELECT. LEADS
- INSTRUMENT CAPILLARY TUBING
- CONNECTION
- CROSSING
- DRYWELL PENETRATION
- OFF GAS
- FLOW DIRECTION
- HEATED LINES
- BALL JOINT
- DIAPHRAGM SEAL

SPECIAL NOTE

L.O. -LOCKED OPEN
L.C. -LOCKED CLOSED
R.M. -REMOTE MANUAL(HANDWHEEL EXTENSION)
L.R. -LANTERN RING
B.S. -BELLOW SEAL
K.O. -KEY OPERATED
R.P.S. -REACTOR PROTECTION SYSTEM
• SUFFIX SUB 'H' OR 'L' MAY BE ADDED (HIGH, LOW)
SUFFIX SUB 'O' OR 'C' MAY BE ADDED (OPEN, CLOSED)

INSTRUMENT SYMBOLS

- PR — SERVICE (SEE TABLE) — LOCAL MOUNTED INST.
- PR — SERVICE (SEE TABLE) — PANEL MOUNTED INST.
- PT — SERVICE (SEE TABLE) — LOCAL MOUNTED TRANS.
- FT — SERVICE (SEE TABLE) — PANEL MOUNTED TRANS.
- RA — SERVICE (SEE TABLE) — ANNUNCIATOR ALARM, AUDIBLE AND/OR VISIBLE
- E/P — ELECTRIC, PNEUMATIC — CONVERTER
- CONTROL COMPONENTS

SYS. -TOTAL CONTROL SYSTEM
√ -SQUARE ROOT EXTRACTOR
Σ -SUMMER
× -MULTIPLIER
÷ -DIVIDER
f -FUNCTION GENERATOR
▷ -PROPORTIONAL AMPLIFIER
MV/I -MILLIVOLT/CURRENT TRANSMITTER
-RELAY
G -INTEGRATOR

- TA — SERVICE (SEE TABLE) — DATA HANDLING SYSTEM

CONTROL VALVE OPERATION

- FLOAT OPERATED
- MO / AC — M.O. -MOTOR OPERATED(AC OR DC), A.O. -AIR PISTON OPER., H.O. -HYDRAULIC PISTON OPER., P.O. -POWER OPER.
- DIAPHRAGM OPERATED
- PRESSURE CONTROLLER (SHOW FLOW DIRECTION)
- DIFF. PRESS. CONTROLLER (SHOW FLOW DIRECTION)
- DIAPHRAGM OPERATED WITH POSITIONER
- SOLENOID VALVE
- RMC — REMOTE MANUAL CONTROL (CONTROL ROOM) EXCEPT AS NOTED OTHERWISE
- RMC — REMOTE MANUAL CONTROL (LOCAL)

FLOW DEVICES

- FE — EQUIPMENT PIECE NO. — FLOW ELEMENT ORFICE
- FI — EQUIPMENT PIECE NO. — IN-LINE FLOW DEVICE
- FE — EQUIPMENT PIECE NO. — FLOW ELEMENT NOZZLE
- PILOT TUBE

PUMPS AND FANS

- CENTRIFUGAL PUMP
- RECIPROCATING UNIT PUMP COMPRESSOR
- FAN OR BLOWER
- ROTARY UNIT PUMP BLOWER COMPRESSOR

PIPING SYMBOLS

- STRAINER
- FILTER
- TRAP
- SEPARATOR
- OPEN VENT
- OPEN DRAIN
- REDUCER
- PLUGGED OR FLANGED END CAP
- SCREWED CAP
- WELDED CAP
- HEAT EXCHANGER
- FLANGED SPOOLPIECE
- 25KW — ELECTRIC HEATER
- SPRAY NOZZLE OR MIXING JET

VENTILATION DAMPERS

- SHUT-OFF
- THROTTLING
- BACK DRAFT
- MULTI-DAMPERS

VALVE POSITIONS

DURING USUAL PLANT OPERATION

OPEN

CLOSED

AIR SUPPLY
CLOSED PORT
NEXT TO CLOSE
VENT

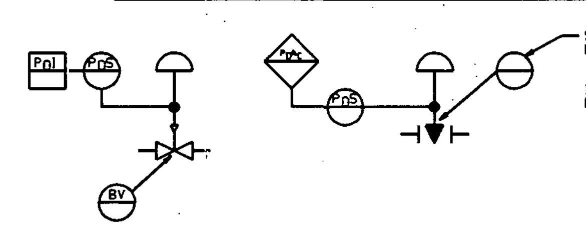
3 WAY SOLENOID VALVE, ALWAYS SHOWN DE-ENERGIZED

EXPANSION JOINTS

NOT SHOWN ON P&I WHEN USED ONLY FOR NORMAL FLEXIBILITY

- PIPE LOOP
- FLEXIBLE HOSE
- BELLOWS JOINT
- SLIP JOINT

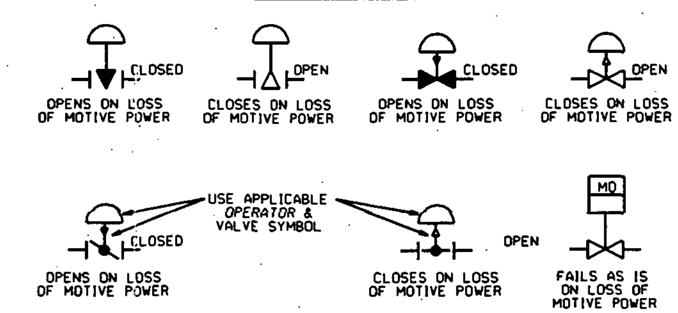
CONTROL VALVE DESIGNATION



IV -DRYWELL ISOLATION VALVE
BV -BLOCKING VALVE

CONTROL VALVE OPERATION

USE APPLICATOR OPERATOR & VALVE SYMBOL



A- 13901

FIGURE I - 1
UFSAR Revision 20
October 2007

A. TURBINE BUILDING

1.0 Design Bases

1.1 Wind and Snow Loadings

Exterior loadings for wind, snow and ice used in the design of the turbine building meet all applicable codes as a minimum. The roof and its supporting structure are designed to withstand a loading of 40 psf of snow or ice. The walls and building structure are designed to withstand an external loading of 40 psf of surface area, which is approximately equivalent to a wind velocity of 125 mph at the 30-ft level.

1.2 Pressure Relief Design

To prevent failure of the superstructure due to a steam line break, a wall area of 1900 ft^2 has been attached with bolts that will fail due to an internal pressure of approximately 62 psf, thus relieving internal pressure. Wall or building structure failure would occur at an internal pressure in excess of 80 psf. Subsequent calculations were performed in accordance with the AISC Manual of Steel Construction, Load & Resistance Factor Design (LRFD), First Edition, to compute the failure load of the building superstructure, and was determined to be at least 135 psf.

1.3 Seismic Design and Internal Loadings

The turbine building is designed as a Class II structure. Components are either Class II or Class I, as outlined on pages III-1, III-2 and III-3 of the First Supplement to the PHSR.

An analysis of the turbine building resulted in the use of the following earthquake design coefficients for the major components.

Component	Percent Gravity	Comment
Feedwater heaters and drain cooler support structures	16.0 - 20.5 (calculation used: 20.0 horizontal 10.0 vertical)	Based on specific dynamic analysis
Turbine generator foundation	23.4 N-S horizontal 26.7 E-W horizontal	Based on specific dynamic analysis
Condenser support structure	11.0 horizontal 5.5 vertical	Based on specific dynamic analysis

For the following components, percent gravity was 20.0 horizontal and 10.0 vertical, based on the Uniform Building Code (UBC).

Steel structure supporting emergency condenser makeup water storage tanks and demineralized water storage tank, condensate filters (CFS), backwash receiving tanks (BWRT), and condensate demineralizer (CND)	Class I
Motor generator (MG) sets for reactor recirculating pump motors	Class II
150/35-ton overhead traveling crane	Class II
Structural anchors supporting main steam, offgas, etc., piping	Class I
Anchor bolts and associated bases and frame for support of all tanks, filters and pumps as well as electrical equipment. (Power boards, control consoles, etc.)	Classes I & II
Supports for moisture separators and reheaters	Class II

Stresses resulting from the functional or operating loads are within applicable codes relating to these structures and components. Stresses resulting from the combination of operating loads and earthquake or wind loads have been limited in accordance with applicable codes to a 33 1/3-percent increase in allowable stresses*. The adjoining walls of the turbine and reactor building superstructures are structurally separated to provide for dissimilar deformations due to earthquake motion.

1.4 Heating and Ventilation

Heating and ventilation is provided for equipment protection, personnel comfort and for controlling possible radioactivity release to the atmosphere.

---

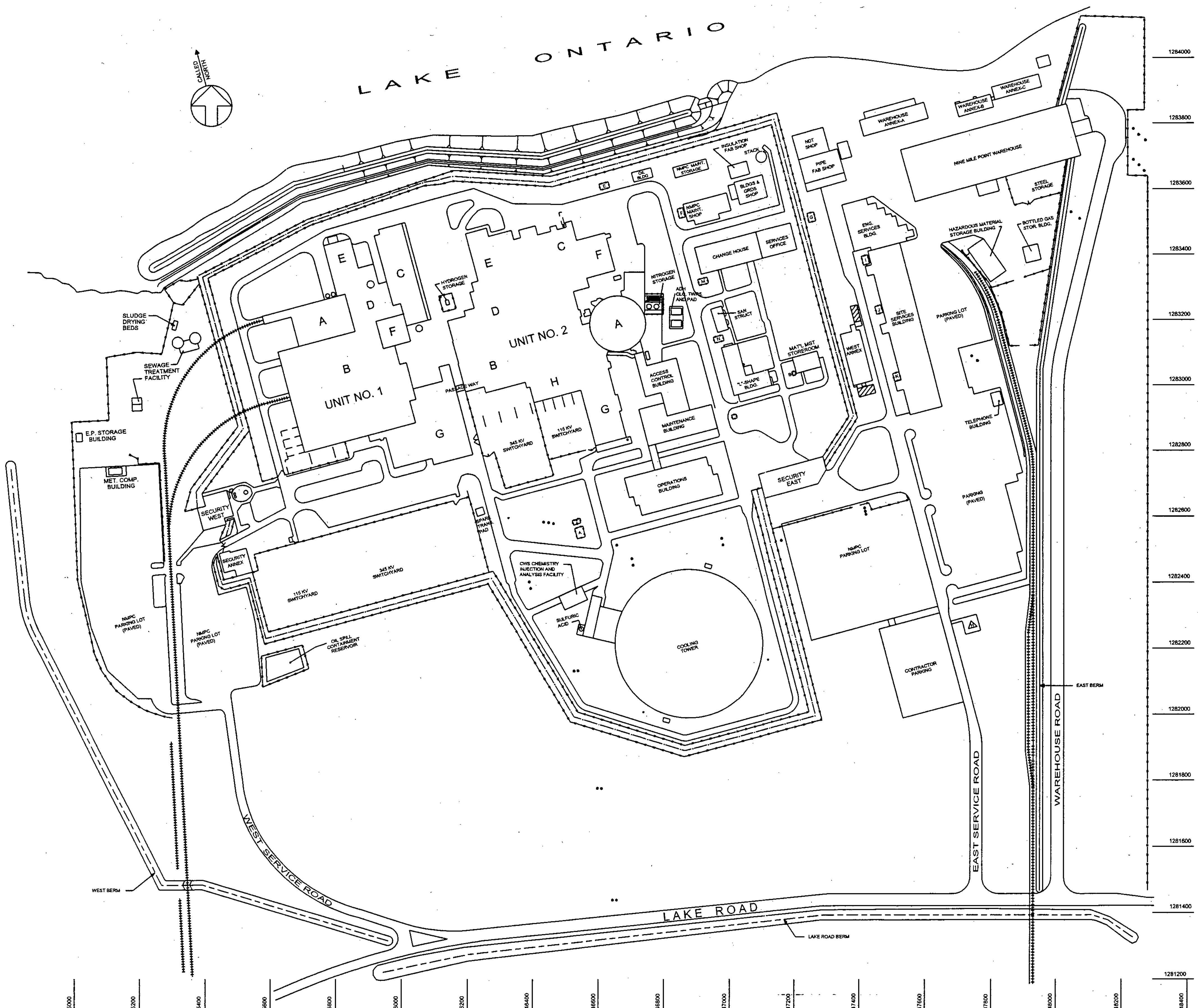
* Also see Section XVI, Subsection G.

1.5 Shielding and Access Control

Shielding is provided around much of the equipment to limit dose rates, as described in Section XII.

Normal access to the turbine building is provided through the administration building.

THIS PAGE INTENTIONALLY BLANK



KEY

- PERMANENT STRUCTURES
- DOCUMENT STORAGE VAULTS
- PERMANENT FENCE
- CONSTRUCTION FENCE
- RAILROAD TRACKS
- TRANSMISSION LINE POLES
- ELECTRIC SUBSTATION
- CONCRETE SLABS AND PADS

UNIT 1 BUILDING KEY

A. REACTOR BUILDING
B. TURBINE BUILDING
C. RADWASTE SOLIDIFICATION STORAGE BUILDING (R.S.S.B.)
D. WASTE STORAGE BUILDING
E. SCREEN AND PUMPHOUSE
F. OFF GAS BUILDING
G. ADMINISTRATION BUILDING

UNIT 2 BUILDING KEY

A. REACTOR BUILDING
B. TURBINE BUILDING
C. RADWASTE BUILDING
D. HEATER BAYS
E. SCREENWELL BUILDING
F. CONDENSATE STORAGE TANK BUILDING
G. CONTROL BUILDING
H. NORMAL SWITCHGEAR BUILDING

Figure III-1
UFSAR Rev. 20 (October 2007)
Plot Plan

Source Documents:
C-35611-C, Rev. 7

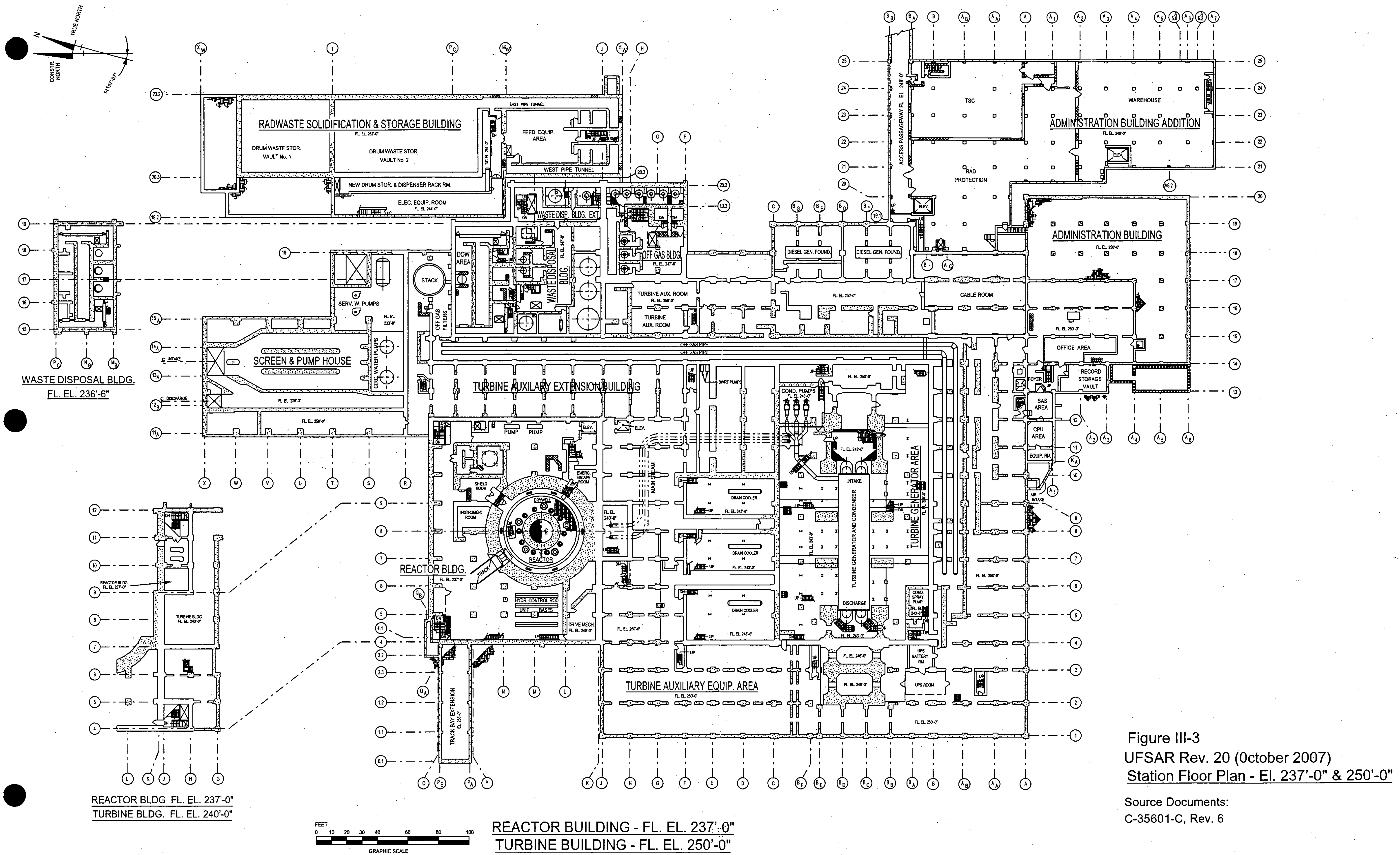
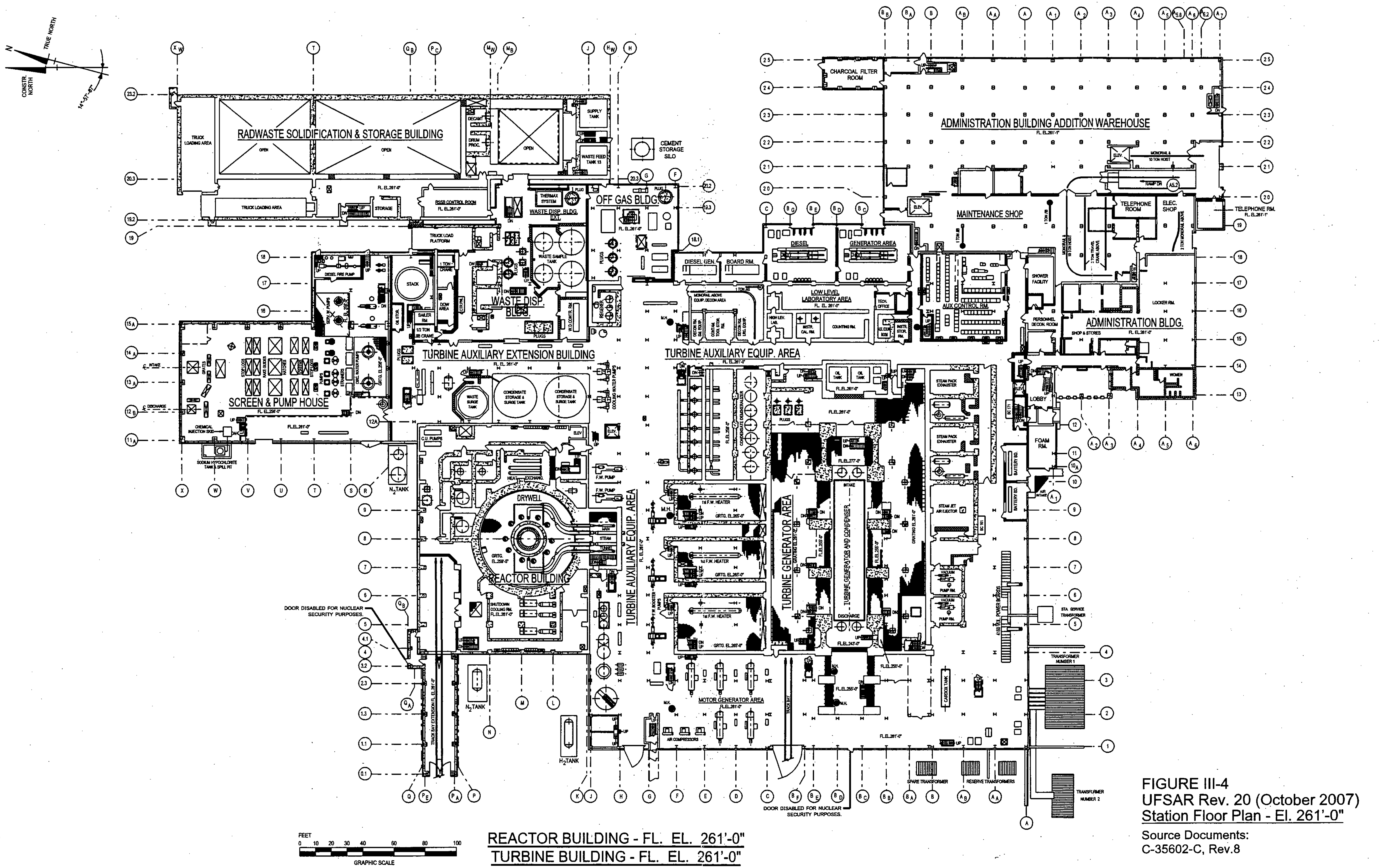


Figure III-3
UFSAR Rev. 20 (October 2007)
Station Floor Plan - El. 237'-0" & 250'-0"

Source Documents:
C-35601-C, Rev. 6



REACTOR BUILDING - FL. EL. 261'-0"
TURBINE BUILDING - FL. EL. 261'-0"

FIGURE III-4
UFSAR Rev. 20 (October 2007)
Station Floor Plan - El. 261'-0"

Source Documents:
C-35602-C, Rev.8

...\E47546\msuser\C-35602-C.dgn 7/26/2007 3:56:11 PM

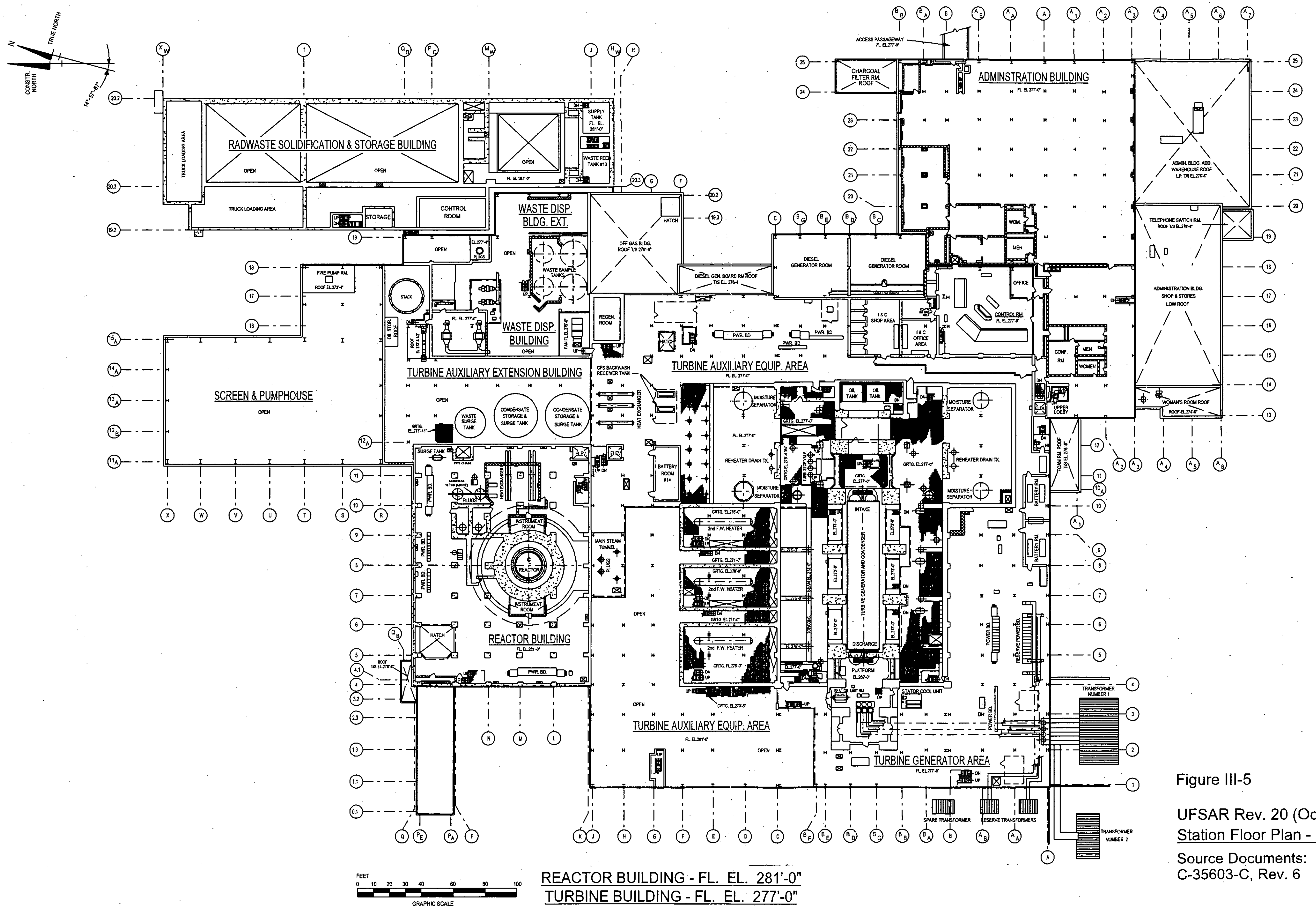
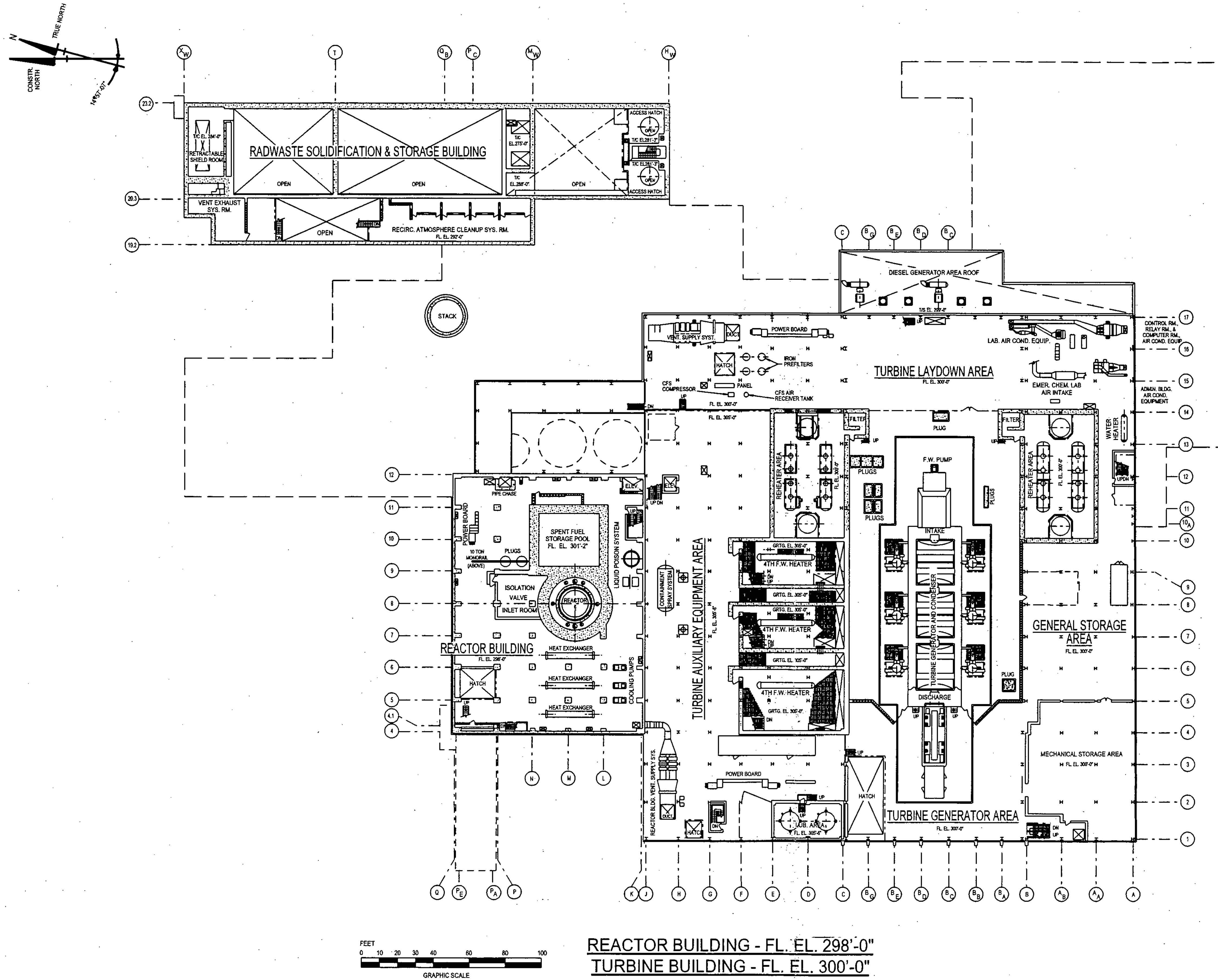


Figure III-5

UFSAR Rev. 20 (October 2007)

Station Floor Plan - El. 277'-0" & 281'-0"

Source Documents:
C-35603-C, Rev. 6



REACTOR BUILDING - FL. EL. 298'-0"
TURBINE BUILDING - FL. EL. 300'-0"

Figure III-7
UFSAR Rev. 20 (October 2007)
Statation Floor Plan - El. 298'-0" & 300'-0"

Source Documents:
C-35605-C, Rev. 5

Stresses in various core components are at maximum during the blowdown resulting from the main steam line (MSL) break discussed in Section XV.

7.1.1 Core Shroud

The core shroud, as shown on Figure IV-9, is a stainless steel cylinder which surrounds the core and provides a barrier to separate the upward flow of coolant through the core from the downcomer recirculation flow. Mounted at the top of the shroud is the shroud headsteam separator assembly. A discharge plenum at the top of the core provides a mixing chamber before the steam-water mixture enters the steam separators. The recirculation inlet and outlet plenums are separated by shroud and shroud support. The shroud support is designed to sustain the differential expansion of the ferritic reactor vessel and the austenitic stainless steel shroud without high stresses. The shroud support is fabricated from solid Inconel. The shroud support essentially sustains all of the vertical weight of the core structure (except the fuel assembly weights transmitted to the guide tube) and the steam separator assembly; the differential upward pressure loading on the shroud under operating conditions; and the vertical and sidewise thrusts developed on the core and core structure during an earthquake.

The cylindrical shroud is joined to the shroud support with a full penetration weld. The shroud support plate, tie-rods, head bolts, and associated welds are fabricated using Inconel stainless steel. The principal stresses produced in the shroud are due to differential pressure loading, differential thermal expansion, deadweight loadings and earthquake loadings.

Core Shroud Intergranular Stress Corrosion Cracking (IGSCC)

The core shroud vertical and horizontal welds are susceptible to IGSCC as discussed in References 12 and 13, and NRC Generic Letter (GL) 94-03. The core shroud horizontal and vertical welds have been inspected and determined to have IGSCC in and near the heat-affected zone (HAZ) of the welds. This cracking has been evaluated and determined to be prototypical of IGSCC reviewed by the NRC as part of GL 94-03 and addressed by the Boiling Water Reactor Vessel and Internals Project (BWRVIP) core shroud IGSCC documents. The NRC safety evaluation report (SER) for the generic application of the BWRVIP core shroud inspection and evaluation document is applicable to the Nine Mile Point Nuclear Station - Unit 1 (Unit 1) IGSCC. The shroud inservice inspections (ISI) have determined that the horizontal and vertical welds inspected satisfy the required structural margins considering the existing IGSCC, and maintain the core shroud such that all design basis requirements are satisfied. The horizontal welds have core shroud stabilizer assemblies (tie-rods) installed which structurally replace horizontal welds H1 through H7 such that ISI of the horizontal welds is not required. The vertical

THIS PAGE INTENTIONALLY BLANK

weld integrity is required considering the core shroud stabilizer design basis assumption of 360-deg throughwall cracking of the horizontal welds. Complete vertical weld throughwall cracking can be tolerated for the vertical welds provided horizontal weld integrity is established by inspection. Since horizontal weld inspections are not performed, vertical weld ISI is required to maintain the core shroud stabilizer design basis assumptions. The required ISI interval for the vertical welds is defined based on the References 12, 13 and 14 approved methods. The specific interval is defined by engineering analysis of the as-found cracking and consideration for potential crack growth and inspection uncertainty.

The primary stress which could cause vertical weld failure results from the internal pressure. Consistent with ASME Code Section XI practice, internal pressure is the only load to be considered for axial cracks. Other loads such as deadweight, seismic and thermal expansion have negligible impact and need not be considered. The design basis internal pressures which define the limiting faulted condition are 22 psi for the upper shroud (H1 through H6A) and 63 psi for the lower shroud (below core plate) (see Table XVI-9). The allowable flaw sizes consider the internal pressures under all conditions: normal, upset and accident. The required ASME Code Section XI safety factors of 3.0 for normal and upset conditions and 1.5 for emergency and faulted conditions are applicable consistent with the ASME Code requirements for evaluating axial flaws.

The potential impact of approximately 180 in of throughwall vertical weld crack leakage has been determined to be less than .11 percent of total core flow. The results show that at rated power and core flow the predicted leakage is sufficiently small so that the steam separation system performance, cavitation protection, core monitoring, fuel thermal margin and fuel cycle length remain adequate. Since the core flow leakage is minor and only a postulated condition, no core monitoring correction should be applied or is required. Also, this leakage flow has no impact on Section XV LOCA analyses since the core cooling function is performed by core spray cooling, not reflood, and, therefore, leakage from the shroud to the annulus region has no effect on core cooling.

The core shroud was reinspected during refueling outage (RFO) 15. A preemptive repair of the V9 and V10 welds was performed during RFO15 by installing a contingency repair clamp design previously approved by the NRC. The vertical weld repair clamps are described in Section IV-B.7.1.10. The vertical repair clamps replace the load carrying function of the V9 and V10 welds; therefore, future inspections of the V9 and V10 welds are not required.

The structural components which guide the control rods have been examined to determine the loadings which would occur in a LOCA (including a steam line break). The core structural components are designed so that deformations produced by accident loadings will not prevent insertion of control rods.

Considerable effort was expended to eliminate possible failures or control instability due to the vibration of reactor internal components. The reactor system was analyzed as a multidegree-of-freedom system. This analysis determined the system's natural frequencies, the resultant vibration mode shapes and the relationship between the vibration amplitudes and the critical stresses in the system, to show that system integrity would be maintained.

7.3 Surveillance and Testing

Rigid quality control requirements assured that the design specifications of the vessel internal components were met. These quality control methods were utilized during the fabrication of the individual components as well as during the assembly process.

Preoperational performance tests and the startup program demonstrated the design adequacy of reactor vessel internals and operability of the core spray spargers.

Periodic testing of the control rod system, i.e., reactivity margin - core loading and stuck control rods; rod scram insertion times and reactivity anomalies, is described in the Technical Specification.

C. REFERENCES

1. 0000-0053-5239-SRLR, Revision 0, "Supplemental Reload Licensing Report for NMP1, Reload 19, Cycle 18," December 2006.

2. Randall and St. John, Nucleonics 16(3), 82-86, 129 (1958).

3. General Electric Standard Application for Reactor Fuel, NEDE-24011-P-A-15-US, September 2005.

4. J. A. Wooley, "Three-Dimensional BWR Core Simulator," NEDO-20953A, January 1977.

5. "Qualification of the One-Dimensional Core Transient Model for BWR's," NEDO-24154, Vol. 1 and 2, and NEDE-24154-P-A, Vol. 3, February 1, 1986.

6. R. B. Linford, "Analytical Methods of Plant Transient Evaluations for the General Electric Boiling Water Reactor," NEDO-10802, December 1986, and Amendments.

7. GE Fuel Bundle Designs, General Electric Company Proprietary, NEDE-31152P, Revision 8, April 2001.

8. GENE-770-31-1292, Rev. 2, "Engineering Report for Application of GE11 to NMP1 Reload 12," General Electric Co. Proprietary Document, April 1993.

9. Safety Evaluation of the General Electric Advanced Long Life Control Rod Assembly, NEDE-22290, January 1985.

10. Letter from C. O. Thomas (NRC) to J. F. Klapproth (GE), July 1, 1985.

11. Safety Evaluation of the General Electric Duralife 230 Control Rod Assembly, NEDE-22290-P-A Supplement 3, May 1988.

12. GENE-523-113-0894, Rev. 1, "BWR Core Shroud Inspection and Evaluation Guidelines," March 1995.

13. BWRVIP-01, Rev. 2, "BWR Core Shroud Inspection and Flaw Evaluation Guideline," October 1996.

14. BWRVIP-07, "Guidelines for Reinspection of BWR Core Shrouds," February 1996.

15. Design Change No. N1-97-033, "Core Shroud Vertical Weld Contingency Repair."

16. GE Marathon Control Rod Assembly, NEDE-31758P-A, October 1991.

17. NEDC-32601P-A, "Methodology and Uncertainties for Safety Limit MCPR Evaluations," August 1999.

18. NEDC-32694P-A, "Power Distribution Uncertainties for Safety Limit MCPR Evaluations," August 1999.

1.4 Primary Coolant Leakage

A double O-ring type seal is provided on the reactor vessel head closure. The area between the seals is monitored for leakage. A groove between the inner and outer O-ring communicates through the vessel flange to a line in which is installed a pressure switch between two solenoid valves. The solenoid valves are operated from the control room. The monitoring instrumentation is shown on Figure V-1.

Other primary coolant leakage is detected by monitoring leakage into the drywell floor drain tank for unidentified drywell leakage, and the drywell equipment drain tanks for identified drywell leakage. Unidentified drywell leakage from the CRDs, valve flanges, packing, component cooling water, service water, recirculation pump suction and discharge valve packing leakoff, and any other leakage not connected to the drywell equipment drain tanks, collects in the drywell floor drain tanks. Identified drywell leakage is hard piped to the drywell equipment drain tanks and includes recirculation pump seal leakage. Abnormal leakage rates for the drywell floor and equipment drain tanks are detected and alarmed in the control room.

The excess leakage alarm function for the drywell floor and equipment drain tanks is performed by measuring volume changes in gallons that occur over a predetermined time period and calculating the resultant rate of change. Volume changes are used to determine the rate of change because of the irregular shape of the drywell floor and equipment drain tanks. By using volume change, excess leakage alarm capability is achieved across the entire instrument range with alarm checking occurring upon each recalculation.

The rate of rise alarm function for the drywell floor drain tank is performed by measuring the amount of time between precise level step changes. When a level increase is detected, the change in tank volume and elapsed time since the last change are used to determine the rate of volume change. The rate of volume change is then used to determine the rate of rise. The calculated rate of rise is output to the control room chart recorders and alarm checked.

The rate of rise for the drywell equipment drain tanks is monitored by evaluating the fill rate recorded on the equipment drain tank level chart recorder in the control room. This is performed every 4 hr.

The integrated flow pumped from the drywell floor and equipment drain tanks to the waste disposal system is another means that can be used to determine leakage into the drywell floor or the equipment drain tanks.

Automatic blowdown will not occur for any primary system leak rate below the maximum allowable total operating leak rate of approximately 25 gpm. However, for breaks below about 50 gpm (although the Technical Specification limit is 25 gpm), the triple low-level setting (6 ft 3 in below minimum normal) would not be reached and automatic blowdown of relief valves would not be initiated. If normal Station offsite power were lost, both CRD hydraulic system pumps would be automatically loaded on the diesel generators to maintain water level in the vessel above the automatic blowdown trip level. It is assumed that only one CRD system is operating. The flow rate of one CRD system pump is 50 gpm at 1000 psig reactor vessel pressure and 180 gpm at zero psig reactor vessel pressure. If both pumps were operating, the flows would be greater.

For much larger leak sizes, the time to reach the automatic blowdown trip level is shown in Table V-5. This table is conservatively based on only one diesel generator and its associated CRD system pump being available.

1.5 Coolant Chemistry

The RCS is not designed to use inhibitors. Limits are set on chlorides, solids and gross coolant radioactivity during normal Station operation.

Hydrogen water chemistry (HWC) injection and noble metal chemical addition (NMCA or NobleChem) systems are installed to reduce the potential for intergranular stress corrosion cracking (IGSCC) of the stainless steel reactor vessel components and recirculation piping. The zinc injection system is installed to reduce Cobalt 60 buildup in the primary piping corrosion films. This has the major benefit of reducing radiation dose rates in the drywell, reducing radiation exposure during outages. Hydrogen injection is provided through the feedwater/condensate systems; NobleChem is periodically added using either the classic method (injection during hot shutdown through the recirculation pump differential pressure transmitter lines) or the On-Line NobleChem (OLNC) method (with injection into feedwater during power operations); and zinc injection is provided through the feedwater system.

2.0 Reactor Vessel

An isometric drawing of the reactor vessel is shown on Figure IV-9. Vessel penetrations are shown on Figure V-2 and data for the reactor vessel in Table V-1. The reactor vessel is a vertical cylindrical pressure vessel. The base plate material is high-strength alloy carbon steel SA-302, Grade B. The vessel interior is clad with Type 308L to produce a 304 composition stainless steel following application by weld overlay.

The head closure is designed for easy removal and reassembly, being bolted to the vessel with high-strength studs. Removable stud bushings are furnished in the body flange to facilitate repair of damaged threads.

The CRD housings and the in-core instrumentation thimbles are welded to the bottom head of the reactor vessel.

Steam outlets are from the vessel body, thus eliminating the need to break flanged joints in the steam lines when removing the vessel head for refueling. Safety valves are mounted on the vessel head. Solenoid-actuated relief valves are mounted on the main steam lines (MSL).

An elevation drawing of the reactor vessel and supporting concrete structures is presented as Figure V-3. The reactor vessel is supported by a steel skirt welded to the bottom head of the vessel. The base of the skirt is continuously supported by a

THIS PAGE INTENTIONALLY BLANK

F. REFERENCES

1. NRC Standard Review Plan, Section 5.2.2, Overpressurization Protection - NUREG 75-087.

2. 0000-0053-5239-SRLR, Revision 0, "Supplemental Reload Licensing Report for NMP1, Reload 19, Cycle 18," December 2006.

3. K. Shure and D. J. Dudziak, "Calculating Energy Release by Fission Products," AEC Report WAPD-T-1309, March 1961.

4. K. Shure, "Fission Product Decay Heat," AEC Report WAPD-BT-24, December 1961.

5. NRC Letter to NMPNS dated November 8, 2004, "Nine Mile Point Nuclear Station Unit Nos. 1 and 2 - Issuance of Amendments RE: Implementation of the Reactor Pressure Vessel Integrated Surveillance Program (TAC Nos. MC1758 and MC1759)."

6. NRC Letter to NMPNS dated October 27, 2003, "Nine Mile Point Nuclear Station, Unit No. 1 - Issuance of Amendment Re: Pressure-Temperature Limit Curves and Tables (TAC No. MB6687)."

U.S. NUCLEAR REGULATORY COMMISSION
DOCKET 50-220
LICENSE DPR-63

NINE MILE POINT NUCLEAR STATION UNIT 1

FINAL SAFETY ANALYSIS REPORT (UPDATED)

VOLUME 2

OCTOBER 2007

REVISION 20

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

THIS PAGE INTENTIONALLY BLANK

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

THIS PAGE INTENTIONALLY BLANK

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

THIS PAGE INTENTIONALLY BLANK

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

THIS PAGE INTENTIONALLY BLANK

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

LIST OF TABLES

A computer analysis was made to determine the maximum induced seismic accelerations, displacements, shears, moments and reactions acting on the RPV and its support and on the reactor building. The analysis includes the response of the RPV and its support to the design earthquake and jet reaction forces. Also included is the effect on the RPV of the displacement of the reactor building and containment vessel due to the postulated earthquake. Results of this analysis are contained on Figures VI-6 through VI-17.

Personnel access into the reactor building is controlled from the track bay extension and from the turbine building. The track bay extension has a railroad entrance and a personnel access air lock passageway from the outside.

The track bay extension consists of a 20-ft by 20-ft by 80-ft long air lock, connected to the track bay compartment by a vertical lift inner door and an airtight seal. The track bay extension is equipped with a motor-operated double swing outer door 16 ft wide by 17 ft 6 in high. The door can also be operated manually and is designed to resist an internal or external load of 40 psf. The outer door closes against a closed cell sponge neoprene closure to provide an airtight seal. The inner vertical lift door bears against a one-piece inflatable seal of reinforced ethylene propylene diene monomer around its perimeter. The entire contact area of the inflatable seal will expand approximately 3/4 in under pressure. The seal material will remain pliable and seal at temperatures of -20°F to 210°F.

Containment integrity for the track bay compartment and extension is provided by an outside double swing door, an inside vertical lift door and personnel doors connected by an airtight access passageway. The track bay compartment (with extension) and its access openings are shown on Figure III-4. Typical door seals for the personnel and equipment doors are shown on Figure VI-18.

Interior doors with air locks are provided in the south wall of the reactor building leading into the turbine room at el 261, as shown on Figure III-4, and at el 340, as shown on Figure III-8. The doors of the air lock have neoprene seals with sealing requirements equivalent to those of the railroad door. Details are shown on Figure VI-19.

Procedures and alarms are used to control access and maintain building integrity. Primary and secondary shielding is discussed in Section XII.

D. CONTAINMENT ISOLATION SYSTEM

1.0 Design Bases

Isolation valves are provided on lines penetrating the drywell and pressure suppression chamber to assure integrity of the containment when required during emergency and post-accident periods. Isolation valves which must be closed to assure containment integrity immediately after a major accident are automatically controlled by the reactor protection system (RPS) described in Section VIII.

The drywell and suppression chamber penetrations are dedicated to specific purposes as shown in Tables VI-1 and VI-2, respectively. The tables list the number, size, and type of penetration associated with each purpose.

<u>Containment isolation valves</u> (also called isolation valves) are defined as any valves which are relied upon to perform a containment isolation function on lines penetrating the primary reactor containment and include all reactor coolant isolation valves and all primary containment isolation valves. Test, vent and drain (TVD) valves located on the containment pressure boundary are containment isolation valves but are not included in the tables of reactor coolant isolation valves or primary containment isolation valves.

<u>Reactor coolant isolation valves</u> are containment isolation valves which are on lines penetrating the primary reactor containment and are connected to the RCS (or a system containing reactor coolant) and function as reactor coolant pressure boundary (RCPB) components. Reactor coolant isolation valves are also primary containment isolation valves.

<u>Primary containment isolation valves</u> are containment isolation valves on lines penetrating the primary reactor containment connecting directly to the free space enclosed by the containment.

Table VI-3a is a listing of all reactor coolant isolation valves, and Table VI-3b lists primary containment isolation valves.

All lines which are part of the RCPB and penetrate the primary reactor containment are provided with redundant isolation valves. As a general rule, one of each pair of isolation valves in series is located inside the containment. The other valve is outside the containment. On the emergency cooling system supply and on the feedwater system where it was necessary to install both valves outside the containment, a guard pipe is installed between the line and the containment vessel penetration sleeve. This sleeve is welded to the body of the first isolation valve outside the containment. This, in effect, extends the containment to include the body of the first isolation valve. For the emergency cooling system supply, the two valve bodies are welded end to end for greater integrity. For the feedwater system, the two valves are separated by a 10-in extension.

Lines which are part of the reactor coolant boundary and may be required to have flow after an accident are provided with check valves. The CRD and liquid poison systems have two check valves in series. One valve is inside the containment. The feedwater system, as described above, has two valves outside the containment, one of which is a check valve.

The cleanup and shutdown cooling systems each have redundant isolation valves with one valve inside the containment. The outer valve on the return to the reactor line is a check valve. Post-accident thermal overpressurization protection is provided for the penetration piping between the isolation valves in the shutdown cooling system.

Instrument lines are provided with redundant valving outside the containment. Automatic flow check valves minimize loss of reactor coolant in the event of an instrument line break.

All external isolation valves are located as close to the containment as possible. Where guard pipes are used between the containment penetration and the line, the outer valve is welded to the guard pipe. For reactor coolant isolation valves on low-temperature lines where no guard pipe is required, the outer valve is welded directly to the penetrations sleeve.

Most lines which connect directly to the containment atmosphere and penetrate the primary reactor containment are provided with redundant isolation valves. Two normally-closed valves outside the containment are provided for systems which are not required to function under accident conditions. Lines which are not equipped with double isolation valves have been determined to be acceptable based upon the fact that the system reliability is not compromised, the system is closed outside containment, and a single active failure can be accommodated with only one isolation valve in the line.

Instrument lines connected to containment atmosphere which penetrate primary containment are provided with two isolation barriers, such as manual valves, caps, or diaphragm assemblies.

Each containment spray line which is required to be open under accident conditions contains a check valve outside the containment. These check valves are installed to minimize bypassing of pressure suppression during the initial pressure transient of the LOCA.

The oxygen sample return line and the nitrogen purge line for the traveling in-core probes use two check valves in series outside the containment. The traveling in-core probe guide tubes use a ball valve and manually-actuated explosive shear valve in series outside containment.

Each line that penetrates primary reactor containment and is neither part of the RCPB nor connected directly to the containment atmosphere, in the case of the drywell cooling and recirculation pump cooling systems, has one isolation valve. These systems circulate cooling water in a closed system into and out of the containment. Each line carrying incoming cooling water is provided with a self-actuating check valve outside the containment. Each line which carries water out of the containment has a MOV which is actuated by remote manual control.

The isolation system for each line is designed to accommodate loss of power to an isolation valve. MOVs (ac or dc) are designed to fail in the mode in which they are when loss of power occurs. Air-operated valves (AOV) fail closed upon loss of power. Different power sources for each valve in series ensure that the isolation function will not be defeated by single failure. Failure of a single power source does not prevent isolation even where a normally open MOV fails open. Isolation is effected either by having a closed piping system which does not communicate with containment atmosphere or by having a redundant separately powered valve in series with the failed valve. In the case of systems which are required to be open following an accident, valves are normally open and fail open, are normally closed but fail open, or are normally closed but fail closed (as is) but have a redundant valve path in parallel that is open and/or fails open.

TABLE VI-3a (Cont'd.)

NOTES:

(4) These valves are provided with a water seal. Valves shall be tested consistent with Appendix J water seal testing requirements. Under 10CFR50, Appendix J, Option B, through RG 1.163, water-sealed CIV test frequency may be set using a performance basis in a manner similar to that described in NEI 94-01, Revision 0, dated 7/26/95, for Type B and Type C test intervals. Leakage rates shall be conservatively limited to 0.5 gpm per nominal inch of valve diameter up to a maximum of 5 gpm.

(5) These valves are tested in accordance with Technical Specification Section 4.2.7.1a.

(6) The self-actuating flow fuse is tested in accordance with Technical Specification Section 4.3.4c.

(7) Two 1" globe valves (38-206 and 208) are provided outside in the seal water (core spray) flow test line and one 3/4" globe valve (38-209) is provided outside in the seal water supply line drain, which also serve as RCS isolation valves.

(8) One 3/4" check valve (38-216) is provided inside primary containment around isolation valve 38-01. This valve is provided with a water seal and tested under the Appendix J program for limited flow in the open direction, and under the IST Program, exercised closed for isolation capability.

(9) Reactor coolant isolation valves are also primary containment isolation valves.

4.0 Tests and Inspections

Each core spray loop was tested initially during preoperational testing with water under full-flow conditions. Data on flows and pressures at various points in the flow lines was obtained. The nozzle spray pattern was observed as far as practical with the reactor head off. Each loop was also operated bypassing the water to the suppression chamber and the corresponding flow and pressure data obtained.

Subsequently, the core spray and topping pumps are periodically operated, and the water pumped from the suppression chamber through the appropriate supply lines to the outer system isolation valve, then returned to the suppression chamber. Flow into the reactor vessel is not attempted since this would introduce relatively impure water into the reactor coolant. Data on the flow rate and pressure at various points for each supply loop are obtained for comparison with the previously established normal conditions. Interlocks are provided such that the valve in the test line cannot be opened unless the motor-operated containment system isolation valves both inside and outside the drywell are closed. These valves cannot be reopened until the test valve is closed. The MOVs on the pump discharge lines to the reactor vessel are periodically opened fully and the time to open is recorded. These valves shall be fully open within 22.5 sec (valve stroke time) after the signal is given to assure that, under accident conditions, the total delay in achieving full core spray flow is less than 37 sec. The safety valves on the core spray lines outside the second system isolation valve are periodically removed and tested for setpoint, as recommended by the ASME Code, Section III-B-1965. These valves are also containment isolation valves and are subject to Appendix J Type B and C testing.

The pumps and valves are tested quarterly by recycling water to the suppression chamber.

During each refueling outage, condensate water is introduced into the pump suction and automatic initiation of the pumps and valves is tested.

At least once per month verification is made that the keep-full system piping is filled with water.

Once each quarter during the scheduled operability test, the system is visually inspected for leakage, and maintenance is performed as required.

For the differential pressure instrumentation that monitors the core spray piping within the reactor vessel, the differential pressure indications are checked once per day, and the instrumentation is tested/calibrated once every three months.

THIS PAGE INTENTIONALLY BLANK

B. CONTAINMENT SPRAY SYSTEM

1.0 Licensing Basis Requirements

The following regulatory documents are applicable to the containment spray system (CSS) and, in general terms, form the basis on which the system is designed and operated.

1.1 10CFR50.49 - Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

An EQ program for electrical equipment has been conducted in accordance with 10CFR50.49. Consequently, electrical equipment important to safety in the CSS system has been qualified to operate in the LOCA environment.

1.2 10CFR50 Appendix A - General Design Criteria for Nuclear Power Plants

The Technical Supplement to Petition for Conversion from Power Operating License to Full Term Operating License covered the Unit 1 positions relative to the General Design Criteria (GDC). Those portions of the documentation that cover both the description of the requirements and NMPC's positions relative to these requirements, as they pertain directly to the CSS system, have been extracted and are shown below:

Criterion 16

Containment Design Reactor containment and associated systems shall be provided to establish an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment, and to assure that the containment design conditions important to safety are not exceeded for as long as postulated accident conditions require.

A pressure suppression containment system consisting of a drywell, suppression chamber (torus), and interconnecting vent piping is the primary containment for the main coolant system. During normal operation, the reactor building, containing the pressure suppression system, provides a secondary containment barrier.

To ensure the integrity of the primary containment, integrated leak tests were performed prior to Station operation and periodically thereafter, as provided in the Technical Specifications. The results demonstrated that the containment met the design leak rate of 0.5 percent per day at a pressure of 35 psig and, therefore, provides an essentially leak-tight barrier. The design basis LOCA was evaluated at the primary containment maximum allowable accident leak rate of 1.9 percent per day at 35 psig. The analysis demonstrates that the offsite

2.0 Design Bases

2.1 Design Basis Functional Requirements

The CSS system shall perform the following functions important to safety in order to prevent containment pressure and temperature from exceeding its design values for reactor coolant system (RCS) leaks up to and including the DBA, double-ended break of a reactor coolant recirculation line:

1. Functional Requirement - Remove energy from the drywell and torus following vessel leaks, up to and including a LOCA, to reduce containment temperature and pressure and maintain them below containment design pressure and temperature limits.

   Basis - A means of removing energy from containment following a LOCA and of transferring energy to the UHS is required by GDC 38 and GDC 44. The CSS system provides the primary means of energy removal from containment after a LOCA.

2. Functional Requirement - Ensure the torus water temperature does not exceed that required to satisfy containment spray and core spray NPSH requirements.

   Basis - Inadequate NPSH can limit the containment spray and containment raw water pump performance and reliability. Without adequate NPSH, the ability of the system to remove energy from containment may be diminished.

3. Functional Requirement - Provide the capability to isolate CSS system piping that penetrates the containment boundary.

   Basis - Unit 1 did not commit to providing isolation valves in the CSS system as would be required to satisfy GDC 56. Containment spray was originally designed as an extension of primary containment. However, Unit 1 has committed to maintaining a water seal in lieu of leak rate testing of the isolation valves.

4. Functional Requirement - The CSS system piping must provide an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment.

   Basis - The CSS system was originally designed as an extension of primary containment. As such, the containment spray piping must satisfy the intent of GDC 16 and provide an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment.

2.2 Controlling Parameters

To meet the design requirements of Section VII-B-2.1, the CSS system must be capable of meeting the following operational requirements:

- CSS pump flow through the drywell sparger nozzles must be ≥3300 gpm.
- CSS pump flow through the torus sparger nozzles must be ≥300 gpm.
- CSS drywell and torus sparger spray droplet size must be ≤1000 microns.
- CSS pump flow in the torus cooling mode must be ≥2800 gpm.
- CSS shell side heat exchanger flow must be ≥3600 gpm (during containment spray).
- CSS pump available NPSH must be ≥34.2 ft for the most restrictive case (least NPSH margin) in which two pumps are operating through separate strainer assemblies at a flow rate of 3759 gpm.
- CSS raw water pump flow, through the heat exchanger tube side, must be ≥3000 gpm.
- CSS raw water pump available NPSH must be ≥31 ft.
- CSS drywell and torus sparger nozzle pressure must be ≥30 psi above containment pressure for a sufficient number of nozzles to achieve minimum required flows.
- CSS spray header pressure must be 110 percent of containment pressure or ≥38.5 psig.
- CSS heat exchangers must be capable of removing at least 120 million Btu/hr, with two containment spray pumps operating and a spray water temperature reduction from 140°F to 100°F.

3.0 System Design

3.1 System Function

The CSS system is an engineered safeguards system designed to prevent overheating and overpressurization of the containment, and to control the pressure suppression chamber water temperature following a design basis LOCA. The system is designed to provide heat removal capabilities for vessel leaks up to and including the DBA, the double-ended break of a reactor recirculation line, without core spray system operation.

3.2 System Design Description

As shown on Figure VII-3, the CSS system is designed with two redundant loops. The primary loop (Loop 11) provides water to the primary or inner drywell sparger and to the torus sparger. The secondary loop (Loop 12) provides water to the secondary or outer drywell sparger and to the torus sparger. The torus sparger is common to both loops. Each of the two loops are cross-connected through the test return lines such that each of the loops can provide flow to both the primary and secondary spargers. Each loop includes two redundant trains and consists of two suction headers, two containment spray pumps, two heat exchangers and the associated containment spray raw water pumps, a common test return line, and associated piping and control valves. All pumps in a loop are powered from the same emergency power bus. Each loop is electrically independent from the other loop.

The CSS system is normally in standby. Containment spray pump operation is automatically initiated by two RPS signals--high drywell pressure and low-low reactor water level. Automatic initiation of the containment spray pumps occurs following the core spray pumps and core spray topping pumps initiation. Upon receipt of an actuating signal, the four containment spray pumps are sequentially started when powered from either the reserve Station service or the diesel generators. Upon containment spray pump initiation, self-actuating check valves open to allow containment spray water to flow through the system. The containment spray raw water pumps must be manually initiated following automatic initiation of the containment spray pumps. A 15-min delay can be tolerated in starting a raw water pump since it provides lake water to a containment spray heat exchanger for the purpose of long-term cooling of the torus water.

Each pump takes suction from the torus through individual suction lines. The water in each suction line flows from the torus through a suction strainer assembly. Two strainers comprise each of two suction strainer assemblies. When two pumps, either 112 and 122, or 111 and 121, are operated, they will take suction from the same suction strainer assembly. The discharge from each pump passes through the shell side of a heat exchanger where it is cooled prior to being distributed to the drywell and torus spray headers. The spraying of the water in the containment increases the heat removal rate, thereby decreasing containment temperature and pressure. The spray headers inside the drywell and torus are arranged to distribute water as uniformly as possible throughout the free volume. The direction of spray from the nozzles is arranged to minimize impact on equipment and allow as much free-fall as possible to maximize steam condensation. In addition, flow from the containment spray pump discharge can be directed to the torus via a 6-in test return line that provides suppression pool cooling.

Each of the containment spray heat exchangers is supplied cooling water from a dedicated containment spray raw water pump. Each containment spray raw water pump takes suction from the condenser circulating water intake tunnel. The pump discharge passes through a duplex strainer prior to entering the tube side of the containment spray heat exchanger. After passing through the heat exchanger and cooling the suppression pool water, the raw water is released to the discharge manifold.

In the event of a total loss of the containment spray primary water source (suppression chamber water below the containment spray pump suction level), raw water pumps 112 and 121 can be aligned to supply the containment spray spargers to provide an alternate source of containment cooling. Likewise, raw water pumps 111 and 122 can be aligned to supply the core spray system.

3.3 System Design

The CSS system was originally designed to operate with Loop 11 and Loop 12 flow paths in the drywell as totally independent redundant systems. However, in order to satisfy 10CFR50 Appendix J, paragraph III.C.3(b) requirements, the current standby configuration of the system provides flow to both primary and secondary spargers, with two pumps including either train 111 or 122 in operation, to form a water seal. This is accomplished by cross-connecting the two trains via the test return line. In this configuration, sufficient header pressures and flows must be provided to meet the Appendix J requirements. Water pressure in the containment spray piping at the drywell and torus spray line penetrations must be at least 110 percent of containment pressure whenever the CSS system is required to spray in the drywell and torus. The calculated peak containment internal pressure is 35 psig, hence, 38.5 psig (3.5 psid) must be maintained in the header to ensure a water seal.

In order to meet the water seal configuration, at least two containment spray pumps are required to operate. Calculation shows that in the limiting case when drywell pressure is 35 psig, the following differential pressures between the sparger header and the drywell would be achieved.

Pumps Operating	Minimum Drywell Sparger Header Pressure (psid)		Minimum Torus Sparger Header Pressure (psid)
	Primary Loop	Secondary Loop	
2 Primary (111 & 112) Separate Strainer Assemblies	50	16	41
2 Secondary (122 & 121) Separate Strainer Assemblies	18	54	43

Spray heat removal effectiveness is a function of droplet size and spray flow rate. The design spray flow requirement to the drywell and torus to remove all decay heat and chemical energy from a 70-percent metal-water reaction was calculated to be 3600 gpm (3300 gpm to the drywell and 300 gpm to the torus). This is the containment spray pump design point. Each pump is rated for 3000 gpm at 375 ft (162 psig). Calculation shows that each pump can deliver sufficient flow under DBA LOCA conditions to meet the minimum required flow. The following shows that the required flows can be met.

	Calculated Flow Rate (gpm)	Required Flow Rate (gpm) (Table XV-32a)
One-Pump Operation (121) Containment Spray Mode	3650	3600
One-Pump Operation (111) Torus Cooling Mode	2850	2800
One-Pump Operation (112) Torus Cooling Mode	2822	2800
One-Pump Operation (121) Torus Cooling Mode	2953	2800
One-Pump Operation (122) Torus Cooling Mode	2816	2800
Two-Pump Operation (111 & 112) Containment Spray Mode Separate Strainer Assemblies	3605 (Pump 111) 3425 (Pump 112)	3000 per pump
Two-Pump Operation (121 & 122) Containment Spray Mode Separate Strainer Assemblies	3438 (Pump 121) 3553 (Pump 122)	3000 per pump

To determine the expected droplet size distribution, tests were performed on spray nozzles similar to those used in the CSS system. The test results show that a droplet size <1000 microns is acceptable. A nozzle pressure differential ≥30 psi is required to achieve the desired droplet size. This requirement is met for the minimum flow required at DBA LOCA conditions as shown above.

Each operating loop, with a total pump flow rate of 6000 gpm, has a heat removal capacity of 120 million Btu/hr with a spray water temperature reduction from 140°F to 100°F as it passes through the heat exchangers. This is the original design basis heat exchanger sizing point. The design basis heat removal requirements associated with a maximum containment spray raw water temperature of 84°F is provided in Section XV-C-5.3. This analysis results in a peak suppression pool temperature of 165°F. The corresponding containment spray heat exchanger K-value in the spray mode is 256 Btu/sec-°F, and in the torus cooling mode is 241 Btu/sec-°F. Therefore, for the conditions specified, the heat exchangers are capable of removing enough heat such that torus and drywell temperature and pressure limits are not exceeded.

The raw water side of the heat exchanger is maintained at a greater pressure than the containment water side to avoid contamination of the environment in the event of a tube leak. Radiation detection alarms are located on the heat exchanger raw water discharge. The containment spray raw water cooling system is considered operable when the pressure on the raw water side of the heat exchanger is greater than 141 psig and when the flow is greater than 3000 gpm. The containment side of the heat exchanger will operate at less than 117 psig, including containment pressure under accident conditions.

NRC Bulletin 96-03 requested implementation of appropriate procedural measures and plant modifications to minimize the potential for clogging of the ECCS suction strainers as a result of debris accumulation from debris generated during a postulated LOCA. Large-capacity ECCS suction strainers have been designed and installed to account for the worst-case generation, transport, and accumulation of post-LOCA debris to assure a sufficient available NPSH to the pumps.

Containment spray pumps NPSH was calculated for the bounding conditions as set forth by Regulatory Guide (RG) 1.1. The conditions that result in the minimum NPSH margin (available NPSH minus required NPSH) was determined to be two operating containment spray pumps drawing suction from the same strainer assembly, less than 15 min after the onset of the LOCA, when torus temperature is 146°F, and containment pressure is 0 psig. These conditions provide the minimum NPSH margin of 1.0 ft, assuring that adequate NPSH will exist for all operating conditions and operating modes.

Containment spray raw water pumps NPSH has been calculated for the limiting conditions of maximum lake water temperature of 83°F and minimum lake water level of 238.5 ft at the screenhouse. The calculated available NPSH for all four pumps at the design flow of 3000 gpm exceeds the required NPSH. Vendor-supplied pump curves indicate that the pumps can operate up to 3600 gpm without exceeding the available NPSH.

The torus cooling mode of operation is used for long-term cooling of the suppression pool. In this mode, all containment spray pump flow is directed to the torus through the test return line. When operating in accordance with the EOPs with only one pump operating, the flow through the heat exchanger is at least 2800 gpm for all pumps.

The piping, heat exchangers, and other equipment are designed for containment pressure and pump shutoff head. The following table summarizes the design pressures of the system's major components.

Equipment	Design Pressure (psig)
Containment spray piping outside drywell	270
Containment spray piping inside drywell	235
Heat exchanger tube side	270
Heat exchanger shell side	220
Raw water piping	300

3.4 Codes and Standards

The piping and valves are designed in accordance with ASA B31.1-1955 Piping Code with certain requirements of the ASME Code Section III-B-1965. The containment spray pump casings and containment spray strainer housings are designed in accordance with ASME Code Section III-1965. The raw water pump casings are designed in accordance with ASME Code Section III-1965, and raw water pump strainer housings are designed in accordance with ASME Code Section VIII. The heat exchangers were designed, fabricated, tested and certified to the 1980 Edition of the ASME Boiler and Pressure Vessel Code Section III (Class 2 for the shell side and Class 3 for the tube side). Valves 80-114 and 80-115 were designed and fabricated in accordance with ASME Code Section III-1977, and tested to ANSI B16.104-76 Class VI for seat leak test. The Mark I Program suction piping is designed in accordance with ASME Code Section III-1977. All electrical power and distribution is designed in accordance with IEEE-279, IEEE-308, IEEE-323, IEEE-336 and IEEE-344 (all 1971 Editions).

No single active failure of any component can prevent the system from fulfilling its design function.

3.5 System Instrumentation

Each CSS system loop has separate and independent pressure and flow indicators. In addition, temperature indications of containment spray water in and out of the containment spray heat exchangers are provided. High temperature alarms are provided for heat exchangers outlet temperatures. Isolation valve control switches and position indicator lights are provided on the main control panel for each isolation valve. Indication of isolation valve position is repeated on the isolation valve mimic on the main control room panel. Each containment spray pump has its own control switch with indicating lights and a motor ammeter on the control room panel. Pressure switches on each loop header are outside the drywell and will indicate low containment spray header pressure if the system has been called upon to operate.

