Entergy

Entergy Nuclear Operations, Inc.
Pilgrim Nuclear Power Station
600 Rocky Hill Road
Plymouth, MA 02360

July 22, 2016

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555-0001

SUBJECT: Errata: Final Safety Analysis Report Update Revision 30, Technical Specifications Bases Changes, 10 CFR 50.59(d) Report, and Regulatory Commitment Changes

Pilgrim Nuclear Power Station
Docket No. 50-293
Renewed License No. DPR-35

REFERENCE: PNPS Letter 2.15.072 Final Safety Analysis Report Update Revision 30, Technical Specifications Bases Changes, 10 CFR 50.59(d) Report, and Regulatory Commitment Changes, dated November 20, 2015

LETTER NUMBER: 2.16.042

Dear Sir or Madam:

Per the above reference, Pilgrim Nuclear Power Station (PNPS) submitted Final Safety Analysis Report (FSAR) Revision 30 updated pages. That update was submitted in accordance with 10 Code of Federal Regulations (CFR) 50.71(e) requirements and included changes implemented during Fuel Cycle 20, ending with refueling outage 20.

An errata change to Revision 30 was created due to the identification of erroneous information on several FSAR pages due to the track changes settings. Several pages of the FSAR were found to have deleted information displayed, as a result of track change settings when converting to PDF through PDF-XChange. Information printed from Microsoft Word to local printers did not contain this information. All affected sections were replaced and correction to the electronic file was made. New CDs were created for the errata and are being re-submitted as required.

If you have any questions or require additional information, please contact me at (508) 830-8323.

There are no regulatory commitments contained in this letter.

Sincerely,

Everett P. Perkins, Jr.

Everett P. Perkins, Jr.
Manager, Regulatory Assurance
EPP/rb

A053
NRR

Attachment 1: Errata Filing Instructions for FSAR Revision 30 Change-out pages (5 Pages)
Attachment 2: Errata FSAR Revision 30 Change-out pages (See Filing Instructions)

cc: Mr. Daniel H. Dorman
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NRC Senior Resident Inspector
Pilgrim Nuclear Power Station

ATTACHMENT 1

Letter Number 2.16.042

Errata Filing Instructions for FSAR Revision 30 Change-out pages

(5 Pages)

Errata Filing Instructions

PNPS-FSAR

Revision 30– November 2015

Volume 1

TAB	Remove	Insert
3.2	Table 3.2-1	Table 3.2-1 - Rev. 30

Errata Filing Instructions

PNPS-FSAR

Revision 30 – November 2015

Volume 2

TAB	Remove	Insert
5.2	Table 5.2-4	Table 5.2-4 – Rev. 30
5.4	Entire Section 5.4	Section 5.4 – Rev. 30

Errata Filing Instructions

PNPS-FSAR

Revision 30 – November 2015

Volume 3

TAB	Remove	Insert
7.3	Entire Section 7.3	Section 7.3 – Rev. 30
7.10	Entire Section 7.10	Section 7.10 - Rev. 30

Volume 4

TAB	Remove	Insert
10.2	Entire Section 10.2	Entire Section 10.2
10.3	Entire Section 10.3	Section 10.3 - Rev. 30
10.8	Entire Section 10.8	Section 10.8 - Rev. 30
10.11	Entire Section 10.11	Section 10.11 - Rev. 30
10.21	Entire Section 10.21	Section 10.21 - Rev. 30
12.2	Entire Section 12.2	Section 12.2 - Rev. 30
12.4	Entire Section 12.4	Section 12.4 - Rev. 30

Errata Filing Instructions

PNPS-FSAR

Revision 30– November 2015

Volume 5

TAB	Remove	Insert
13.3	Entire Section 13.3	Section 13.3 - Rev. 30
14.5	Entire Section 14.5	Section 14.5 - Rev. 30

ATTACHMENT 2

Letter Number 2.16.042

Errata FSAR Revision 30 Change-out pages

(See Filing Instructions)