For each line carrying cooling water to the heat exchangers, flow indication is provided on the main control room panel. Each containment spray raw water pump discharge strainer is monitored for plugging by differential pressure switches. Heat exchanger cooling water effluent is monitored for high radiation before discharging to the tunnel. These alarms are sounded on the control room annunciators.

All sensing instrumentation is in areas accessible during Station operation and is provided with suitable valving for in-place testing at any time.

3.6 System Design Features

The CSS system is designed to provide a high degree of reliability in meeting the design functional requirements. The specific features of the system that assist in achieving this reliability are:

- Each loop is designed with heat removal capacity well in excess of the expected maximum.

- The two loops are sufficiently separated to minimize the possibility of coincident active failures.

- The system is designed to meet any credible seismic force as discussed in Section XVI-C.

- Automatic initiation of all four pumps of the CSS system assures that the containment will not be overpressurized.

- Electric power for the system is available from Station reserve power supplies or from either of two emergency diesel generators.

- The raw water side of the heat exchangers is operated at a higher pressure than the containment water side to prevent out-leakage. Radiation monitors are installed to detect such leakage if it should occur when the raw water pumps are not operating.

- The delay between the time of the accident and full spray operation is less than a minute. This includes signal time for pump start, time required to get pumps up to speed, and diesel generator starting time. Even assuming no core spray and the maximum metal-water reaction, this delay could be as much as 15 min without loss of containment integrity.

- Low pressure alarms are provided in the containment spray piping outside the drywell to signal the Operator if spray water is not reaching the upper nozzles due to a restriction or line break.

- Remotely-operated valves are located on the containment spray bypass line to the waste disposal building to provide isolation of a potential pathway for the transfer of radioactivity, should a LOCA occur during suppression chamber pumpdown.

- Raw lake water can be supplied to the containment spray nozzles as an alternate source of containment cooling.

4.0 Design Performance Evaluation

The performance of the CSS system is determined through application of the 10CFR50 Appendix K evaluation. The SAFER/GESTR-LOCA Analysis was used to evaluate the ECCS (including CSS system) performance during a postulated LOCA. The details of the analysis are discussed in Chapter XV.

4.1 System Performance Analyses

Analysis has been performed which supports the adequacy of the CSS system in maintaining containment pressure and temperature below the design values following a design basis LOCA. The Section XV-C-5.3 design basis reconstitution suppression chamber heatup analysis verifies that the containment design basis heat removal requirements are satisfied at the maximum containment spray raw water (lake water) temperature of 84°F. Each of the two containment spray loops was originally sized to remove all decay heat and chemical energy from a 70-percent metal-water reaction. With a maximum possible reaction of 27 percent, the analysis shows that more than sufficient heat removal capacity exists in the system. This analysis requires the CSS system to satisfy the analysis input assumptions discussed in Section XV-C-5.3.2.

To determine proper distribution of containment spray through the nozzles, testing was performed on a sample spray nozzle of the size and type used in containment spray. Water was run through the nozzle at various pressures from 10 psig to 100 psig, and spray pattern and spray particle fineness was observed. Pressure drops of 80 psig and 30 psig represent the original system configuration pressure conditions for two-pump operation and one-pump operation, respectively. The particle sizes for the two-pump operation are in the range of 10 to 400 microns. For one-pump operation, particle sizes range from 500 to 1000 microns.

4.2 System Response

After an initiation signal is received, there is a time delay of 20 sec to allow the core spray and core spray topping pumps to start. At the 25-sec mark, containment spray pumps 111 and 121 will receive a start signal, and at 30 sec, containment spray pumps 112 and 122 will receive their start signal. If the core spray and core spray topping pumps do not start, a set of backup timer contacts will start the containment spray start sequence in 50 sec to allow the core spray starting logic to be initiated a second time. This will cause pumps 111 and 121 to start at 55 sec, and pumps 112 and 122 to start in 60 sec. This interlock, delaying the starting of the containment spray pumps, is provided to avoid overloading of the diesel generators.

4.3 Interdependency With Other Engineered Safeguards Systems

The CSS system is used in conjunction with the core spray system described in Section VII-A. The core spray system removes heat from the core in the event of a LOCA. In the heat removal process, the core spray water is converted to steam, which is then released to the containment. The containment sprays condense the steam in the drywell and remove heat from the containment vessels through heat exchangers.

The raw water pumps are interconnected with the core spray system and the containment spray loops to provide an emergency source of water. Raw water pump 112 can supply water to containment spray train 122, and raw water pump 121 can supply water to containment spray train 111. The motor-operated valves between raw water and containment spray water are interlocked with the heat exchanger raw water discharge valves. If one valve is open, the other must be closed. In addition, raw water pump 111 is connected to core spray pump train 11 and raw water pump 122 is connected to core spray pump train 12. The air-operated valves located on the connection between the two systems are also interlocked with the raw water discharge valves.

The following systems must be in operation to support the CSS system:

- Instrument air must be operational to permit operation of the containment spray inlet isolation valves and bypass blocking valves.

- 4.16-kV and 600-V ac power distribution systems are required to provide power to the containment spray pumps, raw water pumps, and isolation valves.

- The RPS system is required to provide automatic initiation signals to the containment spray pumps and waste disposal isolation valves.

- The process radiation monitoring system must be operational to alert Operators of leakage of contamination into the raw water system due to heat exchanger leaks.

5.0 System Operation

5.1 Limiting Conditions for Operation

The limiting conditions for operation (LCO) pertaining to the CSS system are listed in Section 3.3.7 of the Unit 1 Technical Specifications. Other LCOs associated with generic equipment and programs are also applicable and are listed in other sections. The intent of the LCOs is to ensure that both loops of the system are operable when fuel is in the vessel and the reactor coolant temperature is greater than 215°F. One containment spray loop will provide the required containment cooling and pressure reduction for the DBA. However, to provide sufficient redundancy to satisfy the single failure criterion, both loops of the CSS system are required to be operable.

If a redundant component in one loop of containment spray or its associated raw water loop becomes inoperable, operation may continue provided the component is returned to an operable condition within 15 days. If a redundant component in both containment spray loops or their associated raw water loops becomes inoperable, operation may continue provided the component is returned to service within 7 days. In both cases, additional surveillance requirements are imposed. If a containment spray loop or its associated raw water loop becomes inoperable and all the components of the other loop are operable, the reactor may remain in operation for a period not to exceed 7 days.

If the LCOs are not met, then a normal orderly shutdown shall be initiated within 1 hr and the reactor shall be placed in cold shutdown within 10 hr.

6.0 Tests and Inspection

To ensure that the performance of the CSS system continues to meet the design requirements, the following surveillance tests and inservice inspections requirements must be satisfied.

- ASME Section XI inservice examination of components
- ASME Section XI inservice testing of pumps and valves
- ASME Section XI system pressure tests
- Appendix J leak rate testing
- System operability surveillance tests

Several programs have been established to meet the requirements of ASME Section XI and Appendix J. These include: 1) NMP1 ISI Program Plan, 2) Component Support Third Ten Year Internal Inservice Inspection Plan, 3) Third Ten Year Testing Program Plan, 4) Third Ten Year Interval Pump and Valve Inservice Testing Program Plan, and 5) Appendix J Testing Program Plan.

The following CSS system tests, inspections, and surveillances are conducted to meet the requirements.

- Containment Spray System Quarterly Operability Test - verifies valve, pump and total system operability and verifies operation of valve limit switches and solenoid-operated valves

- Containment Spray Header and Nozzle Air Flow Test - verifies header, header check valve, and nozzle operability

- Containment Spray System Suction Valve Operability Test - verifies valve operability

- Containment Spray Valve Remote Position Indicator Verification - verifies operability of indicators

- Containment Spray Pressure Test - verifies integrity of the system by VT-2 visual examination

- Containment Spray Raw Water Pressure Test - verifies integrity of the system by VT-2 visual examination

- Containment Spray Raw Water System Intertie Valve Operability Test - verifies the operability of the containment spray/core spray intertie check valves

Testing of the initiating instrumentation and controls portion of the system is discussed in Section VIII. The emergency power system, which supplies electrical power to containment spray in the event that offsite power is unavailable, is tested as described in Section IX. Visual inspections of all system components located outside the drywell can be made at any time during power operation. Components inside the drywell can be visually inspected only during periods of access to the drywell.

I. HIGH-PRESSURE COOLANT INJECTION

1.0 Design Bases

The high-pressure coolant injection (HPCI) system is an operating mode of the feedwater system available in the event of a small reactor coolant line break which exceeds the capability of the CRD pumps (0.003 ft^2). A single train of HPCI, along with one emergency cooling system, has the capability of keeping the swollen reactor coolant level above the top of active fuel (TAF) for small reactor coolant boundary breaks up to 0.063 ft^2 for at least 1000 sec. The HPCI system, with one of the two emergency cooling systems and two core spray systems, will provide core cooling for the complete spectrum of break sizes up to the maximum design basis recirculation discharge line break (5.446 ft^2). Its primary purpose is to:

1. Provide adequate cooling of the reactor core under abnormal and accident conditions.

2. Remove the heat from radioactive decay and residual heat from the reactor core at such a rate that fuel clad melting would be prevented.

3. Provide for continuity of core cooling over the complete range of postulated break sizes in the primary system process barrier.

HPCI is not an engineered safeguards system and is not considered in any LOCA analyses. It is discussed in this section because of its capability to provide makeup water at reactor operating pressure.

2.0 System Design

The HPCI system utilizes the two condensate storage tanks (CST), the main condenser hotwell, two condensate pumps, condensate filters, condensate demineralizers, two feedwater booster pumps, feedwater heaters, two motor-driven feedwater pumps, an integrated control system and all associated piping and valves. The system is capable of delivering 6840 gpm into the reactor vessel at reactor pressure when using two trains of feedwater pumps. However, the design analyses assume a single train of HPCI is operating. The condensate and feedwater booster pumps are capable of supplying the required 3420 gpm at approximately reactor pressures up to 293 psig*. Above 293 psig, a motor-driven feedwater pump is necessary to provide the required flow rate.

The feedwater system pumps have recirculation lines with air-operated flow control valves to prevent the pumps from operating against a closed system. In the event of loss of air pressure, these valves open, recycling part of the HPCI flow to the hotwell. HPCI flow would be reduced to approximately 2600 gpm at a reactor pressure of 1030 psig and 3420 gpm at a reactor pressure of 715 psig for a loss of instrument air event.

Condensate inventory is maintained at an available minimum volume of 180,000 gal.

3.0 Design Evaluation

During a LOCA within the drywell, high drywell pressure due to a line break will cause a reactor scram. This automatic scram will cause a turbine trip after a 5-sec delay. Feedwater flow would be available for considerable time from the shaft-driven feedwater pump. The shaft-driven feedwater pump would coast down while the electric motor-driven condensate pumps and feedwater booster pumps would continue to operate. The coastdown time to reach 3420 gpm delivery to the core is approximately 3.2 min (Figure VII-17), since both the condensate and feedwater booster pumps will continue to operate on offsite power. The curve on Figure VII-17 shows how flow from the shaft-driven feedwater pump decreases as the main turbine is coasting down following a trip. The curve is a representation of the feedwater capability of the shaft-driven pump after a turbine trip at a set of finite conditions. The margin to reach the 3.2-min coastdown time is governed by the turbine coastdown rate and the shaft-driven pump, not system resistance such as flow control valve (FCV) position.

The turbine trip will signal the motor-driven feedwater pump to start. The signal will be simultaneous with the start of the shaft pump coastdown. The motor-driven feedwater pump will be up to speed and capable of supplying 3420 gpm in about 10 sec. As a backup, low reactor water level will also signal the motor-driven pump to start. The initiation signal transfers control from the normal feedwater to the HPCI instrumentation

* 293 psig provides for system pump degradation of 10 percent.

and controller which has been continuously tracking the normal feedwater control signal. To maximize the NPSH to the motor-driven feedwater pumps when operating in HPCI mode, #11 flow control valve (FCV11) for #11 motor-driven feedwater pump (FWP11) does not open if there is sufficient total feedwater flow into the reactor. FCV11 remains closed until total feedwater flow into the reactor drops below 4.5×10^6 lbm/hr (9000 gpm). This logic is bypassed if FWP12 is not running or locked out. In addition, the level setpoint setdown controller (ID66B) limits the controller output to 60 percent of maximum following HPCI actuation. Feedwater flow will continue to be provided by the shaft-driven feedwater pump during turbine coastdown. Thus, there will be a continuous supply of feedwater to the reactor.

The HPCI single element control system will attempt to maintain reactor vessel water level at 65 in or 72 in (depending upon which pump, 11 or 12, respectively, is in service) with a design basis feedwater flow of 3420 gpm.

A sustained high reactor water level RPS signal coincident with an open feedwater flow control valve will selectively trip the associated feedwater pump. The clutch of the shaft-driven pump will also be disengaged immediately upon high reactor water level. Independent of the original high water level trip installed to meet NUREG-0737 commitments, a nonselective backup trip of the motor-driven feedwater pumps will be actuated if reactor water level remains high.

Should the reactor water level reach the low level scram setpoint, the motor-driven pump that tripped on high reactor water level will restart. Necessary feedwater pump recirculation is provided to allow for continued pump operation with the FCV closed.

As feedwater is pumped out of the condenser hotwell, through the selected equipment of the condensate and feedwater systems and into the reactor, the condenser hotwell level will fall. Since condensed steam from the turbine no longer replenishes the

THIS PAGE INTENTIONALLY BLANK

condenser hotwell, condensate will be transferred from the CSTs to the hotwell for makeup.

The FWS system pumps operate on 4160 V. When the plant is in operation, the power is supplied from the main generator through the Station service transformer when the generator is on-line and connected to the grid. When the main generator is off-line, the feedwater pumps are supplied with normal offsite power from the 115 kV system through the reserve transformers. If a HPCI initiation signal should occur, all HPCI/FWS system pumps would start immediately with two feedwater pump trains available for HPCI injection using the single-element feedwater control system for reactor vessel level control. If a major power disturbance were to occur that resulted in loss of the 115-kV power supply to the Nine Mile Point 115-kV bus, power would be restored from a generator located at the Bennetts Bridge Hydro Station. This generator would have the capacity of supplying approximately 6,000 kVA which is sufficient to operate one train of HPCI/FWS system pumps. If HPCI initiation were to occur, the preferred feedwater train pumps (feedwater pump 12, feedwater booster pump 13, condensate pump 13) would start. The nonpreferred train pumps would be electrically locked out on a LOOP and not start until the Operator manually reset the lockout by placing the backup pump control switch in the trip or close position. If a preferred pump train pump control switch had been manually locked out prior to the LOOP, it would remain locked out and the nonpreferred train backup pump would automatically start on HPCI initiation. If both the preferred and backup pumps are running, the preferred pump would remain in service and the backup pump will trip. The use of a Bennetts Bridge hydro generator, while not equivalent to an onsite emergency power source, provides a highly reliable alternate offsite power supply for the HPCI function of the FWS system.

4.0 Tests and Inspections

Tests and inspections of the various components are described in Section XI - Steam-to-Power Conversion.

J. REFERENCES

1. General Electric Standard Application for Reactor Fuel, NEDE-24011-P-A-15, September 2005.

2. R. D. Ackley, R. E. Adams, and W. E. Browning, Jr., "Removal of Radioactive Methyl Iodide from Steam Air Systems," ORNL-4040, January 1967.

3. "Connecticut Yankee Charcoal Filter Tests," CYAP-101, December 1966.

4. R. D. Ackley et al, op cit.

5. Refer to (4), p VII-49.

6. General Electric Report NEDO-10527, "Rod Drop Accident Analysis for Large Boiling Water Reactors," March 1972.

fuel damage from single Operator errors or equipment malfunctions, and provides an indication of the bulk thermal power level of the reactor in the power range.

The TIP may be inserted in the core to get an axial flux distribution at any of the fixed LPRM radial locations. The information obtained from the TIP system is used to calibrate the LPRMs.

1.1.1 Source Range Monitors

The SRM is a special fission detector. It is mounted on a traversing mechanism so that it can be retracted from the core as reactor power level increases, so that the neutron flux is not beyond its range. The signal from the detector is a series of pulses with random arrival times. The average frequency of pulses, counts/second, is proportional to the neutron flux to which the detector is exposed.

There are four lighted SRM channels on the control room console and two stop push buttons for detector position control, which is shared with IRMs. Each channel consists of a detector, pulse preamplifier, a main amplifier and power supply drawer called a SRM, a remote period meter, and a remote log count rate meter. Figure VIII-6 is a block diagram showing one of the four SRM detectors provided.

Figure VIII-7 presents the core locations of the four neutron-sensitive SRM (fission) chambers. A background neutron flux level is provided by reinserted fuel in the core; therefore, no external sources are required.

Count rate and reactor period for each SRM monitor are indicated on the Operator's console. One recorder is provided to record count rate for all SRM channels.

Trip functions on each SRM monitor provide for the following:

1. Upscale high-count-rate interlock to block control rod withdrawal in the startup mode.

2. Monitor inoperative interlock to block control rod withdrawal in the startup mode.

3. Downscale intermediate-count-rate level interlock to bypass a position switch on the detector retraction mechanism, which blocks control rod withdrawal in the

startup mode unless the detectors are inserted to the startup position. The bypass permits control rod withdrawal with the detector withdrawn as long as a count rate above 100 counts per second is maintained.

4. Short-period alarm.

5. Upscale high-count-rate scram (with keylock switches in noncoincident logic position) used for fuel loading and shutdown margin (SDM) demonstration.

6. Downscale, first-count-rate level alarm.

A selector bypass switch located on the Operator's console makes it possible to bypass all trip functions of one of the four SRM monitors for maintenance.

1.1.2 Intermediate Range Monitors

A block diagram of one of the eight IRM monitors is shown on Figure VIII-8. Each monitor consists of a miniature detector, signal conditioning equipment located in the reactor building (preamplifier), electronic signal conditioning equipment (linear amplifier) and trip units located in the control room, and readout instruments located on the Operator's console.

Figure VIII-9 presents the core locations of the eight detectors. Four recorders also provide a record of neutron flux for each monitor. These recorders also monitor neutron flux level from the power range instruments. A range switch is provided on the console for each of the eight IRM monitors. These manually-operated range switches, capable of 12 positions but penned for a maximum of 9 at any one time, permit the Reactor Operator (RO) to keep the output signal from each of the eight channels between the high- and low-level trip setpoints during controlled approach to power. Operation in range 10 unbypasses the low reactor pressure signal input to the vessel isolation circuitry to facilitate APRM overlap. In order to preclude inadvertent MSIV isolation during range switch operation, IRM range 10 selection requires the Operator to pull the range switch handle up and turn the switch. Since each switch position reduces the meter reading for a given monitor output signal by the square root of 10, the useful range of the IRM system spans five decades.

Trip functions on each IRM monitor provide for the following:

1. Upscale neutron flux level scram. As shown on Figure VIII-9, the trips of four of the IRM monitors are incorporated in logic channel 11, and the trips of the other four IRM monitors are incorporated in logic channel 12.

2. Monitor inoperative scram and interlock to block control rod withdrawal in the startup mode.

3. Upscale neutron flux level interlock to block control rod withdrawal in the startup mode. This requires the Operator to select the next higher IRM range in order to continue control rod withdrawal.

4. Downscale neutron flux level interlock to block control rod withdrawal in the startup mode. This interlock is bypassed by the range selector switch in the lowest range to permit startup.

A position switch on the detector retraction mechanism blocks control rod withdrawal in the startup mode unless the detectors are inserted to the startup position.

Two selector bypass switches located on the Operator's console make it possible to bypass all trip functions of one IRM monitor in each of the protective system logic channels for maintenance.

1.1.3 Local Power Range Monitors

The LPRM system consists of miniature detectors located within the core and electronic signal conditioning equipment (linear amplifiers) located in the control room.

Figure VIII-10 presents the core locations of the 30 LPRM detector strings. Each LPRM string contains four miniature fission chambers which are spaced at 3-ft intervals. When installed in the core, the top and bottom chambers are located 1.5 ft from the core boundaries, thereby providing uniform coverage of the axial dimension. Also included in each LPRM string is a calibration tube which accepts the TIP used to measure the axial flux distribution and calibrate the LPRM system.

Figure VIII-11 illustrates the location of the LPRM detectors with respect to the lattice.

A typical LPRM is shown on the LPRM and APRM Block Diagram, Figure VIII-12.

Each LPRM flux level is indicated on the control rod position panel in the control room. The indicators on the panel are located in the same relative position to control rod position indicators as the detectors are located to the control rods in the core. An indicating light adjacent to the indicator provides high- and low-neutron flux alarms. The Station data-logging computer continuously monitors the LPRM outputs and provides high and low alarms and a periodic log of core neutron flux level. A malfunction of the detector, interconnecting cable or amplifier in any LPRM monitor will result in a failure that will be detected by the data logger.

1.1.4 Average Power Range Monitors

The APRM system consists of electronic equipment which averages the output signals from selected groups of LPRM flux amplifiers. Figure VIII-13 illustrates the APRM system, and Figure VIII-12 is a block diagram of a single APRM monitor. There are eight APRMs, each averaging the output signals from eight LPRM flux amplifiers. Average power as measured by each APRM is recorded on recorders also used for IRM monitors.

Trip functions on each APRM monitor provide for the following:

1. Upscale neutron flux level and monitor inoperative scram (one in each logic channel).

2. Upscale neutron flux level interlock to block control rod withdrawal. The trip setpoint is automatically varied with recirculation flow as shown on Figure VIII-14. The APRM flow control trip reference (FCTR) card provides a means for adjusting the trip setpoint on the upscale "Rod Withdrawal and Flow Increase" block. The operating point at which this block occurs is a function of recirculation flow and reactor power level. The recirculation flow signal is obtained from the "flow summer." There are five recirculation pumps. The flow from each individual pump is measured by means of a flow nozzle and differential pressure transmitter. The square root converter changes the differential pressure signal into a signal proportional to flow. The five signals are summed in the "flow summer" to obtain total reactor recirculation flow. For purposes of redundancy and to

preserve the dual bus RPS configuration, the whole flow measurement system (except for the flow nozzle) is duplicated.

The output of the "flow summer" feeds a "flow converter," which in turn feeds to the FCTR card in the associated APRM (total of four in each safety channel). The resultant logic of the trip unit initiating "rod withdrawal and flow increase" block is depicted on Figure VIII-14. There are two independent flow converter units. Each of them provides the trip bias signals to four APRM channels.

3. Downscale neutron flux level and monitor inoperative are interlocked to block control rod withdrawal in the

THIS PAGE INTENTIONALLY BLANK

Containment Suppression (Torus) Temperature Monitors

Temperature sensors allow monitoring of the torus bulk temperature. A dual channel is used. Each channel is independent of the other and contains 12 water temperature sensors (RTDs). A microprocessor analyzes the incoming signals from the RTDs to supply a bulk temperature to a recorder in the auxiliary control room and a dial meter in the control room.

2.2 Evaluation

2.2.1 Nonnuclear Process Instruments in Protective System

The pressure and level analog transmitters and switches used in the protective system are high-quality industrial devices. Redundancy is adequate and there is a sufficient number of sensing lines so that plugging of a line will not cause a failure to scram. The sensors are arranged so that they may be individually actuated with a test signal to initiate a half scram. The use of analog transmitter/trip devices allows the primary sensor to be calibrated once per operating cycle, thus reducing the amount of time required to functionally test or calibrate the safety trip points and the amount of time the Station is in a half-scram mode.

2.2.2 Nonnuclear Process Instruments in Regulating Systems

The level and flow transmitters used in the feedwater control system are high-quality industrial devices which have an excellent performance history. The feedwater control system is independent of the level scram system. A failure in the level control which causes the water level to go out of limits will in no way influence the level signals into the RPS.

The feedwater control system is a dynamic system and malfunctions normally become self evident. The readings can at all times be cross compared with the other level measurements.

2.2.3 Other Nonnuclear Process Instruments

Thermocouples are installed on the reactor vessel to monitor differential heating and cooling of the vessel. The limiting rates of temperature change are related to the temperature observations from the temperature differential across the flange and a selected critical point. Redundant thermocouples are installed and it is expected that the failures that do occur will never deprive the Operator of adequate information to heat or cool the reactor vessel at a prudent rate. During equilibrium conditions, either hot or cold, all the thermocouples monitor approximately the same temperature. This fact is used to detect abnormalities among the thermocouples.

The vessel flange leak detection system gives immediate qualitative information about a leak sensed by level and pressure buildup in a sensing chamber. Quantitative information as to the leak rate gives the Operator the information necessary for a prudent decision regarding repair. Other vessel level and pressure instrumentation used are of the same quality found in the previously discussed sections.

3.0 Radioactivity Instrumentation

3.1 Design Bases

3.1.1 Radiation Monitors in Protective Systems

Main Steam Line Monitor

The MSL monitor, shown on Figure VIII-22, provides for continuous monitoring of each primary steam line to permit the prompt indication of gross release of fission products from the fuel to the reactor primary coolant. The monitoring system is capable of isolating the mechanical vacuum pump if activity levels in the primary steam lines indicate that such action is required.

A gross increase in the gamma radioactivity in the steam line above the normal N-16 and O-19 activity is indicative of a gross release of fission products from failed fuel. Four channels of instrumentation are provided to monitor this activity. The detectors are ionization chambers mounted two each adjacent to two of the MSLs upstream of the outer isolation valves at the drywell penetration. Each detector is connected to a logarithmic amplifier. Each amplifier is equipped with an upscale trip which is connected to the logic of the RPS to isolate the mechanical vacuum pump on activities up to 1.5 x full power background[2]. Each channel is indicated continuously, logged on a computer, and alarmed in the control room.

Reactor Building Ventilation Monitor

Monitoring of gross gamma radiation is provided for the reactor building ventilation with two detectors located near the exhaust plenum upstream of the ventilation system isolation valve (Figure VIII-23). The amplifiers associated with the detectors are logarithmic and cover a range of 0.1 to 1000 mr/hr. The amplifiers and detectors are identical to those used for the area radiation monitoring system (ARMS) described in Section XII-B.2.0. The output of each monitor is indicated in the control room.

When the radiation level in the reactor building exhaust reaches a preset level, the ventilation isolation valves close, the normal ventilation fans are tripped, the emergency ventilation fans are started and the emergency ventilation system is placed in operation. The logic is such that one-out-of-two upscale signals will initiate these functions.

Air Ejector Offgas Monitor

The air ejector offgas monitoring system, shown on Figure VIII-24, continuously monitors the radioactivity level of the effluent gases removed from the main condenser by the steam jet air ejector (SJAE) system.

Two channels of instrumentation are provided. A channel consists of an ionization chamber, a six-decade logarithmic amplifier, and a shared two-pen recorder. The logarithmic amplifier is equipped with upscale trip and downscale alarm.

In normal operation, a sample of gas is drawn from the offgas line into a special section of pipe where it is seen by the ionization chambers. The sample is returned to the condenser, the low pressure point in the system. The holdup time in the sample line allows for approximately 2 min delay of the N-16 and 0-19 so that the activity of the isotopes signaling the presence of a ruptured fuel element is not masked. The output of each channel is recorded continuously on one pen of a two-pen recorder. The other pen is used by one channel of the stack gas monitor. Two such recorders are provided. A continuous recording of offgas flow and sample flow is also provided in the control room. Low sample flow is annunciated.

When the radiation level of the offgas exceeds the maximum offgas vent release rate, control action is initiated to close the offgas isolation valve immediately. A holdup volume in the offgas line after the sample point provides a 30-min delay after the high radiation signal before the radioactivity passes the downstream isolation valve. Therefore, automatic isolation occurring up to 30 min after the high radiation signal prevents highly radioactive materials from being discharged. The system includes three trips; one downscale, one high and one high-high. The downscale and high-high trips are initiated by the radiation monitor itself while the high alarm is initiated by the recorder. A downscale trip gives warning of instrument malfunction. The two channels are so arranged that they operate independently of each other. The logic is so arranged that a closure of the offgas line is initiated by two high-high level signals, or an upscale in combination with a downscale.

Means are provided to take routine grab samples of the offgas so that the offgas monitors can be calibrated.

Emergency Condenser Vent Radiation Monitor (Figure VIII-25)

Monitoring of gross radiation is provided for each EC vent line with two detectors. The amplifiers associated with the detectors are logarithmic with a range of 0.1 to 1000 mr/hr. The detectors are identical to those used for the ARMS. The output of each monitor is indicated in the control room. When the gross activity in a condenser vent line reaches a preset level during system operation, indicating tube leaks in the EC, an alarm is sounded in the control room. Operator action is required to isolate one set of emergency cooling condensers from the rest of the primary system. Isolation of the EC loop is initiated manually.

3.1.2 Other Radiation Monitors (Figures VIII-26 and VIII-26a)

Stack Effluent Monitors

1. OGESMS

The offgas effluent stack monitoring system (OGESMS) stack monitor continuously monitors the activity of the gas released through the stack. A sample is collected by an isokinetic probe located about ten stack diameters above the highest point at which gases enter the stack. The sample is passed through a particulate filter and a halogen filter before being introduced to four scintillation detectors monitoring the stack gas sample. The sample of monitored gas is pumped back into the stack.

Two of the detectors are connected to a seven-decade log count rate meter, and are calibrated to monitor radiation in the 10^{-7} uCi/cc to 1 uCi/cc range. The remaining two detectors are connected to a five-decade meter and are calibrated to monitor radiation in the 10^{-7} uCi/cc to 10^{-2} uCi/cc range. The lower range detectors meet the lower limit of detection (LLD) requirement in the Offsite Dose Calculation Manual. The filters are removed periodically and analyzed for particulate and halogen activity. The flow of gas through the sampler is indicated and alarmed on low flow to indicate a failure of the pump or a stoppage in the filters. An installed spare pump is provided for reliability of the system.

If high radiation is sensed when this monitor is selected, the monitor sends a signal to isolate the drywell and suppression chamber vent and purge valves.

If the stack effluent monitor is inoperable, effluent sampling is performed in accordance with the Offsite Dose Calculation Manual using auxiliary sampling equipment and approved procedures.

2. RAGEMS

The radioactive gaseous effluent monitoring system (RAGEMS) was designed to provide continuous noble gas monitoring of Unit 1 stack effluents during normal or accident conditions. This system is no longer required for monitoring, but provides an auxiliary sampling location for use when OGESMS auxiliary sample points cannot be used. When RAGEMS is selected, operation of the control room selector switch will cause containment vent and purge isolation.

RAGEMS has the capability to continuously monitor noble gas activity released through the stack.

A sample is collected by an isokinetic probe located in the stack. The sample is passed through a particulate and iodine filter and then into the noble gas unit for sampling. Particulate and iodine filters are counted manually in the onsite laboratory in accordance with plant procedures. The sample of monitored gas is pumped back into the stack.

The range of the noble gas monitor is 1.0E-5 to 2.0E5 µCi/cc.

If high radiation is sensed and RAGEMS is selected, the monitor sends a signal to isolate the drywell and suppression chamber vent and purge valves.

Radwaste System Liquid Effluent Monitor

The radwaste system liquid effluent monitor provides a radiation level indication of the radwaste system liquid discharges. The monitor consists of a gamma-sensitive scintillation detector mounted in a shield which surrounds the pipe containing the liquid being monitored. The sensitivity of the monitor can be adjusted up to a factor of 100 from 10-5 to 10-3 uc/ml for 5 cps.

The scintillation detector is connected to a seven-decade log count rate meter which is equipped with an upscale trip for high-level alarm. The log count rate meter also provides a level signal to the Station computer.

Reactor Building Cooling Water Monitor

The reactor building cooling water system return line is continuously monitored for radioactivity concentration levels to

29. NMPC letter to the NRC, NMP1L 0851, dated August 23, 1994, documenting commitment change regarding drywell water level recorder.

30. NRC (Office of Nuclear Reactor Regulation) letter to NMPC, dated October 26, 1994, "Proposed Deletion of Commitment to Install Drywell Level Strip-Chart Recorder for Nine Mile Point Nuclear Station Unit 1."

31. General Electric Company Nuclear Energy Report, GENE B2400005-01-01, "Nine Mile Point 1 Relief Valve Setpoint Tolerance Relaxation Evaluation," March 1999.

32. General Electric Company, GENE J11-03433-16-01-00, "Pressure Regulator Out-of-Service Calculations for Nine Mile Point Unit 1 Cycle 14," March 2001.

33. General Electric Standard Application for Reactor Fuel, NEDE-24011-P-A (latest approved revision).

34. NRC (Office of Nuclear Reactor Regulation) letter to Nine Mile Point Nuclear Station, LLC, dated September 11, 2002, "Nine Mile Point Nuclear Station, Unit No. 1 - Use of the Offgas Effluent Stack Monitoring System to Meet Regulatory Guide 1.97, Revision 2, and NUREG-0737 Guidance (TAC No. MB2443)."

35. NMPNS letter to the NRC, NMP1L 1828, dated April 19, 2004, "License Amendment Request Pursuant to 10CFR50.90: Revision of Intermediate Range Monitor Surveillance Frequency and Relocation of Selected Instrumentation Requirements to a Licensee-Controlled Document."

36. NRC (Office of Nuclear Reactor Regulation) letter to NMPNS, dated January 25, 2005, "Nine Mile Point Nuclear Station, Unit No. 1 - Issuance of Amendment Re: Intermediate Range Monitor and Control Rod Withdrawal Block Instrumentation (TAC No. MC2734)."

37. General Electric Company, SIL-42, "RPV Head Flange Leakage Monitoring System," December 1973.

38. NRC (Office of Nuclear Reactor Regulation) letter to NMPNS, dated October 2, 2006, "Nine Mile Point Nuclear Station, Unit No. 1 - Issuance of Amendment Re: Application for Technical Specification Improvement to Eliminate Requirements for the Hydrogen Monitors Using the

Consolidated Line Item Improvement Process (TAC No. MD0031)."

TABLE VIII-3

TYPE AND INSTRUMENT CATEGORY FOR UNIT 1 RG 1.97 VARIABLES

Type →	EOP	B			C			D			E		
VARIABLE Category →	1	1	2	3	1	2	3	1	2	3	1	2	3
1. Reactor Power - APRM (Note 21)	X	X											
2. Coolant Level in Reactor Vessel	X	X											
3. Reactor Coolant System Pressure (Reactor Vessel)	X	X			X								
4. Suppression Pool (Torus) Water Temperature (Note 20)	X								X				
5. Suppression Pool (Torus) Water Level	X				X				X				
6. Drywell Ambient Temperature (Note 20)	X								X				
7. Drywell Pressure	X	X			X				X				
8. Torus Airspace Pressure	X	X											
9. Containment H_2 Concentration (Note 25)	X				X								
10. Containment O_2 Concentration (Note 26)	X				X								
11. Drywell Water Level (Note 23)	X												
12. Neutron Flux-IRM (Note 22)				X									
13. Neutron Flux-SRM (Note 22)				X									
14. Control Rod Position				X									
15. Reactor Coolant System Soluble Boron Concentration (Note 1)													
16. Core Thermocouple (Note 2)													
17. Drywell Floor and Equipment Drain Sump Water Level (Notes 3 and 4)				X			X						
18. Primary Containment Isolation Valve Position		X											

TABLE VIII-3 (Cont'd.)

Type →	EOP	B			C			D			E		
VARIABLE Category →	1	1	2	3	1	2	3	1	2	3	1	2	3
19. Reactor Coolant System Radioactivity Concentration (Note 6)													
20. Analysis of Primary Coolant (Gamma Spectrum) (Note 7)													
21. Primary Containment Area High Range Radiation Level							X				X		
22. Containment Effluent Radioactivity; Noble Gases (Note 8)													
23. Radiation Exposure Rate (areas adjacent to primary containment) (Note 9)							X						X
24. Effluent Radioactivity; Noble Gases (from areas adjacent to primary containment) (Note 8)													
25. Feedwater Flow Rate									X				
26. Condensate Storage Tank Water Level										X			
27. Suppression Chamber (Torus) Spray Flow Rate, and Valve Position (Note 10)									X				
28. Drywell Spray Flow Rate, and Valve Position (Note 10)													
29. Main Steam Line Isolation Valve Leakage Control System Pressure (Note 11)													
30. Primary System Safety/Relief Valve Position									X				
31. Isolation Condenser Shell Side Water Level									X				
32. Isolation Condenser System Valve Position (Principal Flow Path) (Note 12)													
33. Reactor Core Isolation Cooling System Flow (Injection to RPV) (Note 11)													

TABLE VIII-3 (Cont'd.)

Type →	EOP	B			C			D			E		
VARIABLE Category →	1	1	2	3	1	2	3	1	2	3	1	2	3
34. High-Pressure Coolant Injection System Flow (Injection to RPV) (Note 13)													
35. Core Spray System Flow Rate (Injection to RPV)									X				
36. Low-Pressure Coolant Injection System Flow Rate (Injection to RPV) (Note 11)													
37. Standby Liquid Control (Liquid Poison) System Flow Rate (Injection to RPV) (Note 14)													
38. Standby Liquid Control (Liquid Poison) System Storage Tank Liquid Level									X				
39. RHR System Flow Rate (Injection to RPV) (Note 15)													
40. RHR Heat Exchanger Tube Side (Reactor Coolant) Inlet and Outlet Temperature									X				
41. Cooling Water Flow to Engineering Safeguards Features System (ECCS) Components (Note 16)													
42. Cooling Water Temperature to Engineering Safeguards Features System (ECCS) Components (Note 16)													
43. High Radioactivity Liquid Tank Level										X			
44. Emergency Ventilation Damper Position									X				
45. Status of Standby Power and Other Energy Sources Important to Safety									X				
46. Radiation Level (equipment areas outside containment) (Note 17)													X
47. Airborne Radioactivity Releases of Noble Gases and Ventilation Flow Rate (Note 24)						X	X					X	X

TABLE VIII-3 (Cont'd.)

Type →	EOP	B			C			D			E		
VARIABLE Category →	1	1	2	3	1	2	3	1	2	3	1	2	3
48. Airborne Radioactivity Releases of Particulates and Halogens and Ventilation Flow Rate (Note 18)													
49. Environs Radiation Exposure (meters, for continuous indication at fixed locations) (Note 2)													
50. Environs Airborne Radiohalogens and Particulates													X
51. Plant and Environs Radiation (portable instrumentation)													X
52. Plant and Environs Radioactivity (portable instruments) (Note 19)													
53. Wind Direction													X
54. Wind Speed													X
55. Estimation of Atmospheric Stability													X
56. Post-accident Sample/Analysis-Primary Coolant & Sump Gross Activity													X
57. Post-accident Sample/Analysis-Primary Coolant & Sump Gamma Spectrum							X						X
58. Post-accident Sample/Analysis-Primary Coolant & Sump Boron				X			X						X
59. Post-accident Sample/Analysis-Primary Coolant & Sump Chloride													X
60. Post-accident Sample/Analysis-Primary Coolant Dissolved H_2 or Total Gas													X
61. Post-accident Sample/Analysis-Primary Coolant Dissolved O_2													X

TABLE VIII-3 (Cont'd.)

Type →	EOP	B			C			D			E		
VARIABLE Category →	1	1	2	3	1	2	3	1	2	3	1	2	3
62. Post-accident Sample/Analysis-Primary Coolant & Sump pH													X
63. Post-accident Sample/Analysis-Containment Air H_2 Content													X
64. Post-accident Sample/Analysis-Containment Air O_2 Content													X
65. Post-accident Sample/Analysis-Containment Air Gamma Spectrum													X
66. Liquid Poison System Pump Discharge Pressure									X				
67. Liquid Poison System Squib Valve Status									X				
68. Shutdown Cooling System Pump Discharge Pressure									X				
69. Shutdown Cooling System Heat Exchanger Shell Side (Cooling Water) Inlet and Outlet Temperatures									X				
70. Shutdown Cooling System Valve Position (to/from reactor vessel)									X				
71. Containment Spray System Heat Exchanger Outlet Temperature									X				
72. Containment Spray Raw Water System Flow Rate, and Valve Position									X				

TABLE VIII-3 (Cont'd.)

NOTES (Cont'd.)

definition of a Type A variable. Since drywell water level is not a RG 1.97 Revision 2 recommended variable, the drywell water level recorder does not need to meet the Category 1 criteria. Therefore, a drywell water level recorder is not needed.[29,30]

24. RG 1.97 recommends that noble gas effluent monitoring instrumentation be designed with a range of 1E-06 μCi/cc to 1E+03 μCi/cc. The range of the offgas effluent stack monitoring system (OGESMS) is 1E-07 μCi/cc to 1 μCi/cc (Xe-133). The OGESMS lower limit of detection of 1E-05 μCi/cc meets the NUREG-0737, Item II.F.1, Attachment 1, Position (2) criterion of the instrumentation range beginning at normal conditions (as low as reasonably achievable (ALARA)). The OGESMS upper range limit of 1 μCi/cc (Xe-133) provides a safety margin greater than a factor of two for the site-specific design basis effluent release which occurs at NMP1 from a LOCA.

    RG 1.97 recommends particulates and halogens instrumentation be designed with a range of 1E-03 μCi/cc to 1E+02 μCi/cc, with a 30-min sampling time for detection of significant releases, release assessment, and long-term surveillance. With the use of OGESMS, the particulate samples would be collected by OGESMS and taken to an onsite facility. The onsite analysis facility has a range of 1E-03 μCi/cc to 0.1 μCi/cc with a 30-min sampling time. The onsite analysis facility's upper range of 0.1 μCi/cc provides a safety margin of two for a design basis effluent release from a LOCA. Using NMP1's design basis effluent release from a LOCA, in lieu of 1E+02 μCi/cc as specified in NUREG-0737 and RG 1.97, to determine doses to personnel working with the sampling media during an accident, the results in estimated exposures would be less than the GDC 19 limits.

    In summary, OGESMS meets the objective and purpose of the NUREG-0737 and RG 1.97 guidance. The deviations from NUREG-0737 and RG 1.97 are acceptable.[34]

25. A hydrogen monitoring system capable of diagnosing beyond-design-basis accidents will be maintained in accordance with License Amendment No. 191 (issued by NRC letter dated October 2, 2006[38]).

26. An oxygen monitoring system capable of verifying the status of the inerted containment (post-accident monitoring function) will be maintained in accordance with License Amendment No. 191 (issued by NRC letter dated October 2, 2006[38]).

REACTOR PROTECTION SYSTEM ELEMENTARY DIAGRAM

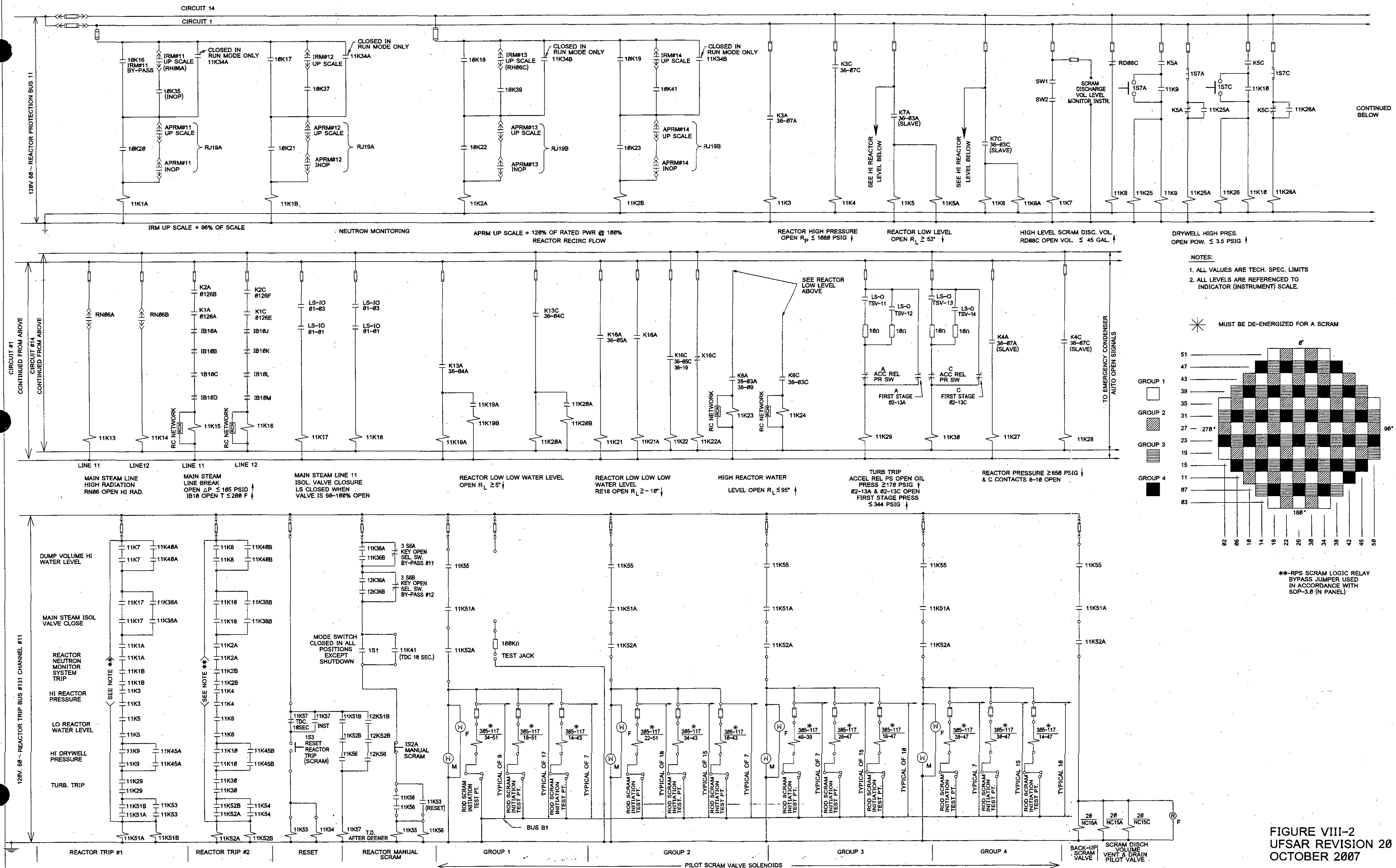


FIGURE VIII-2
UFSAR REVISION 20
OCTOBER 2007

FSAR FIGURE VIII-2

SOURCE RANGE MONITOR (SRM)

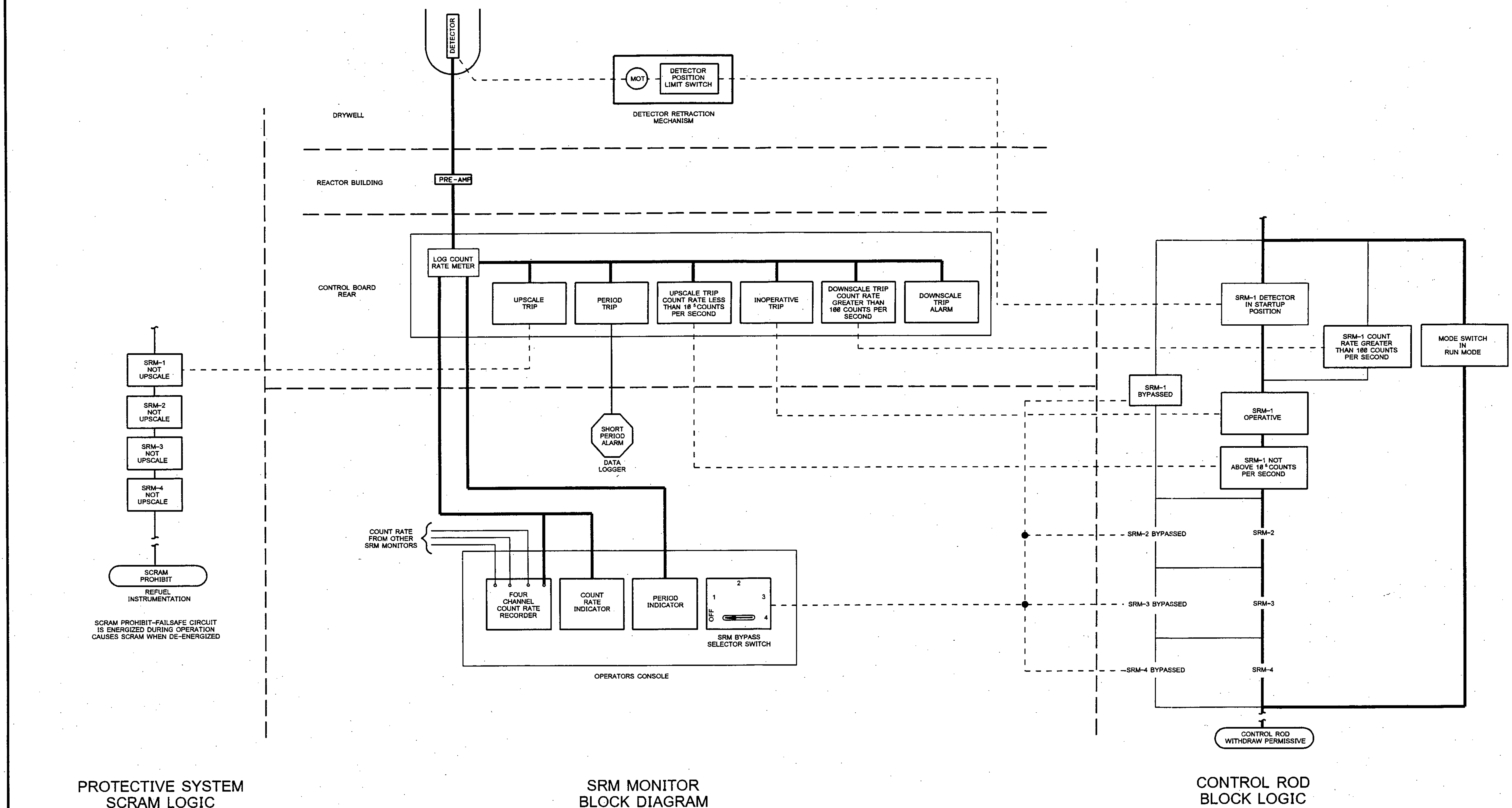
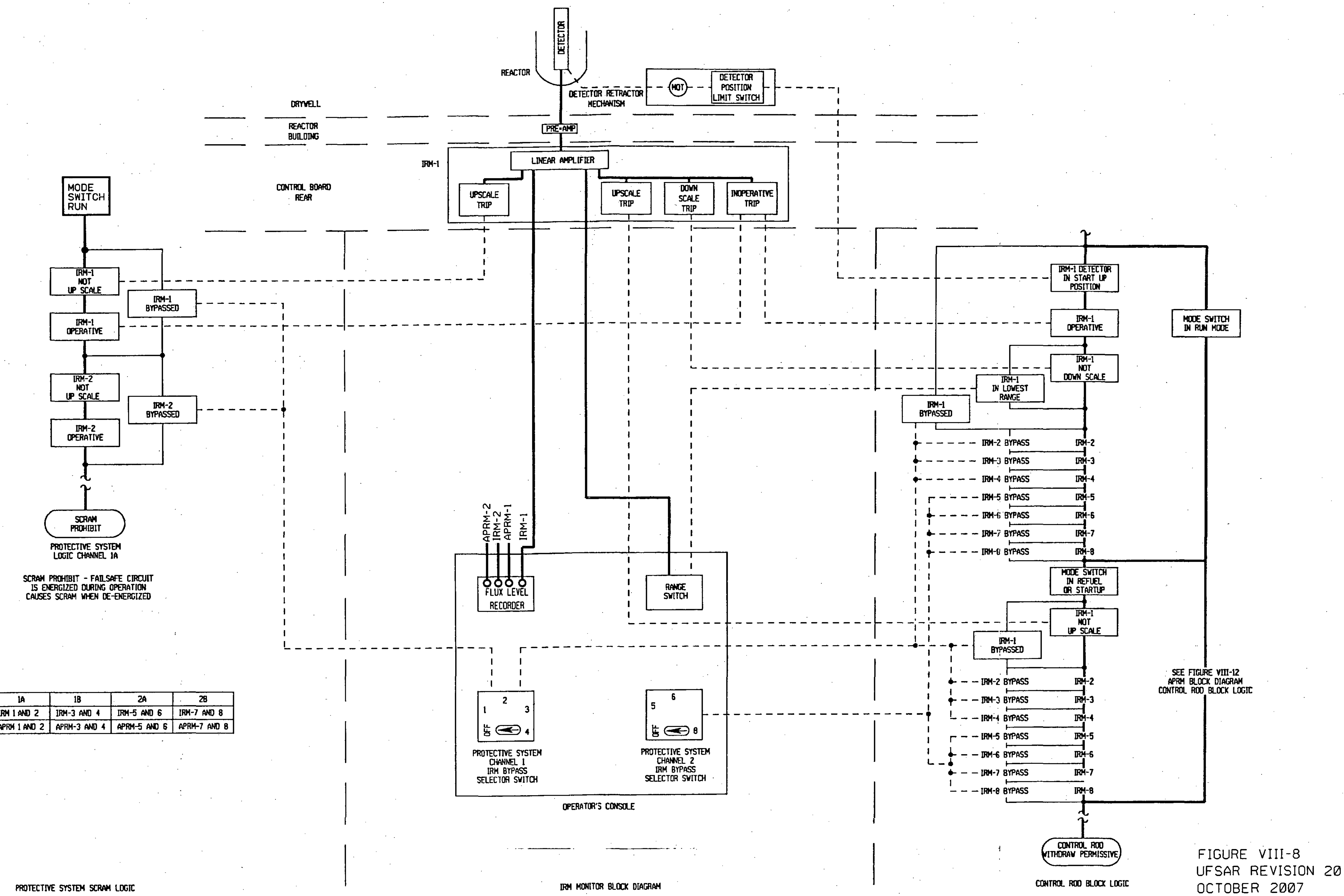


FIGURE VIII-6
UFSAR REVISION 20
OCTOBER 2007

FSAR FIGURE VIII-6

...\MSUSER\FSAR FIGURE VIII-6.dgn 8/3/2007 9:27:22 AM

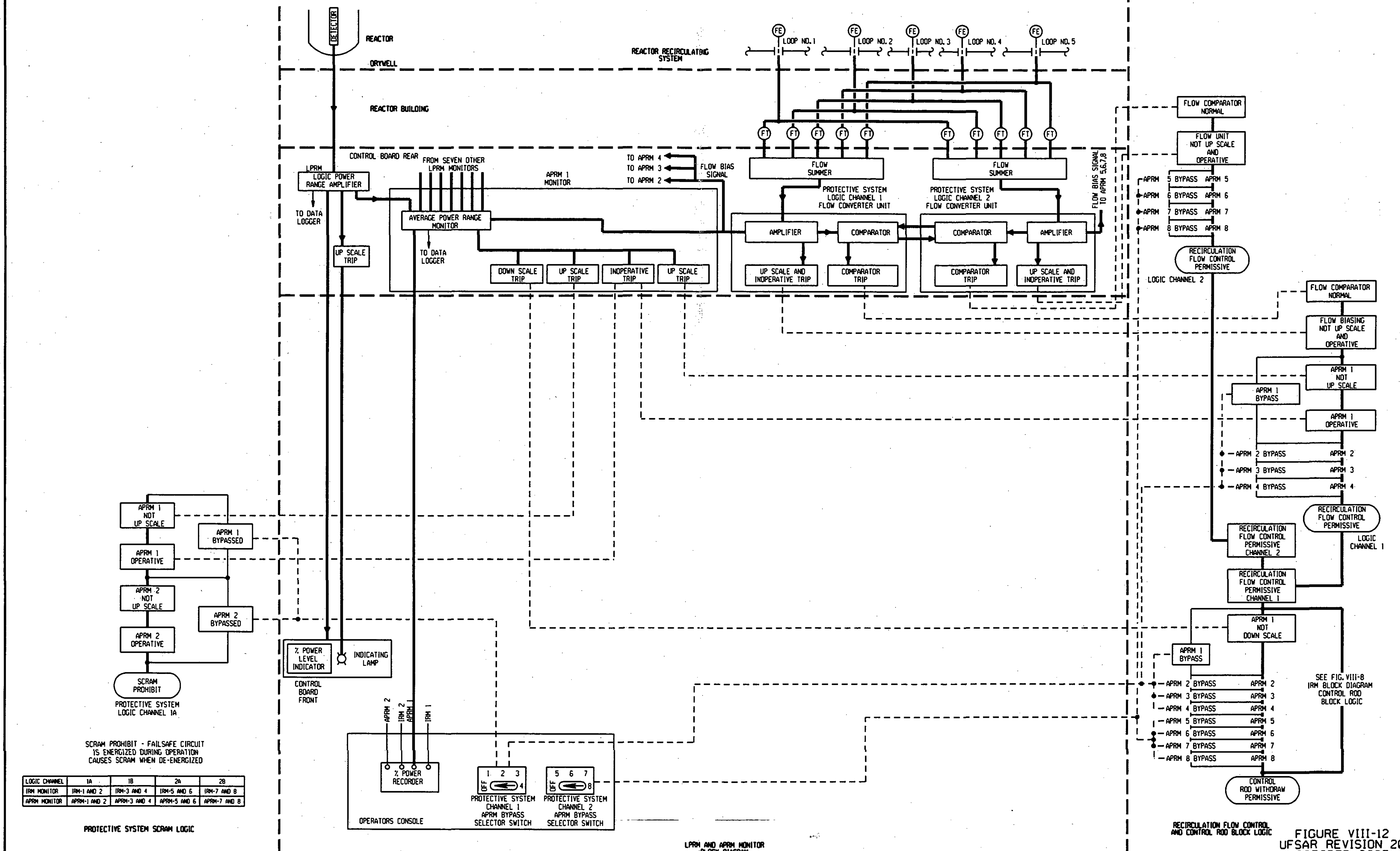
INTERMEDIATE RANGE MONITOR (IRM)



LOGIC CHANNEL	1A	1B	2A	2B
IRM MONITOR	IRM 1 AND 2	IRM-3 AND 4	IRM-5 AND 6	IRM-7 AND 8
APRM MONITOR	APRM 1 AND 2	APRM-3 AND 4	APRM-5 AND 6	APRM-7 AND 8

FIGURE VIII-8
UFSAR REVISION 20
OCTOBER 2007

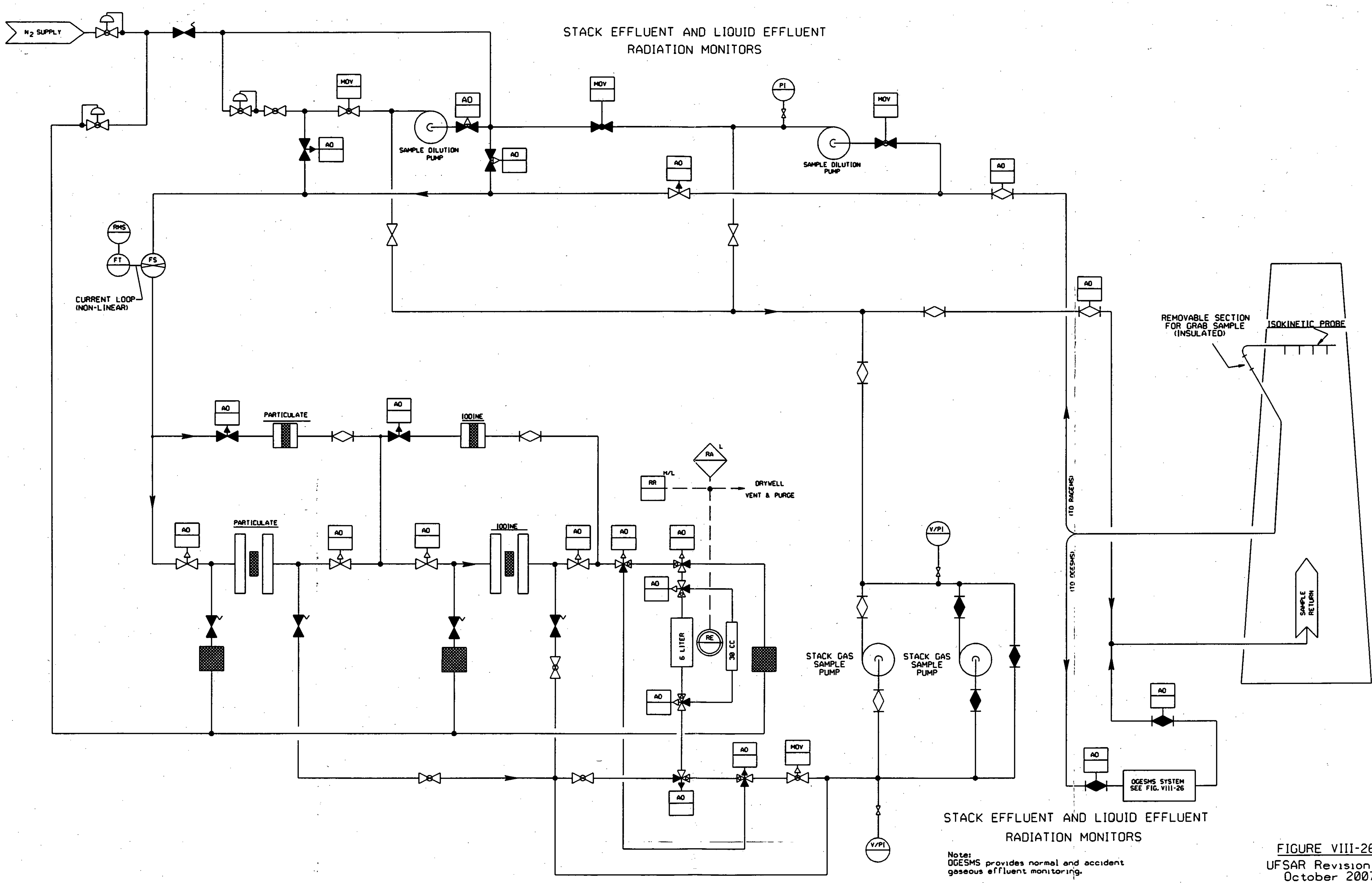
LOCAL POWER RANGE MONITOR (LPRM) AND AVERAGE POWER RANGE MONITORS (APRM)



LOGIC CHANNEL	1A	1B	2A	2B
IRM MONITOR	IRM-1 AND 2	IRM-3 AND 4	IRM-5 AND 6	IRM-7 AND 8
APRM MONITOR	APRM-1 AND 2	APRM-3 AND 4	APRM-5 AND 6	APRM-7 AND 8

FIGURE VIII-12
UFSAR REVISION 20
OCTOBER 2007

STACK EFFLUENT AND LIQUID EFFLUENT
RADIATION MONITORS



STACK EFFLUENT AND LIQUID EFFLUENT
RADIATION MONITORS

Note:
OGESMS provides normal and accident gaseous effluent monitoring.

RAGEMS provides an auxiliary sampling location.

FIGURE VIII-26a

UFSAR Revision 20
October 2007

SECTION IX

ELECTRICAL SYSTEMS

A. DESIGN BASES

The Station electrical system is designed to provide adequate normal and emergency sources of electrical power for normal operation and for the prompt shutdown and continued maintenance of the Station in a safe condition under all credible circumstances.

To guard against the remote possibility of the loss of all electrical power from sources outside the Station coincident with an accident within the Station, two completely independent emergency diesel generator systems are provided, each having a capacity adequate to provide power to all of the loads that are deemed essential on an emergency basis. This complete redundancy in the emergency generator systems parallels that in the core and containment spray systems to assure the highest possible degree of reliability in these safety systems.

The Station design provides two completely independent control battery systems for redundancy and selectivity of control power sources, which greatly enhances the reliability of essential control and protective system circuitry.

Loads essential to Station safety are split and diversified between auxiliary power buses, with means provided for rapid location and isolation of faults.

B. ELECTRICAL SYSTEM DESIGN

1.0 Network Interconnections

1.1 345-kV System

The output of the Nine Mile Point Nuclear Station - Unit 1 (Unit 1) is transmitted over two 345-kV transmission lines (#9 line to Scriba Station, approximately 0.41 mi, #8 line to Clay Station, approximately 26 mi) where it is fed into the Niagara Mohawk Power Corporation (NMPC) cross-state bulk power transmission system.

The two transmission lines occupy a common right-of-way but are physically separated and supported on completely independent structures to minimize the possibility of a double-circuit outage. The lines are designed to meet or exceed the requirements of the National Electric Safety Code for heavy loading districts, Grade B. The design provides theoretical lightning performance of less than 1.17 outages per 100 mi per year.

Transmission lines #8 and #9 are protected by 550-kV, 3000-amp, three-phase, 50-kA, SF_6 gas circuit breakers, as shown on Figure IX-1. Each line has a capacity in excess of the full expected output of the turbine generator. Normal operation is with both breakers closed and all lines energized. Redundant protective relay schemes (per New York Power Pool (NYPP) requirements for protection of bulk power systems), including backup functions coupled with automatic reclosing of line breakers, provides for a high degree of reliability in line operation. In the event that one of the two lines is temporarily out of service (OOS), the other line is capable of carrying the full Station output at no risk to system stability.

Loss of all 345-kV lines will result in load rejection of the Station's net generation output being carried at the time. If the load rejected is within the range where opening of the bypass valves will permit continued operation of the reactor, the turbine generator will continue to run and carry the Station auxiliaries. On the other hand, if the load rejected is greater, reactor trip will result and the Station auxiliaries are automatically transferred to the 115-kV reserve source.

When the main turbine generator is out of service and Station power is being supplied by transformers T101N and T101S, a 345-kV backfeed can be established. Backfeed is accomplished by energizing main transformer T1 or T2 by way of 345-kV lines #8 or #9, after disconnecting the main generator links and closing in on the 345-kV breakers R915 or R925, and after taking the appropriate precautions. This configuration will step down the system voltage from 345 kV to 24 kV, and then through the Station service transformer #10 to 4160 V to energize power boards (PB)

THIS PAGE INTENTIONALLY BLANK

Questions/Answers, December 27, 1989, and NUMARC 87-00, Major Assumptions, December 27, 1989, except where RG 1.155 takes precedence. The results of this evaluation were submitted to the NRC in References 1, 2, 3, 5, 6 and 8 and are summarized below. NRC evaluations and acceptance of the Unit 1 response to the SBO rule were documented in References 4, 7 and 9.

6.1 Station Blackout Duration

A SBO duration of 4 hr was determined based on the following plant factors:

1. Ac Power Design Characteristic Group is "P2" based on:

   a. Expected frequency of grid-related LOOP events does not exceed once per 20 yr.

   b. Estimated frequency of LOOP due to extremely severe weather places the plant in extremely severe weather group 1.

   c. Estimated frequency of LOOP due to severe weather places the plant in severe weather group 3.

   d. The offsite power site is in the I3 group.

   e. Plant-specific prehurricane shutdown requirements and procedures are not required for Unit 1, nor are such procedures credited in the determination of the Ac Power Design Characteristic Group.

2. The Emergency Ac Power Configuration Group is "C" based on:

   a. There are two emergency ac power supplies not credited as alternate ac power sources.

   b. One emergency ac power supply is necessary to operate safe shutdown equipment following a LOOP.

3. The target emergency diesel generator reliability is 0.975. A target emergency diesel generator reliability of 0.975 was selected based on having a nuclear unit average emergency diesel generator reliability for the last 20 demands greater than 0.90.

   An analysis showing the emergency diesel generator reliability statistics for the last 20, 50, and 100 demands which supports this target reliability has also been performed.

6.2 Station Blackout Coping Capability

The characteristics of the following plant systems were reviewed to assure that the systems have the availability, adequacy and capability to achieve and maintain a safe plant shutdown and to recover from a SBO for the 4-hr coping duration.

Condensate Inventory for Decay Heat Removal

It has been determined that 58,700 gal of water are required for decay heat removal and cooldown for 4 hr. The minimum permissible emergency condenser (EC) gravity feed, EC makeup tank and EC levels, per Technical Specifications, provide 114,720 gal of water, which is adequate to provide for decay heat removal for at least 4 hr even if both EC level control valves fail open on loss of air at the start of the SBO, and no other Operator actions are taken. Therefore, no plant modifications or Operator actions are required to ensure adequate condensate capacity exists for decay heat removal during a 4-hr SBO.

The design basis SBO calculations note that if Operators secure one EC from service to control vessel cooldown rate, then manual actions are required within 30 min to conserve condensate inventory and maximize coping duration. The calculations show that the actions to isolate the idle EC from the makeup tank, open the crosstie, and take manual control within 30 min, is required to minimize any overflow from the ECs into the waste building. These actions within 30 min will ensure a coping period of 4.3 hr.

The SBO analysis includes a case that demonstrates the cooldown is below the design analysis 300° per hr emergency cooldown rate and, as such, Operator action to secure one EC is not required. Therefore, securing one EC is not a requirement of the SBO analysis. The decision/option to secure one EC based on cooldown rate is at the discretion of the Operator in accordance with EOPs.

Station Battery Capacity

Battery capacity calculations performed pursuant to NUMARC 87-00, Section 7.2.2, and IEEE-485-1978, verified that the Station batteries have sufficient capacity to meet SBO loads for 4 hr. Operator action is required to shed nonessential loads from Class 1E batteries to cope with a SBO duration of 4 hr.

The shedding of the nonessential loads from Class 1E batteries is identified in plant procedures.

Compressed Air

Air-operated valves (AOVs) relied upon to cope with a SBO for 4 hr can either be operated manually or have sufficient backup sources independent of the preferred and blacked out Unit's Class 1E power supply. Valves requiring manual operation or that need backup sources for operation are identified in plant procedures.

Effects of Loss of Ventilation

The key areas in which the loss of ventilation cooling causes a concern for equipment operability were identified based on the equipment used to respond to the SBO event. Heatup calculations were performed for the:

1. EC condensate return isolation valve room (el 281')
2. EC steam supply isolation valve room (el 298')
3. Reactor building, el 318'
4. Reactor building, el 340'
5. Primary containment
6. Control room

The control room at Unit 1 does not exceed 120°F during a SBO and, therefore, is not a dominant area of concern (DAC).

Reasonable assurance of the operability of SBO response equipment in the dominant areas of concern has been assessed using Appendix F to NUMARC 87-00 and the Topical Report. No hardware modifications are required to provide reasonable assurance for equipment operability.

Procedures direct the Operators to open the control room and auxiliary control room instrument cabinet doors which will increase the cooling of the control room equipment by natural convection.

Containment Isolation

The plant list of containment isolation valves has been reviewed to verify that valves which must be capable of being closed or that must be operated (cycled) under SBO conditions can be positioned (with indication) independent of the preferred and blacked-out Class 1E power supplies. Plant procedures identify valves which must be operated to isolate containment during a SBO.

Reactor Coolant Inventory

An analysis of reactor coolant system (RCS) inventory was performed assuming a leak rate of 18 gpm per recirculation pump (5 pumps) and the maximum allowable (25 gpm) Technical Specification leak rate. The results indicate that reactor water level would reach top of active fuel (TAF) in approximately 1.8 hr.

With a constant leak rate of 115 gpm, plant procedures direct the Operator to actuate the automatic depressurization system (ADS) at or before the time the water level reaches the minimum steam cooling RPV water level (MSCRWL). After the vessel is depressurized, plant procedures direct the Operator to initiate reactor vessel makeup using the diesel-driven fire pump.

6.3 Procedures and Training

Plant procedures, SBO response guidelines, ac power restoration procedures, and SW procedures have been reviewed, and changes necessary to meet NUMARC 87-00, Section 4, guidelines have been implemented to ensure an appropriate response to a SBO event.

Personnel training to ensure an effective response to a SBO event has been incorporated into the training program.

6.4 Quality Assurance

Based on a review of the equipment relied upon to carry out the SBO response, all nonsafety-related components have been upgraded to a "Q" classification and are covered under the Quality Related Program for Nine Mile Point Nuclear Station Operations, which is consistent with the guidance of RG 1.155, Appendix A. The remaining SBO equipment is safety related and is covered by existing quality assurance requirements in the Quality Assurance Topical Report (QATR).

6.5 Emergency Diesel Generator Reliability Program

An Emergency Diesel Generator Reliability Program has been developed for Unit 1 which conforms to the guidance of RG 1.155, Position C.1.2. The program includes a 0.975 emergency diesel generator target reliability based on emergency diesel generator reliability data for the last 20, 50 and 100 demands.

THIS PAGE INTENTIONALLY BLANK

TABLE IX-1

MAGNITUDE AND DUTY CYCLE OF MAJOR STATION BATTERY LOADS

Loads (amps)	Case "b" 0-1 Minute (amps)	Case "b" 1-2 Minutes (amps)
Battery 11		
Battery Board 11		
Instrument and Control Power UPS System 162	211	211
Computer MG Set 167	143	143
Other Continuous Loads	103	82
Diesel Generator 102 Start and Field Flashing, Run	60	34
Breaker Trips		
Two - 345 kV	21.0	
Two - 115 kV	14.9	
Twelve - 4160-V PB 11	72.0	
Three - 4160-V PB 101	18.0	
One - 4160-V R1012	6.0	
Six - 600-V PB 16	12.0	
One - 500-V dc Generator Field Bkr	6.0	
Breaker Closures		
One - 4160-V PB 102 (Diesel Generator)	14.0	
Six - 4160-V PB 102 (ECCS Equip.)	14.0	
One - 600-V PB 16 (CRD, SBC)	44.0	44.0
Battery 12		
Battery Board 12		
Instrument and Control Power UPS System 172	211	211
Other Continuous Loads	87	69
Diesel Generator 103 Start and Field Flashing, Run	60	34

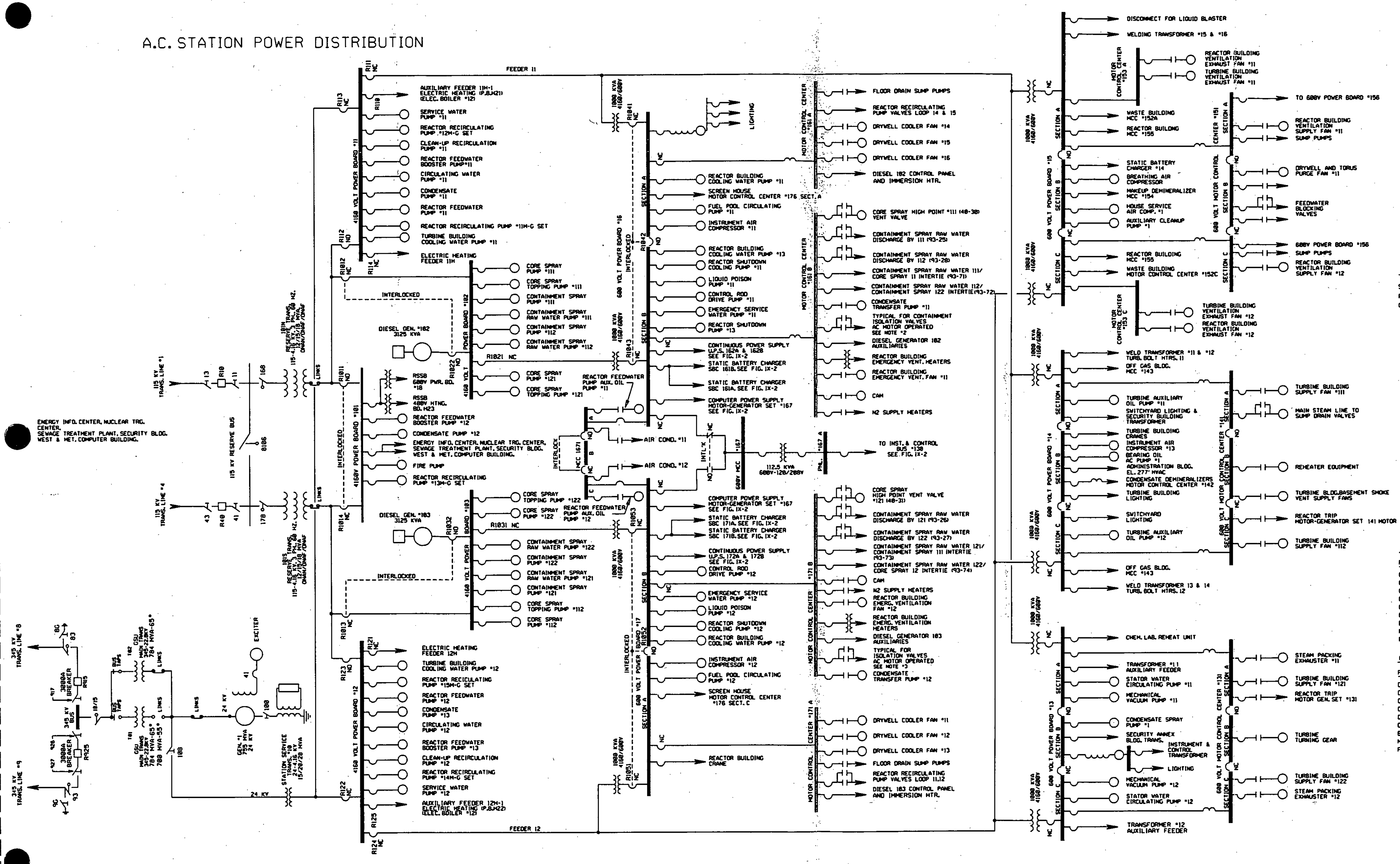
TABLE IX-1 (Cont'd.)

Loads (amps)	Case "b" 0-1 Minute (amps)	Case "b" 1-2 Minutes (amps)
Breaker Trips		
Eleven - 4160-V PB 12	66.0	
One - 4160-V R1014	6.0	
One - 4160-V R1013	6.0	
One - 600-V PB 14	2.0	
Five - 600-V PB 17	10.0	
Breaker Closures		
One - 4160-V PB 103 (Diesel Generator)	14.0	
Six - 4160-V PB 103 (ECCS Equip.)	14.0	
Two - 600-V PB 17 (CRD, SBC)	44.0	44.0
Motor-Operated Valves		
Reactor Cleanup Supply IV #12 (33-04)	106	

NOTES:

1. Case "b" assumes loss of 115-kV offsite power combined with LOCA and unit trip. Case "a" assumes loss of 115-kV offsite power combined with Technical Specification leakage, but without a unit trip. The Case "b" event bounds the Case "a" event with respect to battery loading. Therefore, the Case "a" event is not included in the Table.
2. Continuous and noncontinuous loads are supplied from the battery until the static battery charger is transferred to its ac power source.
3. ECCS breaker closures are staggered utilizing time delays. There are no closure overlaps; therefore, the breaker close current for one breaker is seen throughout the first minute.
4. For detailed load and duty cycle information, see the battery sizing calculations.

A.C. STATION POWER DISTRIBUTION



NOTE *1

SELECTED LOADS ARE SHOWN ON THIS DRAWING. FOR ADDITIONAL LOADS SEE THE FOLLOWING ONE-LINE DIAGRAMS C-19409-C SHEETS 2-11.

PB*101	SH.2
PB*102	SH.3
PB*103	SH.3
PB*11	SH.2
PB*12	SH.2
PB*13	SH.4
MCC*131	SH.4,4A
PB*14	SH.5
MCC*141	SH.5
PB*15	SH.6
MCC*151	SH.7
MCC*151	SH.7
MCC*152	SH.7A
PB*153	SH.6
MCC*154	SH.7
MCC*155	SH.6
MCC*156	SH.12
PB*16	SH.8
MCC*161	SH.8
PB*167	SH.10
PB*1671	SH.11
PB*17	SH.9
MCC*171	SH.9
MCC*176	SH.10

NOTE *2

POWER BOARD 161B ISOLATION VALVES

CORE SPRAY SUCTION ISOLATION VALVE / 111 (81-21)
CORE SPRAY DISCHARGE ISOLATION VALVE / 111 (40-11)
CORE SPRAY SUCTION ISOLATION VALVE / 121 (81-01)
CORE SPRAY DISCHARGE ISOLATION VALVE / 121 (40-01)
CLEAN UP SUPPLY ISOLATION VALVE / 11 (33-02R)
CONTAINMENT SPRAY SUCTION ISOLATION VALVE / 111 (80-01)
EMER. CONDENSERS STEAM ISOLATION VALVE / 121 (39-10R)
MAIN STEAM ISOLATION VALVE / 111 (01-01)
FEEDWATER ISOLATION VALVE / 11 (31-07)

NOTE *3

POWER BOARD 171B ISOLATION VALVES

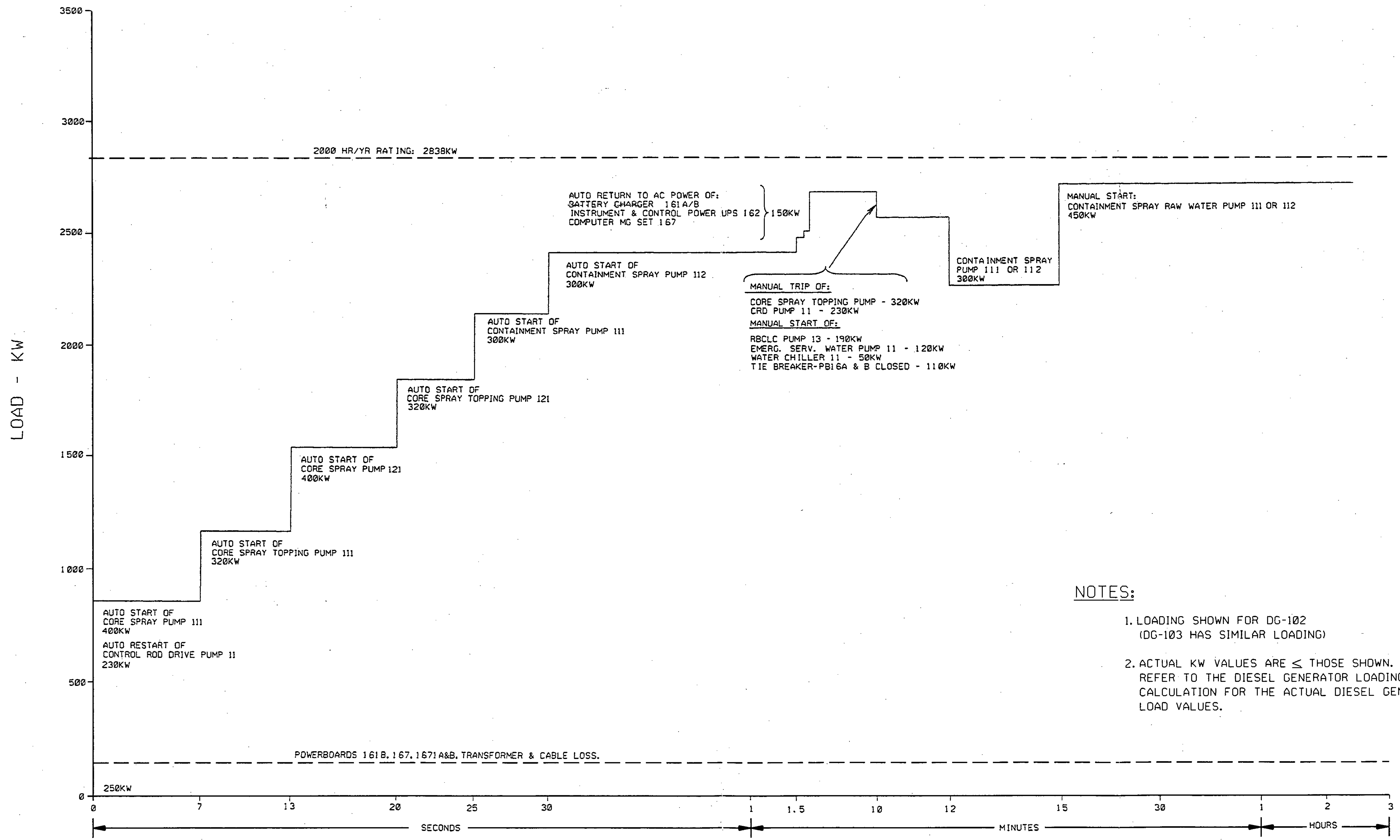
CORE SPRAY SUCTION ISOLATION VALVE / 112 (81-22)
CORE SPRAY DISCHARGE ISOLATION VALVE /112 (40-10)
CORE SPRAY SUCTION ISOLATION VALVE / 122 (81-02)
CORE SPRAY DISCHARGE ISOLATION VALVE / 122 (40-09)
CLEAN UP RETURN ISOLATION VALVE /1 (33-01R)
CONTAINMENT SPRAY SUCTION ISOLATION VALVE /122 (80-22)
EMER. CONDENSER STEAM ISOLATION VALVE / 111 (39-09R)
MAIN STEAM ISOLATION VALVE /121 (01-02)
FEEDWATER ISOLATION VALVE / 12 (31-08)

FIGURE IX-1
UFSAR REVISION 20
OCTOBER 2007

FILE NAME: C19409C_001B

...\E47546\msuser\C19409C_001b.dgn 7/23/2007 2:52:08 PM

DIESEL GENERATOR LOADING FOLLOWING LOSS-OF-COOLANT ACCIDENT



NOTES:

1. LOADING SHOWN FOR DG-102 (DG-103 HAS SIMILAR LOADING)
2. ACTUAL KW VALUES ARE ≤ THOSE SHOWN. REFER TO THE DIESEL GENERATOR LOADING CALCULATION FOR THE ACTUAL DIESEL GENERATOR LOAD VALUES.

FIGURE IX-6
UFSAR Revision 20
October 2007

U.S. NUCLEAR REGULATORY
COMMISSION
DOCKET 50-220
LICENSE DPR-63

NINE MILE POINT NUCLEAR STATION UNIT 1

FINAL SAFETY ANALYSIS REPORT (UPDATED)

VOLUME 3

OCTOBER 2007

REVISION 20

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

THIS PAGE INTENTIONALLY BLANK

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

THIS PAGE INTENTIONALLY BLANK

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

THIS PAGE INTENTIONALLY BLANK

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

THIS PAGE INTENTIONALLY BLANK

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

LIST OF TABLES

D. REACTOR BUILDING CLOSED LOOP COOLING WATER SYSTEM

1.0 Design Bases

The RBCLCW system provides demineralized water at temperatures not exceeding 95°F to cool auxiliary equipment located in the reactor, turbine and waste disposal buildings. The closed loop permits isolation of systems containing radioactive liquids from the service water, which is returned to the lake.

The cooling load imposed on the system will largely depend on the Station power output at any given time; therefore, this system has sufficient capacity and flexibility to cool various combinations of equipment regardless of the Station power output. With a RBCLCW flow of 8500 gpm, a total service water flow of 10,000 gpm, and two RBCLC heat exchangers in service, the RBCLC system was designed (i.e., heat exchangers sized, built and procured) such that the system would have a nominal heat removal capability of approximately 126 x 10^6 Btu/hr. This value is not the RBCLC system cooling capacity requirement. The above performance is dependent on temperatures (RBCLCW temperature and the temperature of the ultimate heat sink (UHS) - Lake Ontario) as well as tube and shell flows. This value does not represent the cooling capacity necessary for plant operation. The cooling load imposed on the system will largely depend on the Station power output and plant condition. The RBCLC heat removal requirements for the most limiting modes of operation are as follows:

Modes of Operation	Heat Load [10^6 Btu/hr]
Normal Operation	74.24
Normal Shutdown	97.82
10-hr Shutdown	156.20

2.0 System Design

The RBCLCW system provides cooling water to the following major components (Figure X-4).

Fuel Pool Heat Exchangers

Instrument Air Compressors

Electric Feedwater Pumps

Condensate Pumps

Feedwater Booster Pumps

Control Room and Laboratory Air Conditioning Equipment

Recirculation Pump Coolers

Cleanup System Nonregenerative Heat Exchangers

Reactor Building Equipment Drain Tank Cooler

Drywell Air Coolers

Waste Disposal System Heat Exchangers

Shutdown Cooling System Heat Exchangers and Pump Coolers

Offgas Vacuum Pump Coolers

The system consists of three horizontal centrifugal pumps rated at 4500 gpm with a total developed head (TDH) of 65 psi each, and three counterflow shell and tube heat exchangers, plus necessary flow control valves, instrumentation and piping. During normal Station operation, one or two pumps may be operated depending on the system heat loads (cooling requirements) and lake temperature. For the most demanding load cases, i.e., 10-hr and normal shutdown, any combination of one RBCLC pump and two RBCLC heat exchangers, or two RBCLC pumps and three RBCLC heat exchangers, will provide adequate cooling, i.e., RBCLC effluent temperature of 90 ± 5°F and sufficient flow to required on-line users. These combinations are intended to limit RBCLC heat exchanger shellside flow to approximately 3000 gpm per heat exchanger to prevent flow-induced tube vibration.

Temperature indication of each component and flow indication on major lines help to maintain the proper amount of cooling water to each component. These indications are either local or in the main control room.

The service water for the RBCLC system (tubeside of heat exchangers) is supplied by the service water (SWP) system utilizing two normal service water pumps and backed up by two emergency service water pumps.

Additional low-conductivity water can be added to the system from the 2000-gal closed loop cooling makeup tank (Figure X-5) located on floor el 351' in the turbine building. The closed loop cooling makeup tank is shared with the turbine building closed loop cooling (TBCLC) system and provides a low-pressure inlet of low-conductivity water to both systems. The tank is supplied with water automatically from the condensate transfer system through a makeup level control valve. Additional makeup is also available from the makeup demineralizer tank. Excess water due to thermal expansion in the RBCLC system will overflow through an elevated drain into the turbine building equipment drain sump.

To facilitate maintenance activities, the RBCLC system is designed for flexibility of operation. Each of the three RBCLC system pumps and heat exchangers may be interchanged as necessary.

Each RBCLC pump is normally started and stopped from the control room. For normal operation, one or two pumps supply the cooling water requirements.

The cooling water pumps and the heat exchangers are designed to withstand seismic forces of 0.26g horizontal and 0.13g vertical.

Heat exchangers are constructed in accordance with the ASME Boiler and Pressure Vessel Code, Section VIII-1986. Pumps conform to the ASME Power Test Code for Centrifugal Pumps. All equipment piping connections are ASA standard. System piping is designed in accordance with Sections 1 and 6 of the ASA B31.1-1955 Code.

3.0 Design Evaluation

The most demanding heat load case on the RBCLC system is the 10-hr shutdown. Assuming the most conservative RBCLC system lineup, i.e., one RBCLC pump, two RBCLC heat exchangers, total service water flow of 9000 gpm to RBCLC system, and lake water temperature equal to 83°F, the RBCLC system will be able to reject enough heat to maintain a mixed mean temperature below 95°F. RBCLC heat exchanger shellside flow is limited to 3000 gpm to prevent flow-induced tube vibration.

Service water velocity within the tubes is normally maintained at not less than 4 fps to minimize tube fouling due to sand and silt (except when operating in the emergency shutdown mode). The emergency shutdown mode is an off-normal condition that addresses the possibility of failure of the controller to the RBCLC heat exchanger temperature control valve. Only the RBCLC essential heat loads associated with accident mitigation were considered. Other design assumptions for the assessment include single-pump, two-heat-exchanger operation. Under this scenario, the tubeside velocities will be less than 4 fps. Since this scenario is a design basis accident (DBA) event that occurs during an off-normal emergency shutdown, it is expected that long-term cooling would be provided for at least 30 days, which, due to the limited duration and conservative analysis assumptions, is unlikely to be impacted by low tube velocities. If the quantity of service water at operating velocities should tend to chill the cooling water below approximately 85°F, a bypass piping arrangement with flow control valves will divert some RBCLC water around the heat exchangers, remixing it downstream to maintain the set temperature. Two temperature-controlled flow control valves regulate the volume of cooling water entering the shellside of the heat exchangers. Operating in tandem, one valve will admit cooling water to the heat exchanger supply manifold and the other will divert the cooling water to the discharge header. As flow to the supply header is diminished, the diverted water flow is increased. A mechanical travel stop in the actuator of the supply header cooling water temperature control valve limits the valve from closing completely to assure heat removal capability during a DBA loss-of-coolant accident (LOCA) event. A temperature element in the cooling water discharge manifold from the heat exchangers actuates the SWP and cooling water control valves. The SWP and RBCLC flow control valves may be manually bypassed/operated in order to maximize cooling and control flow. Manual override of these valves would only be necessary when shellside heat exchanger flow needs to be limited while tubeside heat exchanger flow (service water) needs to be increased.

To evaluate leakage from equipment into the closed loop, the outlet of each major component on the cooling water system is provided with a grab sampling station. Leakage out of the system is noted by a flow switch and flow alarm in the system makeup line.

Major components served by the cooling water system are provided with high temperature alarms and/or temperature transmitters to aid in regulating cooling water flow.

In the event of the loss of normal and reserve ac power, two of the RBCLC pumps are connected to power board (PB) 16 and one to PB 17. These power boards are supplied power from diesel generators in the event of failure of their normal supply, as described in Section IX, Electrical Systems. The emergency service water pumps are also powered by the diesel generators in order to maintain a supply of cooling water to the RBCLC heat exchangers.

4.0 Tests and Inspections

The standby pump(s) are operated periodically to assure that they function properly.

Drywell isolation valves on the cooling water system are exercised periodically to assure proper operation.

THIS PAGE INTENTIONALLY BLANK

E. TURBINE BUILDING CLOSED LOOP COOLING WATER SYSTEM

1.0 Design Bases

The function of the turbine building closed loop cooling water (TBCLCW) system is to provide demineralized cooling water in a closed loop to auxiliary equipment in the turbine building. The closed loop permits isolation of systems containing radioactive liquids from the service water which returns to the lake. The cooling water temperature is maintained at temperatures not exceeding 95°F.

The cooling load imposed on the system will largely depend upon the Station power output at any given time. Therefore, this system has the flexibility to accommodate a wide range of variations. The system has a heat removal capability 52.34×10^6 Btu/hr and a flow capacity of 11,000 gpm. (Although the original design parameters were used in sizing of replacement heat exchangers, the original heat removal capability of 52.5×10^6 Btu/hr was reduced to 52.34×10^6 Btu/hr by the application of more conservative fouling factors.) This capability is based upon using two of three heat exchangers (heat exchangers nos. 11 and 12). Heat exchanger number 13 has a 10 percent higher heat removal capability than the nos. 11 and 12 heat exchangers.

2.0 System Design

The system consists of two full-capacity centrifugal pumps (each rated at 11,000 gpm at a TDH of 61 psi), and three half-capacity heat exchangers plus necessary flow control valves (Figure X-5). Cooling water is supplied to the following equipment:

Shaft-Driven Reactor Feedwater Pump

Oil Tank Coolers

Steam Packing Exhauster Coolers

Mechanical Vacuum Pump Coolers

Hydrogen Coolers

Stator Coolers

Generator Lead Coolers

Recirculating Pump Motor Generator (MG) Set Coolers

House Service Air Compressor

Sample Coolers

Turbine Building Equipment Drain Tank #11

Instrument Air Compressor #13

Instrument Air Dryer #12

Battery Room #14 Air Conditioner

Condensate Filtration System Air Compressor

Temperature indication of each component and flow indication on major lines helps to maintain the proper flow of coolant to each component.

Each turbine building cooling water pump is normally started and stopped from the control room. For normal operation, one pump will supply the cooling water requirements. The second pump will be started manually when required. Service water, when necessary, is supplied by the SWP system (Section X-F) utilizing two service water pumps for the plant.

Additional low-conductivity water can be added to the system from the 2000-gal closed loop cooling makeup tank (Figure X-5), located above the pump suction manifold at el 351. The closed loop cooling makeup tank is shared with the RBCLC system and provides a low-pressure inlet for makeup water in both systems. Makeup water to the tank is automatically supplied from the condensate transfer system through a makeup level control valve. Additional makeup water is also available from the makeup demineralizer tank. Excess water due to thermal expansion in the TBCLC system will overflow through an elevated drain into the turbine building equipment drain sump.

The TBCLC system is designed for flexibility of operation, which permits the use of any combination of pumps and heat exchangers, and also to facilitate maintenance.

The cooling water pumps are designed to withstand the following seismic acceleration forces.

Horizontal	0.15g
Vertical	0.075g

Heat exchangers are constructed in accordance with the ASME Boiler and Pressure Vessel Code, Section VIII-2001 with 2003 addenda (heat exchanger no. 13) and Section VIII-1983 (heat exchanger nos. 11 and 12). Pumps conform to the ASME Power Test Code for Centrifugal Pumps. All equipment piping connections are ASA standard.

3.0 Design Evaluation

Either pump and any two heat exchangers have the capacity to cool the entire system with a maximum 77°F lake water temperature.* Service water velocity within the cooling water heat exchanger tubes is maintained at a minimum velocity of 4 fps to minimize fouling due to sand and silt. In the event that the quantity of service water at this velocity should tend to chill the cooling water, a bypass piping arrangement with flow control valves diverts some TBCLCW around the heat exchangers, remixing it downstream to maintain the set temperature less than or equal to 95°F.

Two temperature-controlled flow control valves regulate the volume of TBCLCW entering the heat exchangers. Operating in tandem, one valve will admit TBCLCW to the cooling water heat exchanger supply manifold, and the other will divert the TBCLCW to the discharge header. As flow to the supply manifold is diminished, the diverted water flow is increased. A temperature element in the TBCLCW discharge manifold from the heat exchangers actuates the SWP and TBCLCW control valves. The SWP control valves located in the SWP discharge manifold can be bypassed by manual control.

To evaluate radiation hazards as a result of leakage from equipment into the cooling water system, the outlet of each major component on this system is provided with a grab sampling station.

High temperature alarms and temperature transmitters for major components served by the cooling water system aid in regulating cooling water flow.

Excessive leakage out of the system is noted by a flow switch and alarm in the system makeup line.

---

* This is a design point reflecting system capacity at 77°F.

4.0 Tests and Inspections

The alternate cooling water pump is exercised periodically to assure its proper operation.

THIS PAGE INTENTIONALLY BLANK

F. SERVICE WATER SYSTEM

1.0 Design Bases

The purpose of the SWP system is to provide strained lake water for cooling the RBCLCW and TBCLCW systems, the steam jet air ejector (SJAE) precooler, ejector vent cooler, the building local air coolers and other building services. Service water also is supplied to the screenwash pumps, the radwaste solidification and storage building (RSSB), and the makeup demineralizer. The system is to be available to cool the reactor building cooling water system under all conditions of operation. The cooling water requirement during the shutdown mode represents the most severe condition and is used as the design basis.

2.0 System Design

The system is shown on Figure X-6. Lake water from the intake tunnel passes through trash racks and traveling screens in the screen and pump house and floods the service water pump well. Two full-capacity (20,000-gpm) vertical sleeve bearing pumps take suction from the well. Each pump is provided with a .03-in mesh automatic self-cleaning strainer. The pump discharges are passed through the self-cleaning strainers and blocking valves and then into two separate headers which deliver water to cooling loads within the plant. A valved crosstie located downstream of the pumps enables either pump to supply either service water header. In the reactor building, the SWP system provides flow to the RBCLC heat exchangers. Downstream of the RBCLC heat exchangers is temperature control valve (TCV) 72-146. This valve regulates the amount of service water flowing through the heat exchangers. The RBCLC system provides the control signal for the valve's position. In parallel with the TCV is bypass valve 72-92R, for use if the TCV is out of service or to increase flow through the heat exchangers during peak loading conditions, as shown on Figure X-4. Listed below are the systems and requirements fulfilled by the SWP system.

RBCLCW Heat Exchangers (Tube Side)		6,200 gpm
TBCLCW Heat Exchangers (Tube Side)		8,000 gpm
Screenwash System Pumps		2,400 gpm
SJAE Precoolers and Vent Cooler		1,000 gpm
Local Building Area Coolers		1,500 gpm
RSSB HVAC Chillers		650 gpm
Makeup Demineralizer		100 gpm
Breathing Air Compressor		7 gpm
	Total	19,857 gpm

To provide for future added capacity, the pump header was extended and two valved branches were added.

In the event of a loss of both normal and reserve ac power, the service water pumps would be unavailable. At this time, service water requirements for the RBCLCW heat exchangers would be met by either of a pair of emergency ac power vertical turbine pumps. One of these pumps is connected to PB 16 and the other to PB 17. These power boards are supplied power from the diesel generators if their normal supply fails, as described in Section IX, Electrical Systems. The emergency pumps, each rated at 3,600 gpm, are in the screenhouse and take their suction from the circulating water intake.

Each of the emergency service water pumps is connected to one of the service water supply lines to the RBCLCW heat exchangers in the reactor building. Each emergency service water pump can supply water to any one of the three heat exchangers.

Each of the TBCLCW heat exchangers is serviced by two full-size service water supply lines. During normal operation, both the supply headers on the RBCLC side and TBCLC side are engaged by keeping the blocking valves open; however, to perform maintenance or other plant activities, one of the RBCLC side and one of the TBCLC side blocking valves can be secured.

3.0 Design Evaluation

Either pump has the capacity with the bypass valve opened to provide maximum service water requirements and can be throttled safely to flows as low as 20 percent of design if a need arises to reduce flow for temperature control. With bypass valve 72-92R closed, two normal service water pumps are required to meet the required flow rates for the most limiting mode of system operation.

The two emergency service water pumps increase the reliability of the SWP system and, as previously mentioned, provide service water during loss of normal and reserve ac power. In the unlikely event both emergency service water pumps fail to operate (i.e., due to a fire), an intertie exists between the diesel fire pump and the emergency service water line. The diesel fire pump is capable of handling the additional emergency service water requirements.

The double supply lines to the closed loop cooling water heat exchangers provide 100-percent backup in the event of pipe failure in either building.

A minimum velocity of 4 fps is maintained in both the RBCLCW and TBCLCW heat exchangers tubes to deter sand buildup, except for the RBCLCW when operating in the emergency shutdown mode.

In the event of loss of a SWP pump, low service water header pressure will be alarmed in the control room and the alternate pump will be started manually.

Differential pressure alarms across all strainers signal excessive pressure drop to the Operator in the control room.

IE Bulletin 80-10 requires effluent radiation monitoring for those systems that are normally considered nonradioactive, but could possibly become contaminated by leakage from interfacing systems.

The 42-in reactor building service water return and 10-in turbine building service water return lines are alternately monitored for radiation at 15-min intervals prior to discharge. Other service water return lines, including cooling to the RSSB air conditioning units which have no credible potential for contamination, are not monitored for radiation prior to discharge.

4.0 Tests and Inspections

To assure its availability, the alternate pump is operated once a month.

Both emergency service water pumps are operated quarterly.

G. MAKEUP WATER SYSTEM

1.0 Design Bases

The makeup demineralizer system is a truck-mounted portable system that is normally parked in the turbine building. It normally receives its supply water from the SWP system. Backup water from the city water system is available. The system was designed to deliver batches of demineralized water to fill the demineralized water makeup tank, the CSTs, and other reservoirs (e.g., the waste surge tank) as necessary.

1. Capacity:

    a. 100-150 gpm continuous

    b. Until the CSTs and the demineralized water makeup tank are filled, up to approximately 335,000 gal.

2. Quality:

    a. Conductivity: < 0.1 Micromhos/cm^3 or < .1 uS/cm

    b. TOC: < 400 ppb

    c. Silica: < 10 ppb

    d. Chlorides: < 10 ppb

    e. Sulfates: < 10 ppb

2.0 System Design

The raw water taken from the discharge side of the Station service water pumps passes through a precipitator and clearwell to either of the demineralizer feed pumps.

The system processes water at a rate of approximately 150 gpm, so it routinely visits the Station for periods of several days to replenish the demineralizer water storage tank and the CSTs. Since the minimum allowable CST volume is 105,000 gal, the portable makeup system is not required to replenish more than 295,000 gal depleted from the CSTs, and another 40,000 gal for a depleted demineralized makeup water storage tank.

The makeup system also has a flanged connection upstream of the retired demineralizers that may be used for connection of a portable skid-mounted (in-plant), as well as the truck-mounted, small-capacity demineralized water unit.

The portable skid- or truck-mounted system typically consists of charcoal filters, followed by demineralizer banks (cation, anion, and mixed). The truck-mounted demineralizer is dispatched with a custom loaded resin charge for a specific influent water supply.

The exact configuration used may vary depending upon demineralizer influent water chemistry quality.

The raw water is taken from the clearwell via either no. 11 or no. 12 demineralizer feed pump. Connection from the pump discharge to the portable demineralizers inlet is effected through a 2-in flexible hose.

The demineralizer effluent goes to the makeup demineralized water storage tank. Connection from the portable demineralizer effluent to the storage tank inlet line is made using a 2-in flexible hose. Diversion of the portable demineralizer discharge to the drain during startup is possible. A discharge line sampling point is also provided.

Operation of the portable makeup demineralizer is manually initiated at the makeup demineralizer system control panel, the skid-mounted or truck-mounted unit, and at various places in the makeup system.

Demineralized effluent goes to the demineralized water storage tank on el 369, which has a capacity of 40,000 gal, and the CSTs on el 261, which have a combined capacity of 400,000 gal. The demineralized water from these tanks can be used to provide an alternate source for the following:

Internals Storage Pit

Head Cavity

Cleanup System

Control Rod Drive System

Resin Transfer and Regeneration Equipment

Spent Fuel Pool

Chemical Addition Tank

Radiation Monitor Flush Line

Closed Loop Cooling Makeup Tank

Main Condenser

Demineralized water is normally provided directly to the following:

Liquid Poison System

Laboratories and Sample Sinks

Stator Winding Liquid Cooling System

Condensate Filtration System Air Compressor

3.0 System Evaluation

Operation of the portable makeup system is on demand at routine infrequent intervals to replenish demineralized water in storage tanks. With the system inoperable or when the portable demineralizer skid is not available, the Station can continue operation with makeup water from the CSTs which have a combined capacity of 400,000 gal. Additional makeup water is available from the demineralized makeup water storage tank which has a 40,000-gal capacity.

As an option, Operators may take a supply of water from city water for processing, depending on the plant operating conditions.

City water is an equivalent or better source for makeup than lake water in terms of contaminants, and delivery capacity is within or exceeds the requirements for supply to the demineralized water system.

4.0 Tests and Inspections

The demineralizer effluent is controlled by effluent conductivity, but periodic samples are taken of conductivity, TOC, silica, chlorides, and sulfates.

H. SPENT FUEL STORAGE POOL FILTERING AND COOLING SYSTEM

1.0 Design Bases

This system is designed to remove the spent fuel assemblies' decay heat and the impurities from the pool water so as to maintain the temperature and purity of the spent fuel pool water at acceptable levels, assuring clarity under all anticipated conditions. The pool water temperature is maintained at or below 140°F during maximum anticipated storage conditions. Normal refueling conditions are based on refueling the reactor every 24 months. During certain instances, it may be necessary to offload the entire core into the spent fuel pool. The maximum heat generation rate was determined by assuming a full core discharge (532 bundles) after 24 months, with the maximum number of previously discharged fuel bundles (3550) being present in the pool. The greatest portion of the decay heat would be produced by the bundles being discharged from the core, rather than those bundles which have been stored in the spent fuel pool from previous discharges. The long-term decay heat rate for GE11 fuel is essentially the same as for previous fuel designs. Therefore, the decay heat rate used as the basis for the spent fuel storage pool filtering and cooling system design remains unchanged.

Prior to Technical Specification Amendment No. 167, the spent fuel pool was licensed for 2776 storage cells. The north half of the pool contained 1066 nonpoison flux trap storage locations, and the south half provided 1710 locations using Boraflex as a neutron absorber. Currently, the spent fuel pool is licensed, per Technical Specification Amendment No. 167, for 4086 spent fuel storage locations using the neutron absorber material Boral, with 1840 storage locations in the north half of the pool and 2246 locations in the south half. The nonpoison racks in the north half of the pool were replaced with new poisoned racks after the 1999 refuel outage. The reracking of the south half of the pool has been partially completed. Six of the eight existing Boraflex racks have been replaced with new Boral racks, increasing the capacity from 1296 to 1656 storage locations. Two Boraflex racks remain in the south half, providing 414 storage locations. The rerack of the remaining two racks has been deferred until further capacity increase is warranted.

Unit 1 committed to the Nuclear Regulatory Commission (NRC) that refueling and core offloading operations would not begin until it was determined that the spent fuel pool cooling systems were operable, to ensure that the bulk pool temperature limits would not be exceeded.

For a normal (full core offload or core shuffle) refueling, the offload time to the spent fuel pool and the RBCLC temperatures shall be verified to be consistent with a bulk pool temperature not to exceed 140°F with one cooling train operating.

For the case of an abnormal maximum heat load (such as a full core offload shortly after a normal refueling), this would require verifying that offload time and RBCLC temperatures were consistent with a pool temperature <140°F with both cooling trains operating.

Based on past experience, sufficient clarity of the pool water can be achieved by a filter capable of removing particles as small as 25 microns in size.

2.0 System Design

The system is shown on Figure X-8. Two full-capacity (600 gpm) pumps take suction from the pool surge tanks and circulate the pool water through two parallel loops consisting of one filter and one heat exchanger. The water is returned to the pool on the side opposite the surge tank skimmers.

The spent fuel pool cooling (SFC) system is designed as seismic Category 1.

The SFC system bounding design conditions are that, under full core discharge conditions with RBCLC coolant water temperature at its maximum of 95°F, and assuming the SFC heat exchangers are fouled to their design maximum and 5 percent of the tubes are plugged, a pool water temperature of 140°F would be reached if a full core offload began 1008 hr after reactor shutdown, and was completed 1129 hr after reactor shutdown with one of the two redundant cooling trains operating.

A more expedited offload may be performed if the plant conditions exist to maintain the pool water temperature at or below 140°F with one SFC train operating.

Flow control valves regulate the flow in each loop at 600 gpm by use of a controller that may be operated in the auto or manual mode.

Cooling water is supplied to the heat exchangers from the RBCLCW system at temperatures not exceeding 95°F. A sample point is incorporated to determine any tube leakage.

Initial filling and level maintenance in the spent fuel pool and surge tanks was from the condensate transfer system. The total volume of the surge tanks is approximately 2000 cu ft. They will normally run at a level of approximately 1000 cu ft. The difference in surge tank volume allows for the displacement of water from the spent fuel storage pool when a shipping cask (or any other object) is placed in the pool.

Makeup water is provided by the condensate transfer system. Normally, makeup is directly to the spent fuel storage pool. Makeup to the spent fuel storage pool is automatically initiated when the surge tank volume decreases to 800 cu ft and stops when the volume reaches 1000 cu ft. If the makeup to the spent fuel storage pool is not sufficient to maintain surge tank volume, makeup water can be provided directly to the surge tanks. The condensate transfer system can provide a makeup rate of 75 gpm or more to either the spent fuel storage pool or the surge tanks. Makeup water can also be supplied directly to the spent fuel pool through fire water hoses.

Any particles that enter the pool either sink to the bottom to be removed by a portable vacuum cleaner or float about in the pool and eventually enter the skimmers, surge tanks and filtering loop. Provision is made for transferring water to the liquid waste disposal system for processing if the pool water becomes highly contaminated.

The precoat-type filters use porous carbon elements. Precoat material is powdered/crushed resins. One precoat mix tank and pump serves both filters. The slurry is circulated through the filter vessel and back to the tank until a uniform coating of precoat material covers all the elements. The filter is then placed in service until differential pressure signals the need for backwashing. The backwashing process consists mainly of first valving off and draining the filter, then filling the filter with condensate from the condensate transfer system. All vents are closed during this filling and air is trapped in the filter dome above the elements. When the pressure in the filter dome reaches approximately 80-100 psig, the drain valve is quickly opened and the filter cake, together with trapped impurities, washes into the fuel pool filter sludge tank. From the sludge tank the suspension of impurities and water is pumped to the waste disposal system.

Aside from its normal function of cooling and purifying the spent fuel pool water, the system is also used after reactor refueling to drain the reactor internals storage pit and head cavity. Alternate lines allow transport of the water to either the main condenser or to the waste disposal system for processing. In either case the water is filtered, demineralized and returned to the CSTs. Each major piece of equipment is designed to withstand seismic forces of 0.25g horizontally and 0.125g vertically. The ASME Boiler and Pressure Vessel Code, Section VIII-1965, is specified for pump casings, heat exchanger, filter vessels, and the sludge tank, as well as for the fuel pool surge tanks.

The fuel pool filters and the surge tanks are shielded with concrete to give a design radiation level of 5 mr/hr outside the shielded area.

3.0 Design Evaluation

Precoat-type filters capable of removing particles as small as 1 micron are provided, although experience indicates that 25-micron particle size filtration should be sufficient to maintain pool clarity.

Each pump filter heat exchanger loop is adequately sized to handle the normal heat load of the spent fuel storage facility, providing a complete standby loop. The two loops are adequate to handle the full core discharge storage heat load.

Various precautions are taken to assure minimum loss of water from the system. All penetrations into the pool are located at a minimum height from the bottom such that there will always be at least 1 ft of water above the fuel. Siphon breakers are used where necessary and the pumps are sealed externally. For flexibility, either pump may be used with a given filter heat exchanger loop.

Makeup water to the spent fuel storage pool is provided by the condensate transfer system. The condensate transfer system can be supplied emergency power from the diesel generators, ensuring the supply of makeup water in the event of loss of both normal and reserve ac power.

Makeup water is also available to the spent fuel storage pool through the fire protection system by the use of a water hose.

The fuel pool cooling system is controlled from a local panel. The Operator is provided with indications of system flow, pool water level, water temperature (on both sides of the heat exchangers), sludge tank level, and valve positions.

Alarms are provided on the annunciator and the computer for high- and low-pressure flow and temperature where critical.

The spent fuel pool system may be secured for maintenance for limited periods as long as: 1) the time available for the maintenance activity has been predicted by an approved calculation, which ensures the pool temperature will remain below 125°F; 2) the pool temperature is closely monitored during the maintenance activity to ensure the temperature does not exceed 125°F (the maintenance time available may be increased based on this empirical data); and 3) the condensate transfer system is available for makeup.

4.0 Tests and Inspections

All equipment in this system will be normally operated, as spent fuel and other components are stored in the pool. However, if equipment such as the spare pump filter heat exchanger loop should stand idle for some time, it will be exercised to assure that it operates properly.

I. BREATHING, INSTRUMENT AND SERVICE AIR SYSTEM

1.0 Design Bases

A reliable supply of clean, filtered air fit for human breathing is distributed to various areas of the Station. Breathing air is filtered and meets the specifications of ANSI Z86.1 Specification G-7.1 Grade D, 1973.

A reliable supply of clean dry air for use of instruments and controls is also provided. Air is supplied at a temperature not exceeding 100°F. The pressure of the instrument air system is controlled between a normal range of 95 and 105 psig, which is the maximum pressure required by some equipment in the Station.

A reliable supply of service air is provided for use in maintenance, alarm and trip functions for the preaction and drypipe fire sprinklers, and as a backup for the instrument air system and condensate filtration system (CFS) backwash air. Service air is supplied at a temperature not exceeding 100°F and at a pressure between a normal range of 98 and 105 psig. When the service air compressor is removed from service for maintenance, a portable air compressor can be used to maintain the service air pressure.

An air receiver with 2,000 cu ft in volume is provided for testing the containment spray system, as described in Section VII-B.

2.0 System Design

The system is shown on Figure X-9. Breathing air is supplied by one single-stage, 200-scfm, motor-belt driven, teflon ring, nonlube piston air compressor. Outside air is drawn through an intake filter from the turbine building roof, compressed, cooled, filtered of dust, and discharged into a 150-ft^3 receiver capable of supplying air to 12 men, at the rate of 7.0 cfm per man for 5 min, in the event of compressor failure. The system pressure is maintained between 93 and 105 psig.

In the event of failure of the breathing air compressor, breathing air can be supplied from the instrument air system. Breathing air will be supplied by the instrument air receiver passing through a dust filter, a solenoid blocking valve, and a check valve before discharging into the breathing air receiver. The check valve and automatic closure of the solenoid valve, when instrument air receiver pressure is 80 psig or less, prevents discharge of air from the breathing air receiver into the instrument air receiver should the instrument air system pressure fail. In addition, automatic closure of the solenoid valve prevents service air from entering the breathing air system, should the crosstie trip open and the check valve between the crosstie and the instrument air receiver fail to close. Closure of the solenoid valve is alarmed and ample breathing air remains to provide sufficient time to recall persons using breathing air.

At the various breathing air outlets, portable or fixed regulating stations are installed to reduce the air pressure from approximately 100 psig by 10-30 psig. Piping for the breathing air is brass and copper to avoid corrosion products.

Air for instruments, controls and as a backup to the breathing air system is supplied by one of the three instrument air compressors. There are two 485-scfm flange-mounted, motor-driven, teflon ring, nonlube piston, 2-stage compressors with a 150-cu ft receiver, and one 729-scfm belt/motor-driven, teflon ring, nonlube piston, 2-stage air compressor with a 210-cu ft receiver. The two 485-scfm compressors are separated from the one 729-scfm compressor by a normally open intertie valve, 94-91, located in the 4-in intertie line.

Outside air is drawn through separate intake filters for each instrument air compressor, compressed, cooled, and discharged into the receiver. Air from the receiver then passes through drying and filtering equipment to the instruments, controls, and to certain processes requiring high-pressure, oil-free air. This air is available in all buildings and at all levels.

Service air for use in maintenance and as a backup to the instrument air system and CFS system air compressor is supplied by one double-stage, nominal 500-scfm, flange-mounted, motor-driven, teflon ring, nonlube piston air compressor. Outside air is drawn through an intake filter from the turbine roof, compressed, cooled and discharged into a 151-cu ft receiver. Air from the receiver then is supplied to outlets maintaining a pressure between 98 and 105 psig not to exceed 100°F.

Service air provides backup for the instrument air. A crosstie is located after the instrument air receiver, but before the dryer and filters. It is set to trip open only if the instrument air supply pressure decreases below 90 psig. With the crosstie open, the system will continue to receive air.

Check valves located in the crosstie line prevent backfeeding of instrument air into the service air and of service air into the instrument air receiver.

The function of the containment spray system air test is covered in Section VII-B, Containment Spray System. During normal operation of the Station, the 2,000-cu ft containment spray system air test receiver is isolated from the containment spray system, and functions as an additional instrument and breathing air receiver. It is capable, together with the 150-cu ft instrument air receiver, of furnishing instrument air for at least 15 min after failure of the instrument air compressors, before air pressure would decrease to 75 psig and service air would be required for backup.

3.0 Design Evaluation

Clean dry air is provided in the system design for instrumentation, breathing, and containment spray system testing. The three instrument, one breathing and one service air compressors are of oil-free cylinder construction. Air passing through the instrument air dryers has its dew point lowered to -10°F. Upon exiting the dryer, instrument air passes through either of two parallel filters. The dual parallel filter arrangement allows filter maintenance to be performed during air system operation.

Instrument air servicing the waste disposal building and other radwaste systems passes through a refrigerant-type dryer and through either of two parallel filters.

Reliable operation of instrument air end users and in-line components is dependent on the filtration and removal of particulates greater than 40 microns. Additional filtration for various components exists where the 40 micron limit is not satisfactory.

System reliability is provided by redundancy of compressors, a large receiver system and the service air system crosstie.

The two 485-scfm instrument air compressors are each sized to furnish full system requirement on a duty cycle of approximately 75 percent or 85 percent duty cycle including air drying. The 729-scfm instrument air compressor is sized to furnish full system requirements on a duty cycle of approximately 50 percent or 60 percent including air drying. The two 485-scfm compressors are on standby. In the event that the duty compressor fails, one of the standby compressors automatically takes over the load. In addition, the 485-scfm compressors are available for operation in an emergency, since it is possible to operate the compressors and their cooling systems with power from the emergency diesel generators.

In the event the piping fails downstream of the 729-scfm instrument air compressor, intertie valve 94-91 will close at approximately 89 psig as sensed in the 4-in intertie line. This will allow the two 485-scfm compressors to continue to supply their loads. The presence of nonsafety-related loads on the safety-related air system does not degrade reliability and performance of the instrument air system.

The large receiver capacity and the combination of the control air receiver and the containment spray system air test receiver provides at least 15 min of instrument air at pressures above 75 psig, should all three of the instrument compressors fail. At the conservative setting of 90 psig, the service air system crosstie trips open and the system requirements are provided for by the service air system.

The redundancy and reliability provided in this system are necessary since loss of instrument air would necessitate shutdown of the Station. An analysis of the effects of an instrument air failure is given in Section XV, Instrument Air Failure Malfunction Analysis.

4.0 Tests and Inspections

Compressor duty will be rotated between compressors on a scheduled basis, providing opportunity to observe the operation and performance of all compressors.

Critical temperatures and pressures are continuously monitored and alarmed. Surveillance of the system filters is accomplished by monitoring and alarming the differential pressure across the filters.

Normally prior to refueling, the fresh fuel is transferred to the spent fuel storage pool using the 25-ton auxiliary overhead hoist.

In preparation for refueling, the concrete shield plugs in the reactor head cavity and the transfer canals are removed by the reactor building crane. The drywell head and reactor vessel head are removed using the same crane.

The steam dryer and the steam separator assemblies are transferred to the reactor internals storage pit. Water levels are controlled such that the steam separator is transferred submerged.

During the disassembly process, demineralized condensate is pumped into the reactor until the head cavity and the reactor internals storage pit are flooded to the normal level of the spent fuel storage pool. The spent fuel storage pool gates are removed after the water level has reached the normal level of the spent fuel storage pool.

Spent fuel is removed from the reactor using a grapple attached to the refueling platform and placed in racks in the spent fuel storage pool. The same equipment is used to transfer the fuel from the spent fuel storage pool to the reactor.

At the completion of reactor refueling, the moisture separator, steam dryer and reactor head are put back into place following the proper maintenance procedures. The drywell head and concrete shield blocks are then restored.

After refueling, the spent fuel bundles are stored in spent fuel storage pool racks. They will remain there until NRC resolution of disposal problems is finalized.

3.0 Design Evaluation

The spacing of fuel bundles in the fresh fuel storage vault maintains k_{eff} <0.95 even if flooded with water. The vault floor drain prevents flooding. The spacing of fuel bundles in the spent fuel storage pool maintains k_{eff} <0.95. A criticality monitor in the fresh fuel storage vault provides warning in the unlikely event of a criticality incident.

Protective interlocks prevent handling of fuel over the reactor when a control rod is withdrawn. Another set of interlocks prevents control rod withdrawal when fuel is being handled over the reactor. Limit switches on the refueling platform hoists interrupt power to the hoists when the TAF is 8 ft below the surface of the water. Brakes on all equipment lock upon loss of power. Spent fuel will not be inadvertently handled with an inadequate depth of water shielding.

The above interlocks can be bypassed to permit the unloading of a significant portion of the reactor core (full core offload, spiral offload) for such purposes as removal of temporary control curtains, CRD maintenance, inservice inspection (ISI) requirements, examination of the core support plate, etc. (Technical Specification 3.5.3).

Fuel stored in the spent fuel storage pool is covered by a minimum of 24 ft of water. Irradiated fuel being moved is at all times covered by a minimum depth of 8 ft of water over TAF, except that the fuel preparation machine is provided with mechanical stops to ensure that active fuel remains under 7 ft of water. Spent fuel pool water level is automatically controlled to ensure that during normal operation, spent fuel will be covered by a sufficient depth of water to permit unrestricted access to the operating floor.

The spent fuel storage pool cannot be completely drained. If draining should be initiated due to Operator error, level alarms will notify operating personnel and makeup water will be supplied automatically. If no action were taken, the fuel would still be covered by approximately 1 ft of water after the pool had drained down to the lowest penetration.

All reactor servicing operations are carried out within the secondary containment, which is described in Section VI-C. A bypass around the refueling platform radiation monitor will allow the monitor to be connected into the RPS during refueling operations or when irradiated fuel or a fuel-loaded shipping cask is being handled. This monitor provides a fast automatic isolation of the reactor building ventilation system and initiation of the reactor building emergency ventilation system.

4.0 Tests and Inspections

During testing prior to initial reactor fueling, the spent fuel storage pool, reactor head cavity, and reactor internals storage pit were filled with water and checked for leakage. Dummy fuel assemblies were run through a complete cycle from the fresh fuel storage vault to the spent fuel storage pool.

During normal operation, telltales are examined for evidence of potential leakage from the spent fuel pool. Prior to fuel handling, all hoists, cranes and tools are inspected and tested to assure safe operation.

ensures the review of daily operations to ensure they do not compromise the level of fire safety at the plant.

2.2 Fire Protection Administrative Controls

These site procedures ensure that daily operations at the plant, including maintenance and modification activities, are carried out in a fire-safe manner. Administrative controls are provided in the following areas:

Control of combustibles (both transient and permanent)
Control of ignition sources
Control of fire detection and suppression system outages
Control of breaches of passive fire protection features
Fire watch activities

2.3 Fire Protection System Drawings and Calculations

Proper surveillance and maintenance of fire protection systems is predicated on adequate, up-to-date drawings of the systems and supporting calculations.

2.4 Fire Protection Engineering Evaluations (FPEEs)

Unit 1 has committed to compliance with numerous industry consensus standards and NRC regulations/recommendations. When appropriate, Unit 1 has taken exception to these commitments. These exceptions/deviations are made on the basis of an engineering evaluation, approved by a Fire Protection Engineer, of the equivalent features proposed in lieu of full compliance.

3.0 Monitoring and Evaluating Program Implementation

The following documents are used to monitor and evaluate the implementation of the fire protection program.

3.1 Quality Assurance Program

Elements of the Quality Assurance Program, as described in the Quality Assurance Topical Report (QATR), are implemented for the Fire Protection Program as discussed in Section 2.3 of Appendix 10A.

3.2 Fire Brigade Manning, Training, Drills and Responsibilities

The Site Fire Brigade has the primary responsibility for responding to fire alarms at the plant and ensuring fire extinguishment. In the event of a major fire, outside fire department assistance will be obtained, but fire-fighting operations will remain under the direction of the Fire Chief.

4.0 Surveillance and Tests

Surveillance and test procedures, carried out by the Fire Brigade, Instrumentation & Controls (I&C), and/or Operations, ensure the readiness of installed fire protection features/systems to perform their intended function.

The fire protection systems necessary to support the conclusions of the SSA are critical. These critical systems are specifically identified and listed in the FHA, along with the surveillance requirements and compensatory actions (when a system is not operable). The surveillance procedures associated with each of these critical systems are an important element of the fire protection program.

M. HYDROGEN WATER CHEMISTRY AND NOBLE METAL CHEMICAL ADDITION (NOBLECHEM) SYSTEMS

1.0 Design Basis

The HWC and NMCA systems are provided to mitigate intergranular stress corrosion cracking (IGSCC) of the recirculation piping and the reactor vessel internals. Mitigation of IGSCC in operating boiling water reactors (BWR) can be effectively accomplished by reducing the bulk liquid oxidant (oxygen and hydrogen peroxide). Hydrogen added to the feedwater suppresses the radiolytic generated oxidant concentration in the core regions, and enhances the recombination reactions in the downcomer. The reduction in oxidant level can reduce the ECP significantly and crack initiation and growth also are greatly reduced, even at high bulk liquid oxidant levels. Reducing the ECP requires high hydrogen addition rates which result in increased main steam line radiation levels from volatile ^{16}N compounds. The catalytic behavior of noble metals provides an opportunity to efficiently achieve a dramatic reduction in ECP by catalytically reacting hydrogen with all oxidants at the catalytic surface.

NobleChem employs the reactor coolant as the transport medium to deposit minute amounts of noble metal on all wetted reactor components. With the ratio of hydrogen to oxygen in excess of stoichiometric, the corrosion potential of the reactor vessel and internal components decreases significantly, and crack initiation and growth also are greatly reduced, even at high bulk liquid oxidant levels.

Low hydrogen addition rates are still necessary to provide sufficient excess hydrogen at the surface of NobleChem treated components. Oxidants that diffuse to the component surface will immediately react with the excess hydrogen (molar ratio of hydrogen to oxidant >2) to form water. In this way, the boundary layer of all NobleChem wetted components is depleted of oxidants and a very low corrosion potential is maintained. In summary, NobleChem utilizes very reactive surfaces to maintain oxidant deficient water in contact with reactor components. Therefore, because of the lower operational dose rates, the NobleChem process in conjunction with low hydrogen addition rates is an effective approach to mitigate and prevent IGSCC.

1.1 Noble Metal Chemical Addition System

The NMCA process involves periodic injection of noble metal compounds using either the classic method or the on-line method.

Classic Hot Shutdown Application

The classic method involves periodic injection of noble metal compounds, containing platinum (Pt) and rhodium (RH), into the recirculation loop(s) and into the reactor vessel, through existing small bore piping connections in the recirculation pump differential pressure transmitter lines. The noble metal compounds are deposited on reactor internal surfaces with the reactor in hot standby condition. The noble metal compounds are distributed by circulating coolant using 3 of 5 recirculation pumps. The resulting coolant flow across the core and core shroud is relatively uniform enhancing proper deposition on wetted surfaces. Appropriate water level in the reactor vessel is maintained by operating the CRD and the RWCU systems. Normal reactor coolant makeup is available per operations procedures for this hot shutdown condition.

The classic noble metal deposition process lasts approximately 48 hr, with the coolant temperature maintained between 250°F and 350°F as required by the General Electric-Nuclear Energy (GENE) Application Procedure. The exact temperature during the application within this range is a GENE process decision, as is the rate of chemical injection. During the process period, a combination of the recirculation pumps and shutdown cooling is used to regulate the coolant temperature.

On-Line Power Operations Application (OLNC)

The OLNC process only injects the platinum compound [$NA_2Pt(OH)_6$] into the reactor vessel through the feedwater system during power operation. To get sufficient catalyst into the cracks and crevices, and stay within nominal chemistry control limits during normal reactor operation, the rate of Pt injection must be significantly reduced and the period of injection increased as compared to the classic NobleChem process (which has injection rates as high as 40g per hour). As a minimum, a typical time period for on-line application is expected to be about 2 weeks (and injection rates less than one-tenth of the classic process).

The noble metal compounds are deposited onto all surfaces that come into contact with the moving reactor coolant in the applicable temperature range. For example, at a nominal deposition of $1 \mu g/cm^2$, the uniform coverage is approximately one atom layer of 3 Å thickness (1 Å is 1×10^{-7} mm or 3.94×10^{-9} in). Surface scans of autoclave treated specimens have shown that the noble metal atoms present on the surface do not completely cover the surface, but are distributed randomly across the surface. On an atomic scale, the deposited noble metals are discontinuous. Even with agglomeration, the maximum thickness of Pt and Rh is significantly less than 0.001 in, which is less than the minimum manufacturing tolerances of the vessel components (e.g., the tolerance of the fuel Zircaloy tubes is 0.003 in and the Zircaloy channels is 0.004 in).

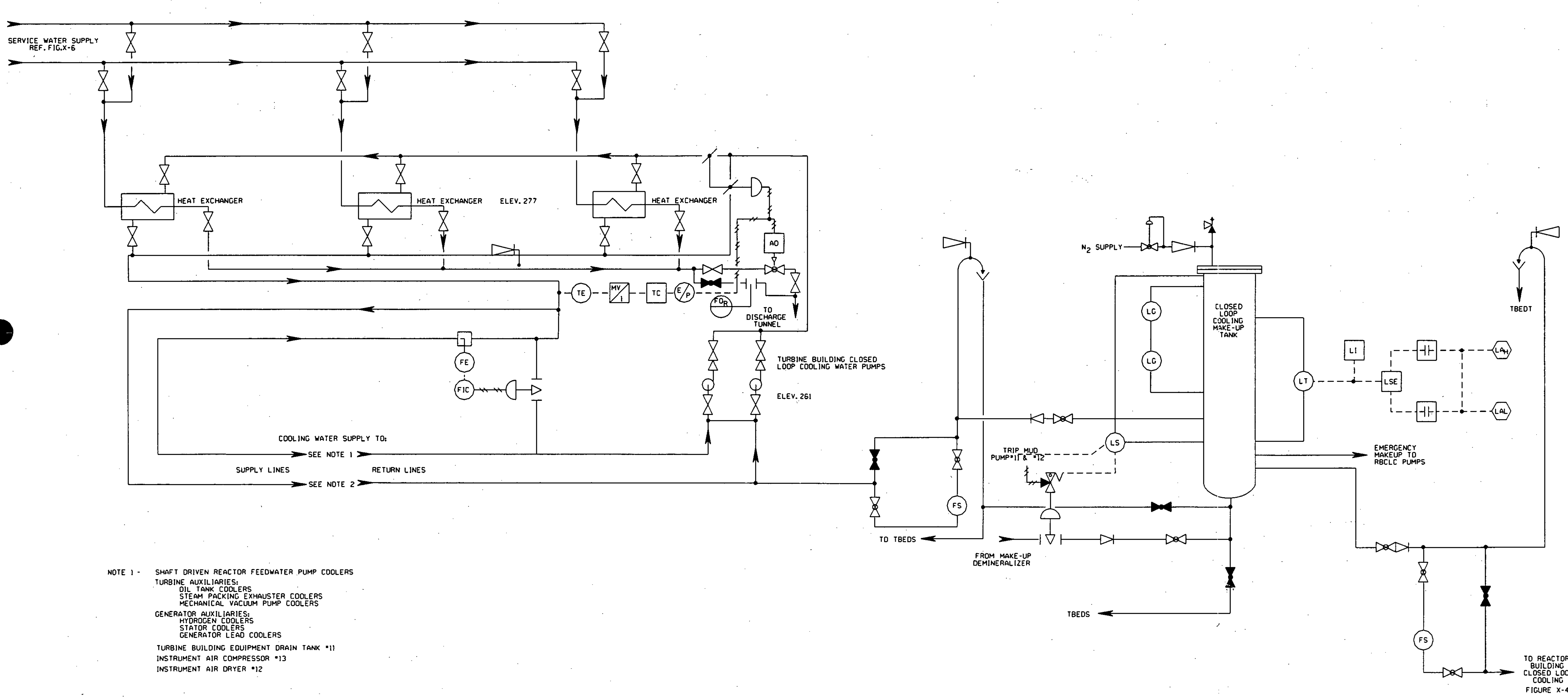
1.2 Hydrogen Water Chemistry System

The HWC system injects hydrogen into the feedwater system at the suction to the feedwater booster pumps. The injected hydrogen causes a reduction in dissolved oxygen within the reactor internals and recirculation piping and lowers the radiolytic production of hydrogen and oxygen in the vessel core region. Hydrogen addition to the feedwater results in an excess ratio of hydrogen to oxygen at the entrance to the offgas (OFG) system. Therefore, the HWC system also provides an oxygen supply upstream of the OFG recombiner to maintain stoichiometric mixture of hydrogen and oxygen in the recombiner.

With the suppression of radiolysis, the main steam line dissolved oxygen concentration decreases. This can result in lower condensate and feedwater dissolved oxygen concentrations. If the condensate and feedwater dissolved oxygen concentration values are less than 20 ppb, accelerated carbon steel corrosion can occur. Unit 1 has an existing oxygen injection system to add oxygen to the condensate feedwater system. The HWC system has a provision to supply oxygen to supplement the existing oxygen injection system for the condensate feedwater system.