Table 3.2-1

FUEL DATA
GE11, GE14, AND GNF2 FUEL DESIGNS

Fuel Assembly	GE11 *	GE14	GNF2
Geometry	9x9	10x10	10x10
Rod Pitch (in.)	0.566	0.510	0.510
Active Fuel Length (in.)	141.24	145.24	145.24
Heat Transfer Area (ft^2)	95.5	109	110
Debris Filter	No	Yes	Yes
Fuel Rods			
Fill Gas	helium	helium	helium
Fill Pressure (atm)	10	10	10
Getter	yes	No	No
Number of Fuel Rods	74	92	92
Fuel			
Material	sintered UO_2	sintered UO_2	sintered UO_2
Pellet Diameter (in.)	0.376	0.345	0.3496
Pellet Length (in.)	0.380	0.350	0.375
Pellet Immersion Density (%TD)	96.5	97	97
Cladding			
Material	Zr-2+ Zirconium	Zr-2+ Zirconium	Zr-2+ Zirconium
Outside Diameter (in.)	0.440	0.404	0.4039
Total Thickness (in.)	0.028	0.026	0.0236
Barrier Thickness (in.)	0.0035	0.0035	0.0035
Water Rod			
Material	Zr-2	Zr-2	Zr-2
Outside Diameter (in.)	0.980	0.980	0.980
Thickness (in.)	0.030	0.030	0.030
Number of Water Rods	2	2	2
Number of Fuel Rods Displaced	7	8	8
Spacers			
Material	Zr-2 with Alloy X-750 Springs	Zr-2 with Alloy X-750 Springs	Alloy-X-750
Number per Bundle	7	8	8
Fuel Channel			
Material	Zr-2	Zr-2	ZRY-2/ZRY-4/NSF
Inside Dimension (in.)	5.278	5.278	5.283
Equivalent** Wall Thickness (in.)	0.0745	0.0745	
Flow Trippers	Yes	No	No

* Cycle 21 has a full core of GNF2 Fuel bundles. The information in this table is maintained as legacy information as GE11 and GE14 fuels are in the spent fuel pool.

** Based on cross-sectional area.

TABLE 5.2-4

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

VALVE #	LINE ISOLATED	PENE. # & OPC/IPC	(NOTE 37) MAX OP TIME (SEC)	CLASS	VALVE TYPE (NOTE 6)	POWER TO OPEN (NOTES 5 & 6)	POWER TO CLOSE	NORMAL POSITION (NOTES 9 & 12)	ISOLATION GRP POSITION	ISOLATION SIGNAL	NOTES
AO-203-1A	Main Steam Line "A"	X-7A,IPC	3.0-5.0	A	Globe	Air/AC,DC	Air & Spring	Open	1 Closed	B,D,P,Q	1
AO-203-2A	Main Steam Line "A"	X-7A,OPC	3.0-5.0	A	Globe	Air/AC,DC	Air & Spring	Open	1 Closed	B,D,P,Q	1
AO-203-1B	Main Steam Line "B"	X-7B,IPC	3.0-5.0	A	Globe	Air/AC,DC	Air & Spring	Open	1 Closed	B,D,P,Q	1
AO-203-2B	Main Steam Line "B"	X-7B,OPC	3.0-5.0	A	Globe	Air/AC,DC	Air & Spring	Open	1 Closed	B,D,P,Q	1
AO-203-1C	Main Steam Line "C"	X-7C,IPC	3.0-5.0	A	Globe	Air/AC,DC	Air & Spring	Open	1 Closed	B,D,P,Q	1
AO-203-2C	Main Steam Line "C"	X-7C,OPC	3.0-5.0	A	Globe	Air/AC,DC	Air & Spring	Open	1 Closed	B,D,P,Q	1
AO-203-1D	Main Steam Line "D"	X-7D,IPC	3.0-5.0	A	Globe	Air/AC,DC	Air & Spring	Open	1 Closed	B,D,P,Q	1
AO-203-2D	Main Steam Line "D"	X-7D,OPC	3.0-5.0	A	Globe	Air/AC,DC	Air & Spring	Open	1 Closed	B,D,P,Q	1
MO-220-1	Main Steam Drain	X-8,IPC	30.0	A	Gate	AC	AC	Closed	1 Closed	B,D,P,Q	9
MO-220-2	Main Steam Drain	X-8,OPC	35.0	A	Gate	DC	DC	Closed	1 Closed	B,D,P,Q	9
6-58A	F W Line "A"	X-9A,IPC	--	A-X	Check	--	process	Open	-- --	Rev. Flow	
6-62A	F W Line "A"	X-9A,OPC	--	A-X	Check	--	process	Open	-- --	Rev. Flow	
1301-50	RCIC Pp Discharge	X-9A,OPC	--	A-X	Check	--	process	Closed	-- --	Rx, Rev. Flow	
MO-1301-49	RCIC Pp Discharge	X-9A,OPC	--	A-X	Gate	DC	DC	Closed	-- --	RM	
MO-1201-80	RWCU Return	X-9A,OPC	30.0	A-X	Globe	AC	AC	Open	6 Closed	A,J,W,Y,RM	29
6-58B	F W Line "B"	X-9B,IPC	--	A-X	Check	--	process	Open	-- --	Rev. Flow	
6-62B	F W Line "B"	X-9B,OPC	--	A-X	Check	--	process	Open	-- --	Rev. Flow	
2301-7	HPCI Pp Discharge	X-9B,OPC	--	A-X	Check	--	process	Closed	-- --	Rx. Rev. Flow	
MO-2301-8	HPCI Pp Discharge	X-9B,OPC	--	A-X	Gate	DC	DC	Closed	-- --	RM	
MO-1001-47	RHR S/D Cooling	X-12,OPC	51.0	A-X	Gate	DC	DC	Closed	3 Closed	A,F,M,U,RM	
MO-1001-50	RHR S/D Cooling	X-12,IPC	32.0	A-X	Gate	AC	AC	Closed	3 Closed	A,F,M,U,RM	

TABLE 5.2-4 (CONT)

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

VALVE #	LINE ISOLATED	PENE. # & OPC/IPC	(NOTE 37) MAX OP TIME (SEC)	CLASS	VALVE TYPE (NOTE 6)	POWER TO OPEN (NOTES 5 & 6)	POWER TO CLOSE	NORMAL POSITION (NOTES 9 & 12)	ISOLATION GRP POSITION	ISOLATION SIGNAL	NOTES
MO-1201-2	RWCU Suction	X-14;IPC	20.0	A-X	Gate	AC	AC	Open	6 Closed	A,J,W,Y,RM	29
MO-1201-5	RWCU Suction	X-14;OPC	34.0	A-X	Gate	DC	DC	Open	6 Closed	A,J,W,Y,RM	29
SV-5065-31B	H2/02 Analyzer Supply	X-15E;OPC	2.0	B	Globe	AC	Spring	Closed	2 Closed	A,F,RM	18
SV-5065-35B	H2/02 Analyzer Supply	X-15E;OPC	2.0	B	Globe	AC	Spring	Closed	2 Closed	A,F,RM	18
1400-9A	Core Spray to Rx Loop A./B	X-16A/IPC	--	A-X	Check	--	Process	Closed	---	Rx, Rev. Flow	
MO-1400-24A	C.S. to Rx. "A" Loop	X-16A;OPC	22.0	A-X	Gate	AC	AC	Open	---	RM	11
MO-1400-25A	C.S. to Rx. "A" Loop	X-16A;OPC	22.0	A-X	Gate	AC	AC	Closed	---	RM	11
1400-9B	Core Spray to Rx Loop A/B	X-16B/IPC	--	A-X	Check	--	Process	Closed	---	Rx, Rev. Flow	
MO-1400-24B	C.S. to Rx. "B" Loop	X-16B;OPC	22.0	A-X	Gate	AC	AC	Open	---	RM	11
MO-1400-25B	C.S. to Rx. "B" Loop	X-16B;OPC	22.0	A-X	Gate	AC	AC	Closed	---	RM	11
AO-7017A	R/W Collection & DW Floor Sump	X-18;OPC	20.0	B	Plug	Air/AC	Spring	Open	2 Closed	A,F, RM	
AO-7017B	R/W Collection and D/W Floor Sump	X-18;OPC	20.0	B	Plug	Air/AC	Spring	Open	2 Closed	A,F, RM	
AO-7011A	R/W Collection and D/W Equipment Sump	X-19;OPC	20.0	B	Plug	Air/AC	Spring	Open	2 Closed	A,F, RM	
AO-7011B	R/W Collection and D/W Equipment Sump	X-19;OPC	20.0	B	Plug	Air/AC	Spring	Open	2 Closed	A,F, RM	
31-CK-167	Instrument Air	X-22;OPC	--	C	Check	--	Process	Open	---	Rev. Flow	
30-CK-432	RBCCW Supply	X-23;OPC	--	C	Check	--	Process	Open	---	Rev. Flow	

TABLE 5.2-4 (CONT)