THIS PAGE INTENTIONALLY BLANK

TURBINE BUILDING CLOSED LOOP COOLING SYSTEM



NOTE 1 - SHAFT DRIVEN REACTOR FEEDWATER PUMP COOLERS
TURBINE AUXILIARIES:
OIL TANK COOLERS
STEAM PACKING EXHAUSTER COOLERS
MECHANICAL VACUUM PUMP COOLERS
GENERATOR AUXILIARIES:
HYDROGEN COOLERS
STATOR COOLERS
GENERATOR LEAD COOLERS
TURBINE BUILDING EQUIPMENT DRAIN TANK #11
INSTRUMENT AIR COMPRESSOR #13
INSTRUMENT AIR DRYER #12

NOTE 2 - RECIRCULATING PUMP MOTOR GENERATOR SET COOLERS
HOUSE SERVICE AIR COMPRESSOR
SAMPLE COOLERS
BATTERY ROOM 14 AIR CONDITIONER
CONDENSATE FILTRATION SYSTEM AIR COMPRESSOR

FIGURE X-5
UFSAR Revision 20
October 2007

FIRE HAZARDS ANALYSIS

TABLE OF CONTENTS

FIRE HAZARDS ANALYSIS

TABLE OF CONTENTS (Cont'd.)

FIRE HAZARDS ANALYSIS

TABLE OF CONTENTS (Cont'd.)

FIRE HAZARDS ANALYSIS

TABLE OF CONTENTS (Cont'd.)

FIRE HAZARDS ANALYSIS

TABLE OF CONTENTS (Cont'd.)

FIRE HAZARDS ANALYSIS

TABLE OF CONTENTS (Cont'd.)

FIRE HAZARDS ANALYSIS

TABLE OF CONTENTS (Cont'd.)

THIS PAGE INTENTIONALLY BLANK

This training program for the Brigade members consists of a combination of classroom sessions and in-plant inspection of site-specific applications of classroom sessions.

Members of the Fire Brigade attend a company-approved fire school annually to provide Fire Brigade work experience in actual fire extinguishment and the use of emergency breathing apparatus under strenuous conditions.

Local fire department personnel are periodically trained in the operational precautions of fighting fires at nuclear power plant sites. In addition, orientation is provided regarding radiation protection at the nuclear station.

2.2.7 Training Guidance

Where applicable, Brigade organization, training and the conduction of fire drills follows the guidance provided by applicable standards of the NFPA Codes. Guidance provided by the fire protection industry is also considered in the development of Fire Brigade training lesson plans.

2.3 QUALITY ASSURANCE PROGRAM

The quality assurance program for fire protection is part of the overall quality assurance program, and applies the criteria of BTP APCSB 9.5-1, Appendix A, dated August 23, 1976. Elements of the Quality Assurance Program, as described in the Quality Assurance Topical Report (QATR), are implemented for the Fire Protection Program as described below.

1. <u>Design Control</u> Design control for fire protection systems, equipment and components is performed in accordance with the following:

    a. Design information (e.g., drawings, specifications and standards) is maintained to ensure that items are designed to the applicable requirements. Applicable work documents invoke design documents as necessary to ensure proper fabrication, inspection and testing.

    b. Design document changes, including field changes and design deviations, are subject to the same level of control, review and approval that was applied to the original design document.

Modifications are performed in accordance with the current plant modification program.

c. Quality standards are specified in the design documents. Appropriate fire protection codes and standards are incorporated in the design documents. Deviations and changes from these design documents are controlled and require approval of the specifying organization.

d. New designs and plant modifications are controlled and reviewed by qualified personnel to assure inclusion of appropriate fire protection requirements. These reviews are performed by selected personnel in accordance with implementing procedures.

2. Procurement Document Control The procurement document control requirements discussed in the applicable section of the QATR apply to the Fire Protection Program. Fire protection items are procured as specified in design documents. Items specified as requiring a listing by an industry organization, such as Underwriters' Laboratories (UL) or Factory Mutual, will be procured with the required listing mark. Design, test, inspection and documentation requirements are included in procurement documents as necessary to assure that the item will perform its intended function. Personnel preparing procurement requirements incorporate these requirements. Input from a Fire Protection Engineer is obtained, as necessary, to accurately define the requirements.

3. Instructions, Procedures, and Drawings Inspections, tests, administrative controls, fire drills and training required by the Fire Protection Program are accomplished in accordance with approved instructions, procedures or drawings.

4. Control of Purchase Material, Equipment and Services Assurance that a fire protection item will perform its intended function is obtained using one or a combination of the following methods:

a. When an item is listed by an industry-recognized testing laboratory, it is verified that the appropriate label is applied.

b. Supplier qualification may be performed to establish that a supplier has the necessary controls in place to assure the items comply with procurement requirements.

c. Source surveillance/inspection and/or receipt inspection is performed on selected attributes which provide confidence that the item is satisfactory.

d. Post-installation testing of an item for critical characteristics is conducted which provides confidence that the item will perform its intended function.

General use items not procured specifically for fire protection applications may be used in fire protection applications. This includes items such as standard hardware items and gaskets. The attributes which require verification are selected by an engineering evaluation. Sample plans may be used which are commensurate with the application of the item. The above functions are performed in accordance with procedures which govern these activities. After acceptance, items are controlled to prevent degradation during storage. Where specific applications are identified, controls are used to prevent misapplication.

5. Inspection A program for inspection and surveillance, as required, for activities affecting fire protection is established to the requirements of the applicable sections of the QATR to verify conformance to documented installation drawings and test procedures. The program includes inspection and surveillance of:

a. Installation, maintenance and modification of fire protection systems.

b. Emergency lighting and communication equipment.

c. Penetration seals and fire-retardant coating.

d. Cable routing.

e. Fire barriers.

f. Emergency breathing apparatus and auxiliary equipment.

6. Test Control A test program is established for fire protection systems, equipment and components and has been implemented to ensure that test requirements are satisfied and that systems conform to design and licensing documents, as applicable. The tests are performed in accordance with written test procedures at a frequency specified by the test program. Test results are documented, evaluated, and their acceptability determined by a qualified individual or group.

7. Control of Measuring and Test Equipment Validity of inspection, surveillance and test results for fire protection systems, equipment and components is assured through the use of appropriate measuring and test equipment of the range, validity and type necessary to determine conformance to requirements. At intervals established to ensure continued validity, measuring devices are verified or calibrated, if appropriate, against certified standards that have a known, valid relationship to national standards.

8. Inspection, Test and Operating Status Measures are established to provide for the identification of fire protection items that have satisfactorily passed required tests and inspections. These measures include provisions for identification by means of tags, labels, documents directly traceable to the affected items, or similar temporary markings to indicate completion of required inspections and tests. Operating status may also be indicated by any of the foregoing means, consistent with plant operating procedures.

9. Nonconforming Materials, Parts or Components Measures are established to control fire protection materials, parts or components that do not conform to specified requirements. The identification (tagging or marking), documentation, segregation, review, disposition and notification to the affected organization of nonconforming materials, parts or components is procedurally controlled.

10. <u>Corrective Actions</u> Conditions adverse to fire protection such as failures, malfunctions, deficiencies, deviations, defective components, uncontrolled combustible material, and nonconformances are promptly identified, reported and corrected. Documentation describes the condition adverse to fire protection, the nonconforming item, and records of the corrective action taken.

THIS PAGE INTENTIONALLY BLANK

2.4 GENERAL GUIDELINES FOR PLANT PROTECTION

2.4.1 Building Design

2.4.1.1 Plant Layout

Fire hazards have been identified and suitable protection has been provided for areas with potential exposures to safety-related equipment. The level of protection may include, but is not limited to, spatial separation, fire detection systems, fire-rated enclosures, and fire suppression systems. Hazardous locations with appropriate means of protection are described in various sections of this evaluation.

Redundant safe shutdown systems are separated in accordance with the requirements of 10CFR50 Appendix R, Section III.G. Where redundant safe shutdown trains could not be separated due to the nature of the area (e.g., control room), alternate means to bring the plant to cold shutdown have been provided. Based on the results of the Unit 1 SSA, a single fire will not incapacitate the ability to achieve hot shutdown and, in most cases, achieve and maintain cold shutdown. In several fire areas, damage repair procedures (DRP) may be necessary to achieve and maintain cold shutdown.

2.4.1.2 Fire Hazards Analysis

A systematic fire hazards analysis of each structure at Unit 1, including the yard, has been performed and documented in Section 3.0. Each building evaluation includes the following:

a. Building Name

b. Introduction/General Information

c. Safety-Related System Status

d. Post-Fire Analysis

e. Radioactive Release Analysis

f. Fire Detection/Suppression System(s)

In addition, a summary hazards analysis has been provided for each fire zone in Tables 3.1.1-1 through 3.1.1-9, which indicates zone number, area description, fire loading, and installed fire detection/suppression systems.

2.4.1.3 Cable Spreading Rooms

The cable spreading rooms are not shared between reactors at the Nine Mile Point site. The walls and ceiling are 3-hr rated fire barriers. Redundant safety division cabling is not separated by fire barriers for this room. The entire room is protected by an automatic smoke detection system, an automatic preaction sprinkler system and a manual total-flooding CO_2 suppression system. Additional information is provided in Section 3.4.

2.4.1.4 Interior Finish

Interior wall and structural components, thermal insulation materials, radiation shielding materials, and soundproofing are noncombustible or have been reviewed for overall impacts to the fire protection program. The use of combustible materials is minimized to the greatest extent possible.

Interior finish materials have flame spread, smoke and fuel contribution ratings of 25 or less. Any exceptions to these ratings are reviewed for overall impacts to the fire protection program.

2.4.1.5 Roof Deck Construction

Metal deck roof construction is listed as Class I by the Factory Mutual System Approval Guide.

2.4.1.6 Suspended Ceilings

Suspended ceilings and their supports are of noncombustible construction. Storage of materials above suspended ceilings is prohibited.

2.4.1.7 Indoor Transformers

Only dry-type transformers are used within buildings at Unit 1. The transformers are generally located at the end of plant power boards.

2.4.1.8 Outdoor Transformers

The Unit 1 oil-filled transformers are located outside of the southwest corner of the turbine building. These transformers are separated from interior safety-related equipment by an 8-in precast concrete wall up to el 285'. The metal wall above el 285' is provided with a manually-initiated water curtain system to protect the turbine building and contained equipment from a transformer exposure fire. The transformers are identified as follows:

abnormal degradation are found, a visual inspection of an additional 10 percent of that type of sealed penetration shall be made for each unsatisfactory finding. This inspection process shall continue until a 10 percent sample with no significant changes in appearance or abnormal degradation is found. Samples shall be selected so that each penetration seal will be inspected at least once every 10 cycles.

b. A visual inspection of a fire barrier penetration after repair or maintenance, prior to restoring barrier penetration to functional status.

2.4.2 Control of Combustibles

2.4.2.1 In Situ Combustibles

Safety-related systems at Unit 1 are protected from in situ combustibles by any one or a combination of the following methods:

a. Fire rated barriers.

b. Automatic fire suppression and detection systems.

c. Spatial separation between the combustible material and the identified equipment.

d. Engineered design provisions to limit potential exposure.

Allowance for transient combustibles, which may increase to the total combustible loading of the area, is included in the FHA Summary Tables (reference Tables 3.1.1-1 to 3.1.1-9).

2.4.2.2 Bulk Gas Storage

Bulk gas storage is not permitted within structures housing safety-related equipment. Bulk hydrogen and nitrogen storage tanks are located outside with their long axes parallel to the turbine building. However, the hydrogen and nitrogen storage tanks are perpendicular to the west wall of the reactor building (reference Section 3.11.1).

The use of compressed gasses inside site structure is controlled.

2.4.2.3 Plastic Materials

Originally-installed cables are largely polyvinyl chloride (PVC) jacketed. The insulation associated with safety-related cables purchased and installed since the middle of 1974 meets the requirements of IEEE-383 flame test. The insulation associated with nonsafety-related cables purchased and installed since the middle of 1974 also generally meets the requirements of IEEE-383 flame test, except those routed totally in conduit. Other requirements of cables and cable trays are discussed in Section 2.4.3. The use of plastic materials in construction for permanent plant facilities is minimized.

2.4.2.4 Flammable Liquids

Flammable liquids are stored in accordance with NFPA 30, Flammable and Combustible Liquids Code. Fire suppression and/or detection systems are provided for identified storage areas.

Generation administrative procedures control the use and storage of flammable and combustible liquids outside the bulk storage areas.

2.4.3 Electric Cable Construction, Cable Trays and Penetrations

2.4.3.1 Cable Trays

Noncombustible materials are used in the construction of cable trays.

2.4.3.2 Cable Spreading Rooms

This room is protected by total-flooding CO_2, preaction sprinkler and smoke detection systems. Manual fire hose stations and portable extinguishers have been provided for this area. See Section 2.6.3 for detailed discussion.

2.4.3.3 Sprinkler Protection

Automatic preaction sprinkler systems are installed to protect open, safety-related cable trays which are stacked more than two trays deep. Early-warning smoke detection is provided to facilitate system operation. Manually-operated hose stations are provided in the vicinity of the protected cable trays. Where identified, safety-related equipment in the vicinity of such cable trays has been protected if damage may occur from sprinkler operation. Specific design requirements of RG 1.75 are not all satisfied. The application of fire-retardant coatings to safety-related cable trays has been limited to those occurrences where sprinkler protection may not be the most desirable means of protection due to the equipment location in the area (i.e., over safety-related power boards). This coating is used primarily to prevent ignition and limit propagation of fire in the application areas. New cables installed in these trays shall be protected by engineering design in lieu of the application of fire-retardant coatings.

Based on the identified design provisions, the level of protection provided should prevent significant fire propagation and assist in cable tray suppression activities.

2.4.3.4 Cable Penetrations

Fire barrier penetrations use approved penetration seal details. The subject configurations have been tested to establish a 3-hr fire rating.

2.4.3.5 Fire Breaks

Fire breaks are provided in vertical cable trays which pass through nonrated floor/ceiling assemblies to limit the vertical propagation of fire along the tray through the building. If required by evaluation of modification activities, fire stops may also be placed in horizontal cable trays to limit horizontal propagation of fire in lieu of coating/recoating cable with a fire-retardant coating.

2.4.3.6 Cable Construction

Originally-installed cable construction does not comply with the requirements of the IEEE-383 flame test. The insulation associated with safety-related cables purchased and installed since the middle of 1974 meets the requirements of IEEE-383 flame test. The insulation associated with nonsafety-related cables purchased and installed since the middle of 1974 also generally meets the requirements of IEEE-383 flame test, except those routed totally in conduit. Protection for existing cable trays which contain nonqualified cable is discussed in Section 2.4.3.3 above.

2.4.3.7 Cable Decomposition

To the extent possible, new cable installations meet the requirements of IEEE-383. Selection of cable in this manner should minimize the installation of cable which may generate corrosive gasses during combustion.

2.4.3.8 Cable Run Exclusions

Only cable is permitted in cable trays or conduits. Cables are not installed in floor trenches or culverts. Miscellaneous storage is prohibited in cable trays, in addition to piping for combustible or flammable liquids or gasses.

2.4.3.9 Cable Tunnel Design

Unit 1 does not utilize cable tunnels and culverts. The cable spreading room is provided with venting capability. This is discussed in Section 2.4.4.

2.4.3.10 Control Room Cables

Cables in the control room are kept to the minimum necessary for operation. Cables entering the control room terminate there.

There is not a concealed floor in the control room or the auxiliary control room.

2.4.4 Ventilation

2.4.4.1 Products of Combustion Removal

All safety-related areas use the installed once-through ventilation to remove products of combustion.

Return air is monitored by the stack monitor prior to release by the stack to determine if the release is within the permissible

c. At least once per 12 months by cycling each manually operable valve through one complete cycle.

d. At least once per 12 months by a flush of the hydrants.

e. At least once per operating cycle.

1. By performing a system automatic start on low header pressure.

2. By verifying that each pump will develop a flow of at least 2500 gpm at a pump discharge of 115 psig.

3. Cycling each valve in the flow path that is not testable during plant operation through at least one complete cycle of full travel.

4. Verifying that each automatic valve in the flow path actuates to its correct position.

f. At least once per 5 yr by performing a flow test of the system in accordance with the NFPA Fire Protection Handbook.

2.5.2.3.2 The fire pump diesel engine shall be demonstrated operable:

a. Daily by checking the starting air tank pressure.

b. At least once per 31 days by verifying:

1. That the fuel day storage tank contains at least 150 gal of fuel.

2. The fuel storage tank contains at least 1000 gal of fuel.

3. The fuel transfer pump starts and transfers fuel from the storage tank to the day tank.

4. The diesel starts from ambient conditions and operates for ≥ 30 min on recirculation flow.

5. The method of starting the diesel fire pump engine will alternate between the normal air start method and the low air pressure start.

c. At least once per 92 days by verifying that a sample of diesel fuel from the fuel storage tank, obtained in accordance with ASTM Standards, is within the acceptable limits specified by ASTM Standards with respect to viscosity, water control and sediment.

d. At least once per six months by using the manual bypass of the solenoid on the starting air system.

e. At least once per 18 months, subjecting the diesel to an inspection in accordance with procedures prepared in conjunction with its manufacturer's recommendations for the class of service, and verifying the diesel starts from ambient conditions on the auto-start signal and operates for ≥30 min while loaded with the fire pump.

2.5.2.4 Water Supply Redundancy

The source of water supply to the fire pumps is Lake Ontario. Each pump takes suction from the service water intake tunnel. Unit 2 fire pumps (rated at 2,500 gpm at net discharge pressure of 125 psig) also take suction from Lake Ontario through a separate and remote intake tunnel. The fire main loops for Unit 1 and Unit 2 are interconnected in two places with normally closed valves, one remotely operable from the Unit 1 control room.

2.5.2.5 Water Supply Capacity

Unit 1 water supply for the fire protection system is designed to provide protection for the following demand:

In the event one fire pump is OOS, a maximum water supply of 3,000 gpm at 90 to 100 psig would be available at the administration building. The maximum demand would occur in the event of a fire at the Unit 1 main transformer no. 2. An initial operation of the water deluge system would result in a demand of 1,400 gpm and 1,000 gpm for hose lines at 97 psi.

2.5.2.6 Lake Supply

The fire pumps have separate water intakes, but are located in the same supply water sump which also feeds the service water system. This sump is part of the UHS intake from Lake Ontario. Sufficient water is available for both systems, and a failure of the fire protection system does not affect the service water system.

2.5.2.7 Yard Hydrants

Yard fire hydrants are installed approximately every 250 ft on the yard main system. Each yard hydrant is provided with a curb box-operated hydrant isolation valve.

Sufficient equipment is provided to establish an effective hose stream.

Couplings and equipment are compatible with local fire department thread design.

The following surveillance requirements will be initiated and corrective actions will be taken when deficiencies are identified for the hydrants which protect safety-related equipment in the yard area.

Action

With one or more of the two safety-related yard fire hydrants (hydrants 3 or 4) inoperable, route sufficient lengths of 2 1/2-in diameter hose to provide service to the unprotected area(s) within 1 hr, if the inoperable fire hydrant is the primary means of fire suppression; otherwise, route an additional hose within 24 hr.

2.5.2.7.1 Surveillance

Yard fire hydrants 3 and 4 with associated equipment shall be demonstrated operable:

a. At least once per 12 months by visual inspection of the associated fire hydrant equipment to assure equipment is available at the Unit 1 administration building vestibule.

b. At least once per 12 months during September, October, or November by visually inspecting each yard fire hydrant, and verifying that the hydrant barrel is dry and that the hydrant is not damaged.

c. At least once per 12 months (36-month interval if hose is stored inside a building) by:

    1. Conducting a hose hydrostatic test at a pressure at least 50 psig greater than the maximum pressure available at any yard fire hydrant.

2. Replacement of all degraded gaskets in couplings.

2.5.3 Water Sprinklers/Standpipe System

2.5.3.1 Supply Arrangement

Each automatic sprinkler and manual hose station standpipe have independent connections to the water supply system for safety-related structures. Sprinkler systems and manual hose station standpipes are connected to the building/underground supply main and arranged so that a single failure will not impair both the automatic fire protection system and a manual means to provide backup protection. Building supply mains make multiple connections to the underground water supply system to minimize service interruptions during a single-failure event. The building supply mains are considered to be an extension of the yard main.

Standpipe risers and sprinkler system supply headers are equipped with manually-operable supply isolation valves (e.g., OS&Y). Automatic sprinkler systems are provided with switches (e.g., pressure, flow) which indicate waterflow through these systems in the form of an alarm at their respective LFCP and the MFCP. Drain and test valves are provided with each system. Protection of water-sensitive equipment from suppression system operation is addressed in Section 2.1.5.

2.5.3.2 Valve Supervision

Water supply system valves up to sprinkler system control valves and hydrant isolation valves are supervised in the correct position through the use of one or more of the following methods:

a. Electric supervision

b. Periodic valve position verification

c. Chained and locked

d. Tamper seals

2.5.3.3 Sprinkler System Design

The sprinkler and water spray systems for Unit 1 conform to the requirements of NFPA 13, Standard for the Installation of

Sprinkler System, and NFPA 15, Standard for Water Spray Fixed Systems, as applicable.

The Station's preaction systems employ closed-head sprinklers and are controlled by preaction deluge valves with alarm check valves. The preaction valves are kept closed with fire system water pressure, and open when the pressure is released from the top chamber. The pressure is released by opening an electric motor-operated valve (MOV) that is controlled automatically by the area fire detection devices or manually from the LFCPs. In the event of power failure or an inoperative detection system, each preaction valve can be manually tripped by opening the manual release valve at the preaction valve location. A pressure switch transmits an alarm to a LFCP and the MFCP indicating water flow. The sprinkler piping is supervised by pressurizing the piping with 18-25 psig air. A low air pressure switch will activate an alarm at the respective LFCP or the MFCP in the event of air loss due to leaks, pipe breaks, or a loss of a sprinkler head.

The Station's dry-pipe systems employ closed-head sprinklers and are controlled by dry-pipe valves. The dry-pipe valves are kept closed with 40-50 psig air pressure in the sprinkler piping. The valves are actuated by loss of air pressure caused by the opening of a sprinkler head. There are pressure switches that activate

THIS PAGE INTENTIONALLY BLANK

Action

With one or more of the above-required Halon 1301 systems inoperable, within 1 hr implement one of the following actions:

a. Verify the operability of fire detectors within the area protected by the system and establish a daily inspection of the area to verify no increase in fire hazards, or

b. Establish a continuous fire watch with backup suppression equipment, or

c. Implement a preplanned provision(s) in accordance with the assessment of a qualified FPE.

2.5.4.1.1 Surveillance

Each of the required Halon systems shall be demonstrated operable:

a. At least once per 12 months by verifying that each valve (manual, power operated or automatic) in the flow path is in its correct position.

b. At least once per 6 months by verifying Halon storage tank weight (level) and pressure.

c. At least once per 18 months by:

    1. Verifying the system and associated ventilation dampers and fire door release mechanisms actuate manually and automatically.

    2. Performance of a flow test through headers and nozzles to assure no blockage.

2.5.4.2 System Maintenance

The systems are periodically inspected and tested in accordance with NFPA 12A.

2.5.4.3 System Design Considerations

During the system pre-discharge period, prior to agent release, local audible and visual alarms are provided in the protected area for personnel notification purposes. In addition, the auxiliary control room and the ECIV room are provided with a glass flask of wintergreen concentrate attached to the discharge piping to add a distinctly identifiable scent to the discharge gas. This flask ruptures upon operation of the system and must be replaced after each operation.

2.5.5 Carbon Dioxide (CO_2) Suppression System

Fire extinguishment by CO_2 is either by the total-flooding or local application method. In total-flooding, sufficient CO_2 is injected into a closed room or space to inert the atmosphere and suppress combustion. Local application is employed for unenclosed hazards and involves application of CO_2 on the equipment protected to extinguish the fire, with additional discharge to permit cooling and inhibit reflash.

Unit 1 automatic CO_2 fire suppression systems have been temporarily placed in alarm-only mode due to life safety concerns until modifications to improve personnel safety are completed.

2.5.5.1 Carbon Dioxide System Design*

Total-flooding and local application CO_2 systems are installed to protect several different hazards in the plant. Automatic protection is provided for the following hazards:

a. Turbine Oil Tank Room - total-flooding; automatic actuation by rate-compensated thermal detectors.

b. Motor Generator Sets - local application to all five units simultaneously; actuated by rate-compensated thermal detectors located over each unit.

c. Power Boards 102 and 103 - total-flooding; actuation by cross-zoned smoke detectors.

d. Diesel Generator 102 and 103 - total-flooding; actuation by cross-zoned smoke, flame and thermal detectors.

e. Hydrogen Seal Oil Enclosure - total-flooding; actuation by rate-compensated thermal detectors.

f. Turbine Oil Reservoir Room - total-flooding; actuation by rate-compensated thermal detectors.

g. Cable Spreading Room - total-flooding; detection by cross-zoned smoke detectors.

---

* Automatic CO_2 fire suppression systems are temporarily in alarm-only mode. See Section 2.5.5.

Manual protection is provided for the following:

a. Generator Exciter Housing - total-flooding; actuation by push button station.

b. Turbine Generator Bearings - local application; actuation by push button station.

c. Turbine Oil Tanks - total-flooding of vapor space of tanks only; actuation by push button station.

d. Auxiliary Control Room - total-flooding; backup to Halon 1301 system.

All the above areas are provided with thermal or smoke detectors.

THIS PAGE INTENTIONALLY BLANK

The supply for the above systems is provided by a 10-ton low-pressure, refrigerated CO_2 storage tank located in the southwest corner of the turbine building at el 261 ft. The design of the tank maintains CO_2 within the tank at a nominal 0°F at 300 psig.

Upon automatic initiation of any system, a 30-sec predischarge period operates area warning devices for total-flooding systems so personnel can safely evacuate the area prior to system discharge. The total-flooding systems are designed to maintain a specified level of concentration for the particular hazard for a 20-min soak time. These systems are designed in accordance with NFPA 12, Standard for Carbon Dioxide Extinguishing Systems. See Table 3.1-1 for a complete list of plant suppression systems.

Carbon dioxide supplied hose reels are located in various areas of the turbine building to provide manual suppression capabilities for energized electrical equipment or spot fires.

The following CO_2 extinguishing systems protect safety-related areas, exposure hazards, or safety-related equipment, and shall be operable with a minimum tank level of 40 percent and pressure of 250 psig in the low-pressure CO_2 tank.

LOCATION	DESCRIPTION	ZONE	MODE
TB 261	Reactor MG Sets	C-2092MG*	AUTO**
DG 261	Diesel Gen 102	C-2141	AUTO**
DG 261	Diesel Gen 103	C-2151	AUTO**
DG 261	Power Board 102	C-2123	AUTO**
DG 261	Power Board 103	C-2113	AUTO**
TB 250	Cable Spread Rm.	C-3011	AUTO**
TB 261	Aux. Control Rm.	C-3031	MANUAL

* For Zone C-2092MG, this action is not required if reactor recirculation pump MG sets are not required to be operable.

** Systems are temporarily in alarm-only mode. See Section 2.5.5.

Action

With one or more of the above-required CO_2 systems inoperable, within 1 hr implement one of the following actions:

a. Verify the operability of fire detectors within the area protected by the system and establish a daily inspection of the area to verify no increase in fire hazards, or

b. Establish a fire watch patrol with backup fire suppression capability, or

c. Implement a preplanned provision(s) in accordance with the assessment of a qualified FPE.

2.5.5.1.1 Surveillance

The CO_2 system shall be demonstrated operable:

a. At least once per 7 days by verifying the CO_2 storage tank level and pressure.

b. At least once per 12 months by verifying that each valve (manual, power operated or automatic) in the flow path is in its correct position.

c. At least once every 12 months by verifying the system valves and associated ventilation dampers actuate automatically to a simulated actuation signal.

2.5.5.2 System Maintenance

At a minimum, the systems are periodically inspected and tested in accordance with NFPA 12.

2.5.5.3 System Design Considerations

During the system predischarge period, for total-flooding systems and prior to agent release, local audible and visual alarms are provided in the protected area for personnel notification purposes. In addition, the systems are provided with a glass flask of wintergreen concentrate attached to the discharge piping to add a distinctly identifiable scent to the discharging gas. This flask ruptures upon operation of the system and must be replaced after each operation.

The total-flooding systems are designed to enable manual initiation from the main fire alarm control panel or the applicable local fire alarm control panel. All system operations are monitored on the MFCP.

In the event of total loss of dc control power to the CO_2 system, all master valves will open since their pilot valve solenoids are below, and separated from, the auxiliary control room by a 3-hr rated assembly.

A general area, cross-zoned smoke detection system has been provided for this area.

Fire suppression systems for the cable spreading room include a preaction sprinkler system, which is automatically initiated by the installed smoke detection system. In addition, an automatically-initiated total-flooding CO_2 system has also been provided for this area.* The CO_2 system would be the primary suppression agent utilized for this area. These systems are in addition to manual hose stations and portable extinguishers. The hose stations are located outside this room.

There is no normal ventilation supplied for this area; however, a smoke removal system has been provided which may be manually initiated by operations personnel. Supply air for this system would be from one of the adjacent turbine building el 250'-0" smoke removal zones through an open doorway.

Cable separation within the cable spreading room does not meet the guidelines of RG 1.75, Physical Independence of Electrical Systems. However, redundant cabling necessary to achieve hot shutdown is independent of the cable spreading room. Cabling for inventory makeup and cold shutdown functions is not totally independent of the cable spreading room. Such functions are achievable outside the cable spreading room via DRPs and manual operations.

Two remote entrances are provided in this area for access by Fire Brigade personnel. In addition, cable trays are installed in this area at the ceiling level. Although 8-ft high clearance is not provided for the total area, the current tray arrangements should have little impact to fire-fighting activities in all areas of the room.

2.6.4 Plant Computer Room

The plant computer room is a part of the auxiliary control room described in Section 2.6.2. All features designed to protect the auxiliary control room also protect the plant computer room.

---

* Automatic CO_2 fire suppression systems are temporarily in alarm-only mode. See Section 2.5.5.

A nonrated 8-ft high partition physically defines the boundary of the plant computer room.

2.6.5 Switchgear Rooms

The safety-related switchgear room consists of power board rooms 102 and 103 on floor el 261'-0" of the diesel generator building.

Each power board room is separated from each other and from other areas of the plant by 3-hr fire-rated barriers. Openings through these barriers are protected. An automatic area smoke detection system is provided for each of these rooms which alarms at a local fire alarm control panel and in the control room.

Individually-zoned, automatic (total-flooding) low-pressure CO_2 suppression systems protect these areas. The system is initiated following activation of the area cross-zoned smoke detection system.* These systems are in addition to manual hose stations and portable extinguishers. The hose stations are located outside the switchgear rooms.

2.6.6 Remote Safety-Related Panels

All the areas and rooms containing safety-related panels have a ceiling detection system either with or without an automatic suppression system. Combustible materials are limited in the vicinity of safety-related panels through administrative procedures. Portable fire extinguishers and manual hose stations are provided for fire suppression activities.

In many areas of the plant, CO_2 hose reels are located in the vicinity of such equipment to assist in fire suppression activities.

2.6.7 Station Battery Rooms

The safety-related battery rooms (turbine building el 277'-0") and battery board rooms (turbine building el 261'-0") are separated from each other and other areas of the plant by a minimum 1 1/2-hr fire-rated barriers. Penetration openings through these barriers are protected. Three-hour rated fire

---

* Automatic CO_2 fire suppression systems are temporarily in alarm-only mode. See Section 2.5.5.

doors are installed to protect entrances. In order to maintain adequate makeup ventilation in the battery rooms, a 3/4-in undercut is required below the doors.

An area smoke detection system is provided for each of these rooms which alarms at the local fire alarm control panel and in the control room. Portable fire extinguishers and manual hose stations are provided for fire suppression activities.

Battery board rooms 11 and 12 are located at el 261'-0" below the respective battery room and are protected in a similar fashion.

The ventilation system serving the battery rooms is provided with a loss-of-air flow monitor that will alarm in the control room upon loss of ventilation. This will enable corrective actions to be taken to ensure that the level of hydrogen in the room is maintained below 2 percent by volume.

Battery room 14 is provided with detection, fire barriers and construction (1 1/2-hr fire rating and 3/4-in undercut doors) similar to the safety-related battery rooms. Operators will be alerted to a loss of the exhaust system forced-air fan by an existing fan failure alarm in the main control room.

2.6.8 Turbine Lubrication/Oil Storage Rooms

2.6.8.1 Turbine Oil Reservoir Room

The turbine oil reservoir room is separated from the main condenser bay area by substantial concrete construction. A concrete wall with all openings protected to provide a 3-hr rated barrier is provided to separate this area from the corridor area to the east, which contains safety-related cable trays. A 3-hr rated sliding fire door is provided at the south entrance to this room. A curb of sufficient size to hold the contents of the turbine oil reservoir is provided at this door.

The turbine oil reservoir is protected by an automatic total-flooding CO_2 suppression system. The system is initiated following activation of the area smoke detection system.* In addition, the reservoir vapor space may be manually inerted by the CO_2 system. A manual water spray system is also provided as

---

* Automatic CO_2 fire suppression systems are temporarily in alarm-only mode. See Section 2.5.5.

backup protection for this area. These systems are in addition to the manual hose stations and portable extinguishers. The hose stations are located outside this area.

2.6.8.2 Turbine Lube Oil Storage Room

The turbine oil storage room is separated from the remainder of the turbine building by 3-hr rated fire barriers to provide protection of nearby turbine building equipment from an oil storage room fire. Unprotected steel columns exposed on the outside of the room are framed into the wall. Exterior building walls (west wall) consist of insulated metal panel on unprotected steel supports. Openings from this area to the turbine building are protected by 3-hr rated components/assemblies. The room is diked to contain the entire contents of the two storage tanks.

The ceiling of this room is the ceiling of the turbine building, supported by unprotected roof steel. Calculations have been performed to demonstrate that this steel will not reach failure temperature (due to the low ventilation rate available for a ventilation-controlled fire).

An automatic total-flooding CO_2 suppression system is installed in this room. The system is actuated by an area cross-zoned smoke detection system.* Actuation of the CO_2 system will initiate closure of the two dampers in the ventilation openings from this room. This system is in addition to manual hose stations and portable extinguishers. The hose stations are located outside this area.

2.6.9 Diesel Generator Rooms

Diesel generator rooms 102 and 103 (el 261'-0"/250'-0" are separated from each other and other areas of the plant by 3-hr rated fire barriers. All primary structural steel necessary to maintain the rating of the barrier for the identified duration has been fireproofed. Penetration openings in these barriers are protected. No curbs are provided at the door separating the two diesel rooms; however, sloped floors and drains are provided in the rooms to contain the contents of a potential day tank failure.

---

* Automatic CO_2 fire suppression systems are temporarily in alarm-only mode. See Section 2.5.5.

Diesel generator 102 cable trays routed within the 103 diesel generator room are enclosed in a fire-rated enclosure (FA18 DG 102 Missile Shield). Roof structural steel in the immediate vicinity of the enclosure is fireproofed to prevent failure of such members during an uncontrolled diesel generator 103 fire from impacting the integrity of the rated enclosure. The majority of the cables in the cable tray enclosure are coated with a flame-retardant coating. An area smoke detection system has also been installed within this enclosure.

Each diesel generator room (el 261'-0") is provided with a total-flooding low-pressure CO_2 suppression system, automatically actuated by an area fire detection system.* Operation of the CO_2 system in either diesel generator room is arranged to automatically close the motor-operated door to the exterior and shut down the ceiling exhaust fans if either is in a position which will not support CO_2 system extinguishment. At el 250'-0", around the diesel generator pedestal, an area preaction sprinkler system with associated fire detection system is installed.

Portable fire extinguishers and hose stations are provided for the diesel generator areas.

The day tank is located beneath the generator. Oil leaks are not expected to accumulate on the operating floor.

2.6.10 Diesel Fuel Oil Storage Areas

Diesel fuel oil storage tanks are located outside the diesel generator building and are buried underground.

2.6.11 Safety-Related Pumps

All safety-related pumps are protected with a local or an area smoke detection system, depending on room configuration. These systems alarm at the LFCP and in the control room. The Unit 1 SSA has evaluated all fire areas containing the pumps for impacts to 10CFR50 Appendix R, Section III.G, for loss of all equipment in identified fire areas. Automatic fire suppression systems have not been provided for all safety-related pumps.

---

* Automatic CO_2 fire suppression systems are temporarily in alarm-only mode. See Section 2.5.5.

Thermal barriers have been erected between pumps where adequate separation does not exist (i.e., diesel generator cooling water pumps). Common exposure hazards are controlled or have been eliminated for these areas. Safe shutdown capability is maintained even with the loss of both pumps.

heat vents or significant smoke generation, the design objectives of 10CFR100 would not be exceeded.

3.3.5 Fire Detection/Suppression Systems

Early-warning general area and spot smoke detection systems are provided for the turbine building to initiate alarm conditions primarily for protection of safety-related equipment and identified hazards within the structure. These zoned detection areas provide alarms locally (LFCP) and in the control room.

Preaction sprinkler systems primarily provide protection of cable tray stacks in this area (reference Section 2.4.3.3). Protection of all cable trays at el 250'-0" has been provided due to the high concentration of cable trays at this elevation, and expected environmental conditions as a result of a fire in this area. Preaction and wet-pipe sprinkler systems have also been provided for identified work and/or storage areas where combustible materials are expected, and protection is warranted due to activity or anticipated storage.

Manually-operated water spray systems are provided for the reactor building and control room emergency ventilation charcoal filters. These systems utilize thermistor wire heat detection.

Manually-initiated deluge systems have been provided for the track bay and turbine building wall (SW). The track bay spray system employs open nozzles that are supplied from a manually-operated deluge valve. There is no automatic initiation of this system. The deluge valve is kept closed with fire protection water system pressure. The valve is opened when the pressure is released from the top chamber. The pressure is released by opening an electric MOV that is controlled manually from the LFCP or from the control room. There is also a manual release valve on the deluge valve. A pressure switch transmits an alarm to the LFCP indicating water flow. A manual shutoff valve, located upstream of the deluge valve and the nozzles, is supervised open by a limit switch. The wall spray system is provided for protection of the structure from an outside transformer fire (open nozzles are supplied from a manually-operated deluge valve).

In addition, a series of seven manually-operated water spray systems provide protection of the turbine generator unit oil hazards, which include hydraulic oil piping, seal and lube oil piping, turbine bearings, hydrogen seal oil unit, and various other equipment in the vicinity of this equipment. These systems are individually controlled by dc MOVs, which can be manually initiated locally and from the control room. They can also be electronically or mechanically operated in the foam room. Six of these systems employ open directional spray nozzles which discharge when the systems are placed in service. A portion of the nozzles on the seventh system (inside the generator exciter) have 175°F fusible elements so that these nozzles would discharge upon system operation only if excessive heat were present in the exciter housing.

Six water spray systems provide protection for the turbine generator unit below the operating floor (el 300'-0"). Of these systems, four are automatically actuated upon initiation of fire detection devices in the area. These four systems provide protection between column lines B to C and 4 to 13. The remaining two systems are manually initiated and protect the hydrogen seal oil unit room and turbine oil reservoir room. These systems are individually controlled by dc MOVs which can be manually initiated locally and from the control room.

Carbon dioxide hose reels are also provided at various locations within this structure.

Automatic total-flooding CO_2 systems are provided for the turbine oil reservoir room, alternator exciter enclosure, hydrogen seal oil unit room, turbine oil storage room, and the lube oil reservoir (including a separate manual system for inerting the vapor space).* In addition, an automatic, local application CO_2 system is also provided for the reactor MG sets which are located north of the turbine building track bay.*

Manual local application CO_2 systems are provided for turbine bearings and turbine lube oil piping above the turbine deck. Manual water spray systems are also provided for these hazards as a backup to the local application CO_2 systems.

Manual water hose reels and portable fire extinguishers provide primary and backup suppression capabilities for this building.

A dike has been installed in the hotwell pit to provide ample ponding capability to contain a lube oil line break and expected water from fire fighting. This dike limits potential flooding to the steam line pipe tunnel and MSIV room.

* Automatic CO_2 fire suppression systems are temporarily in alarm-only mode. See Section 2.5.5.

3.4 CONTROL COMPLEX

3.4.1 Introduction

The control complex is physically within the turbine building. However, it is separated from this structure by 3-hr rated fire barriers. The control complex is divided primarily into two fire areas (see Table 3.4-1). These areas are:

FA 10 CC250 - Cable Spreading Room
FA 11 CC261/277 - Auxiliary Control/Control Room

The building is comprised of three levels as identified above. Floor openings between the auxiliary control and control rooms are sealed to prevent the flow of smoke and heat from affecting both areas. These seals are also provided to contain the discharge of gaseous suppression systems in the auxiliary control room.

Exterior walls below grade are poured concrete. Those walls which are common to turbine building and administration building are 3-hr rated. The outside walls above the administration building are metal panel construction.

Separation between the auxiliary control and cable spreading room is provided by a 3-hr rated floor/ceiling assembly. Penetrations in the control and cable spreading room ceilings are sealed with 3-hr rated configurations. Unprotected steel exists in the control room ceiling/turbine building el 300'-0" floor assembly. Although the total assembly is not 3-hr rated due to the existence of this unprotected steel, its impact to plant operations is not considered significant for a control room fire due to the continuous manning of the control room, low combustible loading and installed automatic fire detection systems. A turbine building el 300'-0" fire is expected to have no impact on control room integrity.

Adequate means of egress, remotely located, have been provided on each elevation of the control complex. The stairwell opening between the auxiliary control and control room is enclosed and provided with a rated door at el 261'-0". This is installed primarily to maintain the envelope required to support gaseous suppression system operation, in addition to limiting smoke and heat movement to the control room area.

An independent smoke exhaust system is provided for each level of the control complex (reference also Section 2.4.4.1).

3.4.2 Safety-Related Systems

The control complex contains numerous shutdown components and cabling within the identified fire area. Loss of shutdown components in these areas will not affect safe shutdown capability since alternate means of safe shutdown exist in other fire areas.

3.4.3 Post-Fire Analysis

A fire in the control complex will not result in loss of capability for safe shutdown. If the installed fire protection systems for protection of equipment and hazards were in service, the fire should be contained within the general area of origin and be extinguished by automatic and/or manual means. In the unlikely event of a fire in the control room or auxiliary control room which would be severe enough to render these rooms uninhabitable, safe shutdown can still be accomplished from remote shutdown panels (RSP) in other fire areas.

3.4.4 Radioactive Release Analysis

The auxiliary control and control rooms do not contain radioactive material. Moderate amounts of smoke generation would be handled by the normal building ventilation system. The cable spreading room does not have a normal ventilation system and contains no radioactive material. However, it is located within a radiation area. Should conditions exist where operation of the smoke exhaust system is required, the design objectives of 10CFR100 would not be exceeded.

3.4.5 Fire Detection/Suppression Systems

Early warning general area smoke detection systems are provided for each level of the control complex. In addition, individual smoke detectors are installed in each auxiliary control room control cabinet, as well as the main control boards in the control room. These zoned detection systems provide alarms locally (LFCP) and in the control room.

A preaction sprinkler system provides area protection for the cable spreading room. System activation is initiated by the installed smoke detection system.

An automatic total-flooding Halon 1301 suppression system is provided for the auxiliary control room. Halon system supply is provided by two banks of cylinders with one bank serving as a

100 percent reserve. System activation is initiated by the installed smoke detection system.

Total-flooding CO_2 systems are provided for the cable spreading and auxiliary control room. The system provided for the cable spreading room is automatically initiated by the installed cross-zoned smoke detection system.* This system serves as the primary suppression agent for this area. In the auxiliary control room, the CO_2 system serves as a manual backup to the installed Halon 1301 extinguishing system.

A manually-operated wall spray system is provided for the control room wall where it protrudes above the administration building roof to protect the control room from an administration building exposure fire (open nozzles controlled by a manual gate valve).

Manual water hose reels and portable fire extinguishers provide primary and backup suppression capabilities for this structure.

3.5 DIESEL GENERATOR BUILDING

3.5.1 Introduction

The diesel generator building is physically within the turbine building. However, it is separated from this structure by 3-hr rated fire barriers. The diesel generator building is divided primarily into 7 fire areas (see Table 3.5-1). These areas are:

FA 18	DG 261	- DG 102 Missile Shield
FA 19	DG 250/261	- Diesel Gen. 103 Room
FA 20	DG 250	- DG 103 Cableway
FA 21	DG 250	- Power Board 102/103 Room
FA 22	DG 250/261	- Diesel Gen. 102 Room
FA 23	DG 261	- Power Board 102 Room
FA 24	DG 261	- Power Board 103 Room

The building is comprised of two levels as identified above. Penetrations occurring through fire-rated assemblies are protected with equivalent rated seal assemblies. The exterior walls below grade are concrete, and those above grade are metal panel construction.

---

* Automatic CO_2 fire suppression systems are temporarily in alarm-only mode. See Section 2.5.5.

Rated barriers and enclosures have been provided in select areas within this structure for protection of redundant equipment from a common exposure fire. These areas are identified below with the primary fire area.

DG 102 Missile Shield	(FA 18)
DG 103 Cableway	(FA 20)

Walls of the diesel generator building that are common to other buildings are 3-hr fire rated.

Adequate means of egress, remotely located, have been provided for each room of the diesel generator building, based on room use and inherent danger posed by the installed fire suppression system (e.g., DG 103 CO_2 system). Access between the two levels of this structure is not provided within the diesel generator building. This access is provided through the turbine building.

Should conditions warrant, the roof exhaust fans in the diesel generator rooms and portable exhaust fans could be utilized to remove smoke or CO_2 from these areas above el 261'-0". Portable smoke exhaust fans would be utilized at el 250'-0", along with the turbine building smoke removal system (smoke zone 1) to assist in the removal of smoke from these areas.

The diesel generator day tank is contiguous to the generator. Failure of the day tank to the floor of the diesel generator room would not spread the contents to adjacent rooms with or without the floor drains functioning.

In the DG 102 missile shield (el 261'-0"), DG 103 cableway (el 250'-0"), and power board 102/103 room (el 250'-0"), fire-rated enclosures have been provided for redundant safety-related cables occurring in common fire areas to prevent a common failure of such equipment as a result of a single fire.

The fuel oil storage tanks are buried underground, east of the diesel generator building.

Fireproofing has been applied to select structural steel members of the DG 103 roof assembly to mitigate a postulated collapse of the roof assembly and its impact on the integrity of the DG 103 missile enclosure containing DG 102 control cable.

3.5.2 Safety-Related Systems

The diesel generator building contains Division 11 and 12 diesel generators and support power boards. These diesel generators provide power to essential equipment should normal Station service power be lost.

3.5.3 Post-Fire Analysis

A fire in one of the divisional diesel generator or power board rooms will not result in loss of capability for safe shutdown. If the installed fire protection systems for the protection of equipment were in service, the fire should be contained within the general area of origin and be extinguished by automatic and/or manual means.

3.5.4 Radioactive Release Analysis

There is no source of radioactivity within this building; however, this structure is located in a radiologically-controlled area (RCA). Should conditions exist where evacuation of gaseous products from these areas would be required, the design objectives of 10CFR100 would not be exceeded.

3.5.5 Fire Detection/Suppression Systems

Early warning general area smoke detection systems are provided for each area of the diesel generator buildings. These zoned detection systems provide alarms locally (LFCP) and in the control room.

Automatic total-flooding CO_2 systems are provided for the diesel generator general areas and power board rooms.*

An automatic preaction sprinkler system provides area suppression capability for the DG 250 areas.

Manual water hose reels and portable fire extinguishers provide backup fire suppression capability for this structure.

---

* Automatic CO_2 fire suppression systems are temporarily in alarm-only mode. See Section 2.5.5.

3.6 SCREENHOUSE

3.6.1 Introduction

The screenhouse is primarily divided into two fire areas and is located adjacent to and north of the turbine building extension (see Table 3.6-1).

3.11 YARD AREA

3.11.1 Introduction

Potential exposure hazards located in the yard area are generally spatially separated from site structures to minimize damage under fire situations. In those situations where adequate spatial separation cannot be maintained, compensatory measures are provided on a case-by-case basis to minimize damage to these structures.

Partial-height fire barriers provide separation of adjacent transformers in the area southwest of the turbine building. In general, penetrations made in these barriers or in the turbine building exterior wall, adjacent to and within 50 ft of the transformers, are sealed with comparable configurations to maintain the integrity of the barrier. Some penetrations, namely the isophase bus ducts, cannot be sealed interior to the bus duct assembly due to inherent design requirements.

The hydrogen and nitrogen storage tanks have their long axes perpendicular to the west wall of the reactor building. An analysis of the path of travel of these vessels following a rupture has indicated that the wall will withstand the impact without failure.

3.11.2 Safety-Related Systems

Reserve transformers 101 north and south provide offsite power to the Station should normal Station power be lost. However, loss of one or both of these transformers will not impact the ability to safely shut down the plant in accordance with the provisions of 10CFR50, Appendix R.

3.11.3 Post-Fire Analysis

A fire in the yard area will not result in loss of capability to achieve safe shutdown. If the installed fire protection systems for protection of equipment were in service, the fire should be contained within the general area of origin and be extinguished by automatic and/or manual means.

3.11.4 Radioactive Release Analysis

Normally there is no source of radioactivity in the yard area. However, under certain conditions, material may be transported through, or be temporarily stored in, DOT-approved shipping containers in the yard area. In either case, should a fire occur in such an application, any release to the environment is expected to be minimized provided prompt Fire Brigade response is attained in these areas.

3.11.5 Fire Detection/Suppression Systems

The transformers and hydrogen storage tank are each protected by an automatically-initiated water spray system. Supply for these systems is from the fire main line with system strainers provided. The systems employ open nozzles and are controlled by deluge valves. Valve actuation is by pneumatic-type rate-of-rise devices installed over the protected equipment, except that the deluge valve for transformer #2 is tripped by electric heat detectors. Supervisory air pressure from the instrument air supply is maintained on the tubing system for the pneumatic detection systems. In addition to the automatic operation, these systems may be tripped manually by mechanical trips either at the deluge valves on el 250'-0" or at remote cable pull stations on el 261'-0". The fire control panel annunciator records system operation, low supervisory air pressure and valve closure.

Trailers with combustible contents located within close proximity of site structures are protected by automatic sprinkler systems.

Yard and wall hydrants are located on the main fire loop and provide a source of water for outside manual fire suppression activities. Fire hose and other equipment has been provided to establish an effective hose stream to aid in extinguishing expected exterior fires.

Table 1.2.2 (Cont'd.)

NFPA STANDARD	SECTION	DEVIATION/JUSTIFICATION
NFPA 20	8-2.1.1	Deviation: The diesel fire pump is not listed for fire service by an approved testing laboratory. Justification: The authority having jurisdiction at the time (NMPC) accepted the manufacture and installation of the diesel fire pump as having met the intent of National Board of Fire Underwriters (NBFU) Standard #20, Centrifugal Fire Pumps, and Underwriters Laboratories Approval Listing Requirement UL-448, Pumping Equipment for Private Fire Service.
NFPA 20-1980	8-6.1	Deviation: NFPA 20 requires that the electric motor-driven fire pump be tested weekly. Testing of the electric motor-driven fire pump for operational readiness is performed every 31 days. Justification: NFPA inspection, testing, and maintenance requirements are intended to cover a broad group of users. Nuclear plants operate under unique conditions that inherently foster high reliability. These favorable operating conditions are conducive to performance-based analysis methods that provide quantitative evidence of high system reliability. NFPA has developed a performance-based approach to fire protection at nuclear power plants. This approach recognizes these unique features and allows for changes and deviations from the normal code requirements. Based on analysis using performance-based techniques, NEIL has recognized that nuclear power plants can be considered outside the normal NFPA code guidelines and has developed their own interpretation of the testing requirements to satisfy their insurance requirements. NEIL recommends testing electric motor-driven fire pumps on a less frequent basis than that recommended by NFPA (monthly vs. weekly). Performing a monthly test frequency for verifying the operational readiness of the electric motor-driven fire pump maintains the licensing and property insurance requirements, and will provide adequate verification of operational readiness of this fire pump.

Table 1.2.2 (Cont'd.)

NFPA STANDARD	SECTION	DEVIATION/JUSTIFICATION
NFPA 20	9-5.2.7	Deviation: The diesel-driven fire pump is not equipped with a weekly program timer. Justification: Station procedure requires a 30-min operating test of the pump weekly.
NFPA 72-2002	10.4.3	Deviation: Fire detectors are not tested annually. Fire detectors are demonstrated operable in accordance with the following test methodology: at least 10 percent of the installed detectors, with a minimum of one detector in each detection loop, shall be tested annually by initiating an alarm per the methods described in the surveillance procedures. Should a detector fail to alarm under test conditions, it will be corrected per procedure, and an additional 20 percent, with a minimum of two detectors in the affected loop, shall be tested. Should a failure to alarm occur in this expanded sample population, the failure will be corrected per procedure, and all remaining detectors in the affected loop will be tested and corrected as necessary. This testing methodology will be cycled through all detectors in a detection loop until all detectors in the loop have been tested. All detectors in a loop shall be tested within a 10-yr time frame. The cycle will then be repeated. Where detector testing cannot be accomplished within the time period specified by the surveillance procedures, due to accessibility or safety concerns during plant operation, the testing for those detectors shall be performed during the next cold shutdown exceeding 24 hr.

SAFE SHUTDOWN ANALYSIS

TABLE OF CONTENTS (Cont'd.)

e. Process Monitoring - The process monitoring function capable of providing direct readings of the process variables necessary to perform and control the above functions.

f. Supporting Functions - The supporting functions shall be capable of providing the process cooling, lubrication, etc., necessary to permit operation of the equipment used for safe shutdown functions.

5.4 ASSUMPTIONS

5.4.1 Generic Assumptions

Analysis of the safe shutdown systems is based on the following generic assumptions:

a. No credit is taken for offsite power for use of mitigating systems.

b. The SOP for a fire in the plant states: ...perform the following BEFORE...evacuating control room

   - Full-scram the reactor by placing reactor mode switch to SHUTDOWN.

   - At panel E, simultaneously turn both vessel isolation switches to ISOLATE.

c. All systems not affected by the fire are considered to be available and capable of functioning as designed. (Equipment markups and single failure need not be considered for the purpose of the Appendix R analysis.)

d. Piping system integrity, including such components as valves, heat exchangers, etc., in a given fire area will not fail by a fire in that fire area.

e. The fire does not occur simultaneously or coincident with any other transient or abnormal condition, e.g., line breaks, equipment markups, single failures, etc., except for the loss of offsite power (LOOP) and those conditions resulting directly from the effect of the fire.

f. Plant operating and system actuation parameters are consistent with the plant Final Safety Analysis Report (FSAR) and Technical Specifications.

g. The primary containment (drywell), for analysis purposes, is considered impervious to fire since it is inerted with a nitrogen atmosphere.

THIS PAGE INTENTIONALLY BLANK

5.4.2 Operator Actions

Credit is taken for the Operator scramming the reactor at normal reactor water level for control room evacuation fire scenarios.

Credit is taken for the Operator isolating the reactor vessel at normal reactor water level for control room evacuation fire scenarios.

Credit is taken for Operator load-shedding actions to conserve battery capacity that are completed within 15 min of the event initiation.

5.4.3 Operating Procedures/Damage Repair Procedures

Credit is taken for Unit 1 emergency operating procedures (EOPs) for providing the proper Operator responses to addressing the full spectrum of fire-induced EOP symptoms to satisfy the Appendix R safe shutdown objectives.

Credit is taken for Unit 1 damage repair procedures (DRPs) to provide procedural guidance to perform the required cold shutdown repairs to restore a diesel generator and a cold shutdown train with reactor makeup within 8 hr of the fire event.

Credit is taken for Unit 1 special operating procedures (SOPs) for providing the procedural guidance necessary to assure sufficient battery capacity to start a diesel generator following completion of repairs on the diesel generator and emergency electrical distribution train, and maintain and monitor hot shutdown process from the remote shutdown panels (RSP).

Credit is taken for Unit 1 operating procedures (OPs) for providing the procedural guidance for the following:

1. Startup and operation of the core spray system.

2. Startup and operation of the emergency cooling system.

3. Startup and operation of the reactor building closed loop cooling (RBCLC) system.

4. Startup and operation of the shutdown cooling system.

5. Startup and operation of the containment spray system.

6. Startup and operation of the emergency service water (ESW) system.

7. Startup and operation of the control rod drive (CRD) system.

TABLE 1 (Cont'd.)

System: Core Spray (cont'd.)			
Component	Component Type	Classification	Resolution
IV 40-31	Ac MOV	Flow Diversion	Valve is closed with breaker to IV 40-31 locked open.

System: Control Rod Drive			
Component	Component Type	Classification	Resolution
PCV 44-05	PCV	Flow Blockage	Manual operate VLV 28-18.
PCV 44-04	PCV	Flow Blockage	Manual operate VLV 28-18.
FCV 44-151	FCV	Flow Blockage	Manual operate VLV 28-18.
FCV 44-149	FCV	Flow Blockage	Manual operate VLV 28-18.

System: Emergency Cooling			
Component	Component Type	Classification	Resolution
IV 39-07R	Dc MOV	Flow Blockage	Spurious isolation of ECS resolved to provide hot shutdown (SE 84-35, 84-57).
IV 39-08R	Dc MOV	Flow Blockage	Spurious isolation of ECS resolved to provide hot shutdown (SE 84-35, 84-57).
IV 39-09R	Ac MOV	Flow Blockage	Spurious isolation of ECS resolved to provide hot shutdown (SE 84-35, 84-57).

TABLE 1 (Cont'd.)

System: Emergency Cooling (cont'd.)			
Component	Component Type	Classification	Resolution
IV 39-10R	Ac MOV	Flow Blockage	Spurious isolation of ECS resolved to provide hot shutdown (SE 84-35, 84-57).
IV 39-05	AOV	Flow Blockage	Spurious isolation of ECS resolved to provide hot shutdown (SE 84-35, 84-57).

TABLE 3

REQUIRED OPERATOR ACTIONS/REPAIRS

	REPAIR ACTIONS	OPERATOR ACTIONS IF REQUIRED	REQUIRED OPERATOR ACTIONS	REMOTE/LOCAL INSTRUMENTATION
Fire Area 1		Initiate Torus Cooling		Monitor idle cont. spray pump discharge pressure (PI 80-54A) and oper. cont. spray pump discharge pressure (PI 80-47A) for torus level changes.
Fire Area 2		Initiate Torus Cooling		Monitor cont. spray HX inlet temp. (TI 80-77B) for torus temperature indication.
Fire Area 4	Open 70-53[(3)]	Throttle 60-11[(1)] Close 60-12[(1)] Open 38-10 Open 72-92R & * 70-80 Open 28-18		
Fire Area 5	Restore DG 103 Open 38-13 Open 38-01 Restore MG Set Restore RSP 11[(4)] DFP/ESW[(5)] Open 70-53[(3)]	Throttle 60-12[(2)] Close 60-11[(2)] Open 38-02 Open 38-04 Open 38-10 Open 72-92R & 70-80 Open 28-18	Disc. Air to 01-03 Disc. Air to 01-04	

TABLE 3 (Cont'd.)

	REPAIR ACTIONS	OPERATOR ACTIONS IF REQUIRED	REQUIRED OPERATOR ACTIONS	REMOTE/LOCAL INSTRUMENTATION
Fire Area 6	Restore DG 102 Open 70-53	Throttle 60-12 (2) Close 60-11 (2) Open 38-09 Open 72-92R & * 70-80 Open 28-18	Disc. Air to 01-03 Disc. Air to 01-04 Close 05-31 Close 05-32	
Fire Area 7	Restore DG 103 Open 70-53	Throttle 60-11 (1) Close 60-12 (1) Open 38-10 Open 72-92R & * 70-80 Open 28-18	Disc. Air to 01-03 Disc. Air to 01-04	
Fire Area 9	Restore DG 102 Open 70-53	Throttle 60-12 (2) Close 60-11 (2) Open 38-10 Open 72-92R & * 70-80 Open 28-18	Disc. Air to 01-04 Close 05-31 Close 05-32	
Fire Area 10	Restore 38-149 Restore 70-01 Restore 28-15 Restore 72-04 Restore DG 102 Open 70-53	Throttle 60-12 (2) Close 60-11 (2) Open 38-09 Open 28-18 Open 72-92R & * 70-80	Disc. Air to 01-03 Disc. Air to 01-04 Close 05-31 Close 05-32	

TABLE 3 (Cont'd.)

	REPAIR ACTIONS	OPERATOR ACTIONS IF REQUIRED	REQUIRED OPERATOR ACTIONS	REMOTE/LOCAL INSTRUMENTATION
Fire Area 11	Restore DG 103 Restore PB 17B Restore PB 171 Restore PB 167 Restore 28-17 Restore 72-03 Restore 70-02 Restore 38-152 Open 38-01 Open 38-13 Restore MG 167(1) Open 70-53(3)	Throttle 60-12(2) Close 60-11(2) Open 28-18 Bypass 72-146 Open 72-92R & * 70-80 Open 38-02 Open 38-10 Open 38-04	Disc. Air to 01-03 Disc. Air to 01-04 Close 05-31 Close 05-32 Pull ERV Fuses	Monitor RSPs for control room evacuation.
Fire Area 12	Open 70-53	Throttle 60-12(2) Close 60-11(2) Open 38-10 Open 72-92R & * 70-80 Open 28-18		
Fire Area 13	Open 70-53(3) DFP/ESW(5)	Throttle 60-12(2) Close 60-11(2) Open 38-10 Open 72-92R & * 70-80 Open 28-18 DFP/DGCW(6)		

TABLE 3 (Cont'd.)

	REPAIR ACTIONS	OPERATOR ACTIONS IF REQUIRED	REQUIRED OPERATOR ACTIONS	REMOTE/LOCAL INSTRUMENTATION
Fire Area 14	Open 70-53[3]	Throttle 60-12[2] Close 60-11[2] Open 38-09 Open 72-92R & * 70-80 Open 28-18		
Fire Area 15	Open 70-53	Throttle 60-12[2] Close 60-11[2] Open 38-10 Open 72-92R & * 70-80 Open 28-18		
Fire Area 16A	Open 70-53[3]	Throttle 60-12[2] Close 60-11[2] Open 38-09 Open 72-92R & * 70-80 Open 28-18		
Fire Area 16B	Open 70-53[3]	Throttle 60-12[2] Close 60-11[2] Open 38-10 Open 72-92R & * 70-80 Open 28-18		

TABLE 3 (Cont'd.)

	REPAIR ACTIONS	OPERATOR ACTIONS IF REQUIRED	REQUIRED OPERATOR ACTIONS	REMOTE/LOCAL INSTRUMENTATION
Fire Area 17A	Open 70-53(3)	Throttle 60-12(2) Close 60-11(2) Open 38-09 Open 72-92R & * 70-80 Open 28-18		
Fire Area 17B	Open 70-53(3)	Throttle 60-12(2) Close 60-11(2) Open 38-10 Open 72-92R & * 70-80 Open 28-18		
Fire Area 18		Throttle 60-12(2) Close 60-11(2) Open 72-92R & * 70-80	Disc. Air to 01-04	
Fire Area 19	Open 70-53(3)	Throttle 60-12(2) Close 60-11(2) Open 38-09 Open 72-92R & * 70-80 Open 28-18		

TABLE 3 (Cont'd.)

	REPAIR ACTIONS	OPERATOR ACTIONS IF REQUIRED	REQUIRED OPERATOR ACTIONS	REMOTE/LOCAL INSTRUMENTATION
Fire Area 20	Open 70-53(3)	Throttle 60-12(2) Close 60-11(2) Open 38-09 Open 72-92R & * 70-80 Open 28-18		
Fire Area 21		Throttle 60-12(2) Close 60-11(2)		
Fire Area 22		Throttle 60-12(2) Close 60-11(2) Open 72-92R & * 70-80	Disc. Air to 01-04	
Fire Area 23		Throttle 60-12(2) Close 60-11(2) Open 72-92R & * 70-80	Disc. Air to 01-04	
Fire Area 24		Throttle 60-12(2) Close 60-11(2)	Disc. Air to 01-04	

* 70-137 controls 2 valves itself and 72-146. If 70-137 fails, two bypasses may be required to be operated -- 72-92R and 70-80.

(1) Loss of instrument air fire scenarios will result in excess makeup to the EC shellside due to LCV 60-18 failing open. Throttle 60-11 to control makeup to the EC shellside and close 60-12 to maintain additional makeup inventory. Open 60-13 to provide additional makeup inventory from idle EC makeup tank.

TABLE 3 (Cont'd.)

(2) Loss of instrument air fire scenarios will result in excess makeup to the EC shellside due to LCV 60-17 failing open. Throttle 60-12 to control makeup to the EC shellside and close 60-11 to maintain additional makeup inventory. Open 60-13 to provide additional makeup inventory from idle EC makeup tank.

(3) Loss of instrument air fire scenarios will result in 70-53 failing closed. Open 70-53 per N1-DRP-GEN-004 instructions.

(4) Restore instrumentation per N1-DRP-GEN-005 instruction.

(5) Restore ESW per Unit 1 operating procedures and DRP-GEN-005 instructions.

(6) Restore diesel generator cooling water per Unit 1 operating procedures.

SAFE SHUTDOWN FIRE AREA ANALYSIS

FIRE AREA 1

Reactor Building, East
El. 198'-0" to 340'-0"

Fire Zones:	R1A, R1C, R1D, R2A, R3A, R4A, R5A, R6A
Detection Zones:	D-4026, DA-4076E, D-4046, DA-4116E, D-4156, D-4166, D-4197, D-4207, DA-4237, D-4267, DX-4217A, DX-4217B

ADJACENT FIRE AREAS

NORTH	5, 6
EAST	5, 6
SOUTH	5, 6
WEST	2, 3
BELOW	None
ABOVE	None

SHUTDOWN COMPONENTS IN AREA

Containment Spray

IV 80-15	IV 80-35
IV 80-16	PMP 80-23
IV 80-21	PMP 80-24
IV 80-22	

Containment Spray Raw Water

BV 93-25	BV 93-28
BV 93-26	FCV 93-72
BV 93-27	FCV 93-73

Control Rod Drive

PMP 28-15
PMP 28-17
VLV 28-18

SAFE SHUTDOWN FIRE AREA ANALYSIS (Cont'd.)

Core Spray

IV 40-02
IV 40-05
IV 81-01
IV 81-02
PMP 81-03
PMP 81-04
PMP 81-51
PMP 81-52

Electrical Distribution

PB 17
PB 167
PB 171
Analog Trip Cabinet C
Analog Trip Cabinet D
S.S.C. Cabinet 2
Cab. 23093-B

Emergency Condenser

Condenser 111
Condenser 112
Condenser 121
Condenser 122
LCV 60-18
LCV 60-17
IV 39-05
IV 39-06
IV 39-07
IV 39-08
IV 39-09
IV 39-10

Emergency Service Water

TCV 72-146

Instrumentation

LT 60-22
LT 60-23
LT 58-05
LT 58-06
LT 60-29
LT 36-03C
LT 36-03D
LT 36-05C
PT 36-32
TE 80-77
PT 36-07D

SHUTDOWN COMPONENT CABLE IN AREA

Containment Spray

IV 80-02

SAFE SHUTDOWN FIRE AREA ANALYSIS (Cont'd.)

Core Spray

IV 40-01
IV 40-09
IV 40-10
IV 81-22

Diesel Generator Cooling Water

PMP 79-54

Electrical Distribution

MG Set 167
UPS 172A
UPS 172B
SC 171A
SC 171B

Electromatic Relief Valves

PSV 01-102C
PSV 01-102D
PSV 01-102F

Emergency Service Water

PMP 72-03
PMP 72-04

Reactor Building Closed Loop Cooling

PMP 70-02

Shutdown Cooling

BV 38-04
IV 38-01
IV 38-13
PMP 38-152

Instrumentation

PT 36-32
TI 80-77B

SAFE SHUTDOWN FIRE AREA ANALYSIS (Cont'd.)