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

VALVE #	LINE ISOLATED	PENE. # & OPC/IPC	(NOTE 37) MAX OP TIME (SEC)	CLASS	VALVE TYPE (NOTE 6)	POWER TO OPEN (NOTES 5 & 6)	POWER TO CLOSE	NORMAL POSITION (NOTES 9 & 12)	ISOLATION GRP POSITION	ISOLATION SIGNAL	NOTES
MO-4002	RBCCW Return	X-24;OPC	--	C	Gate	AC	AC	Open	-- --	RM	
AO-5043A	Drywell 2" Exhaust Bypass	X-25;OPC	10.0	B	Globe	Air/AC	Spring	Closed	2 Closed	A,B,F,Z,RM	9,15,27,30
AO-5043B	Drywell 2" Exhaust Bypass	X-25;OPC	10.0	B	Globe	Air/AC	Spring	Closed	2 Closed	A,B,F,Z,RM	9,15,27,30
AO-5044A	Drywell Purge Exhaust	X-25;OPC	5.0	B	Butterfly	Air/AC	Spring	Closed	2 Closed	A,F,Z,RM	27
AO-5044B	Drywell Purge Exhaust	X-25;OPC	5.0	B	Butterfly	Air/AC	Spring	Closed	2 Closed	A,F,Z,RM	27
SV-5081A	Post Acc. Purge and Vent	X-25;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19
SV-5081B	Post Acc. Purge and Vent	X-25;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19
SV-5082A	Post Acc. Purge and Vent	X-25;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19
SV-5082B	Post Acc. Purge and Vent	X-25;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19
9-CK-340	Drywell Purge/Makeup	X-26;OPC	--	B	Check	--	Process	Closed	-- --	Rev. Flow	
AO-5033A	Drywell Purge/Makeup	X-26:OPC	10.0	B	Globe	Air/AC	Spring	Closed	2 Closed	A,B,F,Z,RM	9,27,30
AO-5033B	Drywell/Torus Purge	X-26;OPC	10.0	B	Gate	Air/AC	Spring	Closed	2 Closed	A,F,Z,RM	9,21,27
AO-5035A	Drywell Purge/Makeup	X-26;OPC	5.0	B	Butterfly	Air/AC	Spring	Closed	2 Closed	A,F,Z,RM	27
AO-5035B	Drywell Purge/Makeup	X-26;OPC	5.0	B	Butterfly	Air/AC	Spring	Closed	2 Closed	A,F,Z,RM	27
SV-5085A	Post Acc. Purge and Vent	X-26;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19
SV-5086A	Post Acc. Purge and Vent	X-26;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19
SV-5086B	Post Acc. Purge and Vent	X-26;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19
SV-5065-33A	H2/O2 Analyzer & PASS Supply	X-29E;OPC	2.0	B	Globe	AC	Spring	Closed	2 Closed	A,F,RM	18
SV-5065-37A	H2/O2 Analyzer & PASS Supply	X-29E;OPC	2.0	B	Globe	DC	Spring	Closed	2 Closed	A,F,RM	18

TABLE 5.2-4 (CONT)

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

VALVE #	LINE ISOLATED	PENE. # & OPC/IPC	(NOTE 37) MAX OP TIME (SEC)	CLASS	VALVE TYPE (NOTE 6)	POWER TO OPEN (NOTES 5 & 6)	POWER TO CLOSE	NORMAL POSITION (NOTES 9 & 12)	ISOLATION GRP POSITION	ISOLATION SIGNAL	NOTES
CV-5065-91	C-19 Return	X-32A:OPC	5.0	B	Globe	DC	Spring	Open	2 Closed	A,F,RM	
CV-5065-92	C-19 Return	X-32A;OPC	5.0	B	Globe	AC	Spring	Open	2 Closed	A,F,RM	
45-300A	Tip Drive	X-35C;OPC	5.0	A-X	Ball Solenoid	AC	Spring	Closed	2 Closed	A,F	9,16
45-300B	Tip Drive	X-35D;OPC	5.0	A-X	Ball Solenoid	AC	Spring	Closed	2 Closed	A,F	9,16
45-300C	Tip Drive	X-35B:OPC	5.0	A-X	Ball Solenoid	AC	Spring	Closed	2 Closed	A,F	9,16
45-300D	Tip Drive	X-35A;OPC	5.0	A-X	Ball Solenoid	AC	Spring	Closed	2 Closed	A,F	9,16
Shear Valve A	Tip Drive	X-35C;OPC	--	A-X	Explosive Shear	DC	DC	Open	---	RM	22
Shear Valve B	Tip Drive	X-35D;OPC	--	A-X	Explosive Shear	DC	DC	Open	---	RM	22
Shear Valve C	Tip Drive	X-35B;OPC	--	A-X	Explosive Shear	DC	DC	Open	---	RM	22
Shear Valve D	Tip Drive	X-35A;OPC	--	A-X	Explosive Shear	DC	DC	Open	---	RM	22
9-CK-353	Tip Purge	X-35E;OPC	--	B-X	Check	--	Process	Open	---	Rev. Flow	
FCV-302-120	CRD Insert (Typ. of 145)	X-37;OPC	--	A-X	FCV	Air/AC	Spring	Closed	---	RM	4
FCV-302-123	CRD Insert (Typ. of 145)	X-37;OPC	--	A-X	FCV	Air/AC	Spring	Closed	---	RM	4
SV-305-121	CRD Withdraw (Typ. of 145)	X-38;OPC	--	A-X	SOV	Air/AC	Spring	Closed	---	RM	4
SV-305-122	CRD Withdraw (Typ. of 145)	X-38;OPC	--	A-X	SOV	Air/AC	Spring	Closed	---	RM	4
MO-1001-23A	RHR Containment Spray	X-39A;OPC	45.0	B-X	Gate	AC	AC	Closed	---	G,S,RM	2,24,25
MO-1001-26A	RHR Containment Spray	X-39A;OPC	45.0	B-X	Gate	AC	AC	Closed	---	G,S,RM	2,24,25
MO-1001-23B	RHR Containment Spray	X-39B;OPC	45.0	B-X	Gate	AC	AC	Closed	---	G,S,RM	2,24,25
MO-1001-26B	RHR Containment Spray	X-39B;OPC	45.0	B-X	Gate	AC	AC	Closed	---	G,S,RM	2,24,25
SV-5065-63	PASS Rx. Sample	X-40Aa;OPC	2.0	A	Globe	DC	Spring	Closed	2 Closed	A,F,RM	18
SV-5065-64	PASS Rx. Sample	X-40Aa;OPC	2.0	A	Globe	AC	Spring	Closed	2 Closed	A,F,RM	18

TABLE 5.2-4 (CONT)

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

VALVE #	LINE ISOLATED	PENE. # & OPC/IPC	(NOTE 37) MAX OP TIME (SEC)	CLASS	VALVE TYPE (NOTE 6)	POWER TO OPEN (NOTES 5 & 6)	POWER TO CLOSE	NORMAL POSITION (NOTES 9 & 12)	ISOLATION GRP POSITION	ISOLATION SIGNAL	NOTES
SV-5065-85	PASS Rx. Sample	X-40Dc;OPC	2.0	A	Globe	DC	Spring	Closed	2 Closed	A,F,RM	18
SV-5065-86	PASS Rx. Sample	X-40Dc;OPC	2.0	A	Globe	AC	Spring	Closed	2 Closed	A,F,RM	18
AO-220-44	Reactor Sample Line	X-41A;IPC	10.0	A	Gate	Air/AC	Spring	Open	1 or 2 Closed	A,B,D,F,P,Q,RM	9,23
AO-220-45	Reactor Sample Line	X-41A;OPC	10.0	A	Y-Globe	Air/AC	Spring	Open	1 or 2 Closed	A,B,D,F,P,Q,RM	9,23
CK-1101-15	SBLC System	X-42;IPC	--	A-X	Check	Process	Process	Closed	-- --	Rev. Flow	
CK-1101-16	SBLC System	X-42;OPC	--	A-X	Check	Process	Process	Closed	-- --	Rev. Flow	
45-HO-106	D/W Test Connection	X-43;OPC	--	B	Gate	Manual	--	Closed	-- --	--	
262-FO-13A	Recirc. Pp. Seals	X-46A;IPC	--	C	Check	--	Process	Open	-- --	Rev. Flow	
262-FO-17A	Recirc, Pp. Seals	X-46A;OPC	--	C	Check	--	Process	Open	-- --	Rev. Flow	
262-FO-13B	Recirc, Pp. Seals	X-46B;IPC	--	C	Check	--	Process	Open	-- --	Rev. Flow	
262-FO-17B	Recirc. Pp. Seals	X-46B:OPC	--	C	Check	--	Process	Open	-- --	Rev. Flow	
9-HO-378	Backup Nitrogen Supply to RV-203-3B and RV-203-3C	X-46E;OPC	--	B	Gate	Manual	--	Closed	--	--	
9-HO-379	Backup Nitrogen Supply to RV-203-3B and RV-203-3C	X-46E;OPC	--	B	Gate	Manual	--	Closed	--	--	
SV-5065-24A	H2O2 & PASS Gas Return	X-46F;OPC	2.0	B	Globe	DC	Spring	Closed	2 Closed	A,F,RM	18
SV-5065-26A	H2O2 & PASS Gas Return	X-46F;OPC	2.0	B	Globe	AC	Spring	Closed	2 Closed	A,F, RM	18
45-HO-102	D/W Test Connection (ILRT Supplemental Test)	X-47;OPC	--	B-X	Globe	Manual	--	Closed	-- --	--	
45-HO-103	D/W Test Connection (ILRT Supplemental Test)	X-47;OPC	--	B-X	Globe	Manual	--	Closed	-- --	--	
45-HO-104	D/W Test Connection (ILRT Supplemental Test)	X-47;OPC	--	B-X	Globe	Manual	--	Closed	-- --	--	
45-HO-105	D/W Test Connection (ILRT Supplemental Test)	X-47;OPC	--	B-X	Globe	Manual	--	Closed	-- --	--	
SV-5065-13B	H2/O2 Analyzer Supply	X-50Ad;OPC	2.0	B	Globe	AC	Spring	Open	2 Closed	A,F,RM	18