DESIGN FEATURES

The north, east, and south boundaries consist of reinforced concrete walls varying in thickness from 1'-4" to 4'-6" and 8-in thick concrete masonry unit block walls. El 340' also has insulated metal wall panels, which establish a 2-hr rated fire barrier from the turbine building side.

The west boundary consists of established fire break zones (FBZs) on each elevation. These FBZs separate FA 1 from FA 2 by a minimum horizontal distance of 20 ft with no intervening combustibles or fire hazards. In addition, smoke detectors and an automatic fire suppression system are installed in each FBZ, unless exempted and/or justified.[1]

Wall penetrations to adjacent fire areas are sealed with 3-hr rated fire assemblies.

Doors to adjacent fire areas are Class "A" fire doors.

Floor penetrations located in nonaligning portions of the FBZs are sealed with at least 1-hr rated fire assemblies.

EXISTING FIRE PROTECTION

Early-warning, ionization-type smoke detectors are provided throughout FA 1 to protect safety-related cables and components.

Detection and automatic suppression is provided for protection of safety-related cable trays and the changing room located on el 237'-0".

Manual fire suppression capability is provided by means of local hose stations and portable fire extinguishers.

---

(1) Cables located in trays in the FBZs were coated with a fire-retardant material as documented in a Unit 1 letter to the NRC on May 11, 1984. In addition, suppression is provided over the trays by the general area preaction suppression systems which cover the entire FBZ on each elevation (except the refuel floor). Cables outside of cable trays are run in conduit. The combination of fire-retardant material and suppression on cable trays, along with fire stops on vertical trays, is considered adequate to classify the exposed (i.e., not in conduit) cables as nonintervening combustibles. The NRC's acceptance of this position, which does not meet the recommendations of NRC Generic Letter 86-10, is documented in the Unit 1 Appendix R Safety Evaluation Report, dated August 6, 1986.

FIRE AREA 4 - COLD SHUTDOWN TRAIN

COMPONENT	NORMAL POSITION	FAIL POSITION	REQUIRED POSITION	POTENTIAL IMPACT	RESOLUTION
SDC					
IV 38-01	CLOSED	AS IS	OPEN	NO	
IV 38-02	CLOSED	AS IS	OPEN	NO	
BV 38-04	CLOSED	AS IS	OPEN	NO	
PMP 38-152	N/A	N/A	OPERABLE	NO	
FCV 38-10	CLOSED	CLOSED	OPEN	NO	MAN. OP.
FCV 38-131	CLOSED	CLOSED	CLOSED	NO	
IV 38-13	CLOSED	AS IS	OPEN	NO	
RBCLC					
PMP 70-02	N/A	N/A	OPERABLE	NO	
TCV 70-137	CLOSED	CLOSED	OPEN/THROTTLED	NO	MAN. OP.
BV 70-53	CLOSED	CLOSED	OPEN/THROTTLED	NO	MAN. OP.
ESW					
PMP 72-03	N/A	N/A	OPERABLE	NO	
TCV 72-146	OPEN	OPEN	OPEN/THROTTLED	NO	
INV. MAKEUP					
PMP 28-17	N/A	N/A	OPERABLE	NO	
VLV 28-18	CLOSED	N/A	OPEN	N/A	MAN. OP.
MONITORING INST.					
RPS UPS 172A	OPERABLE	INOPERABLE	OPERABLE	NO	
RPS UPS 172B	OPERABLE	INOPERABLE	OPERABLE	NO	
BATT. CHG.					
SC 171A	OPERABLE	INOPERABLE	OPERABLE	NO	
SC 171B	OPERABLE	INOPERABLE	OPERABLE	NO	
ELECT. DIST. TRAIN					
TRAIN 12/DG 103	OPERABLE	INOPERABLE	OPERABLE	NO	

SAFE SHUTDOWN FIRE AREA ANALYSIS (Cont'd.)

concrete shield. This annulus air gap communicates with the reactor building (secondary containment) at several locations. Therefore, a potential pathway exists between secondary containment and the turbine building. However, fire, heat and smoke propagation through the air gap is not considered credible due to the large volume of the air gap, the significant available heat transfer surface (heat sink), and virtual nonexistence of any type of combustible loading. Since the potential for fire propagation is considered nonexistent, the need to replace the flexible boots is not justified. Therefore, credit is being taken for the north wall as a 3-hr rated wall with the exception of several nonrated flexible boots.

The stack has been added to FA 6. Consequently, the monolithic stack structure above el 261'-0" has been upgraded to 3-hr fire rating and is a required Appendix R barrier.

EXISTING FIRE PROTECTION

Early-warning, ionization-type smoke detectors are provided to protect trays carrying safety-related cables, SC 161A, 161B, 171A, and 171B, RPS UPS 162A, 162B, 172A, and 172B, the instrument shop, the results shop, the area around the PBs and RSP, all PBs, reactor building ventilation equipment, ventilation/air conditioning equipment, and EC makeup storage tanks 11 and 12.

Detection and automatic suppression are provided to cover the fire break zone on el 277'-0", the low-level laboratory area, the equipment decontamination area, the chemical storage area, the track bay entrance, heavy cable concentrations, and the change area on el 333'-0".

General fire suppression is provided by means of local water, CO_2 hose stations, and portable fire extinguishers.

Cables that pass over PBs are protected by a fire detection system and fire-retardant material.

A manual deluge system and infrared flame detectors are provided to protect the turbine building track bay. Flame detection is also provided for the laydown areas on the turbine building floor.

SAFE SHUTDOWN FIRE AREA ANALYSIS (Cont'd.)

Certain multitray runs (greater than two trays) are protected by automatic suppression systems.

Each reactor recirculation MG set is provided with its own thermal detection and automatic local application CO_2 suppression system.*

Manual outside wall water spray systems are provided for the west and southwest walls within 50 ft of the main, reserve and Station service transformers, protecting the unrated wall from a transformer exposure fire.

In the area of electrical equipment, trays are coated with flame-retardant material.

Automatic suppression is provided in the mechanical storage area.

Automatic-flooding CO_2 systems protect the turbine oil storage room, H_2 seal oil unit room, alternate exciter enclosure, turbine oil reservoir room and lube oil reservoir.*

Detection is provided in the general storage area between columns 5 and 10 on el 300'-0".

Charcoal filter banks are equipped with manual water spray and thermistor-type detectors.

Automatic water deluge sprinkler systems protect the floor areas beneath the turbine generator unit. Additionally, fixed water spray systems protect the turbine bearings and lube oil piping on the turbine generator unit. A local application CO_2 system also protects the turbine bearings.

MODIFICATIONS/EXEMPTIONS

Spurious blowdown by the reactor head vent was resolved to prevent inventory loss (see Safety Evaluation 83-33).

---

* Automatic CO_2 fire suppression systems are temporarily in alarm-only mode. See Section 2.5.5.

SAFE SHUTDOWN FIRE AREA ANALYSIS (Cont'd.)

Spurious blowdown by the ADS was resolved to prevent inventory loss (see Safety Evaluation 84-18).

Spurious isolation of EC loop 11 was resolved to provide for hot shutdown (see Safety Evaluations 84-35 and 84-57).

An exemption was granted for the reactor building/turbine building wall above el 340' not being a 3-hr rated fire barrier (see NRC letter dated March 21, 1983).

An exemption was granted for the (separation) requirements of Appendix R, Section III.G.2, for the redundant 125-V dc cables (11B-1, 11B-2, 12B-1, 12B-2) that feed the battery boards from the Station batteries. The redundant cables are separated by 40 ft, fire detection is provided in this area, and cables in the area are coated with Flamemastic.

ANALYSIS

Both DG 102 and 103 could possibly be lost.

Cold shutdown repair procedure for this fire area is N1-DRP-GEN-005.

Although UPS 162A, 162B, 172A, and 172B, which supply power for RPS instrumentation, are located in this fire area, their existing configuration can be justified to meet the requirements of Appendix R. They are separated by 40 ft with the two battery rooms acting as a partial fire barrier. Fire detection is installed in the area and cables in the area are coated with Flamemastic in lieu of an automatic suppression system. This concept was previously approved by the NRC under the BTP 9.5-1 program. Having been approved as the best possible combination of acceptable fire protection features, no exemption request was submitted.

The 125-V dc Station batteries provide power for the 125-V dc system loads during hot shutdown without the need of charging capability from the Station battery chargers. However, static chargers (SC) 161A, 161B, 171A, and 171B are required for cold shutdown to ensure the necessary 125-V dc system loads are maintained during the 72-hr cold shutdown process. The results of FPEE-1-90-016 show that adequate spatial separation and fire protection features do exist to prevent a single fire from damaging both trains of Station battery recharging capability.

The Cardox control panel, located in turbine building el 261', fire zone T3B, contains relays that control each of the emergency diesel generator rooms' CO_2 injection. In addition, they provide a control signal to each of the emergency diesel generator room roof exhaust fans and the rollup door control circuits. Spurious signals generated due to fire-induced failures of the relays could result in CO_2 injection in the room, closure of the rollup door, and tripping of the roof exhaust fans motors. This may affect, in the long term, the ability of the emergency diesel generators to perform their cold shutdown function(s). The post-fire safe shutdown procedures alert the Operators of the potential for loss of emergency diesel generator room cooling for a fire in FA 5, and directs the Operators to manually open the rollup door. In addition, the DRP for this area includes specific steps for installation of jumpers in the associated breaker cubicles to bypass the spurious signal.

Safe shutdown barrier analysis (FPEE-1-90-013) has identified fire areas that can be consolidated to form general fire areas for analysis purposes and for the purpose of reducing the Appendix R required fire barriers. As a result, FA 12, 13 and 15 have been combined with FA 5 for analysis.

THIS PAGE INTENTIONALLY BLANK

FIRE AREA 5 - COLD SHUTDOWN

COMPONENT	NORMAL POSITION	FAIL POSITION	REQUIRED POSITION	POTENTIAL IMPACT	RESOLUTION
SDC					
IV 38-01	CLOSED	AS IS	OPEN	YES	DRP
IV 38-02	CLOSED	AS IS	OPEN	YES	MAN. OP.
BV 38-04	CLOSED	AS IS	OPEN	YES	MAN. OP.
PMP 38-152	N/A	N/A	OPERABLE	NO	
FCV 38-10	CLOSED	CLOSED	OPEN	YES	MAN. OP.
IV 38-13	CLOSED	AS IS	OPEN	YES	DRP
RBCLC					
PMP 70-02	N/A	N/A	OPERABLE	NO	
TCV 70-137	CLOSED	CLOSED	OPEN/THROTTLED	YES	MAN. OP.
BV 70-53	CLOSED	CLOSED	OPEN/THROTTLED	YES	DRP
ESW					
PMP 72-03	N/A	N/A	OPERABLE	YES	MAN. OP.
TCV 72-146	OPEN	OPEN	OPEN/THROTTLED	YES	MAN. OP.
INV. MAKEUP					
PMP 28-17	N/A	N/A	OPERABLE	NO	
VLV 28-18	CLOSED	N/A	OPEN	N/A	MAN. OP.
BATT. CHG.					
SC 171A	OPERABLE	INOPERABLE	OPERABLE	NO	
SC 171B	OPERABLE	INOPERABLE	OPERABLE	NO	
ELECT. DIST. TRAIN					
TRAIN 12/DG 103	OPERABLE	INOPERABLE	OPERABLE	YES	DRP
MONITORING INST.					
RPS UPS 162A	OPERABLE	INOPERABLE	OPERABLE	NO	
RPS UPS 162B	OPERABLE	INOPERABLE	OPERABLE	NO	
RPS UPS 172A	OPERABLE	INOPERABLE	OPERABLE	NO	
RPS UPS 172B	OPERABLE	INOPERABLE	OPERABLE	NO	

FIRE AREA 6 - COLD SHUTDOWN

COMPONENT	NORMAL POSITION	FAIL POSITION	REQUIRED POSITION	POTENTIAL IMPACT	RESOLUTION
SDC					
IV 38-01	CLOSED	AS IS	OPEN	NO	
IV 38-02	CLOSED	AS IS	OPEN	NO	
BV 38-03	CLOSED	AS IS	OPEN	NO	
PMP 38-149	N/A	N/A	OPERABLE	NO	
FCV 38-09	CLOSED	CLOSED	OPEN	NO	MAN. OP.
IV 38-13	CLOSED	AS IS	OPEN	NO	
RBCLC					
PMP 70-01	N/A	N/A	OPERABLE	NO	
TCV 70-137	CLOSED	CLOSED	OPEN/THROTTLED	NO	MAN. OP.
BV 70-53	CLOSED	CLOSED	OPEN/THROTTLED	NO	MAN. OP.
ESW					
PMP 72-04	N/A	N/A	OPERABLE	NO	
TCV 72-146	OPEN	OPEN	OPEN/THROTTLED	NO	
INV. MAKEUP					
PMP 28-15	N/A	N/A	OPERABLE	NO	
VLV 28-18	CLOSED	N/A	OPEN	N/A	MAN. OP.
MONITORING INST.					
RPS UPS 162A	OPERABLE	INOPERABLE	OPERABLE	NO	
RPS UPS 162B	OPERABLE	INOPERABLE	OPERABLE	NO	
ELECT. DIST. TRAIN					
TRAIN 11/DG 102	OPERABLE	INOPERABLE	OPERABLE	YES	DRP
BATT. CHG.					
SC 161A	OPERABLE	INOPERABLE	OPERABLE	NO	
SC 161B	OPERABLE	INOPERABLE	OPERABLE	NO	

FIRE AREA 7 - COLD SHUTDOWN

COMPONENT	NORMAL POSITION	FAIL POSITION	REQUIRED POSITION	POTENTIAL IMPACT	RESOLUTION
SDC					
IV 38-01	CLOSED	AS IS	OPEN	NO	
IV 38-02	CLOSED	AS IS	OPEN	NO	
BV 38-04	CLOSED	AS IS	OPEN	NO	
PMP 38-152	N/A	N/A	OPERABLE	NO	
FCV 38-10	CLOSED	CLOSED	OPEN	NO	MAN. OP.
IV 38-13	CLOSED	AS IS	OPEN	NO	
RBCLC					
PMP 70-02	N/A	N/A	OPERABLE	NO	
TCV 70-137	CLOSED	CLOSED	OPEN/THROTTLED	NO	MAN. OP.
BV 70-53	CLOSED	CLOSED	OPEN/THROTTLED	NO	MAN. OP.
ESW					
PMP 72-03	N/A	N/A	OPERABLE	NO	
TCV 72-146	OPEN	OPEN	OPEN/THROTTLED	NO	
ELECT. DIST. TRAIN					
TRAIN 12/DG 103	OPERABLE	INOPERABLE	OPERABLE	YES	DRP
INV. MAKEUP					
PMP 28-17	N/A	N/A	OPERABLE	NO	
VLV 28-18	CLOSED	N/A	OPEN	N/A	MAN. OP.
BATT. CHG.					
SC 171A	OPERABLE	INOPERABLE	OPERABLE	NO	
SC 171B	OPERABLE	INOPERABLE	OPERABLE	NO	
MONITORING INST.					
RPS UPS 172A	OPERABLE	INOPERABLE	OPERABLE	NO	
RPS UPS 172B	OPERABLE	INOPERABLE	OPERABLE	NO	

FIRE AREA 9 - COLD SHUTDOWN

COMPONENT	NORMAL POSITION	FAIL POSITION	REQUIRED POSITION	POTENTIAL IMPACT	RESOLUTION
SDC					
IV 38-01	CLOSED	AS IS	OPEN	NO	
IV 38-02	CLOSED	AS IS	OPEN	NO	
BV 38-03	CLOSED	AS IS	OPEN	NO	
PMP 38-149	N/A	N/A	OPERABLE	NO	
FCV 38-09	CLOSED	CLOSED	OPEN	NO	MAN. OP.
IV 38-13	CLOSED	AS IS	OPEN	NO	
RBCLC					
PMP 70-01	N/A	N/A	OPERABLE	NO	
TCV 70-137	CLOSED	CLOSED	OPEN/THROTTLED	NO	MAN. OP.
BV 70-53	CLOSED	CLOSED	OPEN/THROTTLED	NO	MAN. OP.
ESW					
PMP 72-04	N/A	N/A	OPERABLE	NO	
TCV 72-146	OPEN	OPEN	OPEN/THROTTLED	NO	
ELECT. DIST. TRAIN					
TRAIN 11/DG 102	OPERABLE	INOPERABLE	OPERABLE	YES	DRP
INV. MAKEUP					
PMP 28-15	N/A	N/A	OPERABLE	NO	
VLV 28-18	CLOSED	N/A	OPEN	N/A	MAN. OP.
BATT. CHG.					
SC 161A	OPERABLE	INOPERABLE	OPERABLE	NO	
SC 161B	OPERABLE	INOPERABLE	OPERABLE	NO	
MONITORING INST.					
RPS UPS 162A	OPERABLE	INOPERABLE	OPERABLE	NO	
RPS UPS 162B	OPERABLE	INOPERABLE	OPERABLE	NO	

SAFE SHUTDOWN FIRE AREA ANALYSIS (Cont'd.)

Electrical Distribution

DG 103
PB 102
PB 103
PB 17

Electromatic Relief Valve

PSV 01-102A
PSV 01-102B
PSV 01-102E
PSV 01-102C
PSV 01-102D
PSV 01-102F

Emergency Service Water

PMP 72-03
PMP 72-04

Instrumentation

LT 36-03A
PT 36-31
LT 60-28
TE 201.2-493 thru 504
LT 58-06
LT 60-29
LT 58-05

Reactor Building Closed Loop Cooling

PMP 70-01
PMP 70-02
PMP 70-03

Shutdown Cooling

PMP 38-149
PMP 38-152
PMP 38-140

DESIGN FEATURES

The area is bounded on the east side by a 2-ft thick reinforced concrete wall with 1-ft square blocked-up openings; on the west side by a 3-ft thick reinforced concrete wall with 1-ft square blocked-up openings; and on the south side by a 2-ft thick reinforced concrete wall with square blocked-up openings (3-hr fire cutoff).

The north boundary is provided by the 2-ft thick reinforced concrete wall of the diesel generator room and an approximately 12-in thick concrete block wall (3-hr fire cutoff).

SAFE SHUTDOWN FIRE AREA ANALYSIS (Cont'd.)

The ceiling is 9'-4 1/2" high and composed of reinforced concrete 1'-7 1/2" thick (3-hr fire cutoff). Cable penetrations through rated ceiling assemblies are sealed with 3-hr rated seals.

Cables and pipes which breach rated wall assemblies are sealed with 3-hr rated seals, with the exception of the duct banks which are sealed with fire stops.

Class "A" fire doors are installed between this fire area and FA 7 and 9.

EXISTING FIRE PROTECTION

The area is protected by a total-flooding CO_2 system which is automatically actuated by cross-zoned smoke detection.* This system is backed up by an automatic preaction sprinkler system.

A smoke and heat removal system is provided to purge the area of CO_2 as well as smoke and heat.

Additional fire suppression is provided by means of local portable fire extinguishers and hose stations located in the adjacent FA 7 and 9.

MODIFICATIONS/EXEMPTIONS

Spurious blowdown by ADS was resolved to prevent inventory loss (see Safety Evaluation 84-18).

Spurious isolation of the ECs was resolved to provide for hot shutdown (see Safety Evaluations 84-35 and 84-57).

ANALYSIS

DG 103 could be unavailable. DG 102 could be unavailable due to damage to the feeder cable of PB 102.

* Automatic CO_2 fire suppression systems are temporarily in alarm-only mode. See Section 2.5.5.

Cold shutdown repair procedure for this fire area is N1-DRP-GEN-003.

Instrumentation is adequate to monitor the shutdown process.

THIS PAGE INTENTIONALLY BLANK

FIRE AREA 10 - COLD SHUTDOWN

COMPONENT	NORMAL POSITION	FAIL POSITION	REQUIRED POSITION	POTENTIAL IMPACT	RESOLUTION
SDC					
IV 38-01	CLOSED	AS IS	OPEN	NO	
IV 38-02	CLOSED	AS IS	OPEN	NO	
BV 38-03	CLOSED	AS IS	OPEN	NO	
PMP 38-149	N/A	N/A	OPERABLE	YES	DRP
FCV 38-09	CLOSED	CLOSED	OPEN	NO	MAN. OP.
IV 38-13	CLOSED	AS IS	OPEN	NO	
RBCLC					
PMP 70-01	N/A	N/A	OPERABLE	YES	DRP
TCV 70-137	CLOSED	CLOSED	OPEN/THROTTLED	NO	MAN. OP.
BV 70-53	CLOSED	CLOSED	OPEN/THROTTLED	NO	MAN. OP.
ESW					
PMP 72-04	N/A	N/A	OPERABLE	YES	MAN. OP.
TCV 72-146	OPEN	OPEN	OPEN/THROTTLED	NO	
INV. MAKEUP					
PMP 28-15	N/A	N/A	OPERABLE	YES	DRP
VLV 28-18	CLOSED	N/A	OPEN	N/A	MAN. OP.
MONITORING INST.					
RPS UPS 162A	OPERABLE	INOPERABLE	OPERABLE	NO	
RPS UPS 162B	OPERABLE	INOPERABLE	OPERABLE	NO	
RPS UPS 172A	OPERABLE	INOPERABLE	OPERABLE	NO	
RPS UPS 172B	OPERABLE	INOPERABLE	OPERABLE	NO	
BATT. CHG.					
SC 161A	OPERABLE	INOPERABLE	OPERABLE	NO	
SC 161B	OPERABLE	INOPERABLE	OPERABLE	NO	
ELECT. DIST. TRAIN					
TRAIN 11/DG 102	OPERABLE	INOPERABLE	OPERABLE	YES	DRP

FIRE AREA 11 - COLD SHUTDOWN

COMPONENT	NORMAL POSITION	FAIL POSITION	REQUIRED POSITION	POTENTIAL IMPACT	RESOLUTION
SDC					
IV 38-01	CLOSED	AS IS	OPEN	YES	DRP
IV 38-02	CLOSED	AS IS	OPEN	YES	MAN. OP.
BV 38-04	CLOSED	AS IS	OPEN	YES	MAN. OP.
PMP 38-152	N/A	N/A	OPERABLE	YES	DRP
FCV 38-10	CLOSED	CLOSED	OPEN	YES	MAN. OP.
IV 38-13	CLOSED	AS IS	OPEN	YES	DRP
RBCLC					
PMP 70-02	N/A	N/A	OPERABLE	YES	DRP
TCV 70-137	CLOSED	CLOSED	OPEN/THROTTLED	YES	MAN. OP.
BV 70-53	CLOSED	CLOSED	OPEN/THROTTLED	YES	DRP
ESW					
PMP 72-03	N/A	N/A	OPERABLE	YES	MAN. OP.
TCV 72-146	OPEN	OPEN	OPEN/THROTTLED	YES	MAN. OP.
INV. MAKEUP					
PMP 28-17	N/A	N/A	OPERABLE	YES	DRP
VLV 28-18	CLOSED	N/A	OPEN	N/A	MAN. OP.
MONITORING INST.					
RPS UPS 172A	OPERABLE	INOPERABLE	OPERABLE	YES	RSP 11 INST.
RPS UPS 172B	OPERABLE	INOPERABLE	OPERABLE	YES	RSP 11 INST.
BATT. CHG. MG SET					
MG SET 167	OPERABLE	INOPERABLE	OPERABLE	YES	DRP
ELECT. DIST. TRAIN					
TRAIN 12/DG 103	OPERABLE	INOPERABLE	OPERABLE	YES	DRP

FIRE AREA 12 - COLD SHUTDOWN

COMPONENT	NORMAL POSITION	FAIL POSITION	REQUIRED POSITION	POTENTIAL IMPACT	RESOLUTION
SDC					
IV 38-01	CLOSED	AS IS	OPEN	NO	
IV 38-02	CLOSED	AS IS	OPEN	NO	
BV 38-04	CLOSED	AS IS	OPEN	NO	
PMP 38-152	N/A	N/A	OPERABLE	NO	
FCV 38-10	CLOSED	CLOSED	OPEN	NO	MAN. OP.
IV 38-13	CLOSED	AS IS	OPEN	NO	
RBCLC					
PMP 70-02	N/A	N/A	OPERABLE	NO	
TCV 70-137	CLOSED	CLOSED	OPEN/THROTTLED	NO	MAN. OP.
BV 70-53	CLOSED	CLOSED	OPEN/THROTTLED	NO	MAN. OP.
ESW					
PMP 72-03	N/A	N/A	OPERABLE	NO	
TCV 72-146	OPEN	OPEN	OPEN/THROTTLED	NO	
INV. MAKEUP					
PMP 28-17	N/A	N/A	OPERABLE	NO	
VLV 28-18	CLOSED	N/A	OPEN	NO	MAN. OP.
MONITORING INST.					
RPS UPS 172A	OPERABLE	INOPERABLE	OPERABLE	NO	
RPS UPS 172B	OPERABLE	INOPERABLE	OPERABLE	NO	
BATT. CHG.					
SC 171A	OPERABLE	INOPERABLE	OPERABLE	NO	
SC 171B	OPERABLE	INOPERABLE	OPERABLE	NO	
ELECT. DIST. TRAIN					
TRAIN 12/DG 103	OPERABLE	INOPERABLE	OPERABLE	NO	

FIRE AREA 13 - COLD SHUTDOWN

COMPONENT	NORMAL POSITION	FAIL POSITION	REQUIRED POSITION	POTENTIAL IMPACT	RESOLUTION
SDC					
IV 38-01	CLOSED	AS IS	OPEN	NO	
IV 38-02	CLOSED	AS IS	OPEN	NO	
BV 38-04	CLOSED	AS IS	OPEN	NO	
PMP 38-152	N/A	N/A	OPERABLE	NO	
FCV 38-10	CLOSED	CLOSED	OPEN	NO	MAN. OP.
IV 38-13	CLOSED	AS IS	OPEN	NO	
RBCLC					
PMP 70-02	N/A	N/A	OPERABLE	NO	
TCV 70-137	CLOSED	CLOSED	OPEN/THROTTLED	NO	MAN. OP.
BV 70-53	CLOSED	CLOSED	OPEN/THROTTLED	NO	MAN. OP.
ESW					
PMP 72-03	N/A	N/A	OPERABLE	YES	MAN. OP. (Diesel Fire Pump [DFP])
TCV 72-146	OPEN	OPEN	OPEN/THROTTLED	NO	
INV. MAKEUP					
PMP 28-17	N/A	N/A	OPERABLE	NO	
VLV 28-18	CLOSED	N/A	OPEN	N/A	MAN. OP.
MONITORING INST.					
RPS UPS 172A	OPERABLE	INOPERABLE	OPERABLE	NO	
RPS UPS 172B	OPERABLE	INOPERABLE	OPERABLE	NO	
BATT. CHG.					
SC 171A	OPERABLE	INOPERABLE	OPERABLE	NO	
SC 171B	OPERABLE	INOPERABLE	OPERABLE	NO	
ELECT. DIST. TRAIN					
TRAIN 12/DG 103	OPERABLE	INOPERABLE	OPERABLE	YES	MAN. OP. (DFP)

FIRE AREA 14 - COLD SHUTDOWN

COMPONENT	NORMAL POSITION	FAIL POSITION	REQUIRED POSITION	POTENTIAL IMPACT	RESOLUTION
SDC					
IV 38-01	CLOSED	AS IS	OPEN	NO	
IV 38-02	CLOSED	AS IS	OPEN	NO	
BV 38-03	CLOSED	AS IS	OPEN	NO	
PMP 38-149	N/A	N/A	OPERABLE	NO	
FCV 38-09	CLOSED	CLOSED	OPEN	NO	MAN. OP.
IV 38-13	CLOSED	AS IS	OPEN	NO	
RBCLC					
PMP 70-01	N/A	N/A	OPERABLE	NO	
TCV 70-137	CLOSED	CLOSED	OPEN/THROTTLED	NO	MAN. OP.
BV 70-53	CLOSED	CLOSED	OPEN/THROTTLED	NO	MAN. OP.
ESW					
PMP 72-04	N/A	N/A	OPERABLE	NO	
TCV 72-146	OPEN	OPEN	OPEN/THROTTLED	NO	
INV. MAKEUP					
PMP 28-15	N/A	N/A	OPERABLE	NO	
VLV 28-18	CLOSED	N/A	OPEN	N/A	MAN. OP.
MONITORING INST.					
RPS UPS 162A	OPERABLE	INOPERABLE	OPERABLE	NO	
RPS UPS 162B	OPERABLE	INOPERABLE	OPERABLE	NO	
BATT. CHG.					
SC 161A	OPERABLE	INOPERABLE	OPERABLE	NO	
SC 161B	OPERABLE	INOPERABLE	OPERABLE	NO	
ELECT. DIST. TRAIN					
TRAIN 11/DG 102	OPERABLE	INOPERABLE	OPERABLE	NO	

FIRE AREA 15 - COLD SHUTDOWN

COMPONENT	NORMAL POSITION	FAIL POSITION	REQUIRED POSITION	POTENTIAL IMPACT	RESOLUTION
SDC					
IV 38-01	CLOSED	AS IS	OPEN	NO	
IV 38-02	CLOSED	AS IS	OPEN	NO	
BV 38-04	CLOSED	AS IS	OPEN	NO	
PMP 38-152	N/A	N/A	OPERABLE	NO	
FCV 38-10	CLOSED	CLOSED	OPEN	NO	MAN. OP.
IV 38-13	CLOSED	AS IS	OPEN	NO	
RBCLC					
PMP 70-02	N/A	N/A	OPERABLE	NO	
TCV 70-137	CLOSED	CLOSED	OPEN/THROTTLED	NO	MAN. OP.
BV 70-53	CLOSED	CLOSED	OPEN/THROTTLED	NO	MAN. OP.
ESW					
PMP 72-03	N/A	N/A	OPERABLE	NO	
TCV 72-146	OPEN	OPEN	OPEN/THROTTLED	NO	
INV. MAKEUP					
PMP 28-17	N/A	N/A	OPERABLE	NO	
VLV 28-18	CLOSED	N/A	OPEN	N/A	MAN. OP.
MONITORING INST.					
RPS UPS 172A	OPERABLE	INOPERABLE	OPERABLE	NO	
RPS UPS 172B	OPERABLE	INOPERABLE	OPERABLE	NO	
BATT. CHG.					
SC 171A	OPERABLE	INOPERABLE	OPERABLE	NO	
SC 171B	OPERABLE	INOPERABLE	OPERABLE	NO	
ELECT. DIST. TRAIN					
TRAIN 12/DG 103	OPERABLE	INOPERABLE	OPERABLE	NO	

FIRE AREA 16A - COLD SHUTDOWN

COMPONENT	NORMAL POSITION	FAIL POSITION	REQUIRED POSITION	POTENTIAL IMPACT	RESOLUTION
SDC					
IV 38-01	CLOSED	AS IS	OPEN	NO	
IV 38-02	CLOSED	AS IS	OPEN	NO	
BV 38-03	CLOSED	AS IS	OPEN	NO	
PMP 38-149	N/A	N/A	OPERABLE	NO	
FCV 38-09	CLOSED	CLOSED	OPEN	NO	MAN. OP.
IV 38-13	CLOSED	AS IS	OPEN	NO	
RBCLC					
PMP 70-01	N/A	N/A	OPERABLE	NO	
TCV 70-137	CLOSED	CLOSED	OPEN/THROTTLED	NO	MAN. OP.
BV 70-53	CLOSED	CLOSED	OPEN/THROTTLED	NO	MAN. OP.
ESW					
PMP 72-04	N/A	N/A	OPERABLE	NO	
TCV 72-146	OPEN	OPEN	OPEN/THROTTLED	NO	
INV. MAKEUP					
PMP 28-15	N/A	N/A	OPERABLE	NO	
VLV 28-18	CLOSED	N/A	OPEN	N/A	MAN. OP.
MONITORING INST.					
RPS UPS 162A	OPERABLE	INOPERABLE	OPERABLE	NO	
RPS UPS 162B	OPERABLE	INOPERABLE	OPERABLE	NO	
BATT. CHG.					
SC 161A	OPERABLE	INOPERABLE	OPERABLE	NO	
SC 161B	OPERABLE	INOPERABLE	OPERABLE	NO	
ELECT. DIST. TRAIN					
TRAIN 11/DG 102	OPERABLE	INOPERABLE	OPERABLE	NO	

FIRE AREA 16B - COLD SHUTDOWN

COMPONENT	NORMAL POSITION	FAIL POSITION	REQUIRED POSITION	POTENTIAL IMPACT	RESOLUTION
SDC					
IV 38-01	CLOSED	AS IS	OPEN	NO	
IV 38-02	CLOSED	AS IS	OPEN	NO	
BV 38-04	CLOSED	AS IS	OPEN	NO	
PMP 38-152	N/A	N/A	OPERABLE	NO	
FCV 38-10	CLOSED	CLOSED	OPEN	NO	MAN. OP.
IV 38-13	CLOSED	AS IS	OPEN	NO	
RBCLC					
PMP 70-02	N/A	N/A	OPERABLE	NO	
TCV 70-137	CLOSED	CLOSED	OPEN/THROTTLED	NO	MAN. OP.
BV 70-53	CLOSED	CLOSED	OPEN/THROTTLED	NO	MAN. OP.
ESW					
PMP 72-03	N/A	N/A	OPERABLE	NO	
TCV 72-146	OPEN	OPEN	OPEN/THROTTLED	NO	
INV. MAKEUP					
PMP 28-17	N/A	N/A	OPERABLE	NO	
VLV 28-18	CLOSED	N/A	OPEN	N/A	MAN. OP.
MONITORING INST.					
RPS UPS 172A	OPERABLE	INOPERABLE	OPERABLE	NO	
RPS UPS 172B	OPERABLE	INOPERABLE	OPERABLE	NO	
BATT. CHG.					
SC 171A	OPERABLE	INOPERABLE	OPERABLE	NO	
SC 171B	OPERABLE	INOPERABLE	OPERABLE	NO	
ELECT. DIST. TRAIN					
TRAIN 12/DG 103	OPERABLE	INOPERABLE	OPERABLE	NO	

FIRE AREA 17A - COLD SHUTDOWN

COMPONENT	NORMAL POSITION	FAIL POSITION	REQUIRED POSITION	POTENTIAL IMPACT	RESOLUTION
SDC					
IV 38-01	CLOSED	AS IS	OPEN	NO	
IV 38-02	CLOSED	AS IS	OPEN	NO	
BV 38-03	CLOSED	AS IS	OPEN	NO	
PMP 38-149	N/A	N/A	OPERABLE	NO	
FCV 38-09	CLOSED	CLOSED	OPEN	NO	MAN. OP.
IV 38-13	CLOSED	AS IS	OPEN	NO	
RBCLC					
PMP 70-01	N/A	N/A	OPERABLE	NO	
TCV 70-137	CLOSED	CLOSED	OPEN/THROTTLED	NO	MAN. OP.
BV 70-53	CLOSED	CLOSED	OPEN/THROTTLED	NO	MAN. OP.
ESW					
PMP 72-04	N/A	N/A	OPERABLE	NO	
TCV 72-146	OPEN	OPEN	OPEN/THROTTLED	NO	
INV. MAKEUP					
PMP 28-15	N/A	N/A	OPERABLE	NO	
VLV 28-18	CLOSED	N/A	OPEN	N/A	MAN. OP.
MONITORING INST.					
RPS UPS 162A	OPERABLE	INOPERABLE	OPERABLE	NO	
RPS UPS 162B	OPERABLE	INOPERABLE	OPERABLE	NO	
BATT. CHG.					
SC 161A	OPERABLE	INOPERABLE	OPERABLE	NO	
SC 161B	OPERABLE	INOPERABLE	OPERABLE	NO	
ELECT. DIST. TRAIN					
TRAIN 11/DG 102	OPERABLE	INOPERABLE	OPERABLE	NO	

FIRE AREA 17B - COLD SHUTDOWN

COMPONENT	NORMAL POSITION	FAIL POSITION	REQUIRED POSITION	POTENTIAL IMPACT	RESOLUTION
SDC					
IV 38-01	CLOSED	AS IS	OPEN	NO	
IV 38-02	CLOSED	AS IS	OPEN	NO	
BV 38-04	CLOSED	AS IS	OPEN	NO	
PMP 38-152	N/A	N/A	OPERABLE	NO	
FCV 38-10	CLOSED	CLOSED	OPEN	NO	MAN. OP.
IV 38-13	CLOSED	AS IS	OPEN	NO	
RBCLC					
PMP 70-02	N/A	N/A	OPERABLE	NO	
TCV 70-137	CLOSED	CLOSED	OPEN/THROTTLED	NO	MAN. OP.
BV 70-53	CLOSED	CLOSED	OPEN/THROTTLED	NO	MAN. OP.
ESW					
PMP 72-03	N/A	N/A	OPERABLE	NO	
TCV 72-146	OPEN	OPEN	OPEN/THROTTLED	NO	
INV. MAKEUP					
PMP 28-17	N/A	N/A	OPERABLE	NO	
VLV 28-18	CLOSED	N/A	OPEN	N/A	MAN. OP.
MONITORING INST.					
RPS UPS 172A	OPERABLE	INOPERABLE	OPERABLE	NO	
RPS UPS 172B	OPERABLE	INOPERABLE	OPERABLE	NO	
BATT. CHG.					
SC 171A	OPERABLE	INOPERABLE	OPERABLE	NO	
SC 171B	OPERABLE	INOPERABLE	OPERABLE	NO	
ELECT. DIST. TRAIN					
TRAIN 12/DG 103	OPERABLE	INOPERABLE	OPERABLE	NO	

SAFE SHUTDOWN FIRE AREA ANALYSIS

FIRE AREA 19

Diesel Generator 103
El. 250'-0" and 261'-0"

Fire Zones:	D1A, D2A
Detection Zones:	DA-2041S, DX-2151A, DX-2151B, DA-2151

ADJACENT FIRE AREAS

NORTH	20, 22
EAST	None
SOUTH	5, 10, 12
WEST	5, 9, 18
BELOW	None
ABOVE	None

SHUTDOWN COMPONENTS IN AREA

DG 103	Diesel 103 Engine Panel
Diesel 103 Cont. Cabinet	Diesel 103 Ground Cubicle

SHUTDOWN COMPONENT CABLE IN AREA

Core Spray

PMP 81-24

Diesel Generator Cooling Water

PMP 79-54

Electrical Distribution

PB 103

Instrumentation

PT 36-05C

DESIGN FEATURES

The north and south boundaries consist of a 2-ft thick reinforced concrete wall, a 1-ft thick concrete block wall and 8-in thick precast concrete wall panels.

SAFE SHUTDOWN FIRE AREA ANALYSIS (Cont'd.)

The west boundary consists of a 2-ft thick concrete shield wall and a 1'-6" thick block wall.

The east boundary consists of a 2-ft thick reinforced concrete wall and 8-in insulated metal wall panels.

Penetrations are provided with 3-hr rated fire assemblies.

Doors are Class "A" fire doors.

Primary structural steel above the DG 102 missile shield is protected with a 3-hr rated barrier.

EXISTING FIRE PROTECTION

Detection and automatic suppression are provided for area protection on el 250'.

Heat detectors which activate a total-flooding CO_2 suppression system are provided on el 261'.* In addition, cross-zoned infrared and photoelectric-type detectors are provided throughout the room which alarm in the control room and actuate the CO_2 suppression system.

Additional suppression is provided by means of local hose stations and portable fire extinguishers.

MODIFICATIONS/EXEMPTIONS

The availability of DG 102 was assured by the installation of an isolation device in the alternate dc feed (see Safety Evaluation 83-07).

ANALYSIS

Safe shutdown barrier analysis (FPEE-1-90-013) has identified fire areas that can be consolidated to form general fire areas for analysis purposes and for the purpose of reducing the Appendix R required fire barriers. As a result, FA 19 has been combined with FA 6, FA 20 and FA 9 for analysis purposes only.

---

* Automatic CO_2 fire suppression systems are temporarily in alarm-only mode. See Section 2.5.5.

A fire could cause the loss of DG 103.

Both EC loops 11 and 12 are available.

Diesel generator 102 and its associated shutdown systems are also available.

Instrumentation is adequate to monitor the shutdown process.

THIS PAGE INTENTIONALLY BLANK

FIRE AREA 19 - COLD SHUTDOWN

COMPONENT	NORMAL POSITION	FAIL POSITION	REQUIRED POSITION	POTENTIAL IMPACT	RESOLUTION
SDC					
IV 38-01	CLOSED	AS IS	OPEN	NO	
IV 38-02	CLOSED	AS IS	OPEN	NO	
BV 38-03	CLOSED	AS IS	OPEN	NO	
PMP 38-149	N/A	N/A	OPERABLE	NO	
FCV 38-09	CLOSED	CLOSED	OPEN	NO	MAN. OP.
IV 38-13	CLOSED	AS IS	OPEN	NO	
RBCLC					
PMP 70-01	N/A	N/A	OPERABLE	NO	
TCV 70-137	CLOSED	CLOSED	OPEN/THROTTLED	NO	MAN. OP.
BV 70-53	CLOSED	CLOSED	OPEN/THROTTLED	NO	MAN. OP.
ESW					
PMP 72-04	N/A	N/A	OPERABLE	NO	
TCV 72-146	OPEN	OPEN	OPEN/THROTTLED	NO	
INV. MAKEUP					
PMP 28-15	N/A	N/A	OPERABLE	NO	
VLV 28-18	CLOSED	N/A	OPEN	N/A	MAN. OP.
MONITORING INST.					
RPS UPS 162A	OPERABLE	INOPERABLE	OPERABLE	NO	
RPS UPS 162B	OPERABLE	INOPERABLE	OPERABLE	NO	
RPS UPS 172A	OPERABLE	INOPERABLE	OPERABLE	NO	
RPS UPS 172B	OPERABLE	INOPERABLE	OPERABLE	NO	
BATT. CHG.					
SC 161A	OPERABLE	INOPERABLE	OPERABLE	NO	
SC 161B	OPERABLE	INOPERABLE	OPERABLE	NO	
ELECT. DIST. TRAIN					
TRAIN 11/DG 102	OPERABLE	INOPERABLE	OPERABLE	NO	

FIRE AREA 20 - COLD SHUTDOWN

COMPONENT	NORMAL POSITION	FAIL POSITION	REQUIRED POSITION	POTENTIAL IMPACT	RESOLUTION
SDC					
IV 38-01	CLOSED	AS IS	OPEN	NO	
IV 38-02	CLOSED	AS IS	OPEN	NO	
BV 38-03	CLOSED	AS IS	OPEN	NO	
PMP 38-149	N/A	N/A	OPERABLE	NO	
FCV 38-09	CLOSED	CLOSED	OPEN	NO	MAN. OP.
IV 38-13	CLOSED	AS IS	OPEN	NO	
RBCLC					
PMP 70-01	N/A	N/A	OPERABLE	NO	
TCV 70-137	CLOSED	CLOSED	OPEN/THROTTLED	NO	MAN. OP.
BV 70-53	CLOSED	CLOSED	OPEN/THROTTLED	NO	MAN. OP.
ESW					
PMP 72-04	N/A	N/A	OPERABLE	NO	
TCV 72-146	OPEN	OPEN	OPEN/THROTTLED	NO	
MONITORING INST.					
RPS UPS 162A	OPERABLE	INOPERABLE	OPERABLE	NO	
RPS UPS 162B	OPERABLE	INOPERABLE	OPERABLE	NO	
INV. MAKEUP					
PMP 28-15	N/A	N/A	OPERABLE	NO	
VLV 28-18	CLOSED	N/A	OPEN	N/A	MAN. OP.
BATT. CHG.					
SC 161A	OPERABLE	INOPERABLE	OPERABLE	NO	
SC 161B	OPERABLE	INOPERABLE	OPERABLE	NO	
ELECT. DIST. TRAIN					
TRAIN 11/DG 102	OPERABLE	INOPERABLE	OPERABLE	NO	

SAFE SHUTDOWN FIRE AREA ANALYSIS (Cont'd.)

DESIGN FEATURES

The south boundary consists of a 2-ft thick reinforced concrete wall, 1-ft thick concrete block wall, and 8-in thick insulated precast concrete wall panels.

The north boundary consists of a 2-ft thick reinforced concrete wall and a 1-ft thick concrete block wall.

The east boundary consists of a 2-ft thick reinforced concrete wall and 8-in thick insulated metal wall panels.

The west boundary consists of an 8-in thick concrete masonry unit block wall, a 2-ft thick concrete shield wall and a 1'-6" thick concrete block wall.

Penetrations are provided with 3-hr rated seals.

Doors are Class "A" fire doors.

Primary structural steel along the walls is protected with 3-hr rated barriers.

EXISTING FIRE PROTECTION

Detection and automatic suppression are provided for area protection on el 250'-0".

Additional suppression is provided by means of hose stations and portable fire extinguishers.

Heat detectors which activate a total-flooding CO_2 suppression system are provided on el 261'-0".* In addition, cross-zoned infrared and photoelectric-type detectors are provided throughout the room which alarm in the control room and activate the CO_2 system.*

---

* Automatic CO_2 fire suppression systems are temporarily in alarm-only mode. See Section 2.5.5.

SAFE SHUTDOWN FIRE AREA ANALYSIS (Cont'd.)

MODIFICATIONS/EXEMPTIONS

The availability of DG 103 was assured by the installation of an isolation device in the alternate dc feed (see Safety Evaluation 83-07).

Spurious blowdown by the reactor head vent was resolved to prevent inventory loss (see Safety Evaluation 83-33).

Spurious isolation of EC loop 12 was resolved to provide for hot shutdown (see Safety Evaluation 84-35).

Control of the core spray inboard isolation valves was resolved to provide for cold shutdown (see Safety Evaluation 84-24).

ANALYSIS

Safe shutdown barrier analysis (FPEE-1-90-013) has identified fire areas that can be consolidated to form general fire areas for analysis purposes and for the purpose of reducing the Appendix R required fire barriers. As a result, FA 22 has been combined with FA 18 and FA 23 for analysis purposes only.

Diesel generator 102 may be lost due to direct impact.

Instrumentation is adequate to monitor the shutdown process.

SAFE SHUTDOWN FIRE AREA ANALYSIS (Cont'd.)

Shutdown Cooling

BV 38-04
IV 38-01
IV 38-13

Instrumentation

PT 36-32
LT 36-05C

DESIGN FEATURES

The north and south boundaries consist of 1'-0" thick block walls (3-hr fire cutoff).

The west boundary consists of a 1'-3" thick reinforced concrete wall (3-hr fire cutoff).

The east boundary consists of 8-in thick insulated metal wall panels (no exposure).

The floor consists of a 1'-7" thick reinforced concrete slab.

The roof is 15 ft high and consists of metal roof decking with supporting steel.

Cables and pipes breaching the rated wall assemblies of this fire area are sealed with 3-hr rated fire seals.

Cables and pipes penetrating the rated floor assemblies of this fire area are sealed with 3-hr rated fire seals.

Class "A" fire doors are located at the north and south walls between this fire area and FA 22 and FA 24, respectively.

SAFE SHUTDOWN FIRE AREA ANALYSIS (Cont'd.)

EXISTING FIRE PROTECTION

Cross-zoned smoke detection actuating a total-flooding CO_2 suppression system is provided in this fire area.*

Fire-retardant material covers cables that run along the west wall of this area above PB 102.

Additional fire suppression is provided by local hose stations located in the adjacent FA 22 and by local portable fire extinguishers.

MODIFICATIONS/EXEMPTIONS

Spurious blowdown by the reactor head vent was resolved to prevent inventory loss (see Safety Evaluation 83-33).

Control of the core spray inboard isolation valves was resolved to provide for cold shutdown (see Safety Evaluation 82-24).

ANALYSIS

Safe shutdown barrier analysis (FPEE-1-90-013) has identified fire areas that can be consolidated to form general fire areas for analysis purposes and for the purpose of reducing the Appendix R required fire barriers. As a result, FA 23 has been combined with FA 22 and FA 18 for analysis purposes only.

Diesel generator 102 could be lost due to the direct impact of PB 102.

Diesel generator 103 is available.

Instrumentation is adequate to monitor the shutdown process.

---

* Automatic CO_2 fire suppression systems are temporarily in alarm-only mode. See Section 2.5.5.

SAFE SHUTDOWN FIRE AREA ANALYSIS (Cont'd.)

Electrical Distribution

DG 103
UPS 172A
UPS 172B
SC 171A
SC 171B

Instrumentation

LT 36-05C
PT 36-32

Shutdown Cooling

BV 38-04
IV 38-01
IV 38-13

DESIGN FEATURES

The north and south boundaries consist of 12-in thick concrete block walls (3-hr fire cutoffs).

The west boundary consists of a 1'-3" thick reinforced concrete wall (3-hr fire cutoff).

The east boundary consists of 8-in thick insulated metal wall panels (no exposure).

The floor consists of a 1'-7 1/2" thick reinforced concrete slab.

The roof is 15-ft high and consists of metal roof decking with support steel.

Cable and pipes breaching the rated wall assemblies are sealed with 3-hr rated fire seals.

Cables and pipes penetrating the rated floor assemblies of this area are sealed with 3-hr rated fire seals.

Class "A" fire doors are located on the west and south walls between this fire area and FA 5 and FA 23, respectively.

SAFE SHUTDOWN FIRE AREA ANALYSIS (Cont'd.)

EXISTING FIRE PROTECTION

Cross-zoned smoke detection actuating a total-flooding CO_2 suppression system is provided in this fire area.*

Fire-retardant material covers cables that run along the west wall of this fire area above PB 103.

Additional fire suppression is provided by local hose stations and portable fire extinguishers located in the adjacent FA 5.

MODIFICATIONS/EXEMPTIONS

Spurious blowdown by the reactor head vent was resolved to prevent inventory loss (see Safety Evaluation 83-33).

Control of the core spray inboard isolation valves was resolved to provide for cold shutdown (see Safety Evaluation 84-24).

ANALYSIS

Safe shutdown barrier analysis (FPEE-1-90-013) has identified fire areas that can be consolidated to form general fire areas for analysis purposes and for the purpose of reducing the Appendix R required fire barriers. As a result, FA 24 has been combined with FA 21 for analysis purposes only.

Diesel generator 103 could be lost due to direct impact of PB 103.

Instrumentation is adequate to monitor the shutdown process.

* Automatic CO_2 fire suppression systems are temporarily in alarm-only mode. See Section 2.5.5.

10.0 APPENDIX R MODIFICATION REVIEW GUIDELINE

10.1 OBJECTIVE

This guideline is intended to provide general instructions for determining the potential impact of plant modifications on the Unit 1 Appendix R SSA. This guideline should not be interpreted as a "cookbook" instruction for performing Appendix R modification reviews, and this guideline is not intended to replace Nuclear Engineering Procedures.

10.2 DISCUSSION

The Appendix R Engineer is responsible for safeguarding the integrity of the Unit 1 Appendix R SSA, thereby ensuring continued compliance to the rules and regulations set forth in 10CFR50 Appendix R. The first step in maintaining a sound Appendix R program requires providing precise design input for the development of conceptual engineering packages for prospective plant modifications. Once the proper design input is provided and the Appendix R design criteria is accepted and incorporated in the final modification design, the final Appendix R review should be limited to verifying the implementation of the original design input statement and updating the Appendix R analysis, revising the DRPs, and/or updating the prescribed manual operations if necessary. However, a complete Appendix R review must be performed for the final modification design.

Unscheduled modifications or temporary modifications may not provide the opportunity for providing conceptual design input. Unfortunately, these Appendix R reviews are performed after the final modification design is complete prior to Plant Operations Review Committee (PORC) approval, and a rigorous Appendix R review is required to ensure the Appendix R SSA is not compromised.

10.3 METHODOLOGY

The methodology for performing detailed Appendix R modification reviews involves responding to the questions on the Appendix R review sheet and providing the required additional information and resolutions.

10.4 PROCEDURE

When requested to perform a fire protection review by the project engineer, review the 50.59 evaluation and request any additional information necessary to respond to the Appendix R review questions.

1. The first question (Safe Shutdown Systems) is very generic and the proper response to this question requires a detailed knowledge of the Unit 1 SSA. To respond to this question, the following information should be established:

    a. Does the plant change modify any of the safe shutdown components listed in Appendix B of this document? If no, continue responding to the remaining questions. If yes, you must determine what impact the change may have on the Appendix R SSA. The following questions should be answered for any safe shutdown component being modified to determine the impact on the Appendix R SSA.

    b. Is the change restricted to supporting structures such as pipe supports and valve supports? If yes, then the modification does not impact the availability of a safe shutdown system, and you may proceed to Item 2.

    c. Does the plant change involve the substitution of parts for the safe shutdown component (e.g., solenoid valve, AOV diaphragm, motor, gauges, etc.) such that the operating characteristics (e.g., fail position on loss of air, ac power or dc power, flow rate, indicating range and/or operating logic (energize to activate vs. de-energize to activate)) remain unchanged? If yes, the modification does not impact the availability of a safe shutdown system and you may proceed to Item 2.

    d. Does the plant change involve the routing or rerouting of cables associated with the safe shutdown component such that the availability of that component in the fire areas where that component has been selected for safe shutdown has been compromised? If yes, then the modification should not be approved with the proposed cable routing. If alternate cable routing cannot satisfy the separation criteria, then manual operations can be prescribed or DRPs can be developed, provided the component is not required for hot shutdown (DRPs not permitted to achieve hot shutdown).

2. The second question concerns associated circuits that may impact safe shutdown or nonsafe shutdown components such that the safe shutdown capability is compromised. A complete understanding of Section 5.9 is required to properly identify potentially adverse associated circuits. There are three categories of associated circuits that will be discussed.

   a. The first category addresses those circuits which share a common power supply with safe shutdown circuits. The acceptance criteria for this associated circuit is based on maintaining proper breaker/fuse coordination between the components isolation devices and the isolation device of the upstream power supply. Electrical Design is responsible for maintaining the proper breaker/fuse coordination for the ac and dc electrical distribution systems. The Appendix R Engineer should understand the methodology for performing the 125-V dc breaker/fuse coordination study to ensure proper coordination.

   b. The second category addresses those circuits which share common enclosures (e.g., cable trays, conduits, panels) with safe shutdown circuits. Again, these circuits utilize current limiting protection devices (breakers/fuses) to preclude the failure of the cable insulation jacket, which may result in additional spurious operation and/or additional cable fire. Again, due to proper electrical coordination and the use of rated fire barriers, the concept of common enclosures is limited to each separate fire area. Therefore, a fire in a given fire area will not propagate to an enclosure of the redundant system located in an adjacent fire area.

   c. The third category addressed those circuits whose spurious operation could have a potentially serious effect on the safe shutdown capability of the plant (e.g., high/low pressure interface, flow diversion). Spurious operations could be the result of hot shorts, open circuits or shorts to ground. Refer to Section 5.4 for the assumptions used to establish the credibility of the spurious operations and Section 5.9 for further clarification on associated circuits.

3. The third question concerns the fire protection features of a fire area which are required to satisfy the separation criteria of 10CFR50 Section III.G. The Appendix R safe shutdown fire walls and floors, drawings (currently designated as the Technical Specification drawings), and the Appendix R figures (Appendix 10A) list all the fire protection features required to meet Section III.G separation. Additional information on these fire protection features can be found in Appendix C (Exemption Requests) and Appendix D (Appendix R Modifications). The Appendix R Engineer must have a detailed knowledge of the restrictions and requirements imposed by these exemptions and modifications to ensure continued compliance to Section III.G.

4. The fourth question is required to maintain compliance with 10CFR50 Appendix R, Section III.J. This requirement states, "Emergency lighting units with at least an 8-hr battery power supply shall be provided in all areas needed for operation of safe shutdown equipment and in access and egress routes thereto." Therefore, if the modification mandates additional DRP actions and/or manual operations, emergency dc lighting unit(s) with an 8-hr battery power supply shall be installed where required.

5. The last question pertains to any procedure that may be impacted by the plant change. Section 5.4 contains a listing of the Operating Procedures, SOPs, DRPs, Maintenance Procedures and EOPs that are credited for satisfying Appendix R requirements and/or establish the bases for the Appendix R assumptions. Therefore, any plant change that may impact procedures that are relied upon to satisfy Appendix R requirements or assumptions must be reviewed to ensure the Appendix R SSA has not been compromised.

6. If the plant change requires a change to the analysis, the change shall be entered (by the Appendix R Engineer) in the working copy of the analysis and shall be incorporated in the next revision.

10.5 SUMMARY

This guideline has provided general instructions for performing Appendix R reviews for plant changes requiring 50.59 evaluations. This guideline cannot address all the possible plant changes that may impact the Appendix R SSA. A complete understanding of 10CFR50 Appendix R and the Unit 1 Appendix R SSA is required to ensure that plant changes receive the proper Appendix R review.

THIS PAGE INTENTIONALLY BLANK

APPENDIX B (Cont'd.)

System	Component	Train	Location Column-Row/Elevation	Fire Area
CRD	PMP 28-15	11	Rx Bldg., M-12/237'-0"	1
	PMP 28-17	12	Rx Bldg., M-12/237'-0"	1
	VLV 28-18	Manual	Rx Bldg., M-12/237'-0"	1
CS	IV 40-01	11	Drywell	3
	IV 40-09	12	Drywell	3
	IV 40-10	12	Drywell	3
	IV 40-11	11	Drywell	3
	IV 40-05	12	Rx Bldg., K-10/237'	1
	IV 40-06	11	Rx Bldg., K-6/237'	2
	IV 40-12	12	Rx Bldg., K-10/237'	1
	IV 40-02	11	Rx Bldg., L-6/237'	2
	IV 40-30	11	Drywell	3
	IV 40-31	12	Drywell	3
	IV 81-01	12	Rx Bldg., H-11/198'-0"	1
	IV 81-02	12	Rx Bldg., H-11/198'-0"	1
	IV 81-21	11	Rx Bldg., H-5/198'-0"	2
	IV 81-22	11	Rx Bldg., H-5/198'-0"	2
	PMP 81-03	12	Rx Bldg., H-11/198'-0"	1
	PMP 81-04	12	Rx Bldg., H-11/198'-0"	1
	PMP 81-23	11	Rx Bldg., H-4/198'-0"	2
	PMP 81-24	11	Rx Bldg., H-4/198'-0"	2
	PMP 81-49	11	Rx Bldg., K-5/237'-0"	2
	PMP 81-50	11	Rx Bldg., K-4/237'-0"	2
	PMP 81-51	12	Rx Bldg., H-11/237'-0"	1
	PMP 81-52	12	Rx Bldg., H-10/237'-0"	1
DFP	PMP 100-02	N/A	Diesel Fire Pump Room	14
Elect.	Battery 11	11	Battery Room 11	17B
	Battery 12	12	Battery Room 12	17A
	Battery Board 11	11	Battery Board Room 11	16B

APPENDIX B (Cont'd.)

System	Component	Train	Location Column-Row/Elevation	Fire Area
Elect.	Battery Board 12	12	Battery Board Room 12	16A
	DG 102	11	Diesel Generator Room 102	22
	DG 103	12	Diesel Generator Room 103	19
	SC 161A	11	Turbine Bldg., Aa-8/261'-0"	5
	SC 161B	11	Turbine Bldg., Aa-8/261'-0"	5
	UPS 162A	11	Turbine Bldg., A-6/277'-0"	5

service, the suction of the mechanical vacuum pump may be diverted to the condenser water boxes. The condenser water boxes are normally primed using the circulating water priming pumps.

The system consists of two mechanical vacuum pumps, two moisture separators, two seal pumps and two mechanical vacuum pump coolers. This system is capable of evacuating the condenser and associated system from atmospheric pressure to 5-in mercury absolute in approximately 1 hr, with both pumps operating. Operation of one pump extends time to 2 hr.

The mechanical vacuum pump line is capable of automatic isolation initiated from high radioactivity (five times normal) in the main steam line (MSL).

The offgas equipment, piping, valves and filter housings are designed to withstand the high pressure generated by a possible hydrogen-oxygen explosion.

To detect the source of air in-leakage in the OFG system, use of tracer gas monitoring and analyzing equipment temporarily connected to the offgas sampling station has been evaluated. The same technique has been evaluated for condenser tube leaks.

The HWC includes an oxygen injection system to offgas, upstream of the offgas recombiner to maintain stoichiometric mixture of hydrogen and oxygen in the recombiner. The system is provided due to an excess ratio of hydrogen to oxygen at the entrance to the OFG system because of hydrogen injection through the feedwater system.

The HWC includes an additional OFG sample system for monitoring of the offgas percent oxygen concentration from the recombiners to assure that the oxygen addition flows are properly balanced. The HWC OFG sample system draws gas from downstream of the offgas vent coolers.

4.0 Circulating Water System

Two 125,000-gpm vertical, mixed flow, circulating water pumps located in the screenhouse deliver water from Lake Ontario to the condenser water box as shown on Figure XI-4. Each pump discharges in a separate line to one side of the condenser divided water box. Fish screens are installed in each circulating water inlet pipe at the entrance to the water box. These fish screens are in the open position during operation. They are closed just before the circulating water pumps are removed from service to prevent debris from backwashing from the condenser water boxes into the inlet tunnel. This debris collects on the closed fish screen and will be sluiced into the circulating water discharge tunnel.

Each pump suction pit is sectionalized to permit draining of one pit for maintenance while the other pump is in operation. After leaving the condenser, the circulating water is discharged back into the lake. The screenhouse, intake and discharge tunnels are further described in Section III-F.

5.0 Condensate Pumps

Three one-half capacity, centrifugal, motor-driven vertical condensate pumps, each rated at 4,000,000 lb/hr, take suction from the condenser hotwell and discharge it through the full-flow condensate demineralizer (CND) system, the SJAE intercondenser, and the recombiner condensers into the three feedwater booster pumps. Operation of two pumps is sufficient to handle the full operating load (100-percent power) requirements.

Alarms for low condensate discharge header pressure, low and high hotwell level, high condensate temperature leaving the hotwell, and low condenser vacuum are provided to alert the Operator of abnormal conditions.

6.0 Condensate Filtration System

The full-flow CFS is located upstream of the condensate demineralizers, as shown on Figure XI-5, and is designed to remove 99 percent of the insoluble iron and copper from the condensate water. There are four filters sized for 100 percent condensate flow. There is a 25 percent bypass line available for use during filter backwash and a 100 percent bypass line which can be used to bypass all four filters if it is necessary to take the system out of service. The purpose of the filters is to extend the lifetime of the condensate demineralizer resin by reducing the need for ultrasonic cleaning of condensate resin beds. The removal of insoluble iron and copper also results in a reduced possibility of fuel failures and in reduced radiological dose. The filters are cylindrical vessels mounted vertically. Each vessel has a fully removable top head to allow unrestricted insertion and removal of filter element bundles or modules.

The entire CFS is designed and built to the same codes and standards as the condensate and feedwater systems. In addition to the filter tanks, the CFS consists of a backwash receiving tank (BWRT), vent system, air receiver tank, air compressor, control panel, and other miscellaneous components.

The filters are backwashed and reused. Any material removed from the filters by backwashing goes to the BWRT. The material from the BWRT is then sent to radwaste for processing as required. The CFS, backwashing, and associated transfer equipment are manually controlled from a local control panel. The local control panels control all of the main flow valves, initiate and control filter backwash sequences, and contain all controls, indications and alarms for the operation of the CFS.

Replacement of filter media is accomplished from the installed work platform around the filters. The filter head is removed and the filter media is lifted, the filter media replaced, and filter head reinstalled by using the installed monorail hoists. The filter media is processed by radwaste.

The filter vessels each have a cylindrical radiation shield around them. This shield extends above and below the filter portion of the tank. The BWRTs are also shielded. Shielding is designed to ensure that area dose rates are maintained <5 mrem/hr general area.

An alarm is provided for CFS trouble in the main control room.

6.0A Condensate Demineralizer System

The full-flow CND system, as shown on Figure XI-5, assures water of the required purity to the reactor. The full flow of condensate is passed through the CNDs as required for load conditions. There are six mixed-bed demineralizers, sized for rated load condensate flow, piped in parallel. They can be used in any combination as required to remove corrosion products gathered from the turbine, condenser, and the shell side of the feedwater heaters; protect the reactor against condenser tube leaks; and remove condensate impurities which might enter the system in the makeup water. Three of the demineralizer tanks are rubber lined. The other three are lined with a ceramic coating. All six tanks are the carbon steel type, sized for a nominal flow rate of 50 gpm per square foot of bed surface area when six demineralizers are in service at full power (1850 MWt). When it is necessary (due to ultrasonic resin cleaning (URC) or bed replacement) to take one unit out of service (OOS), the flow is approximately 58 gpm per square foot. The maximum nominal design flow is 64 gpm per square foot of bed surface area with five demineralizers on-line.

Strainers located on the discharge side of the demineralizers prevent accidental carryover of resins to the reactor.

Demineralizer resins are normally mechanically cleaned by air scrubbing, backwashing, and sound energy, and reused. Any radioactive material removed from the exhausted resins by the cleaning and rinse solutions is transferred to the waste disposal system described in Section XII-A for processing as required.

The CND and associated transfer and cleaning system are manually controlled from two adjacent local panels, the resin transfer and cleaning panel and the CND control panel. Integrated flow, conductivity, instantaneous flow, differential pressure, and effluent strainer differential pressure monitors are provided at the CND control panel for each demineralizer to indicate when cleaning or resin bed replacement is required.

Main flow valves are remotely operated from the CND control panel. Resin transfers from the demineralizers to the cation tank, and from the resin storage tank to the empty demineralizer tank, are manually initiated. Backwash, mechanical cleaning, and rinsing of the resins, the transportation of ultrasonically cleaned resins to the resin storage tank, and resin mixing are manually initiated at the local resin transfer and cleaning panel.

The demineralizer vessels and resin cleaning tanks are located in concrete shielded areas and are arranged for remote operation. Shielding around the demineralizers is designed to give 1.5 mr/hr in the corridor and 100 mr/hr at the south wall facing turbine operating floor and in the demineralizer piping area. The piping area is shielded to give 30 mr/hr in the demineralizer valve

THIS PAGE INTENTIONALLY BLANK

driven from the shaft of the high-pressure turbine through a quick-disconnect clutch and step-up gear. The other two, each rated at 1,250,000 lb/hr, are electric motor-driven through step-up gears. Operation of the pumps above the rated capacities is acceptable to meet feedwater demand. The normal operating point for the shaft pump at rated reactor thermal output (1850 MWt) is between 5,800,000 and 6,200,000 lbm/hr. The normal operating point for the motor feedwater pumps is between 1,250,000 and 1,750,000 lbm/hr. This operating range is based on years of experience and vendor recommendations. The pumps discharge through regulating valves which provide reactor feedwater control. Minimum flow for pump protection is obtained by recirculation to the condenser.

A radiant heat shield is installed between the two electric motor-driven feedwater pumps to prevent fire damage to the redundant pump in the event of a fire in the other pump.

10.0 Feedwater Heaters

Feedwater is divided into three parallel heater strings, as shown on Figure XI-7. There are four low-pressure feedwater heaters and one high-pressure feedwater heater in each string. A separate drain cooler is provided for each of the lowest-pressure heaters, while the other heaters have integral drain coolers. Each feedwater heater string is based upon the design criterion that the Station have the ability to operate at 80 percent of design rating on two heater strings in the event that one heater string is removed from service. The heaters are horizontal, closed U-tube type. Turbine extraction steam heats the feedwater in each heater. The drips from each heater cascade to the next lower heater and finally to the condenser after passing through the drain cooler (Figure XI-2).

The heater strings are located in separate concrete shielded compartments in the turbine building, enabling maintenance work to be undertaken on an isolated string of heaters during operation. The design radiation level is 5 mr/hr outside the compartments except on the valve operating corridors between compartments where the design level is 30 mr/hr. The shell side of each heater is continuously vented to the condenser to remove all air and disassociated oxygen and hydrogen from the extraction steam. Valve handwheel extensions projecting outside the shielded area are provided on all valves required for remote operation on startup and shutdown of the heaters.

C. SYSTEM ANALYSIS

The design and construction of components in the system whose failure could cause significant uncontrolled release of radioactivity to the environs are in accordance with well-established codes and standards. Codes that apply are:

Standards of Feedwater Heater Manufacturer's Association, Inc.

Standards of Tubular Exchanger Manufacturer's Association

ASME Boiler & Pressure Vessel Code, Section VIII

Pressure Piping Code of the American Standards Association

Components in the power conversion system are designed to withstand seismic forces as outlined in Section XVI-D.1.

During both normal and accident conditions, exclusion areas and shielding around selected components in the system will protect Station personnel from exposures above established limits. Individual components in the steam and power conversion system which handle highly-radioactive steam or condensate are shielded from other components which handle nonradioactive or low radioactivity fluids. Included among the equipment which is shielded are the reheaters, moisture separators, each individual heater string, the condensate pumps, the CNDs, the SJAEs and the steam-packing exhausters.

Pressure-relieving devices are provided on all appropriate components to afford overpressure protection on system malfunction, etc., as follows:

1. Relief valves located upstream of each combined reheat valve are set between 220-225 psig to protect the reheater shell and connecting piping against overpressure. Pressure relief is required in the event higher pressures are applied to the reheat system through malfunction of the turbine valves.

2. The high-pressure steam lines to the reheaters are equipped with flow-restricting Venturi nozzles, and pressure relief valves set at approximately 1,000 psig to protect the reheater tubes and associated piping against malfunction of the turbine valves.

3. Turbine exhaust hood blowout diaphragms are set at 5 psig to protect the low-pressure turbine exhaust hood against overpressure.

4. Feedwater heater shell relief valves protect the heater shells against overpressure on a tube break. Set pressures: #5 heaters - 200 psig, #4 heaters - 125

psig, #3 heaters - 75 psig, #2 and #1 heaters - 50 psig. The set pressures of each relief valve coincide with the heater shell design pressure. Each valve is sized to pass the water flow resulting from one complete tube break at maximum feedwater pressure.

5. The feedwater heater water side snifter relief valve protects the feedwater side of heaters against damage from thermal expansion of the feedwater on heater isolation. Set pressures: #5 heaters - 1400 psig, drain coolers - 530 psig. The pressure setting coincides with the heater water side design pressure.

6. Reactor feedwater pump suction piping relief valves are set at 530 psig to protect the suction piping against overpressure on pump warmup with the pump suction isolation valve closed. The set pressure coincides with the suction piping design pressure.

7. All relief valves with the exception of the turbine exhaust hood relief diaphragm discharge to the condenser.

8. For dependability, a spare motor-driven feedwater pump, a spare booster pump and a spare steam jet element of each stage of the air ejector are provided. The feedwater heaters are designed to carry 80 percent of design load on two heater strings with one string OOS.

9. The materials selected for the condenser and feedwater heater tubes are designed to minimize corrosion and carryover into the reactor system. The employment of full-flow demineralizers also reduces the amount of carryover to the reactor system.

10. All equipment vents are piped to the condenser to minimize the presence of radioactive gases in the turbine room spaces.

11. Trips are provided which are actuated by the steam power conversion system variables to protect the system equipment. These include a condenser low-low-low vacuum main steam line isolation valve (MSIV) closure, stop valve closure and control valve rapid closure reactor scrams, reactor feedwater pump

low suction pressure trip and extraction nonreturn valve (NRV) trip on high heater level.

In addition, certain other steam power conversion system variables are alarmed to alert the Operator of abnormal conditions. These alarms include condensate discharge header (low pressure), hotwell level (low and high), condensate leaving the hotwell (high temperature), condensate filter trouble (alarm at local panel), condensate demineralizer trouble (high differential pressure), had high demineralizer effluent (conductivity at the local condensate panel), turbine exhaust hood spray (low pressure), booster pump suction (low pressure), feedwater heaters (high level), reactor feedwater pump suction (low pressure) and condenser vacuum (low).

D. TESTS AND INSPECTIONS

Tests and inspections are conducted to assure functional performance as required for continued safe operation and to provide maximum protection for operating personnel. Among these tests are periodic exercise of the turbine stop valves and the steam bypass valves. Other control valves not normally in motion are periodically exercised. During normal operating periods, duplicate equipment is rotated on a regular basis to assure the backup equipment is in operational readiness at all times.

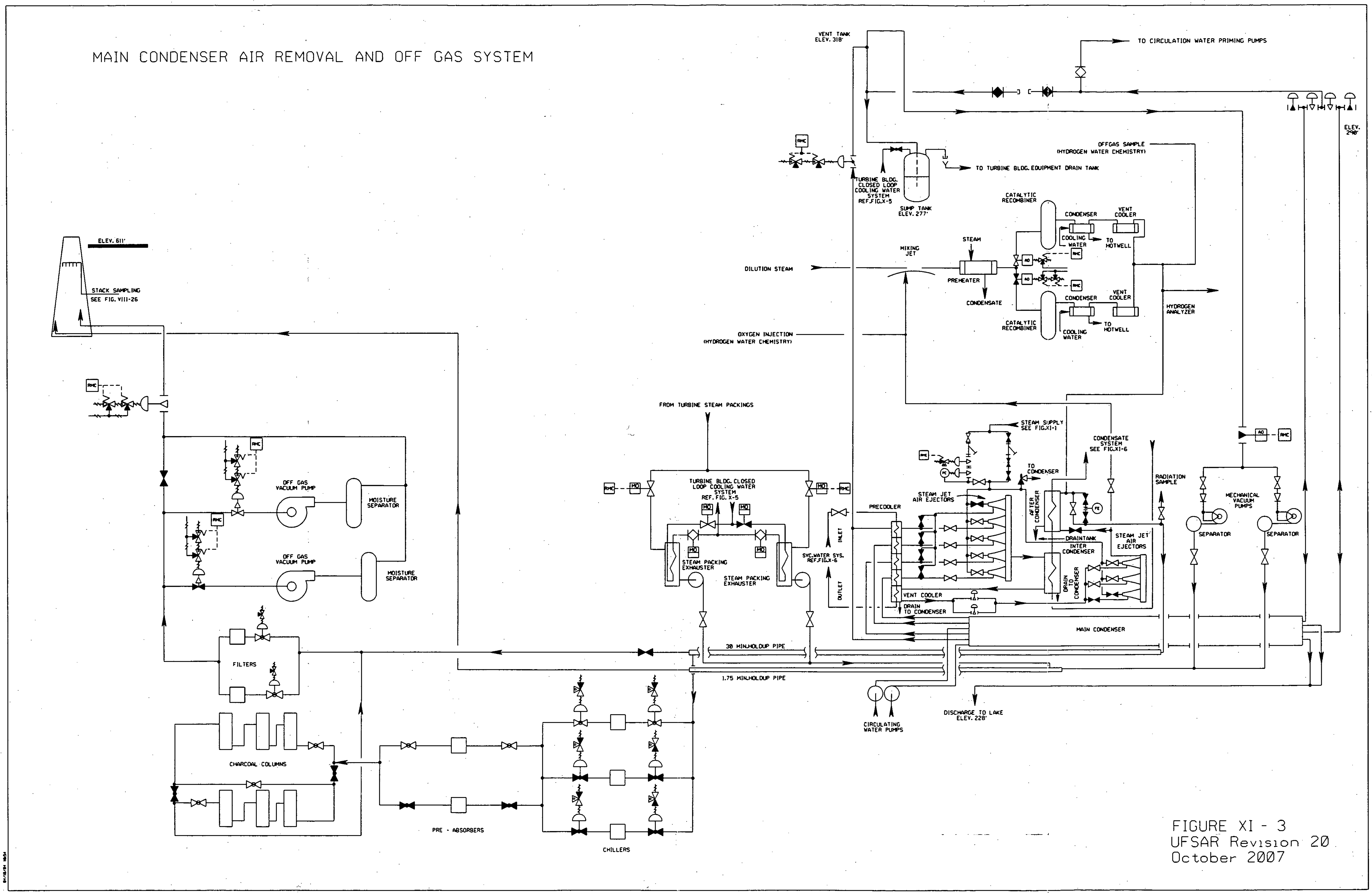


FIGURE XI - 3
UFSAR Revision 20
October 2007

...\msuser\FSAR FIGURE XI-3.dgn 8/31/2007 11:16:29 AM

CONDENSATE FLOW

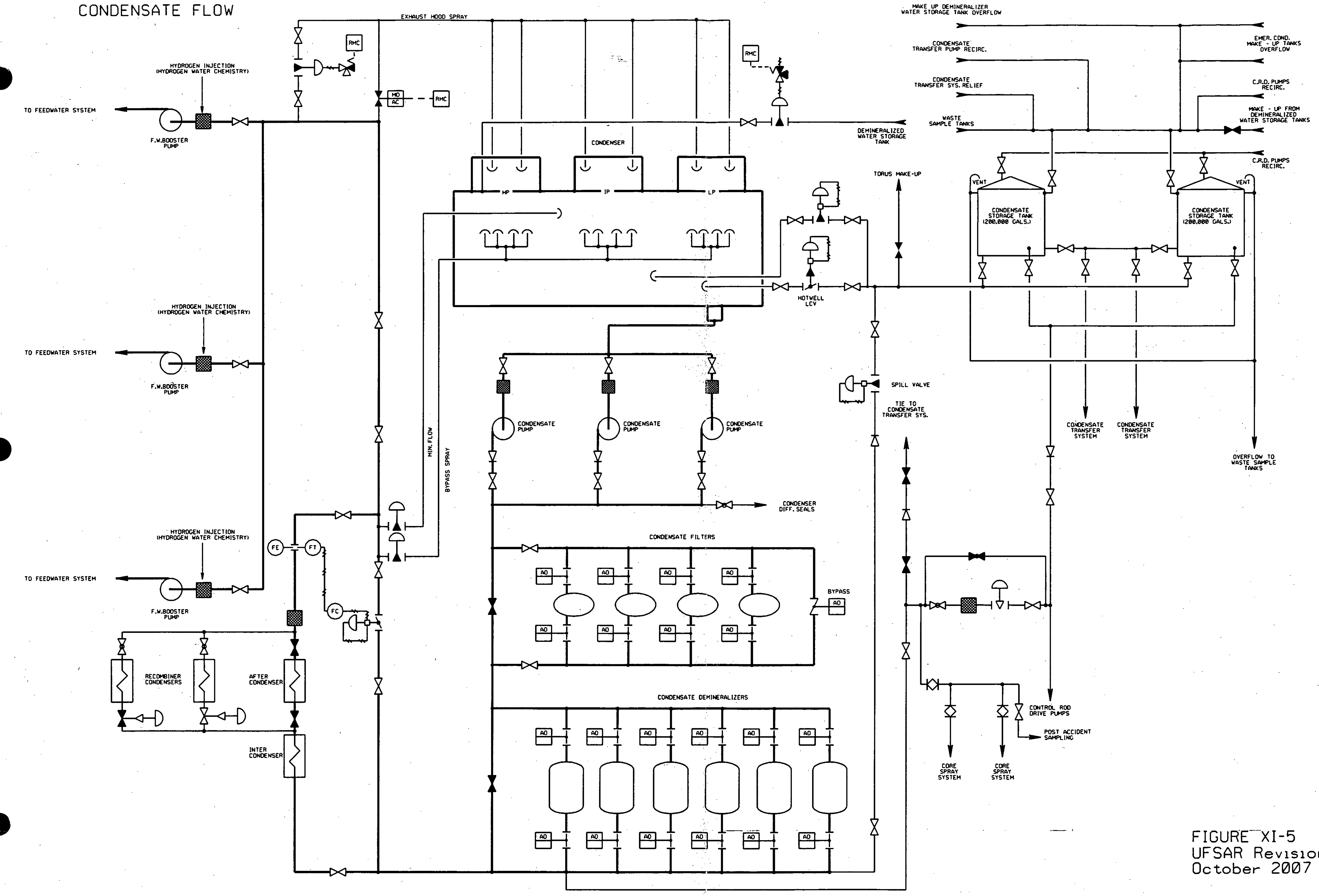


FIGURE XI-5
UFSAR Revision 20
October 2007

SECTION XII

RADIOLOGICAL CONTROLS

A. RADIOACTIVE WASTES

1.0 Design Bases

1.1 Objectives

The radioactive waste handling systems have been designed to meet the following objectives:

1. Collect and process all radioactive waste generated in the Station without limiting normal Station operation.

2. Collect and process radioactive wastes for disposal, or transfer to a vendor for processing and disposal.

3. Release radioactive material to the environment in a controlled manner so that all releases are within the standards set forth in 10CFR20 and the Technical Specifications.

4. Retain radioactive wastes, if they accidentally leak from the systems, so that they can be recovered and reprocessed.

1.2 Types of Radioactive Wastes

1.2.1 Gaseous Waste

Gaseous radioactive wastes include airborne particulates as well as gases vented from process equipment. Sources of gaseous waste activity are the offgas (OFG) system effluent, steam-packing exhauster system effluent, and building ventilation exhausts.

Flows and associated activities for the major sources of gaseous activity are given in Table XII-1 for the normal operating condition.

Station gaseous discharge limits and atmospheric dispersion rates (see Technical Specifications and Offsite Dose Calculation Manual) limit exposures in the uncontrolled environment to values within the standards given in 10CFR20.

1.2.2 Liquid Wastes

Liquid radioactive wastes include all liquids collected in equipment drains and floor drains in areas of the Station which are potentially contaminated with radioactive materials. In addition, shower wastes, laboratory wastes, and decontamination area wastes are handled by the liquid waste system.

Flows and associated activities for the major sources of liquid wastes are given in Table XII-2.

Liquid wastes are handled in one of the four handling processes described in Section XII-A.2.2. Waste which is discharged to the environment in the cooling water effluent is dispersed in that effluent so that activities in the uncontrolled environment are within the standards listed in 10CFR20 and the Technical Specifications.

1.2.3 Solid Wastes

Solid wastes include filter sludge, spent resin, spent condensate filter media, condensate filter backwash sludge, radioactive tools and equipment, and miscellaneous trash from plant operations, laboratory, maintenance and cleanup operations. The solid waste handling system is capable of collecting, processing and temporarily storing these various wastes.

Annual accumulation and average activities of these wastes are given in Table XII-3.

Solid waste is stored in the waste handling facility for decay and for accumulation of enough waste for shipment to a processor or authorized burial site. Radiation levels of shipped containers are maintained within the standards set forth by the Nuclear Regulatory Commission (NRC) and the Department of Transportation (DOT).

2.0 System Design and Evaluation

2.1 Gaseous Waste System

The gaseous waste system is composed of eight major parts.

1. Offgas system

2. Steam-packing exhauster system

3. Turbine building ventilation system

4. Reactor building ventilation system

5. Waste building ventilation system

6. Stack

7. Offgas building ventilation system

8. Radwaste solidification and storage building (RSSB) ventilation system

2.1.1 Offgas System

For a description of the OFG system, see Section XI-B.3.

2.1.2 Steam-Packing Exhausting System

A greater volume of gases is handled by this system than by the OFG system. This larger volume of gases results from the addition of room air to the steam leaking from the turbine gland seals. This system is described in detail in Section XI-B.1.

2.1.3 Building Ventilation Systems

These systems are described in other sections of the report.

1. Turbine building - Section III-A.2.2

2. Reactor building - Section VI-E.2.0

3. Waste building - Section III-C.2.2

4. RSSB - Sections III-I.1.4 and III-I.2.2

Particulate airborne activity exhausted by each of these systems can be monitored by a constant air monitor (see Section XII-B.2.2).

In areas where significant quantities of airborne particulates can be generated, such as the radiochemical laboratory hoods, filters are installed in the exhaust duct to remove these particulates. Because the many tanks and equipment in the waste building can be a source of airborne particulate activity, this entire building exhaust is filtered before discharge to the stack.

2.1.4 Stack

The stack is described in Section III-G.

The stack monitoring system (see Section VIII-C.3.0) is provided to continuously measure the gaseous activity discharged from the stack. This system also incorporates a composite collection of particulate and halogen activity. These filter samples will be removed periodically and the particulate and halogen activity determined in the Station laboratory.

The design features of the stack assure that diffusion of the emitted plume will not be significantly influenced by the eddy currents around the Station structures.

2.2 Liquid Waste System

2.2.1 Liquid Waste Handling Processes

The liquid waste system is designed to handle four types of liquid waste: high-conductivity waste, low-conductivity waste, chemical waste, and miscellaneous waste. Figure XII-1 is a schematic flow diagram for the liquid waste system and shows the processes for handling all four types of liquid waste. The process for handling each type of waste is described below.

1. High-Conductivity Waste

   High-conductivity liquid wastes are collected in the floor drain sumps located within the drywell, the reactor building, the turbine building, the RSSB, the offgas building, and the waste disposal building. The wastes in these floor drain sumps are pumped into the floor drain collector, waste neutralizer tank (WNT), or utility collector tank (during power operation and/or when drywell is inerted, the drywell discharge is routed to the waste collector system), which are located in the waste disposal building. After sufficient waste is collected in the floor drain collector, the waste is pumped to one of two floor drain sample tanks and is available for processing. High-conductivity waste from the condensate pre-filter backwash receiver tank (BWRT) is pumped directly to the WNT during off-normal operation; e.g., when concentrated waste tank #13 is unavailable. Waste collected in the WNT or utility collector tank may be processed directly from that tank or pumped to the floor drain sample tanks. Waste from either the floor drain collector or utility collector may be processed via the floor drain filter or a combination of the floor drain filter and waste demineralizer for processing through the low conductivity system.

High conductivity/low purity aqueous radwaste from the floor drain system is also processed through a series of water treatment modules which include charcoal filtration, small particulate filtration, and demineralization, and, depending on water quality, may include reverse osmosis or ultrafiltration, deionization, oxidizing agents and/or ultraviolet radiation prior to demineralization. Liquid wastes processed in this manner meet the chemistry criteria for recycling to the plant. This water may be directed to the low conductivity/high purity reclamation system (waste collector system) or to the waste sample tanks for chemistry sampling prior to batch transfer to the condensate storage tanks (CST). If the modular processed effluent water quality is unsatisfactory, a conductivity cell will direct the water back to the floor drain system.

An alternate processing route for high conductivity liquid waste is the waste concentrator. The distillate from the concentrator is normally recycled to the plant through the waste collector system.

Under certain conditions, the liquid waste can be pumped into the circulating water discharge tunnel at a flow rate which will assure that concentrations in the effluent will not exceed Station limits.

THIS PAGE INTENTIONALLY BLANK

2. <u>Low-Conductivity Waste</u>

Low-conductivity liquid wastes which usually come from piping and equipment drains are collected in equipment drain sumps or equipment drain tanks located in the drywell, the reactor building, the turbine building, and the waste disposal building. These liquids are pumped to the waste collector tank which is located in the waste disposal building. Other (less frequent) sources of low-conductivity waste are waste effluents from the fuel pool cooling system, the reactor cleanup system, the containment suppression chamber, ECs, resin transfer system, the backwash water from the condensate demineralizers (CND), and the clean backwash water from the condensate filtration system (CFS). This waste is also pumped to the waste collector tank in the waste disposal building.

A waste surge tank, located in the turbine building, is provided to collect the water from Station system surges and provide interim storage for liquids which may be off-standard and which must be recycled through the liquid waste processing system.

The liquid wastes in either the waste collector tank or the waste surge tank are pumped through a high-efficiency precoat type filter and a mixed-bed waste demineralizer to either one of two waste sample tanks. The floor drain filter is also used as a spare filter. Low-conductivity/high-purity aqueous radwaste from the equipment drain/waste collector system may also be processed through a series of water treatment modules which may include charcoal filtration, small particulate filtration, and demineralization, and, depending on water quality, may include reverse osmosis or ultrafiltration, deionization, oxidizing agents and/or ultraviolet radiation prior to demineralization. Liquid wastes processed in this manner meet the chemistry criteria for recycling to the plant and may be directed to the waste sample tanks.

While one of the two waste sample tanks is being filled, the other can be sampled, and after sample analysis, the liquid is normally pumped to the CST in the turbine building. Under certain conditions, this liquid can be pumped into the discharge tunnel, after careful analysis, to assure that concentrations in the effluent will not exceed Station limits.

In addition to being able to pump fuel pool water and reactor cleanup system water to the waste collector tank, these liquids can also be discharged through filters into the condenser hotwell. From the hotwell, the water is processed through the CNDs and pumped to the CST.

3. Chemical Waste

Chemical waste originates at the chemical addition tank, in the laboratory sinks, and equipment decontamination drains. Since this waste is not only high-conductivity waste but also may contain acids and other chemicals, it is collected in the waste neutralizer tank or utility collector tank in the waste disposal building.

The wastes are then neutralized and processed with other high-conductivity waste.

4. Miscellaneous Liquid Waste

Liquid waste from the shower facility, personnel decontamination, or any other radioactive liquid waste which might contain detergents, is collected in the waste neutralizer tank, floor drain collector tank, or utility collector tank in the waste disposal building. The waste is then processed with other high-conductivity waste.

2.2.2 Sampling and Monitoring Liquid Wastes

Sampling lines are provided from each collection tank and each sample tank, which may be used to evaluate filter and demineralizer performance. These sample lines run to a sample station adjacent to the waste disposal facility control room. In addition, local sample points have been provided, where deemed necessary, throughout the waste facility. Samples are analyzed in the Station laboratory.

A composite sample of the circulating water discharge stream is taken at a point downstream of the waste effluent discharge. An aliquot of this composite sample is periodically analyzed in the Station laboratory.

Data from samples taken of the tank to be discharged are recorded along with discharge water volume data so that a continuous record is maintained of released activity.

future shipment, shipped offsite for disposal, or shipped to a vendor for further processing and disposal.

Spent resins are pumped to an approved container in the truck bay where the container is dewatered. The container is then sealed and either placed in storage for future shipment, shipped offsite for disposal, or shipped to a vendor for further processing and disposal.

3. Solid Waste

Low-level solid wastes are collected and placed in approved containers. These solids may be compacted or shipped to vendor facilities for volume reduction and disposal or recycling.

Special containers may be used for large or odd-shaped components.

4. Miscellaneous Solid Wastes

Solid materials such as spent fuel assemblies, spent control blades, poison curtains, in-core chambers, and other equipment originating from the reactor primary system are stored in the spent fuel storage pool until offsite storage or disposal is necessary.

5. Condensate Filtration System Backwash Waste

Liquid waste produced by the CFS backwash is treated by the addition of polyelectrolytes. The polyelectrolytes cause the fine iron to settle to the bottom of the converted concentrated waste tank (CWT) #13. The remaining waste water is then decanted and processed by the liquid waste handling system. The remaining sludge is held in the tank until it is transferred by the sludge pump to a disposal liner for disposal.

2.3.2 Solid Waste System Equipment

Equipment is arranged and shielded to permit operation, inspections and maintenance with minimum personnel radiation exposure. (Shielding is designed to meet the requirements of Table XII-6.) Highly radioactive wastes are loaded into containers with remotely-controlled equipment and using remote viewing devices.

Control of the radwaste system is from the radwaste building control panel or the RSSB control room. Instrumentation is provided both for process control and for detection of abnormal conditions.

Major equipment and their respective capacities are listed in Table XII-5.

2.3.3 Process Control Program

The Process Control Program (PCP) contains the current formula, sampling, analyses, tests, and determinations to be made to ensure that the processing and packaging of radioactive waste, based on demonstrated processing of actual or simulated wet or liquid wastes, will be accomplished in such a way as to assure compliance with 10CFR20, 10CFR61, 10CFR71, federal and state regulations, and other requirements governing the transport and disposal of radioactive waste.

3.0 Safety Limits

Limits for discharge of gaseous and liquid waste from the Station, and the monitoring of these effluents, are in accordance with Technical Specifications.

THIS PAGE INTENTIONALLY BLANK

4.0 Tests and Inspections

4.1 Waste Process Systems

The waste processing systems are used on a routine basis and do not require specific testing to assure operability. The effectiveness of design is ultimately demonstrated by the effluent monitors and the environmental monitoring program.

4.2 Filters

The exhaust ventilation filters are replaced when the pressure drop across the filters exceeds the normal operating range. Test connections are available for checking the efficiency of newly installed filters. Adequate tests to determine filter efficiency are conducted in accordance with the Technical Specifications.

4.3 Effluent Monitors

The effluent monitors will be calibrated periodically to assure that they are accurately detecting effluent activity.

4.3.1 Offgas and Stack Monitors

An isotopic analysis is made of a representative sample of gaseous activity downstream of the steam jet air ejectors (SJAE) and at the stack sample point in accordance with the Technical Specifications and the Offsite Dose Calculation Manual (ODCM).

These waste gas effluent monitors are calibrated and tested in accordance with the ODCM.

4.3.2 Liquid Waste Effluent Monitor

The liquid waste effluent monitor is calibrated* and tested* in accordance with the ODCM.

Accounting of liquid waste discharge will be by laboratory analysis and volume measurement as described in the ODCM.

---

* Required prior to removal of blank flange in discharge line and until blank flange is replaced.

levels due to process conditions, also monitor aging effects on shielding integrity.

4.2 Area Radiation Monitors

Each area radiation monitor is tested to:

1. Determine that the monitor is correctly wired into the control room.

2. Calibrate the monitor so that the control room readout instrumentation indicates true radiation levels. (For the GE monitors, radiation sources are placed at reproducible geometries on each monitor detector to set the calibration of at least two points on the four-decade scale).

3. Set upscale and downscale alarm trip points.

4. Determine that both the control room and the local alarm (when so equipped) function correctly.

Steps 2, 3 and 4 are repeated periodically to assure that calibration and alarm setpoints are correct.

4.3 Area Air Contamination Monitors

Each area air contamination monitor is tested to:

1. Determine that the monitor is correctly wired into the control room.

2. Calibrate the monitor so that meter readings can be interpreted in terms of $\mu c/cc$. (Filter papers impregnated with known quantities of appropriate radionuclides are placed on the detector section of each monitor to set the calibration at no less than two points over the range of the monitor.)

3. Set upscale/downscale (GE) and high/alert (Eberline) alarm trip points.

4. Determine that both control room and the monitor alarms function correctly.

Steps 2, 3 and 4 are repeated periodically to assure that calibration and alarm setpoints are correct.

4.4 Radiation Protection Facilities

4.4.1 Ventilation Air Flows

Ventilation air flows in the radiation protection facilities are checked as part of the turbine building ventilation tests.

4.4.2 Instrument Calibration Well Shielding

The instrument calibration well shielding was tested when the sources were installed.

Station surveys of nearby areas ensure continued shielding integrity.

4.5 Radiation Protection Instrumentation

The following instrumentation is tested and calibrated at a frequency specified in Station procedures, with deviations, not exceeding annually, allowed based on documented instrument reliability:

1. Counting room instrumentation.

2. Portable radiation instruments.

3. Personnel monitoring instruments (except self-reading dosimeters).

4. Emergency instruments.

5. Air samplers.

6. Self-reading dosimeters.

Tests and calibration include (where applicable):

1. Calibration with appropriate calibrated radioactive sources.

2. Calibration of air flow rates with a flow rate measuring system.

TABLE XII-2 (Cont'd.)

	Liquid Waste (Gal/Day)		Activity Level (µCi/ml)	
	Maximum	Normal	Maximum	Normal
High-Conductivity Liquid Wastes (cont'd.)				
Waste Disposal Building				
Floor Drains	---	500	---	10^{-4}
Resin Cleaning and Backwashing Solutions	1,200	696	$4x10^{-1}$	$2x10^{-3}$
Decontamination	---	100	---	1
Filter Backwash	1,324	883	$3.45x10^{-1}$	$4.28x10^{-1}$

NOTE: *In some cases, maximum quantities* are not listed because the exact values are unknown. These maximum values are expected to be close to the values listed as normal.

TABLE XII-3

ANNUAL SOLID WASTE ACCUMULATION
AND ACTIVITY

	Approximate Accumulation	Shipment Activity
Filter Sludge		
Normal Volume	327 cu ft/yr	933 curies
Spent Resins		
Condensate (outage)	500 cu ft/yr	10 curies
Condensate (nonoutage)	270 cu ft/yr	10 curies
Cleanup	400 cu ft/yr	120 curies
Concentrated Waste		
Normal Volume	2,000 gal/yr	14 curies
Dry Wastes		
Compressible (outage)	20,560 cu ft/yr	0.124 curies
Compressible (nonoutage)	5,000 cu ft/yr	0.124 curies
Noncompressible	2,500 cu ft/yr	0.025 curies
Filter septa (prior to incineration)	125.7 cu ft/yr	*

* Filter septa shipment activity will be determined based on plant experience after the new CFS is in service.

TABLE XII-4

LIQUID WASTE DISPOSAL SYSTEM MAJOR COMPONENTS

Component	Qty	Capacity
Concentrated Waste Tank	1	8,000 gal
Chemical Addition Tank	1	600 gal
Drywell Equipment Sump	2	2,000 gal*
Drywell Floor Drain Sump	1	2,000 gal
Electric Boiler	1	16,000 lb/hr
Filter Aid Tank	1	470 gal
Floor Drain Collector Tank	1	10,000 gal
Floor Drain Filter	1	300 gpm
Floor Drain Sample Tank	2	20,000 gal*
Precoat Tank	1	560 gal
Reactor Building Equipment Drain Tank	1	5,000 gal
Reactor Building Floor Drain Sump	6	24,600 gal*
Turbine Building Equipment Drain Tank	2	5,900 gal*
Turbine Building Floor Drain Sump	8	8,200 gal*
Utility Collector Tank	1	16,000 gal
Waste Building Equipment Drain Sump	1	2,300 gal
Waste Building Floor Drain Sump	3	3,200 gal
Waste Collector Tank	1	25,000 gal
Waste Collector Filter	1	300 gpm
Waste Concentrator	1	20 gpm
Waste Demineralizer	1	2,300 gal
Waste Neutralizer Tank	1	15,000 gal
Waste Sample Tank	2	50,000 gal*
Waste Surge Tank	1	70,000 gal

* Total capacity.

TABLE XII-8

AREA RADIATION MONITOR DETECTOR LOCATIONS

Monitor No.	Location	Bldg/ Elev	Range of Monitor (mR/hr)
1	SE Plant Entrance	TB 261	0.01-100
2	New Fuel Room	RB 318	0.01-100
3	Control Room Admin Bldg	AB 277	0.01-100
4	In-Plant I&C Shop	TB 277	0.01-100
5	Generator Area	TB 300 W	0.1-1000
6	Shaft Pump Area	TB 300 E	0.1-1000
7	Cond Pump Vlvs Condenser Bay	TB 261 NE	0.1-1000
8	Outside MSIV Room	TB 261	0.1-1000
9	N of Battery Board Rooms	TB 261	0.1-1000
10	Cond Demin Valve Room	TB 257	0.1-1000
11	Regen Room	TB 261	0.1-1000
12	Truck Bay	TB 261	0.1-1000
13	Deleted		
13A	Condensate Filter System	TB 300	0.1-1000
14	Old RW Bldg S of Stairs	EL 229	0.1-1000
15	Old RW Bldg Control Room	EL 261	0.1-1000
16	Old RW Bldg Door to Pusher Rm	EL 261	0.1-1000
17	Inner TIP Room	RB 249	0.1-1000

TABLE XII-8 (Cont'd.)

Monitor No.	Location	Bldg/ Elev	Range of Monitor (mR/hr)
18	West End of Shield Wall	RB 340	0.1-1000
19	RX Bldg - NE Corner	EL 198	0.1-1000
20	Closed Loop Cooling Area	RB 298	0.1-1000
21	Cleanup Pump Area	RB 261	0.1-1000
22	RX Bldg - NE	EL 281	0.1-1000
23	CRD Accumulator Area	RB 237	0.1-1000
24	Large Equip Decon Room	TB 261	0.1-1000
25	RX Bldg - East Wall	EL 340	0.1-1000
26	High Level Chem Lab	TB 261	0.1-1000
27	RX Bldg - NW	EL 318	0.1-1000
28	North Instr Room	RB 237	0.1-1000
29	Refuel Bridge (Low Range)	RB 340	0.1-1000
-	Refuel Bridge (High Range) (Process Mon)		$10\text{-}10^6$
30	New RW Bldg N of Decon Pan	EL 261	0.1-1000
31	New RW Bldg West Wall	EL 247	0.1-1000
32	New RW Bldg South Wall	EL 229	0.1-1000
33	Offgas Bldg W of Stairs	EL 229	0.1-1000
	RSSB		
1	Cement Fill Area	RSSB 244	0.1-10,000

TABLE XII-8 (Cont'd.)

Monitor No.	Location	Bldg/ Elev	Range of Monitor (mR/hr)
2	Valve & Pump Room West	RSSB 244	0.1-10,000
3	Valve & Pump Room East	RSSB 244	0.1-10,000
4	Electric Switchgear Room	RSSB 244	0.1-10,000
5	Feed Equipment Area Volume Red Sys - South	RSSB 261	0.1-10,000
6	Feed Equipment Area Volume Red Sys - North	RSSB 261	0.1-10,000
7	Access Way - South	RSSB 261	0.1-10,000
8	Access Way - North	RSSB 261	0.1-10,000
9	North-South Truck Bay	RSSB 261	0.1-10,000
10	East-West Truck Bay	RSSB 261	0.1-10,000
11	HVAC Supply Fan - South	RSSB 281	0.1-10,000
12	HVAC Recirc. Atmos. - West	RSSB 281	0.1-10,000
13	HVAC Exhaust Fans - North	RSSB 281	0.1-10,000
14	Concentrated Waste Tank Access - West	RSSB 281	0.1-10,000
15	Concentrated Waste Flush Tank Access - East	RSSB 281	0.1-10,000
16	HVAC Recirc. Atmos. Cleanup System - South	RSSB 292	0.1-10,000
17	HVAC Exhaust System Char. Filter Area	RSSB 292	0.1-10,000

RADIOACTIVE WASTE DISPOSAL SYSTEM

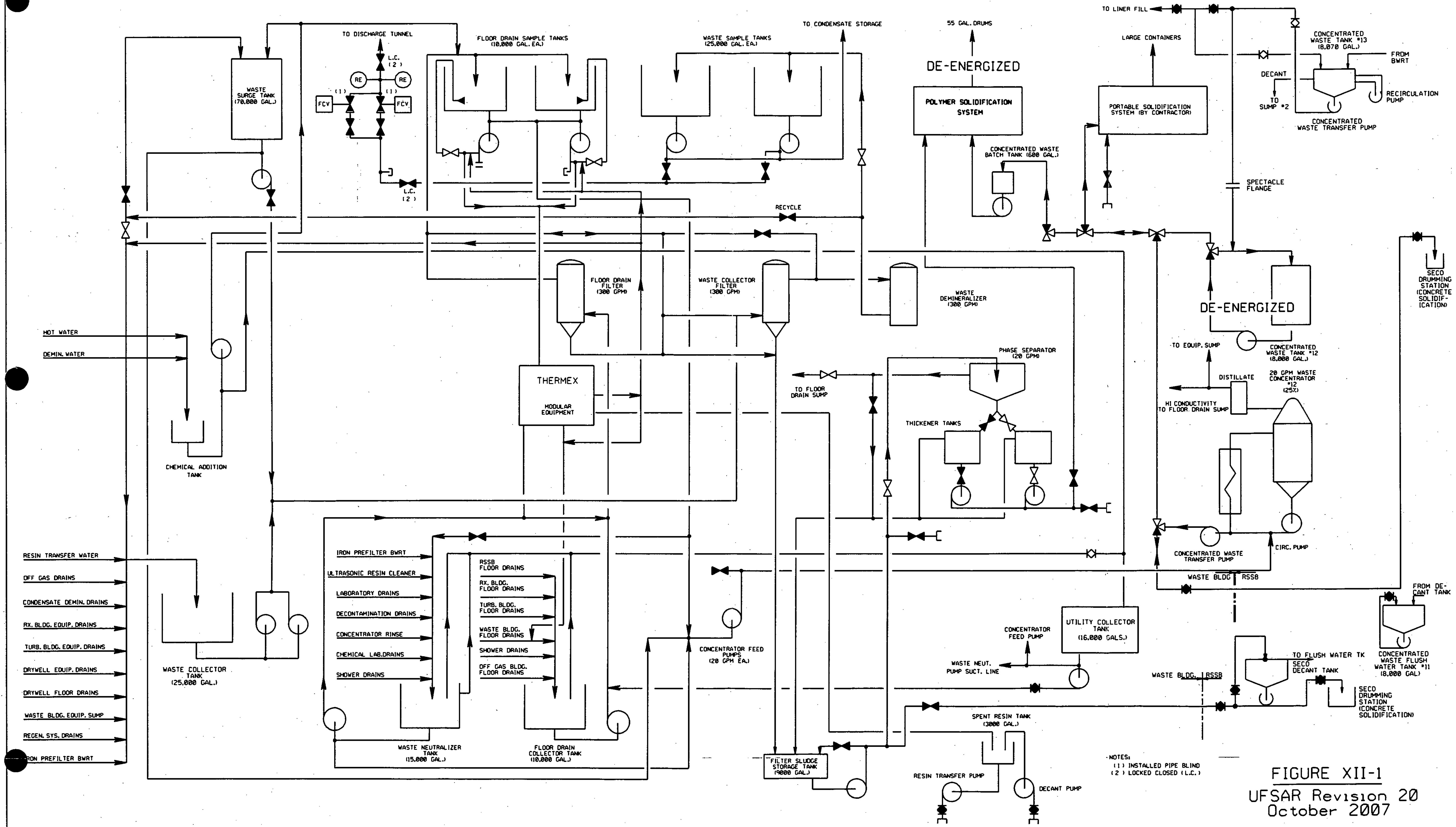


FIGURE XII-1

UFSAR Revision 20
October 2007

SECTION XIII

CONDUCT OF OPERATIONS

A. ORGANIZATION AND RESPONSIBILITY

The following sections describe the organizational structure of NMPNS and delineate the lines of responsibility for the operation of Unit 1 in accordance with established administrative and quality standards. The organizational structure associated with the Quality Assurance (QA) Program for plant operation is described in the Quality Assurance Topical Report (QATR).

1.0 Management and Technical Support Organization

1.1 Station Organization

The senior level Station management organization is depicted on Figure XIII-1. The Vice President Nine Mile Point reports to the Senior Vice President and Chief Nuclear Officer of Constellation Generation Group and has overall responsibility for the administration and operation of the Nine Mile Point Nuclear Station, including: Engineering Services; Quality & Performance Assessment; Nuclear Security; Emergency Preparedness; Human Resources; Business Planning, Budgeting & Cost Control; Nuclear Generation; and Training Nuclear.

1.1.1 Vice President Nine Mile Point

The Vice President Nine Mile Point reports to the Senior Vice President and Chief Nuclear Officer of Constellation Generation Group and has overall responsibility for the administration and operation of the Nine Mile Point Nuclear Station. The Manager Engineering Services, Director Quality & Performance Assessment, Director Nuclear Security, Director Emergency Preparedness, Director Human Resources, Director Business Planning, Budgeting & Cost Control, and the General Supervisor Licensing report directly to Constellation Generation Group (CGG) senior management and have matrixed reporting to the Vice President Nine Mile Point for functional and priority setting direction. The Plant General Manager and Manager Training Nuclear report directly to the Vice President Nine Mile Point.

1.1.2 Matrixed Reporting

1. The Manager Engineering Services reports to the CGG Vice President Nuclear Technical Services for program and policy direction, and has a matrixed reporting to the Vice President Nine Mile Point for functional and priority setting direction. This position has full authority to provide nuclear engineering services that comply with applicable safety, regulatory, and quality requirements within defined cost and scheduling parameters. In addition, this position has single-point accountability for technical concerns and responses.

   The Engineering Services organization chart is provided on Figure XIII-2. The following positions report to this manager:

   a. The General Supervisor Design Engineering supervises design engineering services to assure safe, reliable, and economic operation of Nine Mile Point Nuclear Station. Specific responsibilities are to ensure:

      - Engineering is performed in accordance with applicable regulatory and code requirements (e.g., the UFSAR, Technical Specifications, etc.).

      - Detailed design/engineering is completed based upon conceptual design information including specifications and drawings necessary to implement these designs.

      - As-installed conditions are reflected on drawings.

      - Implementation of the NMP Configuration Management Program.

      - Implementation of conceptual engineering.

      - Plant evaluations are performed to monitor and detect internal and external factors that would indicate an actual or potential degradation of design bases or margin in design bases for initial plant systems and components.

procedures. Contract support for Unit 1 is utilized in the same general manner as contract support at Unit 2.

2.0 Nuclear Generation Organization

This section describes the structure, function, and responsibilities of the onsite organizations established to operate and maintain the plant. The onsite and offsite independent review committees are described in Section XIII-G. Unit 1 and Unit 2 operations are independent of each other, including backshift operation. Only licensed individuals may direct licensed activities.

An organization chart showing the title of each position is shown on Figures XIII-4 through XIII-4c. The lines of authority are described in administrative procedures.

2.1 Plant General Manager

The Plant General Manager reports to the Vice President Nine Mile Point, is responsible for overall unit operation, shall have control over those resources necessary for safe operation of the plant, and assumes the duties and responsibilities of the Vice President Nine Mile Point, in his absence, for matters affecting the Station. The Plant General Manager has overall responsibility for safe and efficient Station operation, in accordance with applicable licensing, regulatory and Quality Assurance Program requirements, and controlling the preparation, review, and approval of Station procedures.

The Plant General Manager maintains an organization comprised of the following direct reports with associated responsibilities:

1. The Manager Operations performs the following functions:

    a. Ensures safe operation of the Station in accordance with approved procedures and regulatory requirements.

    b. Advises Shift Manager (SM) (formerly the Station Shift Supervisor) during emergency conditions.

    c. Performs the duties associated with PORC membership.

    d. Assists in the development of training programs.

e. Administers implementation of the Fire Protection Program for the Nine Mile Point site.

f. Maintains an organization comprised of the following functional sections:

- Station Operations
- Operations Planning
- Reactor Engineering
- Operations Programs & Procedures
- Fire Protection
- Radwaste Management

2. The Manager Radiation Protection manages radiation protection monitoring and control programs in support of Station operation. This manager meets the radiation protection manager qualifications in Technical Specifications Section 6.3.1. The Manager Radiation Protection has:

- Direct access to appropriate levels of corporate management, including the Chief Nuclear Officer, to resolve radiation protection concerns.

- Authority to require plant shutdown if unsafe radiological conditions exist.

The Manager Radiation Protection manages Radiation Protection and ALARA personnel and ensures procedures/qualifications comply with Federal and Technical Specification requirements related to monitoring, control and minimization of radiation exposure to plant personnel. This manager:

a. Performs the duties associated with PORC membership.

b. Controls preparation, review, and approval of Radiation Protection and Waste Handling procedures, and assists in the development of training programs.

c. Maintains an organization comprised of the following functional sections:

- ALARA
- Radiological Support

- Radiation Protection Operations

3. The General Supervisor Chemistry monitors and controls programs, including personnel, procedures and qualifications, to ensure compliance with Federal and Technical Specification requirements related to primary and secondary system chemistry and radiochemistry, radioactive effluent, chemistry control, post-accident assessment, and solid radioactive waste measurements. This manager:

   a. Manages operation of, and waste disposal aspects of, the Sewage Treatment Facility.

   b. Performs the duties associated with PORC membership.

   c. Assists in development of training programs.

   d. Maintains an organization comprised of the following functional sections:

      - Chemistry Operations
      - Chemistry Support

4. The Manager Assessment and Corrective Action establishes and maintains the program documents and procedures for implementing the Corrective Action Program (CAP).

5. The Supervisor Fuels reports to the CGG Director Nuclear Fuels Services and is matrixed to the Plant General Manager. This position:

   a. Provides reliable, safe and economic fuel supply for NMPNS by performing the activities necessary to specify the procurement, receipt, use and disposal of nuclear fuel.

   b. Administers, maintains, and controls the Core Operating Limits Report (COLR).

6. The Manager Maintenance ensures modifications, surveillance, maintenance, preventative maintenance, radiation instrument calibration, and housekeeping and decontamination are properly performed in accordance

with applicable rules, regulations, approved procedures, codes and standards. This position:

a. Manages relay and control testing activities, measuring and test equipment calibration, and maintenance planning functions.

b. Performs the duties associated with PORC membership.

c. Assists in the development of training programs.

d. Ensures necessary maintenance personnel are available to maintain the Station in a safe and efficient manner.

e. Ensures radiologically-controlled area (RCA) housekeeping and decontamination are maintained.

f. Maintains an organization comprised of the following functional sections:

- Mechanical Maintenance
- Electrical Maintenance
- I & C Maintenance
- FIN
- Construction/Outage Services

7. The Manager Work Control/Outage Management ensures the safe and efficient planning and implementation of forced, planned and refuel outages at NMPNS, as well as planning and implementation of weekly work schedules. This position:

a. Manages the scheduling function.

b. Ensures integrity of the Work Control Center and scheduling databases.

c. Maintains interfaces among Nuclear Generation departments for maintenance, modification and testing activities.

d. Maintains an organization comprised of the following functional sections:

- Outage Management

- On-line Work Management
- Work Management Programs
- Planning

e. Is the onsite interface and contact for Project Management. The General Supervisor Project Management has a matrixed reporting relationship to the Manager Work Control/Outage Management and reports directly to the CGG Director Project Management.

f. Is the onsite interface and contact for materials and services. The Director Materials and Services has a matrixed reporting relationship to the Manager Work Control/Outage Management and reports directly to the CGG Manager Procurement and Warehouse Services.

8. The Director Personnel Safety interprets Occupational Safety and Health Administration (OSHA) requirements and advises, assists, and coordinates efforts in the implementation of those requirements.

9. The Technical Advisor reports to the Plant General Manager and performs the following functions:

   a. Advises the Plant General Manager on technical and nuclear safety matters.

   b. Serves as rotating Chairman of the Corrective Action Review Board and Self-Assessment Review Board.

2.2 Other Functions Reporting to the Vice President Nine Mile Point

1. The Manager Training Nuclear reports directly to the Vice President Nine Mile Point and manages the activities of the Training organization, including the development, administration, and coordination of training and retraining programs for NMPNS personnel. This manager ensures activities within the Training

organization are properly conducted per applicable regulations, codes, standards, and procedures.

2. The Director Employee Concerns Program reports to the Vice President Nine Mile Point for implementation of the Employee Concerns Program, and administratively to the Director Human Resources.

2.3 Supervisor Reactor Engineering

The Supervisor Reactor Engineering reports to the Manager Operations and is responsible for proper implementation of the Reactivity Management Program. This position:

1. Provides direction and engineering expertise to Operations and other groups for the control of reactivity.

2. Evaluates site and industry reactivity related events for applicability and lessons learned.

3. Supports review of plant procedures, maintenance activities, and modifications for potential reactivity effects.

4. Monitors the effectiveness of the Reactivity Management Program.

5. Ensures that training is provided to Operations personnel prior to implementation of new core design or new core operating strategies.

6. Controls and verifies proper implementation of the Fuel Handling Procedures.

7. Performs duties associated with PORC membership.

Acts as the Special Nuclear Material Custodian and is responsible to ensure:

1. Applicable procedures are developed and implemented to control receipt, storage, movement, and shipment of special nuclear material (SNM).

2. The possession and use of SNM is confined to the locations and purposes authorized by the Station's Operating License.

3.0 Quality Assurance

The operations phase QA Program is described in the Quality Assurance Topical Report (QATR). The QATR identifies the organizations responsible for activities affecting the operation, maintenance or modification of safety-related structures, systems, or components, and describes the assigned authorities and duties for quality-attaining functions and for quality verification functions.

4.0 Operating Shift Crews

Table XIII-2 shows the position titles, applicable Operator licensing requirements, and minimum numbers of personnel planned for each shift for the various reactor operating conditions. Unique requirements for additional personnel for the refueling condition are also noted in Table XIII-2. The following additional requirements apply:

1. At least one licensed Operator shall be in the control room when fuel is in the reactor. During reactor operation, this licensed Operator shall be present at the controls of the facility.

2. A licensed Senior Reactor Operator or licensed Senior Reactor Operator Limited to Fuel Handling shall be responsible for all movement of new and irradiated fuel within the site boundary.

5.0 Qualifications of Staff Personnel

Each member of the facility staff shall meet or exceed the minimum qualifications of ANSI N18.1-1971. Position qualification requirements are shown in Table XIII-1.

A retraining and replacement training program for the facility staff shall be maintained under the direction of the Manager Training Nuclear, and shall meet or exceed the recommendations and requirements of Section 5.5 of ANSI N18.1-1971 and of 10CFR55, and shall include familiarization with relevant industry operational experience.

B. QUALIFICATIONS AND TRAINING OF PERSONNEL

1.0 (This section deleted)

2.0 (This section deleted)

3.0 (This section deleted)

4.0 Training of Personnel

4.1 General Responsibility

The Manager Training Nuclear is responsible for all training at the Nine Mile Point Nuclear Station.

4.2 Implementation

1. The Manager Training Nuclear reports directly to the Vice President Nine Mile Point and manages the activities of the Training organization, including the development, administration, and coordination of training and retraining programs for site personnel.

2. The Manager Training Nuclear develops and ensures implementation of the Training organization portion of the business plan.

3. The Manager Training Nuclear ensures activities within the Training organization are properly conducted per applicable regulations, codes, standards, and procedures.

4. The Manager Training Nuclear maintains appropriate safety and budget control programs, and ensures adequate resources are assigned within the Training organization.

4.3 Quality

Responsibility for the general quality of training in each area shall be distributed as follows:

4.3.1 For Operator Training

The Plant General Manager with the assistance of the Manager Operations.

6. State Emergency Operations Center

Formal training along with drills and exercises are essential in maintaining an in-depth emergency preparedness program.

The Site Emergency Plan and Implementing Procedures have been submitted to the NRC under separate cover.

The current version of the Site Emergency Plan is Revision 49.

E. SECURITY

A detailed Nine Mile Point Nuclear Station Physical Security, Safeguards Contingency, and Security Training and Qualification Plan, identified as safeguards information and withheld from public disclosure in accordance with 10CFR73.21, has been submitted to the NRC.

The security plan described above details the measures taken to provide adequate Site and Station security and conforms to 10CFR73.55.

The current version of the plan is the Physical Security, Safeguards Contingency, and Security Training and Qualification Plan - Issue 6, Revision 2.

5.0 Special Nuclear Materials

The special nuclear materials records will be maintained and reported in conformity with 10CFR70.

6.0 Calibration of Instruments

The calibration of instruments and controls, both nuclear and conventional, will be recorded, as well as maintenance performed on them.

7.0 Administrative Records and Reports

1. Investigations of abnormal operation will be prepared in report form and distributed to interested parties.

2. Records will be kept of all changes to equipment or procedures.

3. Reports of production and pertinent operating data with a summary of items of interest will be produced at regular intervals and distributed to interested parties and to those who audit Station operations.

4. Reports of exposure to individuals, loss or theft of licensed material, etc., as outlined in 10CFR20 will be reported in the time and manner specified.

G. REVIEW AND AUDIT OF OPERATIONS

A means is provided for processing changes and assuring safe operation and compliance by periodic audit through the establishment of two review bodies, as illustrated on Figure XIII-5.

1.0 Plant Operations Review Committee

The Plant General Manager shall appoint PORC members in writing, including the PORC Chairperson and Vice Chairpersons, drawn from the committee members. The PORC maintains written minutes of each meeting, and copies are provided to the Site Vice President, Chairperson of the Nuclear Safety Review Board (NSRB), and the Plant General Manager. Open items shall be assigned, tracked and resolved.

Specific PORC requirements associated with the committee composition and member qualifications, including alternates, and meeting frequency, quorums, and record requirements are contained in the QATR.

1.1 Function

The PORC functions to advise the Plant General Manager on all matters related to nuclear safety and plant operations. PORC meetings include a review of in-house and industry operating experience at the discretion of the Plant General Manager.

2.0 Nuclear Safety Review Board

The NSRB ensures that periodic independent reviews and audits of activities are conducted by qualified individuals free from the pressures of plant operations. The NSRB serves in an advisory capacity to the Chief Nuclear Officer. The NSRB ensures periodic independent reviews and audits of activities, as stated in the facility Technical Specifications and the QATR, are performed. Review of events shall include the results of any investigations made and the recommendations resulting from such investigations to prevent or reduce the probability of recurrence of the event. Additional review activities by the NSRB should be performed to verify adequate organizational response to adverse performance trends. The NSRB should monitor the results of audits, evaluations, and assessment activities to ensure that items which could affect plant safety are reviewed. The NSRB may delegate review functions to subcommittees that may include NSRB members, provided that the subcommittees report the results of their reviews to the NSRB.

Specific NSRB requirements associated with the committee composition and member qualifications, including alternates, and meeting frequency, quorums, and record requirements are contained in the QATR.

2.1 Function

The NSRB shall function to provide independent review and audit of designated activities in the areas of:

1. nuclear power plant operations

2. nuclear engineering

3. chemistry and radiochemistry

4. metallurgy

5. instrumentation and control

6. radiological safety

7. mechanical and electrical engineering

8. quality assurance practices

9. other appropriate fields associated with the unique characteristics of the nuclear power plant

3.0 Review of Operating Experience

Internal and external operating experience is reviewed and assessed via corrective action procedures to ensure that information pertinent to plant safety is supplied to Operators and other appropriate personnel, and is used for effecting design and procedural changes to correct generic or specific deficiencies and to enhance plant safety when warranted.

An initial applicability review of externally-generated operating experience shall be performed primarily by individuals in the Assessment and Corrective Action group. These reviews include, but are not limited to, NRC issuances such as Generic Letters (GL), Information Notices (IN), Bulletins, and

Administrative Letters; INPO issuances such as Significant Operating Experience Reports (SOER), Significant Event Reports, Significant Event Notifications (SEN), Significant by Others (SO), and Operations and Maintenance Reminders (O&MR); Vendor issuances such as General Electric (GE) Service Information Letters (SIL), Rapid Information Communication Service Information Letters (RICSIL), Technical Information Letters (TIL), Service Advisory Letters (SAL), and potential 10CFR21 notifications.

External operating experiences that require further evaluation are assigned to responsible Station organizations, via the Deviation/Event Report (DER) process, as appropriate, for evaluation and corrective and preventive action. The evaluations and dispositions are reviewed by the applicable Branch Manager and the Plant General Manager when PORC review is required. Hardware and software modifications, procedure revisions, design changes, etc., resulting from the reviews are then implemented by the responsible groups. The evaluations and dispositions are reviewed by PORC as required by the Plant General Manager.

In-house operating experience, such as significant equipment malfunction, adverse trends developed from testing and operations surveillance, reactor core operating trends, operability problems, and/or organizational and programmatic problems that may impact plant safety and reliability, will be treated as an event/deviation and processed accordingly. Processing shall be accomplished by the appropriate Branch Manager allowing the Plant General Manager to designate PORC review as appropriate.

SAFETY ORGANIZATION

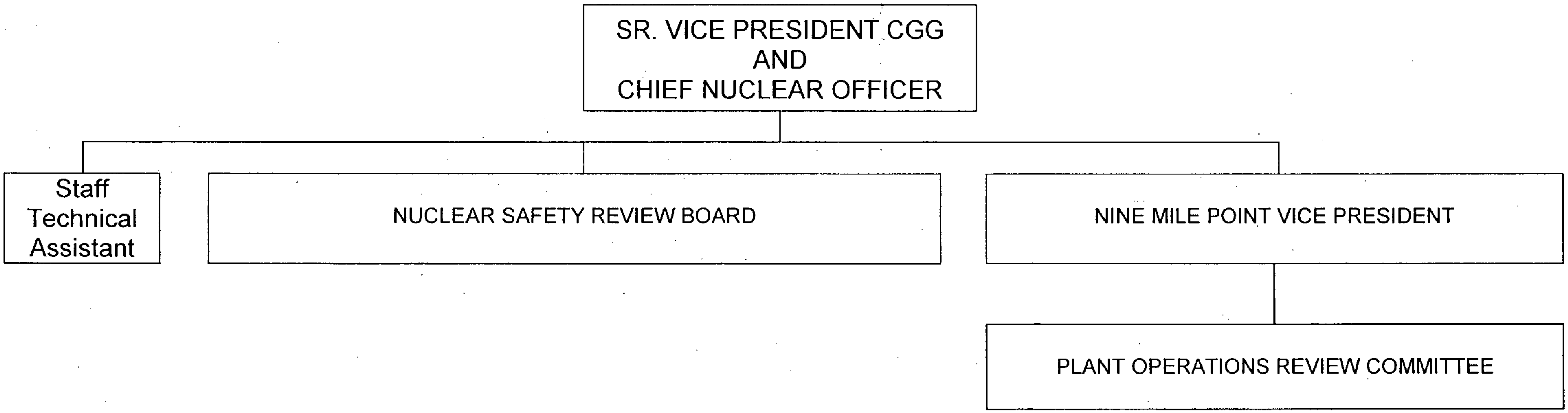


Figure XIII-5

U.S. NUCLEAR REGULATORY COMMISSION
DOCKET 50-220
LICENSE DPR-63

NINE MILE POINT NUCLEAR STATION UNIT 1

FINAL SAFETY ANALYSIS REPORT (UPDATED)

VOLUME 4

OCTOBER 2007

REVISION 20

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

THIS PAGE INTENTIONALLY BLANK

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

THIS PAGE INTENTIONALLY BLANK

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

THIS PAGE INTENTIONALLY BLANK

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

THIS PAGE INTENTIONALLY BLANK

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

LIST OF TABLES

well as the decay energy and the original sensible energy in the core are also released during this time. As a result, the containment pressure rises rapidly to 25 psig at 1800 sec. After 1800 sec the hydrogen release stops and the energy release falls to decay power level. Consequently, the containment spray loop is able to quickly cool the gases in the system, sharply reducing pressure. After 2000 sec the containment pressure response is similar to the case for which the core spray system functions, except that the pressure is approximately 11 psi higher. The 11 psi difference is the result of the hydrogen generated.

The temperature variations with time of the drywell and suppression chamber are shown on Figure XV-60.

5.2.4 Fission Product Release from the Fuel

As the fuel heats, fission products are released from the plenums through clad perforations. The fuel continues heating until recrystallization (3000°F) and melting take place. All of the noble gases and halogens are released from the fuel, along with 50 percent of the volatile solids and 1 percent of the other solids.

5.2.5 Fission Product Release from the Reactor and Containment

Five percent of the released halogens are assumed to be organic in form and do not plateout or fallout. Fifty percent of the remaining inorganic halogens plateout in the primary system, reactor vessel and piping. Seventy percent of the solids are assumed to plateout. A partition factor of 10^2 for inorganic halogens is used (water-to-steam concentration ratio).

The resulting airborne fission product activities are shown in Tables XV-30, XV-31 and XV-32.

5.2.6 Meteorology and Dose Rates

The doses resulting from the above stack releases using conservative meteorological assumptions are well below 10CFR100 limits. The thyroid dose (2 hr) at the site boundary is 5.68 x 10^{-4} rem and the whole body dose is 5.45 x 10^{-4} rem. The complete dose for the entire period of the accident is 0.68 rem to the thyroid and 2.00 x 10^{-1} rem whole body.

5.2.7 Required Reactor Building Emergency Ventilation System Charcoal Filter Efficiency

As noted in Section XV-C.5.1.8.1, the doses resulting from the containment DBA were originally calculated assuming a 99 percent charcoal filter efficiency for the removal of inorganic and organic halogens by the reactor building emergency ventilation system (EVS). In License Amendment No. 4[57], the NRC approved a required EVS charcoal filter efficiency of 90 percent. This value is supported by the results of analyses documented in the

Technical Supplement to Petition for Conversion from Provisional Operating License to Full-Term Operating License, dated July 1972[58], and in Amendment No. 1 thereto, notarized November 21, 1973[59]. These analyses concluded that radioactive releases during postulated accident conditions will not exceed the guideline values of 10CFR100.

5.3 Design Basis Reconstitution Suppression Chamber Heatup Analysis

This DBR analysis considers containment spray system operation at up to a maximum containment spray raw water temperature of 84°F.

5.3.1 Introduction

The DBR program analyzed the long-term containment suppression chamber response following the containment DBA. The containment DBA, described in Section VI-B.1.2, is identified as the instantaneous rupture of the reactor coolant system (RCS) corresponding to a double-ended break of the largest pipe in the containment (coolant recirculation line).

The DBR long-term containment suppression chamber response analysis[35] was performed consistent with the LOCA, described in Section XV-C.2.0, which assures that 10CFR50.46 limits are not exceeded. The Section XV-C.2.0 LOCA analysis is based on the loss of offsite power (LOOP), the single failure of one of the emergency diesel generators, and the dynamic effects of the postulated pipe break, which result in one core spray pump set available to provide core cooling. Therefore, the DBR analysis of the suppression chamber response considers core spray available and assumes less than 1 percent metal-water reaction consistent with the LOCA analysis and 10CFR50.46 limits.

The design basis requirement for the containment spray system is to assure that the primary containment design pressure and temperature limits are not exceeded. In addition, the containment spray heat removal system must maintain the torus water temperature such that adequate net positive suction head (NPSH) is provided to the core spray pumps and containment spray pumps, assuming no increase in containment pressure from that present prior to the postulated LOCA.

The DBR analysis of the containment heat removal design basis for the containment spray system provides a working model to assess system performance and operability since the original calculations were not available. The DBR analysis[35] methodology produces conservative results as compared with the original design basis analysis (Sections XV-C.2.0 and XVI-C.2.0). The DBR analysis results require that the heat removal requirements be increased, as compared with those described in Section VII-B, to assure the design basis requirements are satisfied. The increased heat removal requirements are necessary to maintain the DBR analysis conservative, as compared to the calculations described in Sections XV-C.2.0 and XVI-C.2.0.

The DBR analysis evaluates the containment suppression chamber response assuming the containment spray system is operated in the drywell and wetwell spray mode. Additional analyses verify that operating the containment spray system in accordance with the emergency operating procedures (EOPs) creates conditions which are bounded by the spray mode of operating the containment spray system.

5.3.2 Input to Analysis

A list of significant input parameters to the DBR suppression chamber heatup analysis is presented in Table XV-32a. The method-specific inputs are discussed in Section 5.3.3.2.

5.3.3 DBR Suppression Chamber Heatup Analysis

The DBR suppression chamber heatup analysis[35,60] determines the maximum torus water temperature which is expected to occur following the containment DBA. This analysis is intended to reconstitute the design basis for the containment spray system, such that the performance requirements for operation up to a maximum containment spray raw (lake) water temperature of 84°F can be assessed. This analysis does not supersede the design basis analysis discussed in Section VI-B.1.2.

The Reference 35 analysis has been reanalyzed with new containment spray heat exchanger heat removal rates (K-value) in Reference 60. The revised analysis also includes different modeling assumptions on vessel pressure used for the post-blowdown break flow calculations and a different modeling of the vessel liquid and metal sensible energy. The Reference 60 analysis also includes ANS 5.1-1979 (nominal) decay heat data consistent with the Reference 35 analysis but with additional actinides and activation products included per GE Service Information Letter (SIL) 636.

5.3.3.1 Computer Codes

The original calculations and/or computer analyses used to determine the design basis heat removal requirements for the containment spray system were not described in the FSAR and are not available. The DBR program chose to perform a new analysis using GE's proprietary computer code, SHEX-04. SHEX is designed to model long-term containment pressure and temperature responses to a variety of normal and abnormal operating transients, including LOCAs. SHEX-04 has been applied by GE-Nuclear Energy in this type of analysis and has been reviewed and accepted by the NRC.[35]

SHEX-04 evaluates the containment response by performing mass and energy balances on four main nodes: reactor pressure vessel (RPV), drywell, suppression pool and wetwell airspace. These nodes are interconnected via one or more of the auxiliary systems; e.g., the drywell and the suppression pool are connected by the downcomers; the suppression pool and the RPV are connected by the core spray system; the drywell and wetwell airspace are connected by the wetwell to drywell vacuum breakers, etc. External mass and energy sources such as decay heat and feedwater are added to the system.

The results predicted by this computer code are conservative when compared with the results of the original analysis performance assumptions based on the results of cases 1 and 2 of the Reference 35 analysis.

The SHEX code has been revised for the Reference 60 analysis to allow the vessel pressure modeling described in Section 5.3.3.2. However, the methods applied for this analysis are consistent with the basic GE methodology used in long-term LOCA containment analyses. The changes to the Reference 35 analysis are for inputs and modeling assumptions and do not represent any change in the methodology.

5.3.3.2 Analysis Methods

The model used in this analysis includes the RPV, drywell, wetwell (including the suppression pool), core spray system, containment spray system, feedwater, safety relief valves (SRV), main turbine, torus vents and downcomers, the drywell to wetwell vacuum breakers, and the wetwell to reactor building vacuum breakers.

RPV

The RPV break flow from the double-ended recirculation line break is calculated using Moody slip flow. The energy stored in the feedwater train and the energy stored in the RPV structure is added to the blowdown energy. The core spray flow is added to RPV blowdown flow to model the energy transfer.

The Reference 60 re-analysis has been performed with a more realistic modeling assumption on the post-blowdown vessel pressure. The SHEX vessel fluid model used in the production version of the SHEX code assumes that the vessel pressure is always equal to the saturation pressure corresponding to the vessel liquid temperature. This modeling implicitly assumes the break is always covered with water throughout the event with no inflow from the drywell. This assumption is not realistic for the DBA-LOCA. During the post-blowdown period, this modeling can result in a partial vacuum condition in the vessel which can, in turn, induce a condition whereby an unrealistic amount of the water is accumulated above the break location. This water accumulation produces the water head necessary to enable break flow out of the vessel to the drywell when the vessel is at a lower pressure than the drywell. This condition can result in an overprediction of the energy transferred from the vessel metal to the liquid. The re-analysis assumes that for a DBA-LOCA, part of the break is open to the drywell atmosphere after the initial blowdown period. The revised SHEX version simulates this assumption by ensuring that vessel pressure used in the vessel break flow calculation is no lower than the drywell pressure.

The Reference 60 re-analysis has also implemented a revised approach to the vessel metal sensible energy modeling. This approach assumes that all vessel metal below 95 in above instrument zero is in contact with liquid water. This elevation corresponds to the maximum water level that is maintained by the Operator in the EOPs if the break size is insufficiently large to maintain water level below this elevation. This approach conservatively maximizes the heat transfer between the vessel metal and vessel liquid. This conservative approach also makes the transfer of metal energy to the vessel liquid effectively independent of water level. This approach ensures that the peak temperature defined for this containment accident analysis bounds the entire potential break size spectrum.

Drywell/Wetwell

The model of the drywell includes a holdup volume of approximately 30,200 gal. The drywell and wetwell model excludes the effect of heat transfer through the containment structures.

ECCS Systems

The operation of the core spray and containment spray systems is modeled consistent with the design basis requirements of these systems. Refer to Table XV-32a for a listing of the input assumptions.

Energy Sources

In addition to the reactor coolant energy and the sensible energy of the reactor and components, the following energy sources are added:

1. Energy is added to the containment consistent from a metal-water reaction consistent with 10CFR50.46 limits (1.8 MBtus).

2. Decay heat energy consistent with an infinite exposure profile, assuming 102 percent of rated power (1887 MWt) calculated using the 1979 ANS-5.1 standard with additional actinides and activation products per GE SIL 636 is added.

5.3.3.3 Analysis Results for Containment Spray Design Basis Assumptions[60]

Figure XV-60A shows the suppression chamber pool temperature heatup profile. The maximum suppression chamber pool temperature is 163.8°F, which occurs at 12,267 sec following the LOCA. The wetwell air space pressure at this time is 1.24 psi greater than the assumed initial pressure of 14.7 psia.

Two containment spray pumps are assumed to auto-start when the high drywell pressure and low-low level signals occur, which is essentially at t=0. The containment spray lineup is such that the drywell and wetwell spray begin as soon as the pumps start at t=55 sec. The Operator is assumed to secure one of the two containment spray pumps at t=10 min and start one of the containment spray raw water pumps within 15 min. The containment spray heat exchanger begins to remove heat at t=15 min. The containment spray system is operated in this mode independent of drywell or wetwell pressure conditions until the temperature increase is terminated.

The suppression chamber pool temperature increases from 85°F to 119°F within 30 sec. At t=190 sec, the temperature has increased to 131°F and is 142°F at t=10 min. At the 15-min mark the temperature is 146°F, at which point the containment spray heat exchangers begin to remove energy from the suppression chamber water. The temperature slowly increases and reaches the peak temperature of 163.8°F at t=12,267 sec (3 hr 24 min).

The drywell and wetwell pressure decreases immediately upon initiation of the sprays and is 3.5 psi within 5 min. The Operator reduces from two containment spray pumps to one at t=10 min, at which point the drywell pressure increases slightly. The pressure then decreases to about 16 psia when the raw water pump begins to cool the containment spray flow at t=15 min. The pressure then remains at about 15 psia for the duration of the event.

5.3.3.4 Analysis Results for EOP Operation Assumptions[60]

Operation of the containment spray system in accordance with the EOPs requires that the Operators evaluate and perform the following actions:

1. Terminate containment spray when drywell pressure drops below 3.5 psig.

2. Initiate containment spray if the torus pressure increases above the suppression chamber spray initiation pressure.

3. Initiate torus cooling when the torus temperature is greater than 85°F.

The analysis of the effect of these actions upon the peak suppression chamber temperature and pressure is performed by modeling these manual actions.

Figure XV-60B shows the heatup profile. The maximum suppression chamber pool temperature is 164.9°F which occurs at t=14,288 sec. The torus airspace pressure corresponding to this peak temperature is 20.2 psia. The minimum pressure occurs at t=5 min when the drywell spray is terminated at 3.5 psig.

The drywell and wetwell pressure immediately begins to increase, with the wetwell pressure reaching 20 psia at t=15 min and then slowly decreasing as heat is removed from the torus.

This analysis case shows that the reduced heat removal rate associated with the torus cooling mode increases the peak temperature by about 1°F. The effect of terminating the drywell and wetwell sprays at 3.5 psig is to increase the NPSH available to the core spray and containment spray pumps, such that a less severe NPSH condition exists relative to the design basis spray mode.

5.3.4 Conclusions

The DBR analysis results show that the peak bulk torus water temperature is between 163.8°F and 164.9°F occurring between 3

THIS PAGE INTENTIONALLY BLANK

and 4 hr after the DBA event. The difference between the DBR analysis peak temperatures compared with the Section XV-C.5.2 peak of 140°F @ 1 hr is primarily because of the change in methods, not the change in maximum lake temperature assumptions. The DBR analysis could not duplicate all of the original Safety Analysis Report (SAR) methods and assumptions.

Analysis of the DBR profile shows that the temperature increases to 140°F within 10 min because of the DBA blowdown. From 10 min until the peak temperature is reached, the torus heatup is governed by the heat removal capability of the containment spray system versus the heat added from decay heat. When the heat removal rate exceeds the heat added from decay heat, the temperature increase is terminated.

The analysis shows that the Operator actions taken in accordance with the EOPs create conditions which assure torus pressure conditions and, in turn, improve available NPSH to the core spray pumps. The analysis also shows that the Operator actions taken in accordance with the EOPs to maintain level below 95 in ensures the peak temperature determined by the analysis bounds the entire potential break size spectrum.

The DBR analysis results conclude that all the design criteria associated with maximum torus water temperature are satisfied at the calculated peak temperatures.

The operability requirements imposed upon the suppression chamber (i.e., 3.5 ft minimum downcomer submergence and 85°F maximum initial torus water temperature) and upon the containment spray system (i.e., initiate containment spray raw water within 15 min) by the DBR analysis for 84°F lake temperature, limit the peak suppression chamber water temperature to less than the original heatup profile discussed in Section XV-C.5.2 when calculated on an equivalent basis.[35,60]

6.0 New Fuel Bundle Loading Error Analysis

6.1 Identification of Causes

A fuel bundle loading error accident results from a misoriented or mislocated new fuel bundle in the core. This accident can only occur as a result of multiple Operator errors during reloading. A misoriented bundle (i.e., misoriented - rotated 90° to 180°) has been determined to be the limiting condition for this accident.

D. REFERENCES

1. Technical Supplement to Petition to Increase Power Level, Nine Mile Point Unit 1, April 1970.

2. 0000-0053-5239-SRLR, Revision 0, "Supplemental Reload Licensing Report for NMP1, Reload 19, Cycle 18," December 2006.

3. F. J. Moody. "Maximum Flow Rate of a Single Component, Two-Phase Mixture," Journal of Heat Transfer, Trans. ASME, Series "C" - Volume 87, February 1965, p 134.

4. "Nine Mile Point Unit One SAFER/CORECOOL/GESTR-LOCA Loss-of-Coolant Accident Analysis," NEDC-31446P, June 1987, and NEDC-31446P, January 2001.

5. "Nine Mile Point Nuclear Generating Station Unit 1 SAFER/CORECOOL/GESTR-LOCA Loss-of-Coolant Accident Analysis," NEDC-31446P Supplement 4, September 1993, and NEDC-31446P Supplement 5, January 2001.

6. P. E. Francisco. "Licensing Basis for Core Spray System Single Failure/Pipe Whip," March 28, 1990.

7. Letter, J. F. Klapproth (GE) to R. C. Jones (NRC), "Refueling Accident Analysis," dated April 24, 1992.

8. GE letter, J. F. Klapproth to USNRC, "Refueling Accident Analysis," April 24, 1992.

9. Letter, R. E. Engel (GE) to D. M. Vassallo (NRC), "Elimination of Control Rod Drop Accident Analysis for Banked Position Withdrawal Sequence Plants," February 24, 1982.

10. "Steady-State Nuclear Methods," April 1985 (NEDE-30130-P-A and NEDO-30130-A).

11. J. A. Woolley. "Three Dimensional BWR Core Simulator," January 1977 (NEDO-20953A).

12. Report, "Reduced Notch Worth Procedure, Rev. 2" transmitted by letter from C. M. Richards (GE) to W. R. D'Angelo (NMPC) dated August 6, 1979.

13. C. J. Paone. "Banked Position Withdrawal Sequence," NEDO-21231, January 1977.

14. "GE Standard Application for Reactor Fuel," NEDE-24011-P-A-13-US, August 1996.

THIS PAGE INTENTIONALLY BLANK

15. H. E. Williamson and T. C. Rowland. "Performance of Defective Fuel in the Dresden Nuclear Power Station," APED-3894, 1962.

16. F. J. Moody, op cit.

17. Louis Baker, Jr., and Louis C. Just. "Studies of Metal Water Reactions at High Temperatures III. Experimental and Theoretical Studies of the Zirconium-Water Reactions," Argonne National Laboratory, ANL 6548 (1962).

18. D. A. Collins, et al. "International Symposium on Fission Product Release and Transport under Accident Conditions," Paper 59, 1965, Oak Ridge, Tennessee.

19. Parker, et al. SIFTOR Draft, Volume II, Chapter 18, "Fission Product Release."

20. R. D. Collins and Hillary. "International Symposium on Fission Product Release and Transport under Accident Conditions," Paper 44, April 1965, Oak Ridge, Tennessee.

21. H. R. Diffey, et al. "International Symposium on Fission Product Release and Transport under Accident Conditions," Paper 41, April 1965, Oak Ridge, Tennessee.

22. C. E. Miller, Jr., et al. "International Symposium on Fission Product Release and Transport under Accident Conditions," Paper 12, April 1965, Oak Ridge, Tennessee.

23. T. L. Allen and R. M. Keefer. "The Formation of Hyporodus Acid and Hydrated Iodine Cation by the Hydrolysis of Iodine," JACS 77, No. 11, June 1965.

24. Watson, Bancroft and Aoelke. AECL-130, "Iodine Containment by Dousing in NPD-11," 1960.

25. ORNL-NSIC-5, U.S. Reactor Containment Technology, p 10.47.

26. G. W. Keilholtz and C. J. Barton. ORNL-NSIC-4, "Behavior of Iodine in Reactor Containment Systems," February 1965, p 64.

27. R. E. Adams and W. E. Browning, Jr. "International Symposium on Fission Product Release and Transport Under Accident Conditions," Paper 46, April 1965, Oak Ridge, Tennessee.

28. D. A. Collins, et al. "International Symposium on Fission Product Release and Transport Under Accident Conditions," Paper 45.

29. R. E. Adams and W. E. Browning, Jr., op cit.

30. R. D. Collins and Hillary. "International Symposium on Fission Product Release and Transport Under Accident Conditions," Paper 44.

31. Collins and Eggleton. ORNL-NSIC-4, "Behavior of Iodine in Reactor Containment Systems," February 1965, p 66.

32. R. E. Adams and W. E. Browning, Jr. ORNL-NSIC-4, "Behavior of Iodine in Reactor Containment Systems," February 1965, p 65.

33. Louis Baker, Jr., and Louis C. Just, op cit.

34. Louis Baker, Jr., and Louis C. Just, op cit, Figure 26.

35. GENE-770-91-34, "Nine Mile Point Unit 1 Pool Heatup Analysis," July 1991; NMPC Calculation SO-TORUS-M009 and NMPC Safety Evaluation 91-028.

36. Deleted.

37. Deleted.

38. Letter, R. E. Engel (GE) to D. G. Eisenhut (NRC), "Fuel Assembly Loading Error," November 30, 1977.

39. Letter, D. G. Eisenhut (NRC) to R. E. Engel (GE), MFN-200-78, May 8, 1978.

40. J. O. Irminger and Chr. Nøkkentved. "Wind Pressure on Buildings, Second Series," Copenhagen, 1936.

41. Martin Jensen and Niels Franck. "Model-Scale Tests in Turbulent Wind, Part II Phenomena Dependent on the Velocity Pressure Wind Loads on Buildings," The Danish Technical Press, Copenhagen, 1965.

42. Jensen and Franck. "Model-Scale Tests in Turbulent Wind, Part II, Phenomena Dependent on the Velocity Pressure Wind Loads on Buildings," The Danish Technical Press (Copenhagen, 1965), pp 51-54, 66.

43. R. L. Koontz, et al. "Low Pressure Containment Buildings - Components Tests and Design Data," NAA-SR-7234, Atomics International, March 15, 1963. R. L. Koontz, et al, Conventional Buildings for Reactor Containment," NAA-SR-10100, Atomics International, June 15, 1965.

44. Koontz, et al. NAA-SR-10100.

45. Koontz, et al. NAA-SR-7234 and NAA-SR-10100.

46. W. W. Pagon. "Wind Tunnel Studies Reveal Pressure Distributions on Buildings," Engineering News Record, December 1934.

47. Staff Report of the Federal Radiation Council, Report No. 5, July 1964.

48. AECU 3066, July 1955.

49. Calculation of Distance Factors for Power and Test Reactor Sites, TID 14844, pp 23, 24.

50. Health Physics, Volume 3, 1960, pp 125, 126, and 193.

51. TID 8205, "Compendium of Information for Use in Controlling Radiation Emergencies," p 55.

52. GENE-770-31-1292, Revision 2, "Engineering Report for Application of GE11 to NMP1," April 1993.

53. "Rod Drop Accident Analysis for Large Boiling Water Reactors," NEDO-10527, March 1972.

54. NMPC Modification N1-98-016.

55. GE SAFER/GESTR Analysis, GE-NE-E2100145-00-01-R1, Revision 1, "Core Spray Flow Reduction LOCA Analysis for Nine Mile Point, Unit 1," January 1999.

56. GENE-C5100196-04, "APRM Flow-Biased Trip Setpoints Long-Term Solution Option II," June 1997, NMPC Calculation No. SP-APRM-RI02A-D and NMPC Safety Evaluation No. 96-022.

57. NRC Letter dated November 10, 1975, issuing License Amendment No. 4 to Facility Operating License No. DPR-63 for Nine Mile Point Nuclear Station, Unit 1.

58. Technical Supplement to Petition for Conversion from Provisional Operating License to Full-Term Operating License, July 1972.

59. Amendment No. 1 to Application to Convert Provisional Operating License to Full-Term Operating License, notarized November 21, 1973.

60. SO-TORUS-M009, NMP-1 Torus Pool Heat-up Analysis.

TABLE XV-32a

SIGNIFICANT INPUT PARAMETERS TO THE
DBR CONTAINMENT SUPPRESSION CHAMBER HEATUP ANALYSIS

Plant Parameters	
Core Thermal Power (MWt)	1887 (102% Rated)
Initial Dome Pressure (psia)	1045
Initial Drywell and Wetwell Pressure (psia)	14.7
Maximum Recirculation Line Break Area (ft^2)	5.45
Initial Torus Water Level (ft of downcomer submergence)	3.5
Initial Torus Water Temperature (°F)	85
Maximum Raw (Lake) Water Temperature (°F)	84
Initial Suppression Chamber Pool Volume (ft^3)	79,800
Initial Wetwell Airspace Free Volume (ft^3)	125,000
Initial Wetwell Airspace Temperature (°F)	105
Drywell Free Volume (ft^3)	180,000
Initial Drywell Temperature (°F)	150
Emergency Core Cooling System Parameters	
Core Spray System	
Single Failure	See Section XV-C.2.0
Flow vs. Reactor Pressure	See Table XV-9a

Table XV-32a (Cont'd.)

Containment Spray System	
Assumptions	Loss of Offsite Power
Single Failure (See Section VII)	Loss of One Emergency Diesel
Number of Containment Spray Pumps:	
Assumed to Auto Start	2
Available for Heat Removal	1
Available for Spray Assuming No Heat Removal	2
Number of Containment Spray Raw Water Pumps Manually Started	1
Number of Containment Spray Heat Exchangers	1
Time of Heat Exchanger Activation (min)	15
Containment Spray Pump Flow	
1-Pump Operation Spray Mode (gpm)	3600
2-Pump Operation Spray Mode (gpm)	3000 per pump
Torus Cooling Mode Flow (gpm)	2800 maximum
Containment Spray Raw Water Pump Flow (gpm)	3000
Containment Spray Heat Exchanger K-Value in Spray Mode (Btu/sec °F)	256
Containment Spray Heat Exchanger K-Value in Torus Cooling Mode (Btu/sec °F)	241

DBR ANALYSIS SUPPRESSION POOL AND WETWELL AIRSPACE TEMPERATURE RESPONSE CONTAINMENT SPRAY DESIGN BASIS ASSUMPTION

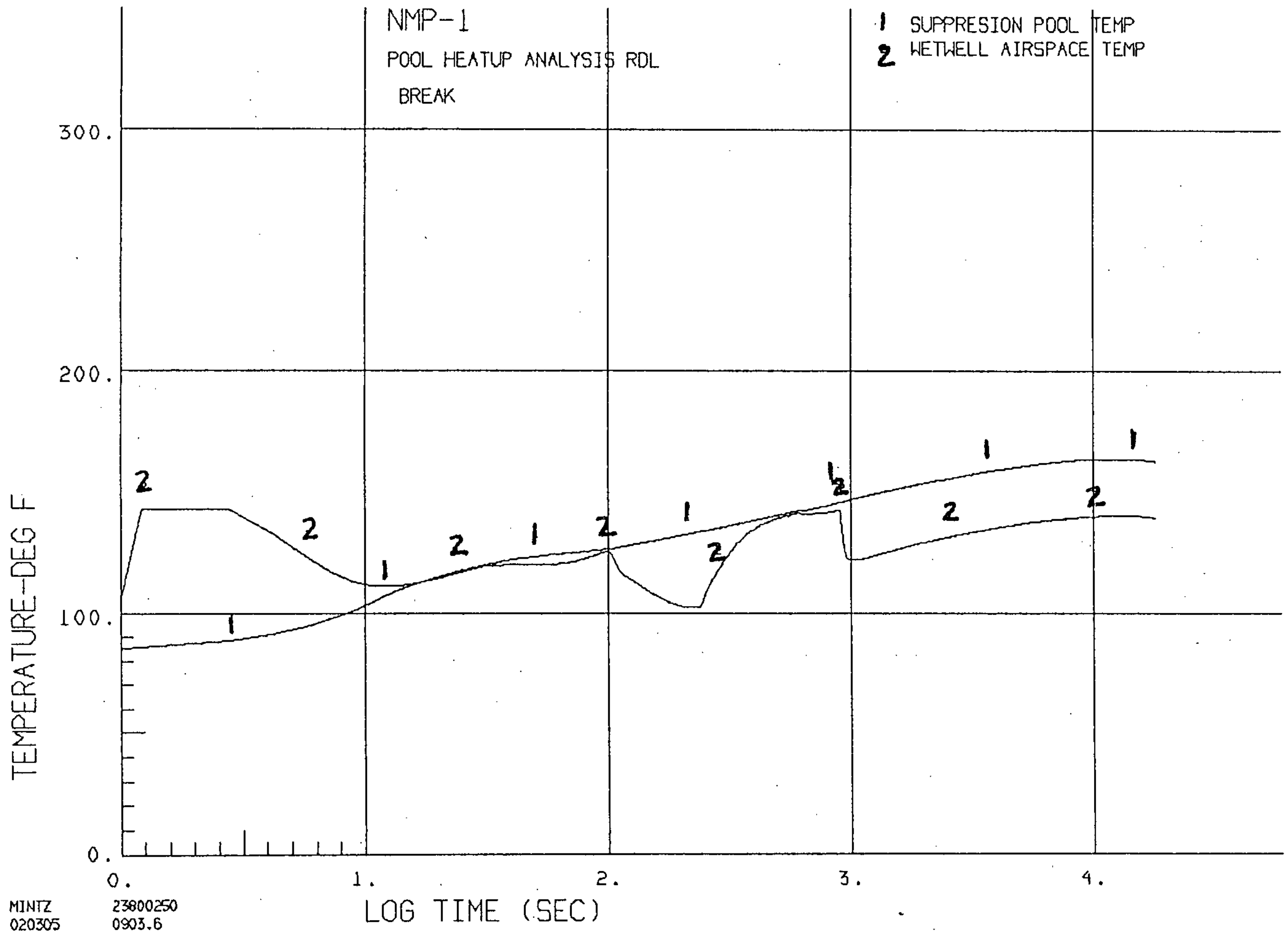


FIGURE XV-60A
UFSAR Revision 20 OCTOBER 2007

DBR ANALYSIS SUPPRESSION POOL AND WETWELL AIRSPACE TEMPERATURE RESPONSE EOP OPERATION ASSUMPTIONS

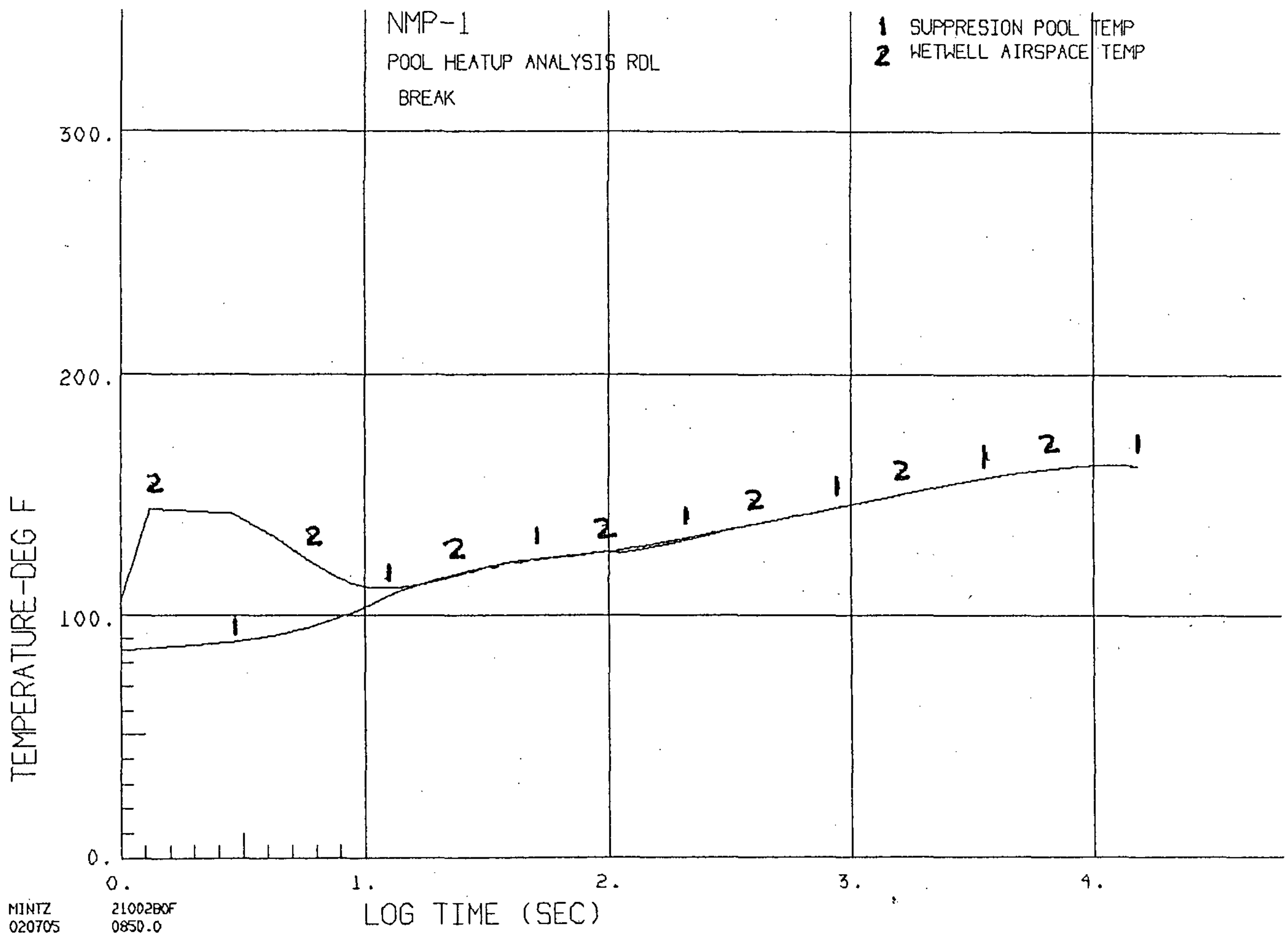


FIGURE XV-60B
UFSAR Revision 20 October 2007

E185-66 except for the material withdrawal schedule, which was originally specified in the Technical Specifications.

Three surveillance capsules were installed in the Unit 1 reactor in 1969 prior to initial operation. Since plant life extension is being considered, two capsules (A' and C') were reinserted. The prime indicator is used to designate the new capsule in the same azimuthal location as the original capsules. The radial location of the new capsules is slightly closer to the core than the original capsules to increase the neutron flux.

In Reference 40, the NRC approved Unit 1 participation in the BWR Vessel and Internals Project (BWRVIP) Integrated Surveillance Program (ISP), as described in BWRVIP-78 (Reference 37) and BWRVIP-86-A (Reference 38). The NRC approved the ISP for the industry in their safety evaluation dated February 1, 2002 (Reference 39). The ISP meets the requirements of 10CFR50, Appendix H. Participation in the ISP replaces the Unit 1 plant-specific vessel material surveillance program.

The current surveillance capsule withdrawal schedule for Unit 1 representative materials is based on the latest NRC-approved version of BWRVIP-86 (Reference 38). No capsules from the Unit 1 vessel are included in the ISP. Capsules from other plants will be removed and specimens will be tested in accordance with the ISP implementation plan. The results from these tests will provide the necessary data to monitor embrittlement of the Unit 1 vessel.

4.2 Periodic Inspection

Periodic inspections of the reactor vessel and its components are performed in accordance with the Inservice Inspection (ISI) Program (Technical Specification 4.2.6).

5.0 Core Shroud Repair Design Description

5.1 Horizontal Weld Repair

The reactor core shroud stabilizers are designed to structurally replace horizontal shroud welds H1 through H7. Figure XVI-12a depicts the Unit 1 horizontal shroud welds. The Unit 1 shroud stabilizers consist of two separate design features as shown on Figure XVI-12b. Tie-rod assemblies combined with core plate wedges replace welds H1 through H7 and the upward vertical load-carrying capability of weld H8. The shroud stabilizers are designed to maintain the shroud functions described in Section IV-B.7.0, in the event welds H1 through H7 become cracked 360 deg circumferentially throughwall. The design of the shroud stabilizers is in accordance with the Boiling Water Reactor Owners' Group Vessel Internals Project (BWROG VIP) criteria[8]. The shroud repair design was approved by the NRC as documented in NRC Safety Evaluation for NMP1, Evaluation of Core Shroud Stabilizer Design, dated March 31, 1995. Details of the stabilizer design are located in the reference documents listed in Table XVI-9a.

Modifications to the tie-rod assemblies were made during refueling outage 14 (RFO14), RFO15, and RFO19 to correct original design deficiencies. Details of the design analyses are included in the shroud repair hardware analysis listed in Table XVI-9a. The original design of the tie-rod assemblies was performed as an alternative to ASME Section XI as permitted by 10CFR50.55a(a)(3), which required NRC approval of the original design. Consequently, the modifications made during RFO14, RFO15, and RFO19 also require approval by the NRC. The NRC safety evaluations that approved the various tie-rod modifications are listed in Table XVI-9a. The NRC safety evaluations describe the design basis of the tie-rod modifications.

5.2 Vertical Weld Repair

The reactor core shroud vertical weld repair clamps are designed to structurally replace vertical shroud welds V9 and V10. Figure XVI-12c provides a roll-out drawing of the shroud and depicts the vertical shroud welds. Figure XVI-12d provides a schematic of the vertical weld repair clamps. The vertical weld repair design was reviewed and approved by the NRC as an alternative code repair pursuant to 10CFR50.55a(a)(3)(i) as documented in References 35 and 36. Core shroud vertical weld repair design documentation is listed in Table XVI-9a.

the computer-generated stresses. The curves compare stresses due only to bending and torsion of the pipe. From Figure XVI-26 and similar curves for the rest of the system, it is demonstrated that the static analysis technique compares favorably with dynamic analysis.

2.0 Containment Spray System

The analysis discussed in this section must be supplemented with analyses discussed in Sections XV-C.5.1 and XV-C.5.2. Section XV-C.5.3 specifically discusses analyses applicable to containment spray operability at maximum containment spray raw water temperatures of 84°F.

2.1 Design Adequacy at Rated Conditions

2.1.1 General

The purpose of the containment spray system is to condense steam in the pressure suppression system and remove heat from the system.

2.1.2 Condensation and Heat Removal Mechanisms

Water is pumped from the pressure suppression pool through a heat exchanger to the spray nozzles within the containment vessels. The water breaks up into droplets as it sprays into the drywell and suppression chamber.

Heat is transferred to the spray droplets mainly by two mechanisms--convection heat transfer and mass transfer. The former represents the surface heat transfer from the hot steam-gas mixture to the droplet and is represented by:

$$Q_c = hA\ (T_m - T_d) \qquad (1)$$

Where:

Q_c = Rate of convective heat transfer from the mixture to the droplet surface, (Btu/hr)

h = Convective heat transfer coefficient, (Btu)/(hr)(ft^2)(F)

A = Surface area of the droplet, (ft^2)

T_m = Temperature of the steam-gas mixture, (F)

T_d = Temperature of the water droplet surface, (F)

The mass transfer represents the latent heat of the steam condensed on the surface of the water droplet and is represented by:

THIS PAGE INTENTIONALLY BLANK

$$Q_{mt} = K_g A \lambda \ (pp_s - pp_d) \tag{2}$$

Where:

Q_{mt} = Rate of heat transfer due to condensing steam, (Btu)/(hr)

K_g = Mass transfer coefficient from liquid interface to the gas, $(lb_m)/(hr)(ft^2)$ (atmosphere)

λ = Heat of condensation of water, $(Btu)/(lb_m)$

A = Surface area of the droplet, (ft^2)

pp_s = Partial pressure of steam, (atmosphere)

pp_d = Partial pressure of water vapor at droplet temperature, (atmosphere)

Combining both forms of heat transfer:

$$Q_t = hA \ (T_m - T_d) + K_g \ A\lambda \ (pp_s - pp_d) \tag{3}$$

Since partial vapor pressures are a function of temperature, over a relatively small range:

$$Q_t = U_s A \ (T_m - T_d) \tag{4}$$

Where:

Q_t = Rate of heat transfer, (Btu)/(hr)

U_s = Overall surface heat transfer coefficient for convection and mass transfer, $(Btu)/(hr)(ft^2)(F)$

Heat flows from the surface of the droplet inward by conduction and is represented by the partial differential equation:

$$\frac{\partial T}{\partial \tau} = \alpha \left(\frac{\partial^2 T}{\partial r^2} + \frac{2}{r} \frac{\partial T}{\partial r} \right) \tag{5}$$

Where:

α = $k/C_p\rho$ = Thermal diffusivity, $(ft^2)/(hr)$

k = Thermal conductivity, $(Btu)/(hr)(ft^2)(F/ft)$

C_p = Specific heat, $(Btu)/(lb_m)$ (F)

ρ = Density, $(lb_m)/(ft^3)$

drop strikes a surface. In reality, most drops would not strike a surface for many more feet and would continue to absorb heat even after contact.

2.1.4 Loss-of-Coolant Accident

Following blowdown of steam and water to the drywell and subsequent purging of steam and nitrogen to the suppression chamber, the pressure in both chambers equilibrates at about 21 or 22 psig. This assumes that all the drywell nitrogen is purged to the suppression chamber. As steam purges it is condensed in the suppression chamber pool. Following this initial transient, the only mechanisms for increasing containment pressure are the energy inputs due to decay heat and metal-water reactions. Heat exchangers in the containment spray loops remove heat from the containment and transfer it to raw cooling water. Assuming that all the energy released in the reactor core is used to produce steam results in the highest possible pressure conditions in the containment.

During the metal-water reaction, hydrogen is released to the drywell and subsequently purged to the suppression chamber. In order to prevent this purging of hydrogen and possible overpressurization of the suppression chamber, the containment sprays condense steam in the drywell and reduce the steam pressure. This reduces the driving force needed to purge the hydrogen.

The spray water enters the heat exchangers at the temperature of the suppression chamber. Each of the four heat exchangers is sized to remove 60 million Btu/hr when the spray flow and raw water cooling flow are each 3000 gpm. This capacity is based on reducing spray flow temperature from 140°F to 100°F for the maximum cooling water temperature of 77°F.

The Section XV-C.5.3 design basis reconstitution suppression chamber heatup analysis verified that the containment design basis heat removal requirements are satisfied at the maximum containment spray raw water temperature of 84°F.

Using metal-water reaction rates from Section XV, the pressure transient in the containment is calculated with the results shown on Figure XVI-28. The pressures were calculated for four cases:

1. Core spray is inoperative and only one containment spray pump operates.

2. Core spray is inoperative and two containment spray pumps operate.

3. One core spray pump and one containment spray pump operate.

4. One core spray pump and two containment sprays operate.

For cases 1 and 2 there is a 27-percent metal-water reaction. Less than 1-percent metal-water reaction occurs in cases 3 and 4.

The previous cases were analyzed for initial containment pressure of 0 psig and suppression chamber temperature of 90°F. As a limiting case it is assumed that core spray is inoperative and only one containment spray pump operates. The results are shown on Figure XVI-29. Note that the suppression chamber pressure reaches the design value after about 1000 sec.

2.2 Summary of Test Results

2.2.1 Spray Tests Conducted

A sample spray nozzle of the size and type used in the containment spray system was tested at the Huntley Station in Buffalo, New York. Water was run through the nozzle at various pressures from 10 psig to 100 psig and spray pattern and spray particle fineness observed.

A close-up of the nozzle and spray pattern for 80 psig pressure drop is shown on Figure XVI-30. The spray pattern is more clearly defined on Figure XVI-31. This shows that the spray breaks up into a misty rain with gravity having little effect on the small droplets. Figure XVI-32 is a close-up of the nozzle and spray pattern for a 30 psig pressure drop. The spray pattern for this pressure is shown on Figure XVI-33. This shows that the spray breaks up into a moderate rain with gravity causing the particles to fall as opposed to the many suspended particles on Figure XVI-31.

The above nozzle pressure drops of 80 psig and 30 psig represent the pressure conditions for two-pump and one-pump operation, respectively.

Table XVI-19 shows the relationship between particle size and the type of spray pattern.

The particle sizes for two-pump operation are in the range of 10 to 400 microns. For one-pump operation, particle sizes range from 500 to 1000 microns.

The nozzle used in the test had a throat size of 0.6-in diameter. The largest nozzles used in the containment spray system are 0.5-in diameter. This smaller nozzle size results in greater breakup of the spray than was actually observed. The containment spray system as designed should result in smaller droplet sizes than assumed in Section C.2.1.

3.0 Core Spray and Containment Spray Suction Strainers

The installation of new core spray and containment spray suction strainers under Modification N1-96-005 involved adding piping and components inside the torus. The required new hydrodynamic load generation and piping system analysis followed the existing methodologies documented in the Plant Unique Analysis Report (PUAR). The PUAR is a plant-specific Teledyne document providing a summary of the analytical methods used and stress results obtained during the original Unit 1 Mark I analysis performed by Teledyne. Under Modification N1-96-005, a PUAR supplement has been prepared and issued under Safety Evaluation 98-104.

THIS PAGE INTENTIONALLY BLANK

Drywell sump piping (drywell sump to external isolation valve)

Class II Piping Systems

Main steam outside drywell
Bypass steam to condenser
Steam supply to air ejector
Extraction steam piping
Makeup demineralizer
Turbine building closed loop cooling
Reactor and turbine buildings, sump pump discharge
Seal water
Turbine oil storage
City water
Laboratory drains
Offgas (turbine gland seal exhaust)

Class I Equipment Housed in and Supported by Combination Class I and II Structures

Emergency service water pumps and piping
Containment spray cooling pumps and piping
Diesel generator cooling water pumps and piping

Class I Equipment Housed in and Supported by Class II Structures

Condensate storage tanks and piping
Condensate pumps, suction and discharge piping
Feedwater booster pumps and discharge piping
High-pressure reactor feed pumps and discharge piping
Diesel generator fuel oil, starting air and cooling water piping
Emergency condenser storage tanks
Reactor building closed loop cooling piping (partial)
Breathing air piping (partial)
Instrument air compressors
Instrument air piping (partial)
Emergency service water piping (partial)

1.1 Design Techniques

1.1.1 Structures

The design basis load combinations of dead load, live load (including piping, equipment, and temperature), moving loads, and incident loads are directly combined with horizontal and vertical earthquake loads for structures consisting in whole or in part of Class I elements. The resulting stress levels are within normal

Code* values with no increase allowed for the earthquake condition for Class I structures or components except for:

1. Suppression chamber columns, and

2. Ventilation stack

for which a one-third increase was allowed.

---

* Also see Section XVI, Subsection G.

THIS PAGE INTENTIONALLY BLANK

Tables XVI-20 through XVI-26 present the load combinations and allowable stresses for structures consisting in whole or in part of Class I elements.

Figures XVI-34 through XVI-41 present the computed deflections from the design earthquake excitation.

For concrete design criteria such as bar spacing, bar cover, minimum reinforcement, temperature steel, etc., ACI Code 318-63* was used. For proportioning of concrete members, Part IV-A, "Working Stress Design," of Code 318-63* was followed. The reinforced concrete ventilation stack was analyzed and designed in accordance with ACI Code 505-54.

The AISC Specification* for the design, fabrication and erection of structural steel for buildings was rigorously followed in the analysis and design of all structural steel framing and components. For structural components not covered by this specification, applicable documents such as the Uniform Building Code (UBC) and manufacturer-referred specifications were used[21]. It should be noted that Unit 1 has been historically conservative in the application of design specifications.

A large-scale static structural analysis was conducted with internally developed two- and three-dimensional-matrix structural analysis computer programs. These programs utilize the stiffness method and are similar to programs such as "STRESS" and "FRAN." Hand computations for static structural analysis utilized classical techniques such as moment distribution, slope deflection and energy methods.

The dynamic analysis of each Class I and Class II structure was conducted in the following manner. The structure was idealized as a multilumped mass system interconnected by weightless structural elements. These structural elements took into consideration flexural, shear, and axial deformations. The moment of inertia for a particular story was calculated directly from the plan view of that story. The shear stiffness of each significant structural component was determined individually, then summed directly to give the total story shear stiffness. Utilizing the story moment of inertia and the total story shear

---

* Also see Section XVI, Subsection G.

TABLE XVI-9a

CORE SHROUD REPAIR DESIGN SUPPORTING DOCUMENTATION

Document Number	Description
GENE-B13-01739-04 (NMPC Calculation #SQ-Vessel-M028)	NMP1 Shroud and Shroud Repair Hardware Analysis
GENE-B13-01739-05 (NMPC 50.59 Evaluation 94-080)	Safety Evaluation for Installation of Stabilizers on the NMP1 Core Shroud
GENE-B13-01739-03 (NMPC Calculation #SQ-Vessel-M027)	Seismic Design Report of the Shroud Repair for NMP1 Power Plant
24A56426 (NMPC Calculation #SQ-Vessel-M026)	Stress Report, "Shroud & Stabilizers Code Design Specification - Shroud Stabilizers"
25A5583	Design Specification, "Shroud Repair Hardware"
107E5679, Sheets 1-4	Modifications & Installation Drawings
25A5584	Fabrication Specification, "Fabrication of Shroud Stabilizer"
FDI 0245-90800	Field Disposition Instruction
25A5585	Installation Specification, "Stabilizer Installation"
21A2040	Cleaning and Cleanliness Control
24A5586	Shroud Stabilizer Code, Design Specification
GENE-771-44-0894	Justification of Allowable Displacements of the Core Plate and Top Guide - Shroud Repair
GENE-B13-01739-5.1 (NMPC 50.59 Evaluation 96-018)	Modification to GE Core Shroud Repair Design
NMPC 50.59 Evaluation 98-103	Core Shroud Vertical Weld Repair Clamp

TABLE XVI-9a (Cont'd.)

Document Number	Description
NER-IM-059	NMP-1 Core Shroud Vertical Weld Repair Design Report, MPR Report No. MPR-1966
NRC Safety Evaluation	NMP1 Core Shroud Repair, dated 3/31/95
NRC Safety Evaluation	Modifications to Correct Core Shroud Repair Deviations, dated 3/3/97
NRC Safety Evaluation	Modifications to Core Shroud Stabilizer Lower Wedge Retaining Clip and Evaluation of Shroud Vertical Weld Cracking, dated 5/8/97
NRC Safety Evaluation	Modification of Core Shroud Tie Rod Upper Spring Assemblies, dated 6/7/99
NRC Safety Evaluation	Modification of Core Shroud Tie Rod Upper Support and Tie Rod Nut Assemblies

TABLE XVI-26

ALLOWABLE STRESSES* FOR CONCRETE SLABS, WALLS, BEAMS, STRUCTURAL STEEL, AND CONCRETE BLOCK WALLS

1. Turbine Building - Class II
2. Control Room - el 277-0 - Class I
3. Battery Room - el 277-0 - Class I
4. Auxiliary Control Room - el 261-0 - Class I
5. Battery Board Room - el 261-0 - Class I
6. Diesel Generator Area - el 261-0 - Class I

Stresses Considered	Dead Load Plus Live Load Plus Operating Load Plus Design Earthquake
Reinforcing steel--allowable tensile stress	$0.5\ F_y = 20{,}000$ psi
Reinforcing steel--allowable compressive stress	$0.34\ F_y = 13{,}600$ psi
Concrete--allowable compressive stress	$0.45\ F'_c = 1{,}575$ psi
Concrete--allowable shear stress	$1.1\ \sqrt{F'_c} = 65$ psi
Reinforced concrete shear walls--allowable shear stress	$2.67\ \sqrt{F'_c} = 160$ psi
Structural steel--allowable bending stress	
36 ksi material	0.6 Fy = 21,600 psi
50 ksi material	0.6 Fy = 30,000 psi
Structural steel--allowable web shear stress	
36 ksi material	0.4 Fy = 14,500 psi
50 ksi material	0.4 Fy = 20,000 psi
Reinforced concrete block walls--allowable mortar unit stress	$0.04\ F'_c = 36$ psi

TABLE XVI-26 (Cont'd.)

NOTES:

1. 11% horizontal ground acceleration.
2. 5% damping.

* Also see Section XVI, Subsection G.

APPENDIX B

NINE MILE POINT NUCLEAR STATION, LLC QUALITY ASSURANCE PROGRAM TOPICAL REPORT NINE MILE POINT NUCLEAR STATION UNITS 1 AND 2 OPERATIONS PHASE

The previous Nine Mile Point Nuclear Station, LLC, Quality Assurance Program Topical Report, Nine Mile Point Nuclear Station Units 1 and 2, Operations Phase, has been superseded by Constellation Generation Group, LLC, Quality Assurance Topical Report (QATR), approved by the Nuclear Regulatory Commission (NRC) on December 21, 2006. The previous Appendix B has been deleted. The effective QATR is maintained as a separate document.

APPENDIX C

LICENSE RENEWAL SUPPLEMENT - AGING MANAGEMENT PROGRAMS AND TIME-LIMITED AGING ANALYSES

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont'd.)

TABLE OF CONTENTS (Cont'd.)

LIST OF TABLES

APPENDIX C

LICENSE RENEWAL SUPPLEMENT - AGING MANAGEMENT PROGRAMS AND TIME-LIMITED AGING ANALYSES

C.0 INTRODUCTION

The original operating license for Nine Mile Point Nuclear Station - Unit 1 (Unit 1) was issued by the Nuclear Regulatory Commission (NRC) on August 22, 1969, and authorized operation for 40 yr. Per 10CFR54, licensees could apply for a renewed operating license that would authorize up to an additional 20 yr of operation. Unit 1 applied for a renewed license on May 26, 2004, and amended the application on July 14, 2005. The NRC granted approval of a renewed license on October 31, 2006. The environmental and safety reviews conducted by the NRC are documented in NUREG-1437 Supplement 24, and NUREG-1900, respectively.

This appendix to the Unit 1 Updated Final Safety Analysis Report (UFSAR) meets the requirements of 10CFR54.21(d) and describes the programs credited for managing the aging of applicable structures, systems and components (SSC), describes the time-limited aging analyses (TLAA) performed for license renewal, lists the commitments made to meet the regulations, and describes the generic quality assurance program requirements for license renewal.

The Aging Management Programs (AMP) described in this appendix have been credited with managing the aging of SSCs that have been determined to be within the scope of license renewal [per 10CFR54.4(a)] and subject to aging management [per 10CFR54.21(a)(1)]. There are 41 AMPs described in this appendix. Six are new programs while the remaining 35 are existing (some have license renewal names but they include activities already performed at the station). For each AMP, a description of the program is provided along with the identification of any enhancements (i.e., commitments) and/or exceptions taken to the NRC guidance documents (NUREG-1800 Rev. 0 and NUREG-1801 Rev. 0).

This appendix also describes the TLAA dispositions performed for license renewal per 10CFR54.21(c). The dispositions address existing Unit 1 calculations and analyses that include, as one of the criteria, a time limit. The time limit is normally the duration of the original license, i.e., 40 yr, but can be any length of time. Each TLAA description includes the scope of the evaluation and a conclusion of how the evaluation is dispositioned for the period of extended operation (i.e., 41 to 60 yr).

A table documenting each of the commitments made as part of the license renewal application (LRA) is also provided. Each commitment is associated with a TLAA or AMP and is described in those sections. The table provides a single location for all the commitments. The source document for the commitment is listed along with the due date. Where the source document is listed as "LRA Section...," it refers to the Amended License Renewal Application (ALRA) submitted on July 14, 2005, under letter number NMP1L 1962. A due date of "Prior to period of extended operation" means prior to August 22, 2009.

The final section of this appendix addresses the generic quality assurance program requirements for license renewal. Each AMP must meet three attributes that are the same for all AMPs. The attributes are corrective actions, confirmation process, and administrative controls. The final section describes how each attribute is addressed for the Unit 1 AMPs.

C.1 AGING MANAGEMENT PROGRAMS

C.1.1 10CFR50 Appendix J Program

The 10CFR50 Appendix J Program detects degradation of the containment structure and components that comprise the containment pressure boundary, including seals and gaskets. Containment leak rate tests are performed to assure that leakage through the primary containment and systems and components penetrating primary containment does not exceed allowable leakage limits specified in the Technical Specifications. This program complies with Option B requirements of 10CFR50 Appendix J, with plant-specific exceptions approved by the NRC as part of license amendments, and implements the guidelines provided in NRC Regulatory Guide (RG) 1.163 and NEI 94-01.

C.1.2 ASME Section XI Inservice Inspection (Subsection IWE) Program

The American Society of Mechanical Engineers (ASME) Section XI Inservice Inspection (Subsection IWE) Program (referred to herein as the IWE ISI Program) manages aging effects due to 1) corrosion of carbon steel components comprising the containment pressure boundary; and 2) degradation of containment pressure-retaining polymers. Program activities include visual examination, with limited surface or volumetric examinations when augmented examination is required. The IWE ISI Program is based on the 1998 edition of the ASME Boiler and Pressure Vessel Code, Section XI (Subsection IWE), for containment inservice inspection with plant-specific exceptions approved by the NRC. This is an exception to the evaluation in NUREG-1801 (which covers ASME Section XI requirements from both the 1992 edition with the 1992 addenda, and the 1995 edition with the 1996 addenda).

The Unit 1 ASME Section XI Inservice Inspection (Subsection IWE) Program is being improved to add an augmented VT-1 visual examination of the Unit 1 containment penetration bellows. This inspection will be performed using enhanced techniques qualified for detecting stress corrosion cracking (SCC) per NUREG-1611, Table 2, Item 12. This improvement is not required for consistency with NUREG-1801 but is an activity being adopted to ensure consistency with industry practice.

C.1.3 ASME Section XI Inservice Inspection (Subsection IWF) Program

The ASME Section XI Inservice Inspection (Subsection IWF) Program (referred to herein as the IWF ISI Program) manages aging of carbon steel component and piping supports, including ASME Class MC supports, due to general corrosion and wear. Program activities include visual examination to determine the general mechanical and structural condition of components and their supports. The IWF ISI Program is based on the 1989 edition of the ASME Boiler and Pressure Vessel Code, Section XI (Subsection IWF), for inservice inspection of supports, and implements the alternate examination requirements of ASME Code Case N-491-1. There are exceptions to the evaluation in NUREG-1801 (which covers ASME Section XI requirements from the 1989 edition through the 1995 edition and addenda through the 1996 addenda).

C.1.4 ASME Section XI Inservice Inspection (Subsections IWB, IWC, IWD) Program

The ASME Section XI Inservice Inspection (Subsections IWB, IWC, IWD) Program manages aging of Class 1, 2, or 3 pressure-retaining components and their integral attachments. Program activities include periodic visual, surface, and/or volumetric examination and pressure tests of Class 1, 2, and 3 pressure-retaining components. The ASME Section XI Inservice Inspection (Subsections IWB, IWC, IWD) Program is based on ASME Section XI, 1989 edition with no addenda, and ASME Section XI, Appendix VIII, 1995 edition through 1996 addenda. Examination categories B-F, B-J, C-F-1, C-F-2, and intergranular stress corrosion cracking (IGSCC) Category A are inspected using NRC-approved risk-informed methodology. Prior to the period of extended operation, the ISI Program will be updated to the latest edition and addenda of ASME Section XI, as mandated by 10CFR50.55a and 10CFR54 requirements. There are exceptions to the program described in NUREG-1801 (which cites ASME Section XI requirements covered in the 1995 edition through 1996 addenda).

C.1.5 Boraflex Monitoring Program

The Boraflex Monitoring Program manages degradation of neutron absorbing material in spent fuel pool storage racks resulting from radiation exposure and possible water ingress. Program activities include 1) inspection of the test coupons to detect dimensional changes; 2) correlation of measured levels of silica in the spent fuel pool with analysis using a predictive code (e.g., RACKLIFE) to estimate boron loss from Boraflex panels; and 3) neutron attenuation testing to measure the boron areal density of the short-length test coupons. The Boraflex Monitoring Program is based on existing technology and methods for testing and evaluating material properties necessary to ensure the required 5-percent margin to criticality in the spent fuel pool is maintained. The Boraflex Monitoring Program for Unit 1 will be enhanced to perform periodic in-situ neutron attenuation testing and measurement of boron areal density for those Boraflex racks that remain in use during the period of extended operation. It will also be enhanced to create a new activity which provides instruction for the trending of silica levels, coupon results, and the results of in-situ testing.

Enhancements will be completed prior to the period of extended operation.

C.1.6 Buried Piping and Tanks Inspection Program

The Buried Piping and Tanks Inspection Program is a new program that will manage the aging effects on the external surfaces of carbon steel, low-alloy steel, and cast iron components (e.g., tanks, piping) that are buried in soil. Program activities will include visual inspections of external coatings and wrappings to detect damage and degradation. Prior to entering the period of extended operation, Nine Mile Point will verify that there has been at least one opportunistic or focused inspection within the past 10 yr. Upon entering the period of extended operation, Nine Mile Point will perform a focused inspection within 10 yr, unless an opportunistic inspection occurred within this 10-yr period. All credited inspections will be performed in areas with the highest likelihood of corrosion problems, and in areas with a history of corrosion problems. This program will be implemented prior to the period of extended operation.

C.1.7 BWR Feedwater Nozzle Program

The Unit 1 Feedwater Nozzle Program requires ultrasonic test (UT) inspections of the feedwater nozzles every 10 yr to verify the nozzles are acceptable for continued service.

The Feedwater Nozzle Program is implemented through the ISI Program which, at the time the LRA was submitted, conformed to the requirements in ASME Section XI, Subsection IWB, Table IWB 2500-1 (1989 edition, no addenda), and ASME Section XI, Appendix VIII, "Performance Demonstration for Ultrasonic Examination Systems," 1995 edition through 1996 addenda. NUREG-1801, Section XI.M5, identifies the 1995 edition (including the 1996 addenda) of ASME Section XI as the basis for the Generic Aging Lessons Learned (GALL) Feedwater Nozzle Program. The ISI Programs will not comply with the edition and addenda of ASME Section XI cited in the GALL report because the programs are updated to the latest edition and addenda of ASME Section XI, as mandated by 10CFR50.55a, prior to the start of each inspection interval.

UT and particle test inspections required by NUREG-0619 have been superseded because the inspections are now performed in accordance with ASME Section XI, Appendix VIII.

C.1.8 BWR Penetrations Program

The Boiling Water Reactor (BWR) Penetrations Program manages the effects of cracking in the various penetrations of the reactor pressure vessels (RPV) at Nine Mile Point. The BWR Penetrations Program is based on guidelines issued by the BWR Vessel and Internals Project and approved by the NRC. This program is implemented by the BWR Vessel and Internals Program (BWRVIP) for managing specific aging effects. The attributes of the BWR Penetrations Program related to maintaining reactor coolant water chemistry are included in the Water Chemistry Control Program.

C.1.9 BWR Reactor Water Cleanup System Program

The BWR Reactor Water Cleanup (RWCU) System Program manages the effects of stress corrosion cracking or IGSCC on the intended function of austenitic stainless steel piping in the RWCU system. This program is based on the NRC criteria related to inspection guidelines for RWCU piping welds outboard of the second isolation valve, as delineated in NUREG-0313, Revision 2, and Generic Letter (GL) 88-01. An exception is taken to the acceptance criteria program element in that Unit 1 utilizes the 1989 edition with no addenda of the ASME Section XI Code versus the 1995 edition through the 1996 addenda as defined in the GALL report. The attributes of the BWR RWCU System Program related to maintaining reactor coolant water chemistry are included in the Water Chemistry Control Program.

C.1.10 BWR Stress Corrosion Cracking Program

The BWR Stress Corrosion Cracking (SCC) Program manages IGSCC in reactor coolant pressure boundary (RCPB) piping made of stainless steel, as delineated in NUREG-0313, Revision 2, and GL

88-01 and its Supplement 1, as modified by BWRVIP-75. Augmented inspections are performed in accordance with these documents. An exception to the program described in NUREG-1801 is that the acceptance criteria for the BWR SCC Program are based upon the 1989 edition of the ASME Section XI Code versus the 1995 edition through the 1996 addenda, as described in NUREG-1801. The attributes of the BWR SCC Program related to maintaining reactor coolant water chemistry are included in the Water Chemistry Control Program.

C.1.11 BWR Vessel ID Attachment Welds Program

The BWR Vessel ID Attachment Welds Program manages the effects of cracking in RPV inside diameter (ID) attachment welds. This program is based on industry guidelines issued by the BWRVIP and approved by the NRC. The BWR Vessel ID Attachment Welds Program is implemented by the BWRVIP for managing specific aging effects. The attributes of the BWR Vessel ID Attachment Welds Program related to maintaining reactor coolant water chemistry are included in the Water Chemistry Control Program.

C.1.12 BWR Vessel Internals Program

The BWRVIP manages aging of materials inside the reactor vessel. Program activities include 1) inspections for the presence and effects of cracking; and 2) monitoring and control of water chemistry. This program is based on guidelines issued by the BWRVIP and approved (or pending approval) by the NRC. Inspections and evaluations of reactor vessel components are consistent with the guidelines provided in the following BWRVIP reports:

- BWRVIP-18, BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines
- BWRVIP-25, BWR Core Plate Inspection and Flaw Evaluation Guidelines
- BWRVIP-26, BWR Top Guide Inspection and Flaw Evaluation Guidelines
- BWRVIP-27, BWR Standby Liquid Control System/Core Plate ΔP Inspection and Flaw Evaluation Guidelines
- BWRVIP-38, BWR Shroud Support Inspection and Flaw Evaluation Guidelines
- BWRVIP-47, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines
- BWRVIP-48, Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines

- BWRVIP-49, Instrument Penetration Inspection and Flaw Evaluation Guidelines
- BWRVIP-74, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines
- BWRVIP-76, BWR Core Shroud Inspection and Flaw Evaluation Guidelines

Unit 1 has completed, or will complete, each of the license renewal applicant action items described in the NRC safety evaluations for these BWRVIP reports. In addition, Unit 1 will implement the NRC-approved inspection and flaw evaluation guidelines for the steam dryer and inaccessible core spray component welds when issued. The attributes of the BWRVIP related to maintaining reactor coolant water chemistry are included in the Water Chemistry Control Program.

Enhancements to the BWRVIP include the following revisions to existing activities that are credited for license renewal:

1. The reinspection scope and frequency for the grid beam going forward will be based on BWRVIP-26A guidance for plant-specific flaw analysis and crack growth assessment. The maximum reinspection interval for the grid beam will not exceed 10 yr, consistent with standard BWRVIP guidance for the core shroud. The reinspection scope will be equivalent to the UT baseline 2005 inspection scope. In addition, the reinspection scope will include an EVT-1 sample inspection of at least two locations with accessible indications within the initial 6 yr of the 10-yr interval. The intent of the EVT-1 is to monitor the known cracking to confirm flaw analysis crack growth assumptions.

2. Nine Mile Point will implement the resolution of the open item documented in BWRVIP-18 regarding the inspection of inaccessible welds for core spray. It will be included in the BWRVIP response to be reviewed and accepted by the NRC.

3. Once the guidelines for inspection and evaluation for steam dryers currently under development by the BWRVIP committee are documented, reviewed and accepted by the NRC, the actions will be implemented in accordance with the BWRVIP.

4. The baseline inspections recommended in BWRVIP-47 for the BWR lower plenum components will be incorporated into the program.

5. If the October 19, 2005, draft of Code Case N-730 is approved by ASME, Unit 1 will implement the final Code case as conditioned by the NRC. If the Code case is not approved by ASME, Unit 1 will seek NRC approval of the October 19, 2005, Code case draft on a plant-specific basis as conditioned by the NRC.

   During the period of extended operation, should a control rod drive (CRD) stub tube rolled in accordance with the provisions of the Code case resume leaking, Unit 1 will implement one of the following zero leakage permanent repair strategies prior to startup from the outage in which the leakage was detected:

   a. A welded repair consistent with BWRVIP-58-A, "BWRVIP Internal Access Weld Repair" and Code Case N-606-1, as endorsed by the NRC in RG 1.147.

   b. A variation of the welded repair geometry specified in BWRVIP-58-A subject to the approval of the NRC using Code Case N-606-1.

   c. A future developed mechanical/welded repair method subject to the approval of the NRC.

6. Unit 1 will evaluate component susceptibility to loss of fracture toughness due to neutron fluence and thermal embrittlement. Assessments and inspections will be performed, as necessary, to ensure that intended functions are not impacted by the aging effect.

7. An EVT-1 examination of the Unit 1 feedwater sparger end bracket welds will be added to the BWRVIP. The inspection extent and frequency of the end bracket weld inspection will be the same as the ASME Section XI inspection of the feedwater sparger bracket vessel attachment welds.

8. Unit 1 will perform an EVT-1 inspection of the thermal shield to flow shield weld starting in 2007, and proceeding at a 10-yr frequency thereafter consistent with the ISI inspection interval.

Enhancements will be completed prior to the period of extended operation.

C.1.13 Closed-Cycle Cooling Water System Program

The Closed-Cycle Cooling Water System (CCCWS) Program manages loss of material and fouling of components exposed to CCCW environments. The applicable piping systems include the reactor building closed loop cooling (RBCLC) system, control room heating, ventilation and air conditioning (HVAC) system, and the heat exchanger jacket water cooling portions of the emergency diesel generator (EDG) system. Also included are portions of non-safety related systems credited in the aging management review. Program activities include chemistry monitoring, surveillance testing, data trending, and component inspections. The CCCWS Program implements the guidelines for controlling system performance and aging effects described in Electric Power Research Institute (EPRI) Report TR-107396.

Enhancements to the CCCWS Program include the following revisions to existing activities that are credited for license renewal:

1. Direct periodic inspections to monitor for loss of material in the piping of the CCCW systems.

2. Implement a Corrosion Monitoring Program for larger bore CCCW piping not subject to inspection under another program.

3. Establish periodic monitoring, trending, and evaluation of performance parameters for the RBCLC and control room HVAC systems.

4. Implement a program to use corrosion inhibitors in the RBCLC system and control room HVAC system in accordance with the guidelines given in EPRI TR-107396.

5. Establish the frequencies to inspect for degradation of components in CCCW systems, including heat exchanger tube wall thinning.

6. Perform a heat removal capability test for the control room HVAC system at least every 5 yr.

7. Expand periodic chemistry checks of CCCW systems consistent with the guidelines of EPRI TR-107396.

8. Provide the controls and sampling necessary to maintain water chemistry parameters in CCCW systems within the guidelines of EPRI Report TR-107396.

9. Ensure acceptance criteria are specified in the implementing procedures for the applicable indications of degradation.

The enhancements will be completed prior to the period of extended operation.

C.1.14 Compressed Air Monitoring Program

The Compressed Air Monitoring Program manages aging effects for portions of the compressed air systems within the scope of license renewal, including cracking and loss of material due to general corrosion, by controlling the internal environment of systems and components. Program activities include air quality checks at various locations to detect contaminants that would affect the system's intended function. Additional visual inspections are credited for identification and monitoring of degradation for air compressors, receivers, and air dryers. The Compressed Air Monitoring Program is based on GL 88-14 and recommendations presented in Institute of Nuclear Power Operations (INPO) Significant Operating Event Report (SOER) 88-01. The program also includes good practice elements of the general maintenance and inspection activities for the compressor, receiver, and air drier discussed in EPRI TR-108147 (revision to EPRI NP-7079) and ASME OM-S/G-1998, Part 17. However, specific exception is taken to any maintenance recommended in EPRI TR-108147 that is not also endorsed by the equipment manufacturers, and to the preservice and inservice testing guidelines of ASME OM-S/G-1998, Part 17. This is an exception to the program described in NUREG-1801. Unit 1 also takes exception to the use of ISA-S7.0.01-1996 for air quality standards. The system air quality is monitored and maintained in compliance with the requirements of ANSI/ISA-S7.3-1975, which meets or exceeds the quality requirements for dew point, hydrocarbons, and particulate of Section 4.4 of EPRI TR-108147 and ISA-S7.0.01-1996.

Enhancements to the Compressed Air Monitoring Program include the following revisions to existing activities that are credited for license renewal:

1. Develop new activities to manage the loss of material, stress corrosion cracking, and perform periodic system leak checks.

2. Expand the scope, periodicity, and inspection techniques to ensure that the aging of certain subcomponents of the dryers and compressors (e.g., valves, heat exchangers) is managed.

3. Establish activities that manage the aging of the internal surfaces of carbon steel piping and that require system leak checks to detect deterioration of the pressure boundaries.

4. Expand the acceptance criteria to ensure that the aging of certain subcomponents of the dryers and compressors (e.g., valves, heat exchangers) is managed.

5. Develop and implement the activities to address the failure mechanism of stress corrosion cracking in unannealed red brass piping in Unit 1.

Enhancements will be completed prior to the period of extended operation.

C.1.15 Environmental Qualification Program

The Environmental Qualification (EQ) Program manages thermal, radiation, and cyclical aging for electrical equipment important to safety and located in harsh plant environments at Unit 1. Program activities 1) identify applicable equipment and environmental requirements; 2) establish, demonstrate, and document the level of qualification (including configuration, maintenance, surveillance, and replacement requirements); and 3) maintain (or preserve) qualification. The EQ Program employs aging evaluations based on 10CFR50.49(f) qualification methods. Components in the EQ Program must be refurbished, replaced, or have their qualification extended prior to reaching the aging limits established in the evaluation. Important attributes for the reanalysis of an aging evaluation include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions (if acceptance criteria are not met).

C.1.16 Fatigue Monitoring Program

The Fatigue Monitoring Program (FMP) manages the fatigue life of RCPB components by tracking and evaluating key plant events. The FMP monitors operating transients to date, calculates cumulative usage factors (CUF) to date, and directs performance of engineering evaluations to develop preventive and mitigative measures in order not to exceed the design limit on fatigue usage.

The FMP will be enhanced with guidance for the use of the FatiguePro software package and updated methodology for environmental fatigue factors in establishing updated fatigue life calculations for components, and to add safety relief valve (SRV) actuations for Unit 1 as a monitored transient. These enhancements will be completed prior to the period of extended operation.

C.1.17 Fire Protection Program

The Fire Protection Program provides guidance for performance of periodic visual inspections to manage aging of the various materials comprising rated fire barriers. These include 1) sealants in rated penetration seals (subject to shrinkage due to weathering); 2) concrete and steel in fire-rated walls, ceilings, and floors (subject to loss of material due to flaking and abrasion; separation and concrete damage due to relative motion, vibration, and shrinkage); and 3) steel in rated fire doors (subject to loss of material due to corrosion and wear or mechanical damage). In addition, this program requires testing of the diesel-driven fire pump to verify that it is performing its intended function. This activity manages aging of the fuel oil supply line to, and the exhaust system from, the diesel engine, both of which may experience loss of material due to corrosion. Inspection and testing is performed in accordance with the guidance of applicable standards.

There are two exceptions to the Fire Protection Program as described in NUREG-1801. Inspections on hollow metal fire doors will be performed on a plant-specific schedule, and valve lineups will not be used for aging management of fire suppression systems. These exceptions are consistent with NRC Interim Staff Guidance (ISG) 04.

The Fire Protection Program will be enhanced to include the following: 1) periodic visual inspections of piping and fittings in a non-water environment in the Halon and carbon dioxide (CO_2) fire suppression systems components to detect signs of degradation; 2) periodic functional tests of the diesel-driven fire pump will be enhanced to include inspection of engine exhaust system components to verify that loss of material is managed; 3) the fire door inspection frequency will be determined by a plant-specific analysis; and 4) Halon and CO_2 functional test frequencies will be revised to semi-annual. These enhancements will be completed prior to the period of extended operation.

C.1.18 Fire Water System Program

The Fire Water System Program manages aging of water-based fire protection systems due to loss of material and biofouling. Program activities include periodic maintenance, testing, and inspection of system piping and components containing water (e.g., sprinklers, nozzles, fittings, valves, hydrants, hose stations, standpipes). Inspection and testing is performed in accordance with the guidance of applicable National Fire Protection Association (NFPA) Codes and Standards and the Nuclear Electric Insurance Limited (NEIL) Members' Manual. Enhancements to the Fire Water System Program include the following revisions to existing activities that are credited for license renewal:

1. Incorporate inspections to detect and manage loss of material due to corrosion into existing periodic test procedures.

2. Specify periodic component inspections to verify that loss of material is being managed.

3. Add procedural guidance for performing visual inspections to monitor internal corrosion and detect biofouling.

4. Develop new procedures and preventive maintenance tasks to implement sprinkler head replacement and/or inspections to meet NFPA 25, Section 5.3.1 (2003 edition) requirements.

5. Add requirements to periodically check the water-based fire protection systems for microbiological contamination.

6. Measure fire protection system piping wall thickness using non-intrusive techniques (e.g., volumetric testing) to detect loss of material due to corrosion.

7. Establish an appropriate means of recording, evaluating, reviewing, and trending the results of visual inspections and volumetric testing.

8. Define acceptance criteria for visual inspections and volumetric testing.

Enhancements will be completed prior to the period of extended operation.

C.1.19 Flow-Accelerated Corrosion Program

The Flow-Accelerated Corrosion (FAC) Program (also referred to as the Erosion/Corrosion Program) manages aging effects due to FAC in carbon steel and low-alloy steel piping containing single-phase and two-phase high-energy fluids. Program activities include 1) analysis using a predictive code (CHECWORKS) to determine critical locations; 2) baseline inspections to determine the extent of thinning at the selected locations; 3) follow-up inspections to confirm the predictions; and 4) repair or replacement of components, as necessary. The program considers the recommended actions in NRC Bulletin 87-01 and Information Notice 91-18, and implements the guidelines for an effective FAC Program presented in EPRI Report NSAC-202L-R2. The program also implements the recommendations provided in NRC Generic Letter (GL) 89-08, "Erosion/Corrosion Induced Pipe Wall Thinning."

C.1.20 Fuel Oil Chemistry Program

The Fuel Oil Chemistry Program manages loss of material due to corrosion that may result from introduction of contaminants into the plant's fuel oil tanks. Program activities include 1) sampling and chemical analysis of the fuel oil inventory at the plant; 2) sampling, testing, and analysis of new fuel oil as it is unloaded at the plant; and 3) cleaning and inspection of fuel oil tanks. The Fuel Oil Chemistry Program is based on maintaining fuel oil quality in accordance with the guidelines of American Society for Testing Materials (ASTM) Standards D975, D1796, D2276, and D4057.

The Fuel Oil Chemistry Program takes exceptions to the following NUREG-1801, Section XI.M30 (Fuel Oil Chemistry Program) evaluation elements:

1. Unit 1 takes exception to using both ASTM D1796 and ASTM D2709 to determine the concentration of water and sediment in the diesel fuel oil tanks. Unit 1 uses only the guidance given in ASTM D1796.

2. Unit 1 takes exception to using the modified ASTM D2276, Method A, which specifies a pore size of 3.0 μm. Unit 1 uses a filter with a pore size of 0.8 μm as specified in ASTM D2276.

3. Unit 1 takes exception to multilevel sampling in the diesel fuel oil tanks. The physical configuration of the fuel oil tanks does not allow a representative fuel oil sample to be taken at multiple levels.

4. Unit 1 takes exception to periodically sampling the fuel oil day tanks. These small tanks do not have a provision for sampling.

5. Unit 1 takes exception to periodic internal inspection of any fuel oil day tank. The physical size and configuration are not suitable for such inspections and, after enhancement, all such tanks will be routinely drained, thereby removing any contaminants from the tank that would provide an aging mechanism.

6. Unit 1 takes exception to the addition of biocides, stabilizers, and corrosion inhibitors to the diesel fuel oil storage tanks.

Enhancements to the Fuel Oil Chemistry Program include the following revisions to existing activities that are credited for license renewal:

1. Add a requirement for quarterly trending of water, sediment, and particulate contamination analysis results.

2. Add requirements to periodically inspect the interior surfaces of the emergency diesel generator fuel oil tanks for evidence of significant degradation, including a requirement that the tank bottom thickness be determined. Bottom thickness measurements will be

performed using UT or other industry-recognized methods.

3. Provide guidelines for the appropriate use of biocides, corrosion inhibitors, and fuel stabilizers to maintain fuel oil quality.

4. Ensure acceptance criteria are specified in the implementing procedures for the applicable indications of potential degradation.

5. Add periodic opening of the diesel fire pump fuel oil day tank drain.

6. Add steps for removal of water, if found.

Enhancements will be completed prior to the period of extended operation.

C.1.21 Fuse Holder Inspection Program

The Fuse Holder Inspection Program is a new plant-specific program that applies to fuse holders located outside of active devices that have aging effects requiring management. This program requires testing to detect deterioration of metallic clamps that would affect the ability of in-scope fuse holders to perform their intended function. The Fuse Holder Inspection Program includes the following aging stressors: moisture, fatigue, ohmic heating, mechanical stress, vibration, thermal cycling, electrical transients, chemical contamination, oxidation, and corrosion.

Analytical trending will not be included in this activity because the parameters monitored may vary depending upon the test method selected. This is an exception to the "Monitoring and Trending" element in Appendix A.1.2.3.5 to NUREG-1800, but is consistent with the latest regulatory and industry license renewal precedence. This program will be implemented prior to the period of extended operation.

C.1.22 Inspection of Overhead Heavy Load and Light Load Handling Systems Program

The Inspection of Overhead Heavy Load and Light Load Handling Systems Program (referred to herein as the Crane Inspection Program) manages loss of material due to corrosion of cranes within scope of license renewal (WSLR). Program activities include 1) performance of various maintenance activities on a specified frequency; and 2) preoperational inspections of equipment prior to lifting activities. Crane inspection activities are based on the mandatory requirements of applicable industry standards and implement the guidance of NUREG-0612.

The Crane Inspection Program will be enhanced to add specific direction for performance of corrosion inspections of certain hoist-lifting assembly components. The enhancement will be completed prior to the period of extended operation.

C.1.23 Masonry Wall Program

The Masonry Wall Program manages aging effects so that the evaluation basis established for each masonry wall WSLR remains valid through the period of extended operation. The Masonry Wall Program is based on the structures monitoring requirements of 10CFR50.65. The Masonry Wall Program is implemented by the Structures Monitoring Program for managing specific aging effects.

C.1.24 Non-EQ Electrical Cables and Connections Program

The Non-EQ Electrical Cables and Connections Program is a new program that manages aging of cables and connectors WSLR exposed to adverse localized temperature, moisture, or radiation environments. Program activities include periodic visual inspection of susceptible cables for evidence of cable and connection jacket surface anomalies. This program will be implemented prior to the period of extended operation.

C.1.25 Non-EQ Electrical Cables and Connections Used in Instrumentation Circuits Program

The Non-EQ Electrical Cables and Connections Used in Instrumentation Circuits Program manages aging of cables and connections exposed to adverse localized temperature and radiation environments that could result in loss of insulation resistance. It applies to accessible and inaccessible electrical cables that are not in the EQ Program and are used in circuits with sensitive, high-voltage, low-level signals such as radiation monitoring, nuclear instrumentation, and other such cables subject to aging management review that are sensitive to a reduction in insulation resistance. Activities include routine calibration tests of instrumentation loops, or direct testing of the cable system in those cases where cable testing is conducted as an alternate to surveillance testing, and in either case are implemented through the Surveillance Testing and Preventive Maintenance Programs. Testing is based on requirements of the particular calibrations, surveillances, or testing performed on the specific instrumentation circuit or cable and is implemented through the work control system. Where cable testing is conducted as an alternate to surveillance testing, the acceptance criteria for each test will be defined by the specific type of test performed and the specific cable tested.

Enhancements to the Non-EQ Electrical Cables and Connections Used in Instrumentation Circuits Program include the following revisions to existing activities that are credited for license renewal:

1. Implement reviews of calibration or surveillance data for indications of aging degradation affecting instrument circuit performance. The first reviews will be completed prior to the period of extended operation and every 10 yr thereafter.

2. In cases where a calibration or surveillance program does not include the cabling system in the testing circuit, or as an alternative to the review of calibration results described above, provide requirements and procedures to perform cable testing to detect deterioration of the insulation system, such as insulation resistance tests or other testing judged to be effective in determining cable insulation condition. The first test will be completed prior to the period of extended operation. The test frequency of these cables shall be determined based on engineering evaluation, but the test frequency shall be at least once every 10 yr.

Enhancements will be completed prior to the period of extended operation.

C.1.26 Non-Segregated Bus Inspection Program

The Non-Segregated Bus Inspection Program manages aging effects for components and materials internal to the non-segregated bus ducts that connect the reserve auxiliary transformers to the 4160V buses required for the recovery of offsite power following a station blackout (SBO) event. Based upon the most recent industry and regulatory license renewal precedence, this program also includes normally energized bus ducts associated with boards feeding components WSLR. These normally-energized components are not subject to the EQ requirements of 10CFR50.49, but can be affected by elevated temperatures prior to the end of the period of extended operation. Program activities include 1) visual inspections of internal portions of the bus ducts to detect cracks, corrosion, debris, dust, and moisture; 2) visual inspections of the bus insulating system to detect embrittlement, cracking, melting, swelling, and discoloration; 3) visual inspections of bus supports (insulators) to detect cracking and lack of structural integrity; and 4) as an alternative to thermography or measuring connection resistance of bolted connections, a visual inspection for the accessible bolted connections that are covered with heat shrink tape, sleeving, insulating boots, etc. The program considers the technical information and guidance provided in applicable industry publications.

Analytical trending is not included in this activity because the ability to trend inspection results is limited. This is an exception to the "Monitoring and Trending" element in Appendix A.1.2.3.5 to NUREG-1800.

Enhancements to the Non-Segregated Bus Inspection Program include expanded visual inspections of the bus ducts, their supports and insulation systems. Enhance program documents to develop acceptance criteria for visual inspection of the bus ducts, their supports and insulation systems, and the low-range ohmic checks of connections.

Enhancements will be implemented prior to the period of extended operation.

C.1.27 One-Time Inspection Program

The One-Time Inspection Program is a new program that manages aging effects with potentially long incubation periods for susceptible components WSLR. Program activities include visual, volumetric, and other established inspection techniques consistent with industry practice to provide a means of verifying that an aging effect is either 1) not occurring, or 2) progressing so slowly that it has a negligible effect on the intended function of the structure or component. The program also provides measures for verifying the effectiveness of existing AMPs. This program is a new program that will be implemented prior to the period of extended operation.

C.1.28 Open-Cycle Cooling Water System Program

The Open-Cycle Cooling Water System (OCCWS) Program manages aging of components exposed to raw, untreated (e.g., service) water. For Unit 1, this includes portions of the service water system, the emergency service water system, shell side of the RBCLC heat exchangers, the EDG cooling water system, containment spray raw water system, and portions of the circulating water system. Also included are other components WSLR wetted by the service water system that are credited in the aging management review.

The program also manages internal portions of non-safety related segments of the circulating water and service water systems which are WSLR per 10CFR54.4(a)(2). It also manages all aging effects for components subject to the scope of recommendations for GL 89-13.

Program activities include 1) surveillance and control of biofouling (including biocide injection); 2) verification of heat transfer capabilities for components cooled by the service water system; 3) inspection and maintenance; 4) walkdown inspections; and 5) review of maintenance, operating, and training practices and procedures. Inspections may include visual, UT, and eddy current testing (ECT) methods. This program is based on the recommendations of GL 89-13.

Enhancements to the OCCWS Program include the following activities that are credited for license renewal:

1. Ensure that the applicable Unit 1 commitments made for GL 89-13, and the requirements in NUREG-1801, Section XI.M20, are captured in the Unit 1 implementing documents for GL 89-13.

2. Where the requirements of the NUREG-1801, Section XI.M20, are more conservative than the GL 89-13 commitments, they will be incorporated into the OCCWS Program.

3. Revise Unit 1 preventive maintenance and heat transfer performance test procedures to incorporate specific inspection criteria, corrective actions, and frequencies.

Enhancements will be completed prior to the period of extended operation.

C.1.29 Preventive Maintenance Program

The scope of the Preventive Maintenance (PM) Program includes, but is not limited to, valve bodies, heat exchangers, expansion joints, tanks, ductwork, fan/blower housings, dampers, and pump casings. This program provides for performance of various maintenance activities on a specified frequency based on vendor recommendations and operating experience. These activities provide opportunities for component condition monitoring to manage the effects of aging for many SSCs WSLR.

Enhancements to the PM Program include the following revisions to existing activities that are credited for license renewal:

1. Expand the PM Program to encompass activities for certain additional components identified as requiring aging management.

2. Explicitly define the aging management attributes, including the systems and the component types/commodities included in the program.

3. Specifically list activities credited for aging management, parameters monitored, and the aging effects detected.

4. Establish a requirement that inspection data be monitored and trended.

5. Establish detailed parameter-specific acceptance criteria.

Enhancements will be completed prior to the period of extended operation.

C.1.30 Reactor Head Closure Studs Program

The Reactor Head Closure Studs Program manages cracking and loss of material from the RPV closure studs. This program implements the preventive measures of RG 1.65. Inservice examinations are performed in accordance with the 1989 edition of the ASME Boiler and Pressure Vessel Code with no addenda, and ASME Section XI, Appendix VIII, "Performance Demonstration for Ultrasonic Examination Systems," 1995 edition through 1996 addenda as approved by the NRC in plant-specific exemptions. This is an exception to the program described in NUREG-1801 (which cites

ASME Section XI requirements covered in the 1995 edition through 1996 addenda).

C.1.31 Reactor Vessel Surveillance Program

The Reactor Vessel Surveillance Program manages loss of fracture toughness due to neutron irradiation embrittlement in the RPV beltline material. Program activities include 1) periodic withdrawal and testing of surveillance capsules from the RPV; 2) use of test results and allowable stress loadings for the ferritic RPV materials to determine operating limits; and 3) comparison with a large industry data set to confirm validity of test results. Analysis and testing are based on the requirements of 10CFR50 Appendix H, and ASTM Standard E-185. Nine Mile Point commits to implement the Integrated Surveillance Program (ISP) described in BWRVIP-116 (if approved by the NRC staff). When the NRC issues a final safety evaluation report (SER) for BWRVIP-116, Nine Mile Point will address any open items and complete the SER action items. Should BWRVIP-116 not be approved by the NRC, a plant-specific Reactor Vessel Surveillance Program will be submitted to the NRC 2 yr prior to commencement of the period of extended operation.

Enhancements to the Reactor Vessel Surveillance Program include the following revisions to existing activities that are credited for license renewal:

1. Incorporate the requirements and elements of the ISP, as documented in BWRVIP-116, if approved by the NRC or an NRC-approved plant-specific program, into the Reactor Vessel Surveillance Program, and include a requirement that if Unit 1 surveillance capsules are tested, the tested specimens will be stored in lieu of optional disposal.

2. Project analyses of upper-shelf energy (USE) and pressure-temperature (P-T) limits to 60 yr using methods prescribed by RG 1.99, Revision 2, and include the applicable bounds of the data, such as operating temperature and neutron fluence.

Enhancements will be completed prior to the period of extended operation.

C.1.32 Selective Leaching of Materials Program

The Selective Leaching of Materials Program is a new program that manages aging of components susceptible to selective leaching. The potentially susceptible components include valve bodies, valve bonnets, pump casings, and heat exchanger components in various systems. This program will be implemented through the One-Time Inspection Program prior to the period of extended operation.

C.1.33 Structures Monitoring Program

The Structures Monitoring Program manages aging of structures, structural components, and structural supports WSLR. The program provides for periodic visual inspections, surveys, and examination of all safety-related buildings (including the primary containment and substructures within the primary containment), and various other buildings WSLR. Program activities identify degradation of materials of construction, which include structural steel, concrete, masonry block, sealing materials, and a Unit 1 wooden structure. While not credited for mitigation of aging, protective coatings are also inspected under this program. The Structures Monitoring Program, which was initially developed to meet the regulatory requirements of 10CFR50.65, implements guidance provided in RG 1.160, NUMARC 93-01, and NEI 96-03.

Enhancements to the Structures Monitoring Program include the following revisions to existing activities that are credited for license renewal:

1. Expand the parameters monitored during structural inspections to include those relevant to aging effects requiring management identified for structural bolting.

2. Implement regularly scheduled groundwater monitoring to ensure that a benign environment is maintained.

3. Expand the scope of the program to include the steel electrical transmission towers required for the SBO recovery path that are WSLR, but not within the current scope of 10CFR50.65.

4. The Masonry Wall Program (as managed by the Structures Monitoring Program) will be enhanced to provide guidance for inspecting non-reinforced masonry walls

that do not have bracing and are WSLR more frequently than the reinforced masonry walls.

Enhancements will be completed prior to the period of extended operation.

C.1.34 Systems Walkdown Program

The Systems Walkdown Program manages aging effects for accessible external surfaces of pumps, valves, piping, bolts, heat exchangers, tanks, heating, ventilation and air conditioning (HVAC) components, and other components. Visual inspections identify corrosion, changes in material properties, signs of material degradation, and leakage. The program also identifies adverse conditions that can lead to aggressive environments for systems and components within the scope of license renewal. Program activities include system engineer walkdowns (i.e., field evaluations of system components to assess material condition), documentation and evaluation of inspection results, and appropriate corrective actions.

Enhancements to the Systems Walkdown Program include the following revisions to existing activities that are credited for license renewal:

1. Train all personnel performing inspections in the Systems Walkdown Program to ensure that age-related degradation is properly identified, and incorporate this training into the site training program.

2. Specify acceptance criteria for visual inspections to ensure aging-related degradation is properly identified and corrected.

Enhancements will be completed prior to the period of extended operation.

C.1.35 Torus Corrosion Monitoring Program

The Torus Corrosion Monitoring Program manages corrosion of the Unit 1 suppression chamber (torus) through inspection and analysis. This program provides for 1) determination of torus shell thickness through ultrasonic measurement; 2) determination of corrosion rate through analysis of material coupons; and 3) visual inspection of accessible external surfaces of the torus support structure for corrosion. The Torus Corrosion Monitoring

Program ensures that the Unit 1 torus shell and support structure thickness limits are not exceeded.

C.1.36 Water Chemistry Control Program

The Water Chemistry Control Program manages aging effects by controlling the internal environment of the reactor water, feedwater, condensate, and control rod drive systems, and related auxiliaries (such as the torus, condensate storage tank, and spent fuel pool). The aging effects of concern are 1) loss of material; and 2) crack initiation and growth. Program activities include monitoring and controlling concentrations of known detrimental chemical species below the levels known to cause degradation. The Water Chemistry Control Program implements the guidelines for BWR water chemistry presented in EPRI Reports TR-103515-R1 and TR-103515-R2. This is an exception to the program described in NUREG-1801 (which identifies EPRI TR-103515-R0 as the basis for BWR water chemistry programs).

C.1.37 Bolting Integrity Program

The Bolting Integrity Program manages aging effects due to loss of preload, cracking, and loss of material of bolting within the scope of license renewal, including safety-related bolting, bolting for nuclear steam supply system (NSSS) component supports, bolting for other pressure-retaining components, and structural bolting. Program activities include periodic inspections of bolting for indication of loss of preload, cracking, and loss of material due to corrosion, rust, etc. This program is based on the guidelines delineated in NUREG-1339 and the guidance contained in EPRI NP-5769, with exceptions noted in NUREG-1339, for safety-related bolting and EPRI TR-104213 for other bolting. The Bolting Integrity Program is implemented through the ASME Section XI Inservice Inspection (Subsections IWB, IWC, IWD) Program, ASME Section XI Inservice Inspection (Subsection IWE) Program, ASME Section XI Inservice Inspection (Subsection IWF) Program, Structures Monitoring Program, Preventive Maintenance Program, and Systems Walkdown Program. An exception is taken to the GALL report in that Unit 1 utilizes the 1989 edition with no addenda of the ASME Section XI Code versus the 1995 edition through the 1996 addenda.

Enhancements to the Bolting Integrity Program include the following:

1. Establish an augmented inspection program for high-strength (actual yield strength ≥150 ksi) bolts. This augmented program will prescribe the examination requirements of Tables IWB-2500-1 and IWC-2500-1 of ASME Section XI for high-strength bolts in the class 1 and class 2 component supports, respectively.

2. The Structures Monitoring, Preventive Maintenance, and Systems Walkdown Programs will be enhanced to include requirements to inspect bolting for indication of loss of preload, cracking, and loss of material, as applicable.

3. Include in administrative and implementing program documents references to the Bolting Integrity Program and industry guidance.

Enhancements will be completed prior to the period of extended operation.

C.1.38 BWR Control Rod Drive Return Line Nozzle Program

The Unit 1 BWR Control Rod Drive Return Line (CRDRL) Nozzle Program is an existing program that requires UT inspections of the CRDRL nozzle every 10 yr to verify the nozzle is acceptable for continued service. A CRDRL crack growth fracture mechanics analysis was used to demonstrate the adequacy of the 10-yr inspection frequency. The crack growth analyses are TLAAs that are managed in accordance with 10CFR54.21(c)(1)(iii), as described in Section 4.3.3.

The three exceptions to NUREG-1801, Section XI.M6, are:

1. The Unit 1 Inservice Inspection (ISI) Program does not comply with the specific edition and addenda of ASME Section XI cited in the GALL report because the program is updated to the latest edition and addenda of ASME Section XI, as mandated by 10CFR50.55a, prior to the start of each inspection interval;

2. The Unit 1 program uses enhanced ultrasonic inspection techniques instead of PT inspections to satisfy the recommendations of NUREG-0619 (now superseded by Appendix VIII to ASME Section XI, Division 1, 1995 edition with the 1996 addenda); and,

3. The Unit 1 program uses an inspection frequency of every 10 yr versus every sixth refueling outage or 90 startup/shutdown cycles specified in NUREG-0619.

C.1.39 Protective Coating Monitoring and Maintenance Program

The Protective Coating Monitoring and Maintenance Program is described in the Unit 1 response to GL 98-04, "Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System after a Loss-Of-Coolant Accident because of Construction and Protective Coating Deficiencies and Foreign Material in Containment." The program applies to Service Level 1 protective coatings inside the primary containment and items within the torus (outside surface of the vent [ring] header and downcomer, inside surface of the vent piping, ring header, vent header junctions, and downcomers). The condition assessments and resulting repair, replacement, or removal activities ensure that the amount of coatings subject to detachment from the substrate during a loss-of-coolant accident (LOCA) is minimized to ensure post-accident operability of the emergency core cooling system (ECCS) suction strainers. The Protective Coating Monitoring and Maintenance Program takes exception to certain NUREG-1801, Section XI.S8 (Protective Coating Monitoring and Maintenance Program) evaluation elements, in that it is not credited for prevention of corrosion of carbon steel. The program will be enhanced following the guidance within ASTM D5163-05a, and measurements of cracks, peeling, or delaminated coatings will be estimated via visual methods.

Planned program enhancements include the following:

1. Specifying the visual examination of coated surfaces for any visible defects including blistering, cracking, flaking, peeling, and physical or mechanical damage.

2. Performance of periodic inspection of coatings every refueling outage versus every 24 months.

3. Setting minimum qualifications for inspection personnel, the inspection coordinator, and the inspection results evaluator.

4. Performing the thorough visual inspection and areas noted as deficient along with the general visual inspection.

5. Specifying the types of instruments and equipment that may be used for the inspection.

6. Requiring pre-inspection reviews of the previous two monitoring reports before performing the condition assessment.

7. Establishing guidelines for prioritization of repair areas and monitoring these areas until they are repaired.

8. Requiring that the inspection results evaluator determine which areas are not acceptable and initiates corrective action.

Enhancements will be completed prior to the period of extended operation.

C.1.40 Non-EQ Electrical Cable Metallic Connections Inspection Program

The Non-EQ Electrical Cable Metallic Connections Inspection Program is a new plant-specific program that manages the aging effects of the metallic portion of electrical cable connections that are not subject to the qualification requirements of 10CFR50.49, but are still subject to aging effects caused by various stressors. These aging stressors include: thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation. All connections associated with cables that are in scope for license renewal are part of this program. This program is a condition monitoring program that will require periodic inspection of electrical cable metallic connections to ensure that degraded conditions that would affect the ability of the non-EQ electrical cable metallic connections to perform their intended function are identified and corrected.

Analytical trending will not be included in this program because the parameters monitored may vary depending upon the test method selected. This is an exception to the "Monitoring and Trending" element in Appendix A.1.2.3.5 to NUREG-1800. This program will be implemented prior to the period of extended operation.

C.1.41 Drywell Supplemental Inspection Program

The Drywell Supplemental Inspection Program manages the aging effects of localized areas of the Unit 1 drywell shell identified as having major corrosion in the Unit 1 Owner Activity Report dated July 23, 2003. Volumetric examinations will be performed during the 2007 refueling outage, and an engineering evaluation will be performed to determine what actions, beyond those required by the ASME Section XI Inservice Inspection (Subsection IWE) Program, are necessary for operation through the period of extended operation. Corrective actions could include increased monitoring, application of a protective coating, repair or replacement of affected sections, or other actions deemed appropriate by Engineering.

The Unit 1 Drywell Supplemental Inspection Program is a new program that will be implemented prior to the period of extended operation.

C.2 TIME-LIMITED AGING ANALYSES SUMMARIES

As part of the application for a renewed license, 10CFR54.21(c) requires that an evaluation of TLAAs for the period of extended operation be provided. The following TLAAs have been identified and evaluated to meet this requirement.

C.2.1 Reactor Vessel Neutron Embrittlement Analysis

The ferritic materials of the reactor vessel are subject to embrittlement due to high-energy neutron exposure. The evaluation of reactor vessel neutron embrittlement is a TLAA. The following TLAA discussions are related to the issue of neutron embrittlement.

- Upper-shelf energy
- Pressure-temperature limits
- Elimination of circumferential weld inspection
- Axial weld failure probability

C.2.1.1 Upper-Shelf Energy

Ferritic RPV materials undergo a transition in fracture behavior from brittle to ductile as the temperature of the material is increased. Charpy V-notch tests are conducted in the nuclear industry to monitor changes in the fracture behavior during irradiation. Neutron irradiation to fluences above approximately $1x10^{17}$ n/cm^2 causes an upward shift in the ductile-to-brittle transition temperature and a drop in USE. To satisfy the acceptance criteria for USE contained in 10CFR50 Appendix G, the RPV beltline materials must have a Charpy USE of no less than 50 ft-lbs throughout the life of the RPV unless it can be demonstrated that lower values of Charpy USE will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code.

The USE for the limiting beltline weld materials for Unit 1 is predicted to remain above 50 ft-lbs throughout the period of extended operation based on projected fluence values. The USE of the limiting plate material for Unit 1 is below 50 ft-lbs but is predicted to remain above the value required by an equivalent margins analysis based on projected fluence values. Therefore, the USE for the Unit 1 RPV beltline materials has been projected (reevaluated) for the period of extended operation in accordance with 10CFR54.21(c)(1)(ii).

C.2.1.2 Pressure-Temperature Limits

10CFR50 Appendix G requires that the RPV be operated within established P-T limits during heatup and cooldown. These limits specify the maximum allowable pressure as a function of reactor coolant temperature. Unit 1 Technical Specifications contain P-T limit curves for heatup, cooldown, inservice leakage testing, and hydrostatic testing, and limit the maximum rate of change of reactor coolant temperature.

The P-T limit curves are periodically revised to account for changes in fracture toughness of the RPV components due to anticipated neutron embrittlement effects for higher accumulated fluences. Calculation of P-T limit curves using the projected fluence at the end of the period of extended operation would result in unnecessarily restrictive operating curves. However, projection of the adjusted reference temperature (ART), which is used in development of the curves, to the end of the period of extended operation provides assurance that development of P-T limit curves will be feasible up to the maximum predicted effective full power year (EFPY).

Projections of the ART values for the beltline materials have been made for the period of extended operation, providing reasonable assurance that it will be possible to prepare P-T curves that will permit continued plant operation. The P-T curves (and the related Technical Specifications) will continue to be updated, either as required by 10CFR50 Appendix G to assure the operational limits remain valid at the current cumulative neutron fluence levels, or on an as-needed basis to provide appropriate operational flexibility.

C.2.1.3 Elimination of Circumferential Weld Inspection

Relief from reactor vessel circumferential weld examination requirements under GL 98-05, "Boiling Water Reactor Licensees Use of the BWRVIP-05 Report to Request Relief from Augmented Examination Requirements on Reactor Pressure Vessel Circumferential Shell Welds," is based on probabilistic assessments that predict an acceptable probability of failure per reactor operating year. The analysis is based on reactor vessel metallurgical conditions as well as flaw indication sizes and frequencies of occurrence that are expected at the end of a licensed operating period. Unit 1 has received relief from reactor vessel circumferential weld examination requirements under GL 98-05 for the remainder of its current 40-yr license term (Reference 1).

Projected values of mean and upper bound reference temperature nil ductility transition temperature (RT_{NDT}) for the limiting circumferential welds at Unit 1 are below the bounding mean RT_{NDT} determined by the NRC staff in the SER for BWRVIP-05 (Reference 7). Thus, there is reasonable assurance the conditional probability of vessel failure due to Unit 1 RPV circumferential weld failure is bounded by the NRC analysis.

Unit 1 will apply for relief from circumferential weld inspections for the period of extended operation. Supporting analyses, procedural controls, and operator training will be completed prior to the period of extended operation to support and confirm that the RPV circumferential weld failure probability remains acceptable for the period of extended operation. Based on the scoping evaluation discussed above, there is reasonable assurance the failure probability will remain acceptable for the period of extended operation.

C.2.1.4 Axial Weld Failure Probability

In the safety evaluation presented in "Supplement to Final Safety Evaluation of the BWR Vessel and Internals Project BWRVIP-05 Report" (Reference 8), the NRC staff indicates that the RPV failure frequency due to failure of the limiting axial welds in the BWR fleet at the end of 40 yr of operation is less than $5x10^{-6}$ per reactor year, given the assumptions on flaw density, distribution, and location described in the SER. Projected values of mean RT_{NDT} and upper bound RT_{NDT} for the limiting axial welds at Unit 1 are below the bounding mean RT_{NDT} value determined by the NRC staff in the SER for BWRVIP-74-A (Reference 2). Thus, there is reasonable assurance that the RPV failure frequency due to failure of the limiting axial weld is expected to remain less than $5x10^{-6}$ per reactor year for Unit 1 during the period of extended operation.

Inspection of the axial welds in accordance with the ASME XI Code requirements will continue at Unit 1 during the period of extended operation. Supporting analyses will be completed prior to the period of extended operation to confirm that the RPV axial weld failure probability for the limiting Unit 1 axial weld remains bounded for the period of extended operation. Based on the scoping evaluation discussed above, there is reasonable assurance the failure probability will remain acceptable for the period of extended operation.

C.2.2 Metal Fatigue Analysis

ASME Section III requires calculation of CUFs to demonstrate fatigue-tolerant design for reactor vessels, vessel internals, Class 1 piping and components, metal containments, and penetrations. These values are indexed to the number of transients anticipated over the design life of the component (usually 40 yr).

Designated plant events have been counted and categorized to ensure that the number of actual operational transient cycles does not exceed the number of transients assumed in the plant design for fatigue. For certain events that affect fatigue usage, linear projections of the actual data to the end of the period of extended operation will exceed the analyzed number of design basis transients. For those locations where additional fatigue analysis is required to take advantage of the implicit margin (and to more accurately determine CUFs), the EPRI FatiguePro fatigue monitoring software will be implemented.

The following thermal and mechanical fatigue analyses of mechanical components have been identified as TLAAs:

1. Reactor Vessel Fatigue Analysis
2. Feedwater Nozzle and Control Rod Drive Return Line Nozzle Fatigue and Cracking Analyses
3. Non-ASME Section III Class 1 Piping and Components Fatigue Analysis
4. Reactor Vessel Internals Fatigue Analysis
5. Environmentally Assisted Fatigue
6. Fatigue of the Emergency Condenser

C.2.2.1 Reactor Vessel Fatigue Analysis

The original design of RPV pressure boundary components included analyses of fatigue resistance. Components were evaluated by calculating the alternating stresses associated with applicable design transients and determining a CUF based on the number of anticipated transients for the original 40-yr life of the plant.

Fatigue-tolerant design is demonstrated for those locations with CUFs less than 1.0.

For the critical RPV component locations, transients contributing to fatigue usage will be tracked by the FMP (Section C.1.16) with additional usage added to the baseline CUF. The FMP provides an analytical basis for confirming that the number of cycles established by the analysis of record will not be exceeded before the end of the period of extended operation.

C.2.2.2 Feedwater Nozzle and Control Rod Drive Return Line Nozzle Fatigue and Cracking Analyses

BWRs have experienced fatigue crack initiation and growth in feedwater system and CRDRL nozzles. Rapid thermal cycling (occurring as a result of bypass leakage past loose-fitting thermal sleeves, or in nozzles lacking thermal sleeves) initiated fatigue cracks that propagated due to larger (in terms of the magnitude of temperature and pressure change) thermal cycles resulting from plant transients. NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking," identifies interim and long-term procedural and design changes to minimize thermal fatigue cracking, as well as inspection requirements.

Various calculations were prepared in response to NUREG-0619 (e.g., to support enhanced inspection intervals, to incorporate updated fatigue crack growth curves, etc.), and CUFs were determined on the basis of anticipated transients for the original 40-yr life of the plant. Fatigue-tolerant design is demonstrated for those locations with CUFs less than 1.0.

The Unit 1 feedwater nozzles require continued monitoring (including analysis using FatiguePro) to demonstrate compliance over the period of extended operation. Transients contributing to fatigue usage of the feedwater nozzles will be tracked by the FMP (Section C.1.16) with additional usage added to the baseline CUF. Additionally, the Unit 1 feedwater nozzles will be periodically inspected in accordance with Unit 1 commitments related to NUREG-0619. The fatigue usage of the Unit 1 CRDRL nozzle has been calculated to be significantly below the allowable fatigue usage of 1.0 over the life of the plant, including a 20-yr license extension. However, Unit 1 will continue to perform enhanced inspections of the CRDRL nozzle in accordance with commitments to NUREG-0619.

C.2.2.3 Non-ASME Section III Class 1 Piping and Components Fatigue Analysis

Piping and components WSLR were designed to codes other than ASME Section III Class 1. Applicable codes include ASA B31.1-1955. These codes do not require explicit fatigue analyses. Instead, the effects of cyclic loading are accounted for through application of stress range reduction factors based on the anticipated number of equivalent full temperature thermal expansion cycles over the original 40-yr life of the plant.

The original design for cyclic loading is expected to remain valid for the period of extended operation for the majority of non-ASME Class 1 systems and components. However, non-ASME Class 1 locations meeting one or more of the following criteria require development of fatigue analyses (similar to those performed for ASME Class 1 piping):

1. The location experiences high fatigue usage due to significant thermal transients due primarily to on/off flow, stratification, and local thermal cycling effects;

2. The location experiences high fatigue usage due to structural or material discontinuities that result in high stress indices (e.g., at thickness transitions);

3. The location has been identified in NUREG/CR-6260 (Reference 3) for the older-vintage BWRs (i.e., locations equivalent to the recirculation line at the RHR return line tee, the RHR line at the tapered transition, and the feedwater line at the RCIC tee).

Based on the above criteria, portions of the following Unit 1 systems were identified for further analysis:

1. Feedwater/high-pressure coolant injection (HPCI) system;

2. Core spray system;

3. RWCU system (piping inside the RCPB); and

4. Reactor recirculation system (and associated shutdown cooling system lines).

Prior to the period of extended operation, a baseline CUF (based on a conservative analysis of the fatigue usage to-date) will be determined for the specified portions of the Unit 1 systems listed above. If the baseline CUF for a specified portion of a system exceeds 0.4 (considered a general threshold of significance), the limiting location may require monitoring to demonstrate compliance over the period of extended operation. For the limiting locations, those transients contributing to fatigue usage will be tracked by the FMP with additional usage added to the baseline CUF.

C.2.2.4 Reactor Vessel Internals Fatigue Analysis

Determination of CUFs was not a design requirement for reactor vessel internals at Unit 1. However, core shroud stabilizer assemblies (tie-rods) and mechanical clamps installed as repairs for cracked horizontal and vertical core shroud welds were evaluated for fatigue using ASME Section III methods to calculate alternating stresses and determine CUF values. Fatigue-tolerant design is demonstrated for the tie-rods and mechanical clamps with CUFs less than 1.0.

The potential for cracking of components comprising the reactor vessel internals, both due to fatigue and (more significantly) IGSCC, is managed by the BWRVIP (Section C.1.12), which incorporates comprehensive inspection and evaluation guidelines issued by the BWRVIP and approved by the NRC. These activities provide assurance that any unexpected degradation resulting from fatigue in the reactor vessel internals for the current license period and the period of extended operation will be identified and corrected. Therefore, the effects of fatigue on the intended function(s) of the reactor vessel internals will be adequately managed for the period of extended operation.

C.2.2.5 Environmentally-Assisted Fatigue

Generic Safety Issue (GSI) 190, "Fatigue Evaluation of Metal Components for 60-Year Plant Life," was established to address NRC concerns regarding environmental effects on fatigue of pressure boundary components for 60 yr of plant operation. The NRC staff studied the probability of fatigue failure for selected metal components based on the increased CUFs determined in NUREG/CR-6260 (Reference 3) and a 60-yr plant life. The NRC closed this GSI and concluded that environmental effects did not substantially affect core damage frequency. However, since the nature of age-related degradation indicated the potential for an increase in the frequency of pipe leaks as plants continue to operate, licensees are required to address the effects of coolant environment on component fatigue life as AMPs are formulated in support of license renewal.

Unit 1 will assess the impact of the reactor coolant environment on a sample of critical component locations, including locations equivalent to those identified in NUREG/CR-6260 as part of the FMP (Section C.1.16). These locations will be evaluated by applying environmental correction factors (F_{en}) to existing and future fatigue analyses. Evaluation of the sample of critical components will be completed prior to the period of extended operation.

C.2.2.6 Fatigue of the Emergency Condenser

The emergency cooling system provides for decay heat removal from the reactor fuel in the event that reactor feedwater capability is lost and the main condenser is unavailable. The tube and shell sides of the emergency condensers were designed in accordance with ASME Section III Class 2 and 3, respectively. The original tubing has experienced thermal fatigue resulting from leakage past the condensate return valve to the RPV. As part of the subsequent modification and repair, fatigue loading was evaluated by calculating the alternating stresses associated with applicable design transients and determining a CUF based on the number of anticipated transients for the life of the condensers. Fatigue-tolerant design is demonstrated for components with CUFs less than 1.0.

While the CUFs were shown to be less than 1.0, certain locations in the Unit 1 emergency condensers require continued monitoring (including analysis using FatiguePro) to demonstrate compliance over the period of extended operation. The FMP (Section C.1.16) will track transients specific to the emergency cooling system with additional usage added to the baseline CUF for the condensers.

C.2.3 Environmental Qualification

The following EQ analysis has been identified as a TLAA:

- Electrical Equipment EQ

C.2.3.1 Electrical Equipment EQ

10CFR50.49 requires that certain safety-related and non-safety related electrical equipment remain functional during and after identified design basis events. To establish reasonable assurance that this equipment can function when exposed to postulated harsh environmental conditions, licensees are required to determine the equipment's qualified life and to develop a program that maintains the qualification of that equipment.

For components within the scope of the EQ Program (Section C.1.15), analyses of thermal exposure, radiation exposure, and mechanical cycle aging that cannot be shown to remain valid for the period of extended operation will be projected to extend the qualification of components before reaching the aging limits established in the applicable evaluation, or the components will be refurbished or replaced.

C.2.4 Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analysis

The following containment liner plate, metal containments, and penetrations fatigue analyses have been identified as TLAAs:

- Torus Shell and Vent System Fatigue Analysis
- Torus-Attached Piping Analysis
- Torus Wall Thickness
- Fatigue of Primary Containment Penetrations

C.2.4.1 Torus Shell and Vent System Fatigue Analysis

Large-scale testing of the Mark III containment and in-plant testing of Mark I primary containment systems identified additional hydrodynamic loads that were not considered in the original design of the Mark I containment used at Unit 1. To provide the bases for generic load definition and structural assessment techniques, General Electric Company (GE) initiated the Mark I Containment Program. NUREG-0661, "Safety Evaluation Report, Mark I Containment Long Term Program, Resolution of Generic Technical Activity A-7," requires a plant-unique analysis for each Mark I configuration to evaluate the effects of the hydrodynamic stresses resulting from a LOCA and SRV discharge.

The 60-yr CUF values for the controlling locations in the torus shell are less than 1.0. Therefore, the Unit 1 torus shell has been evaluated and is qualified for the period of extended operation.

C.2.4.2 Torus-Attached Piping Analysis

As a result of the Mark I Containment Program, modifications were performed at Unit 1, including changes to the configuration of SRV piping and other piping penetrating the suppression chamber (torus) (generically referred to herein as torus-attached piping). As part of the generic Mark I Containment Program, fatigue analyses were performed considering the design loads identified in NUREG-0661 and its supplements. Fatigue-tolerant design is demonstrated for those locations with CUFs less than 1.0.

The bounding 40-yr CUFs for the subject piping and associated penetrations are less than 0.5; therefore, the 60-yr CUF values for all controlling locations can be demonstrated to remain less than 1.0. However, SRV actuations, which are the only non-accident or earthquake contributor to torus-attached piping fatigue usage, have not been counted historically. SRV actuations for Unit 1 to date have been estimated. To ensure that the fatigue usage of the torus-attached piping remains within design values, SRV actuations will be added to the FMP (Section C.1.16) as a transient that is monitored. The two torus-attached piping locations with the highest calculated fatigue usage will be added to the FMP as locations to be monitored. Therefore, the effects of fatigue on the Unit 1 torus-attached piping will be adequately managed for the period of extended operation.

C.2.4.3 Torus Wall Thickness

The Unit 1 suppression chamber (torus) is constructed of A201 Grade B (firebox) steel plates with a certified minimum thickness of 0.460 in. This value included an original corrosion allowance of 0.0625 in, which was added to the minimum wall thickness required by the applicable design codes. However, subsequent addition of hydrodynamic loads (resulting from LOCA and SRV actuation) to the containment design bases resulted in a reduction of the corrosion allowance. To establish reasonable assurance that the revised minimum wall thickness of 0.431 in is not reached, Unit 1 is required to monitor torus wall thickness and corrosion rate (Reference 4). Determination of torus corrosion rates is an ongoing activity that considers inspection results and the remaining corrosion allowance.

The Torus Corrosion Monitoring Program (Section C.1.35) has been developed to monitor the torus shell material thickness and ensure it is maintained within the bounds of the qualification bases. Therefore, the effects of loss of material on the intended function(s) of the torus shell will be adequately managed during the period of extended operation.

C.2.4.4 Fatigue of Primary Containment Penetrations

The Unit 1 drywell was designed as a Class B vessel in accordance with Section III of the ASME Boiler and Pressure Vessel (B&PV) Code, 1965 edition (ASME Section III, 1965). The 1965 edition of the ASME Section III B&PV Code did not require fatigue analysis of Class B vessels. The drywell penetrations were considered an extension of the drywell and thus did not require fatigue analysis. For Unit 1, fatigue of torus penetrations was addressed in the same analysis as the torus-attached piping, the "Plant Unique Analysis Report of the Torus Attached Piping for Nine Mile Point Unit 1 Nuclear Generation Station," which was transmitted to the NRC in a letter dated May 22, 1984. This analysis was performed in accordance with ASME Section III, 1977 edition through the summer 1977 addenda. Fatigue analyses were performed for the SRV penetration (where the SRV line penetrates the vent header spherical intersection) and torus-attached piping penetrations.

The fatigue analyses for the SRV and torus-attached piping penetrations considered a number of cycles related to anticipated transients for the original 40-yr life of the plant. The number of anticipated significant transient cycles for a 40-yr life divided by the maximum number of allowable cycles for the transient producing the maximum stress was used to estimate the 40-yr design CUF. Linear projection of this CUF to 60 yr results in a CUF far below the allowable.

C.2.5 Other Plant-Specific TLAAs

The following plant-specific TLAAs have been identified for Unit 1:

- Reactor Vessel and Reactor Vessel Closure Head Weld Flaw Evaluations
- RWCU System Weld Overlay Fatigue Flaw Growth Evaluations

C.2.5.1 Reactor Vessel and Reactor Vessel Closure Head Weld Flaw Evaluations

During refueling outage (RFO) 15, augmented examinations identified unacceptable flaw indications in two RPV shell welds (Reference 5). During RFO17, UT examinations identified an unacceptable flaw indication in a closure head meridional weld (Reference 6). Structural evaluations of these flaws (performed in accordance with ASME Section XI, Subsection IWB-3600) compared the flaw characteristics to predetermined acceptability criteria to justify continued operation without repair of the flaw. Since the acceptability criteria were based on an assumed number of transient cycles applicable to the original 40-yr license term, the subject evaluations satisfy the criteria of 10CFR54.3(a). The number of cycles from the time of inspection to the end of the evaluation period is used to determine crack growth. With the addition of the period of extended operation (20 yr), the Unit 1 RPV can be expected to accumulate fatigue usage for no more than an additional 25 yr. During this interval, it is unlikely that the number of startup/shutdown cycles that occur will result in exceeding the 240 additional startup/shutdown cycles that were the bases for the evaluation. The actual interval is the period of time from the date of the inspection (March 2003) through the end of the period of extended operation. Therefore, the RPV closure head weld flaw evaluation remains valid for the period of extended operation.

No later than 2 yr prior to the period of extended operation, the RPV weld flaw evaluation will be revised to consider additional fatigue crack growth and the effects of additional irradiation embrittlement associated with operation for an additional 20 yr, and submitted to the NRC for review and approval. The flaws will be reexamined in accordance with ASME Section XI as necessary.

C.2.5.2 Reactor Water Cleanup System Weld Overlay Fatigue Flaw Growth Evaluations

Fatigue crack growth analyses have been performed for two weld overlays in the RWCU system. The repaired welds are located at the inlet nozzle of the regenerative heat exchanger and the transition pipe between the upper and lower shells of the regenerative heat exchanger, respectively. The weld overlays consist of IGSCC-resistant austenitic stainless steel material and, thus, are not susceptible to continued IGSCC crack propagation. However, the first 1/16-in thick layer of weld metal deposited is not assumed to be IGSCC-resistant due to weld dilution; thus, it is assumed to be cracked. A fatigue crack growth analysis for each weld overlay was performed in accordance with ASME Section XI, Appendix C, with the crack propagating into the overlay from the hypothetical 1/16-in deep crack. The results of those analyses showed that the welds were acceptable per the Code criteria through the end of the period of extended operation. Additionally, however, the overlaid welds are UT examined periodically under the BWR Stress Corrosion Cracking Program, thus ensuring there is no fatigue crack propagation into the overlays. The maximum interval between inspections is defined by the requirements of BWRVIP-75-A. Therefore, the aging of the RWCU weld overlays will be adequately managed through the balance of the initial 40-yr licensing term and the period of extended operation.

C.3 GENERIC QUALITY ASSURANCE PROGRAM REQUIREMENTS FOR LICENSE RENEWAL

The Nine Mile Point Quality Assurance Program implements the requirements of 10CFR50 Appendix B, and is consistent with the summary in Appendix A.2 of NUREG-1800, "Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants," published July 2001. The elements of corrective action, confirmation process, and administrative controls in the Quality Assurance Program are applicable to both safety-related and non-safety related SSCs that are subject to an aging management review. Generically, these three elements are applicable as follows:

1. Corrective Actions

   Corrective actions are implemented in accordance with the requirements of 10CFR50 Appendix B, as committed to in the Quality Assurance Topical Report (QATR). The Corrective Action Program provides for the identification, evaluation, and resolution of nonconforming conditions.

2. Confirmation Process

   The confirmation process is part of the Corrective Action Program, which is implemented in accordance with the requirements of 10CFR50 Appendix B, as committed to in the QATR. The focus of the confirmation process is on the verification that corrective actions are effective. The measure of effectiveness is in terms of correcting the adverse condition and precluding repetition of significant conditions adverse to quality.

3. Administrative Controls

   AMPs are implemented through various plant documents. These implementing documents are subject to administrative controls, including a formal review and approval process, in accordance with the requirements of 10CFR50 Appendix B, as committed to in the QATR.

C.4 REFERENCES

1. Letter from U.S. Nuclear Regulatory Commission to Niagara Mohawk Power Corporation, dated April 7, 1999, Subject: Alternatives for Examination of Reactor Pressure Vessel Shell Welds, Nine Mile Point Nuclear Station, Unit 1 (TAC No. MA4383).

2. Letter from U.S. Nuclear Regulatory Commission to BWRVIP Chairman, dated October 18, 2001, Subject: Acceptance for Referencing of EPRI Proprietary Report TR-113596, "BWR Vessel and Internals Project, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines (BWRVIP-74-A)," and Appendix A, "Demonstration of Compliance with the Technical Information Requirements of the License Renewal Rule (10CFR54.21)."

3. NUREG/CR-6260, INEL-95/0045, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," February 1995.

4. Letter from U.S. Nuclear Regulatory Commission to Niagara Mohawk Power Corporation, dated August 11, 1994, Subject: Approval of Reduction Factors for Condensation Oscillation Loads in Nine Mile Point Nuclear Station Unit No. 1 (NMP1) Torus (TAC No. M85003).

5. Letter from Niagara Mohawk Power Corporation (NMP1L 1467) to U.S. Nuclear Regulatory Commission, dated September 14, 1999, Subject: Submittal of 1999 Inservice Inspection Summary Report and Flaw Indication Evaluations.

6. Letter from Nine Mile Point Nuclear Station (NMP1L 1776) to U.S. Nuclear Regulatory Commission, dated September 19, 2003, Subject: Nine Mile Point Unit 1, Docket No. 50-220, Facility Operating License No. DPR-63 - Reactor Pressure Vessel Flaw Evaluation.

7. Letter from U.S. Nuclear Regulatory Commission to BWRVIP Chairman, dated July 28, 1998, Subject: Final Safety Evaluation of the BWR Vessel and Internal Project BWRVIP-05 Report (TAC No. M93925).

8. Letter from U.S. Nuclear Regulatory Commission to BWRVIP Chairman, dated March 7, 2000, Subject: Supplement to Final Safety Evaluation of the BWR Vessel and Internal Project BWRVIP-05 Report (TAC No. MA3395).

TABLE C-1

COMMITMENTS

Item	Commitment	Source	Schedule
1	Incorporate Appendix A1 into the UFSAR.	· LRA Section A.0	Following issuance of the renewed Operating License
2	In accordance with 10CFR54.21(b), during NRC review of this application, provide an annual update to the application to reflect any change to the current licensing basis that materially affects the contents of the LRA.	· LRA Section 1.2.1	Completed - Letters dated December 20, 2005, and March 23, 2006
3	Apply for relief from reactor vessel circumferential weld inspections for the period of extended operation. Supporting analyses, procedural controls, and operator training will be completed prior to the period of extended operation to support and confirm that the RPV circumferential weld failure probability remains acceptable for the period of extended operation.	· LRA Section 4.2.3 · LRA Appendix A.1.2.1.3	Prior to period of extended operation
4	Supporting analyses will be completed prior to the period of extended operation to confirm that the failure probabilities for the limiting RPV axial welds remain bounded for the period of extended operation.	· LRA Section 4.2.4 · LRA Appendix A.1.2.1.4	Prior to period of extended operation
5	For those locations where additional fatigue analysis is required to take advantage of the implicit margin, and to more accurately determine CUF, the EPRI FatiguePro fatigue monitoring software will be implemented prior to the period of extended operation.	· LRA Section 4.3 · LRA Appendix A.1.2.2 · LRA Appendix B.3.2	Prior to period of extended operation
6	For the critical reactor vessel components locations shown in Table 4.3-3 of the LRA, additional usage will be added to the baseline CUF using one of the methods described in Section 4.3 of the LRA.	· LRA Section 4.3.1 · LRA Appendix A.1.2.2.1	Prior to period of extended operation
7	Transients contributing to fatigue usage of the feedwater nozzles will be tracked by the FMP, with additional usage added to the baseline CUF using the stress-based fatigue method described in Section 4.3 of the LRA.	· LRA Section 4.3.3 · LRA Appendix A.1.2.2.2	Prior to period of extended operation
8	Develop a baseline CUF for the specified portions of the following systems: 1. Feedwater/HPCI; 2. Core spray; 3. RWCU (piping inside the RCPB); and 4. Reactor recirculation (and associated shutdown cooling systems lines). If the baseline CUF for a specified portion of a system exceeds 0.4, the limiting locations may require additional monitoring to demonstrate compliance over the period of extended operation.	· LRA Section 4.3.4 · LRA Appendix A.1.2.2.3	Prior to period of extended operation

TABLE C-1 (Cont'd.)

Item	Commitment	Source	Schedule
9	Assess the impact of the reactor coolant environment on a sample of critical component locations, including locations equivalent to those identified in NUREG/CR-6260, as part of the FMP. These locations will be evaluated by applying environmental correction factors (F_{en}) to existing and future fatigue analyses.	· LRA Section 4.3.6 · LRA Appendix A.1.2.2.5 · LRA Appendix B.3.2	Prior to period of extended operation
10	The FMP will track transients specific to the emergency cooling system with additional usage added to the baseline CUF for the emergency condensers as described in Section 4.3 of the LRA.	· LRA Section 4.3.7 · LRA Appendix A.1.2.2.6	Prior to period of extended operation
11	Enhance the FMP to: 1. Ensure that fatigue usage of the torus-attached piping and other torus locations does not exceed the design limits, add ERV lifts as a transient to be counted by the FMP; and 2. Add the two highest usage torus-attached piping locations, the 12-in core spray suction line for core spray pump 111 that enters the torus at penetration XS-337, and the 3-in containment spray line that enters the torus at penetration XS-326 as fatigue monitoring locations.	· LRA Section 4.6.2 · LRA Appendix A.1.2.4.2 · LRA Appendix B.3.2	Prior to period of extended operation
12	The RPV weld flaw evaluations will be revised to consider additional fatigue crack growth and the effects of additional irradiation embrittlement (for beltline materials) associated with operation for an additional 20 yr (i.e., out to at least 46 EFPY) and submitted for NRC review and approval no later than 2 yr prior to the period of extended operation. If the revised calculation shows the identified flaws cannot meet the applicable acceptance criteria, the indications will be reexamined in accordance with ASME Section XI requirements.	· LRA Section 4.7.4 · LRA Appendix A.1.2.5.1	August 22, 2007
13	Enhance the BWRVIP to address: 1. BWRVIP-18 open item regarding the inspection of inaccessible welds for core spray system. As such, Nine Mile Point will implement the resolution of this open item as documented in the BWRVIP response and reviewed and accepted by the NRC; 2. The inspection and evaluation guidelines for steam dryers are currently under development by the BWRVIP committee. Once these guidelines are documented and reviewed and accepted by the NRC, the actions will be implemented in accordance with the BWRVIP program; 3. The baseline inspections recommended in BWRVIP-47 for the BWR lower plenum components will be incorporated into the appropriate program and implementing documents; and 4. The reinspection scope and frequency for the grid beam going forward will be based on BWRVIP-26A guidance for plant-specific flaw	· LRA Appendix B.2.1.8	Prior to period of extended operation

TABLE C-1 (Cont'd.)

Item	Commitment	Source	Schedule
	analysis and crack growth assessment. The maximum reinspection interval for the grid beam will not exceed 10 yr consistent with standard BWRVIP guidance for the core shroud. The reinspection scope will be equivalent to the UT baseline 2005 inspection scope. In addition, the reinspection scope will include an EVT-1 sample inspection of at least two locations with accessible indications within the initial 6 yr of the 10-yr interval. The intent of the EVT-1 is to monitor the known cracking to confirm flaw analysis crack growth assumptions.		
14	Enhance the OCCWS Program to: 1. Ensure that the applicable commitments made for GL 89-13, and the requirements in NUREG-1801, Section XI.M20, are captured in the implementing documents for GL 89-13, "Service Water System Problems Affecting Safety Related Equipment Program Plan;" 2. Incorporate into the OCCWS Program the requirements of NUREG-1801, Section XI.M20, that are more conservative than the GL 89-13 commitments; and 3. Revise the preventive maintenance and heat transfer performance test procedures to incorporate specific inspection criteria, corrective actions, and frequencies.	LRA Appendix B.2.1.10	Prior to period of extended operation
15	Enhance the CCCWS Program to: 1. Expand periodic chemistry checks of the system consistent with the guidelines of EPRI TR-107396; 2. Implement a program to use corrosion inhibitors in the RBCLC systems and control room HVAC system in accordance with the guidelines given in EPRI TR-107396; 3. Direct periodic inspections to monitor for loss of material in the piping of the CCCWS; 4. Implement a Corrosion Monitoring Program for larger bore CCCW piping not subject to inspection under another program; 5. Establish the frequencies to inspect for degradation of components in CCCWS, including heat exchanger tube wall thinning; 6. Perform a heat removal capability test for the control room HVAC system at least every 5 yr; 7. Establish periodic monitoring, trending, and evaluation of performance parameters for the RBCLC and control room HVAC; 8. Provide the controls and sampling necessary to maintain water chemistry parameters in CCCWS within the guidelines of EPRI Report TR-107396; and 9. Ensure acceptance criteria are specified in the implementing procedures for the applicable indications of degradation.	LRA Appendix B.2.1.11	Prior to period of extended operation

TABLE C-1 (Cont'd.)

Item	Commitment	Source	Schedule
16	The Boraflex Monitoring Program will be enhanced to: 1. Require periodic neutron attenuation testing and measurement of boron areal density to confirm the correlation of the conditions of test coupons to those of Boraflex racks that remain in use during the period of extended operation; and 2. Establish monitoring and trending instructions for in-situ test results, silica levels, and coupon results.	· LRA Appendix B.2.1.12	Prior to period of extended operation
17	Revise applicable procedures related to the Crane Inspection Program to add specific direction for performance of corrosion inspections, with acceptance criteria, for certain hoist-lifting assembly components.	· LRA Appendix B.2.1.13	Prior to period of extended operation
18	Enhance the Compressed Monitoring Program to: 1. Develop new activities to manage the loss of material, stress corrosion cracking, and perform periodic system leak checks; 2. Expand the scope, periodicity, and inspection techniques to ensure that the aging of certain subcomponents of the dryers and compressors (e.g., valves, heat exchangers) are managed; 3. Develop and implement activities to address the failure mechanism of stress corrosion cracking in unannealed red brass piping; 4. Establish activities that manage the aging of the internal surfaces of carbon steel piping and that require system leak checks to detect deterioration of the pressure boundaries; and 5. Expand the acceptance criteria to ensure that the aging of certain subcomponents of the dryers and compressors (e.g., valves, heat exchangers) are managed.	· LRA Appendix B.2.1.14	Prior to period of extended operation
19	Enhance the Fire Protection Program to: 1. Incorporate periodic visual inspections of piping and fittings located in a non-water environment, such as Halon and CO_2 fire suppression systems components, to detect evidence of corrosion and any system mechanical damage that could affect its intended function; 2. Expand the scope of periodic functional tests of the diesel-driven fire pump to include inspection of engine exhaust system components to verify that loss of material is managed; 3. Perform an engineering evaluation to determine the plant-specific inspection periodicity of fire doors; and 4. Revise Halon and CO_2 functional test frequencies to semi-annual.	· LRA Appendix B.2.1.16	Prior to period of extended operation

TABLE C-1 (Cont'd.)

Item	Commitment	Source	Schedule
20	Enhance the Fire Water System Program by revising applicable existing procedures to: 1. Incorporate inspections to detect and manage loss of material due to corrosion into existing periodic test procedures; 2. Specify periodic component inspections to verify that loss of material is being managed; 3. Add procedural guidance for performing visual inspections to monitor internal corrosion and detect biofouling; 4. Add requirements to periodically check the water-based fire protection systems for microbiological contamination; 5. Measure fire protection system piping wall thickness using non-intrusive techniques (e.g., volumetric testing) to detect loss of material due to corrosion; 6. Establish an appropriate means of recording, evaluating, reviewing, and trending the results of visual inspections and volumetric testing; 7. Define acceptance criteria for visual inspections and volumetric testing; and 8. Develop new procedures and PM tasks to implement sprinkler head replacement and/or inspections to meet National Fire Protection Association (NFPA) 25, "Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," Section 5.3.1 (2003 edition) requirements.	LRA Appendix B.2.1.17	Prior to period of extended operation
21	Enhance the Fuel Oil Chemistry Program to: 1. Establish a requirement to perform quarterly trending of water and sediment; 2. Provide guidelines for the appropriate use of biocides, corrosion inhibitors, and/or fuel stabilizers to maintain fuel oil quality; 3. Add requirements to periodically inspect the interior surfaces of the emergency diesel fuel oil storage tanks for evidence of significant degradation, including a specific requirement that the tank bottom thickness be determined by UT or other industry-recognized methods; 4. Add a requirement for quarterly trending of particulate contamination analysis results; 5. Ensure acceptance criteria are specified in the implementing procedures for the applicable indications of potential degradation; 6. Establish a requirement for periodic opening of the diesel fire pump fuel oil day tank drain; and 7. Establish a requirement to remove water, if found.	LRA Appendix B.2.1.18	Prior to period of extended operation

TABLE C-1 (Cont'd.)

Item	Commitment	Source	Schedule
22	Enhance the Reactor Vessel Surveillance Program to: 1. Incorporate the requirements and elements of the ISP, as documented in BWRVIP-116 and approved by NRC, or an NRC-approved plant-specific program, into the Reactor Vessel Surveillance Program, and include a requirement that if Nine Mile Point surveillance capsules are tested, the tested specimens will be stored in lieu of optional disposal. When the NRC issues a final SER for BWRVIP-116, Nine Mile Point will address any open items and complete the SER action items. Should BWRVIP-116 not be approved by the NRC, a plant-specific Reactor Vessel Surveillance Program will be submitted to the NRC 2 yr prior to commencement of the period of extended operation; and 2. Project analyses of USE and P-T limits to 60 yr using methods prescribed by RG 1.99, Revision 2, and include the applicable bounds of the data, such as operating temperature and neutron fluence.	· LRA Appendix B.2.1.19	August 22, 2007
23	Develop and implement a One-Time Inspection Program, which also includes the attributes for a Selective Leaching of Materials Program.	· LRA Appendix B.2.1.20 · LRA Appendix B.2.1.21	Prior to period of extended operation
24	Develop and implement a Buried Piping and Tank Inspection Program which includes a requirement that before entry into the period of extended operation, if an opportunistic inspection has not occurred, Nine Mile Point will excavate Unit 1 degradation susceptible areas to perform focused inspections. Upon entering the period of extended operation, Nine Mile Point will perform a focused inspection within 10 yr, unless an opportunistic inspection occurred within this 10-yr period.	· LRA Appendix B.2.1.22	Prior to period of extended operation
25	An augmented VT-1 visual examination of the containment penetration bellows will be performed using enhanced techniques qualified for detecting SCC, per NUREG-1611, Table 2, Item 12.	· LRA Appendix B.2.1.23	Prior to period of extended operation
26	Enhance the Structures Monitoring Program to: 1. Expand the program to include the following activities or components in the scope of license renewal but not within the current scope of 10CFR50.65: a. The steel electrical transmission towers required for the SBO and recovery paths. 2. Expand the parameters monitored during structural inspections to include those relevant to aging effects identified for structural bolting; and 3. Implement regularly scheduled groundwater monitoring to ensure that a benign environment is maintained.	· LRA Appendix B.2.1.28	Prior to period of extended operation

TABLE C-1 (Cont'd.)

Item	Commitment	Source	Schedule
27	Develop and implement a Non-EQ Electrical Cables and Connection Program.	· LRA Appendix B.2.1.29	Prior to period of extended operation
28	Enhance the Non-EQ Electrical Cable and Connections Used in Instrumentation Circuit Program to: 1. Implement reviews of calibration or surveillance data for indications of aging degradation affecting instrument circuit performance. The first reviews will be completed prior to the period of extended operation and every 10 yr thereafter; and 2. In cases where a calibration or surveillance program does not include the cabling system in the testing circuit, or as an alternative to the review of calibration results described above, provide requirements and procedures to perform cable testing to detect deterioration of the insulation system, such as insulation resistance tests or other testing judged to be effective in determining cable insulation condition. The first test will be completed prior to the period of extended operation. The test frequency of these cables shall be determined based on engineering evaluation, but the test frequency shall be at least once every 10 yr.	· LRA Appendix B.2.1.30	Prior to period of extended operation
29	Enhance the Preventive Maintenance Program to: 1. Expand the PM Program to encompass activities for certain additional components identified as requiring aging management. Explicitly define the aging management attributes, including the systems and the component types/commodities included in the program; 2. Specifically list those activities credited for aging management; 3. Specifically list parameters monitored; 4. Specifically list the aging effects detected; 5. Establish a requirement that inspection data be monitored and trended; and 6. Establish detailed parameter-specific acceptance criteria.	· LRA Appendix B.2.1.32	Prior to period of extended operation
30	Enhance the System Walkdown Program to: 1. Train all personnel performing inspections in the Systems Walkdown Program to ensure that age-related degradation is properly identified and incorporate this training into the site Training Program; and 2. Specify acceptance criteria for visual inspections to ensure aging-related degradation is properly identified and corrected.	· LRA Appendix B.2.1.33	Prior to period of extended operation

TABLE C-1 (Cont'd.)

Item	Commitment	Source	Schedule
31	Enhance the Non-Segregated Bus Inspection Program to: 1. Expand visual inspections of the bus ducts, their supports and insulation systems; 2. Create new provisions to perform as an alternative to either thermography or periodic low-range resistance checks of a statistical sample of the bus ducts accessible bolted connections, a visual inspection for the connections that are covered with heat shrink tape, sleeving, insulating boots, etc., and 3. Define acceptance criteria for inspection of the bus ducts, their support and insulation systems, and the low-range ohmic checks of connections.	· LRA Appendix B.2.1.34	Prior to period of extended operation
32	Develop and implement a Fuse Holder Inspection Program.	· LRA Appendix B.2.1.35	Prior to period of extended operation
33	Enhance the Bolting Integrity Program to: 1. The Structures Monitoring, PM, and Systems Walkdown Programs will be enhanced to include requirements to inspect bolting for indication of loss of preload, cracking, and loss of material, as applicable; 2. Include in administrative and implementing program documents references to the Bolting Integrity Program and industry guidance; and 3. Establish an augmented inspection program for high-strength (actual yield strength ≥150 ksi) bolts. This augmented program will prescribe the examination requirements of Tables IWB-2500-1 and IWC-2500-1 of ASME Section XI for high-strength bolts in the Class 1 and Class 2 component supports, respectively.	· LRA Appendix B.2.1.36	Prior to period of extended operation
34	Enhance the Protective Coating Monitoring and Maintenance Program to: 1. Specify the visual examination of coated surfaces for any visible defects includes blistering, cracking, flaking, peeling, and physical or mechanical damage; 2. Perform periodic inspection of coatings every refueling outage versus every 24 months; 3. Set minimum qualifications for inspection personnel, the inspection coordinator, and the inspection results evaluator; 4. Perform thorough visual inspections in areas noted as deficient concurrently with the general visual inspection; 5. Specify the types of instruments and equipment that may be used for the inspection; 6. Pre-inspection reviews of the previous two monitoring reports before performing the condition assessment; 7. Establishment of guidelines for prioritization of repair areas and monitoring these areas until they are repaired; and	· LRA Appendix B.2.1.38	Prior to period of extended operation

TABLE C-1 (Cont'd.)

Item	Commitment	Source	Schedule
	8. Require that the inspection results evaluator determine which areas are unacceptable and initiate corrective action.		
35	Develop and implement a Non-EQ Electrical Cable Metallic Connections Inspection Program.	· LRA Appendix B.2.1.39	Prior to period of extended operation
36	As acknowledged by the NRC, the ASME Code Committee is evaluating the acceptability of roll/expansion techniques as a permanent repair for CRD stub tubes via Code Case N-730. Nine Mile Point will continue to follow the status of the proposed ASME Code case and will implement the final Code case, as conditioned by the NRC, once it has been approved. If the Code case is not approved by ASME, Unit 1 will seek NRC approval of the October 19, 2005, Code case draft on a plant-specific basis as conditioned by the NRC. During the period of extended operation, should a CRD stub tube rolled in accordance with the provisions of the Code case resume leaking, Nine Mile Point will implement one of the following zero leakage permanent repair strategies prior to startup from the outage in which the leakage was detected: 1. A welded repair consistent with BWRVIP-58-A, "BWRVIP Internal Access Weld Repair" and Code Case N-606-1, as endorsed by the NRC in RG 1.147. 2. A variation of the welded repair geometry specified in BWRVIP-58-A subject to the approval of the NRC using Code Case N-606-1. 3. A future developed mechanical/welded repair method subject to the approval of the NRC.	· LRA Appendix B.2.1.8	August 22, 2009
37	Enhance the program to evaluate component susceptibility to loss of fracture toughness. Assessments and inspections will be performed, as necessary, to ensure that intended functions are not impacted by the aging effect.	· LRA Appendix B.2.1.8	Prior to period of extended operation
38	An EVT-1 examination of the Unit 1 feedwater sparger end bracket welds will be added to the BWRVIP. The inspection extent and frequency of the end bracket weld inspection will be the same as the ASME Section XI inspection of the feedwater sparger bracket vessel attachment welds.	· NMP Letter NMP1L 2005, December 1, 2005	Prior to period of extended operation
39	The Masonry Wall Program (as managed by the Structures Monitoring Program) will be enhanced to provide guidance for inspecting Unit 1 non-reinforced masonry walls that do not have bracing and are within scope of license renewal more frequently than the reinforced masonry walls.	· NMP Letter NMP1L 2005, December 1, 2005	Prior to period of extended operation

TABLE C-1 (Cont'd.)

Item	Commitment	Source	Schedule
40	Unit 1 will perform an EVT-1 inspection of the thermal shield to flow shield weld starting in 2007 and proceeding at a 10-yr frequency thereafter consistent with the ISI inspection interval.	· NMP Letter NMP1L 2005, December 1, 2005	Prior to period of extended operation
41	The NRC review of BWRVIP-76 is not yet complete. When the NRC review of BWRVIP-76 is complete, Nine Mile Point will evaluate the NRC SER and complete the SER action item(s), as appropriate.	· LRA Appendix B.2.1.8	Prior to period of extended operation
42	Nine Mile Point will perform volumetric examinations on the Unit 1 drywell shell during the 2007 refueling outage, and an engineering evaluation will be performed to determine the actions necessary for Unit 1 operation through the period of extended operation in accordance with the Drywell Supplemental Inspection Program.	· NMP Letter NMP1L 2037, April 4, 2006	Prior to period of extended operation