TABLE 5.2-4 (CONT)

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

VALVE #	LINE ISOLATED	PENE. # & OPC/IPC	(NOTE 37) MAX OP TIME (SEC)	CLASS	VALVE TYPE (NOTE 6)	POWER TO OPEN (NOTES 5 & 6)	POWER TO CLOSE	NORMAL POSITION (NOTES 9 & 12)	ISOLATION GRP POSITION	ISOLATION SIGNAL	NOTES
SV-5065-20B	H2/O2 Analyzer Supply	X-50Ad;OPC	2.0	B	Globe	DC	Spring	Open	2 Closed	A,F,RM	18
MO-1001-28A	RHR Injection "A" Loop	X-51A;OPC	30.0	A-X	Globe	AC	AC	Open	-- --	E,T,RM	
MO-1001-29A	RHR Injection "A" Loop	X-51A;OPC	30.0	A-X	Gate	AC	AC	Closed	3 Closed	A,E,F,U,T,RM	11,17
1001-68A	RHR Injection A	X-51A;IPC	--	A-X	Check	--	Process	Closed	-- --	Rx, Rev. Flow	
MO-1001-28B	RHR Injection "B" Loop	X-51B;OPC	30.0	A-X	Globe	AC	AC	Open	-- --	E,T,RM	
MO-1001-29B	RHR Injection "B" Loop	X-51B;OPC	30.0	A-X	Gate	AC	AC	Closed	3 Closed	A,E,F,U,T,RM	11,17
1001-68B	RHR Injection B	X-51B;IPC	--	A-X	Check	--	Process	Closed	-- --	Rx, Rev. Flow	
M0-2301-4	HPCI Steam to Turbine	X-52;IPC	25.0	A-X	Gate	AC	AC	Open	4 Closed	L,RM,AA	13
MO-2301-5	HPCI Steam to Turbine	X-52;OPC	34.0	A-X	Gate	DC	DC	Open	4 Closed	L,RM.AA	13
MO-1301-16	RCIC Steam to Turbine	X-53;IPC	20.0	A-X	Gate	AC	AC	Open	5 Closed	K,RM,AA	10
MO-1301-17	RCIC Steam to Turbine	X-53;OPC	29.0	A-X	Gate	DC	DC	Open	5 Closed	K,RM,AA	10
SV-5065-14A	$H_2/0_2$ Analyzer Supply	X-106Ab;OPC	2.0	B	Globe	AC	Spring	Open	2 Closed	A,F,RM	18
SV-5065-21A	$H_2/0_2$ Analyzer Supply	X-106Ab;OPC	2.0	B	Globe	DC	Spring	Open	2 Closed	A,F,RM	18
9-CK-341	Torus Makeup	X-205;OPC	--	B	Check	--	Process	Closed	-- --	Rev. Flow	9
AO-5033B	Drywell/Torus Purge	X-205;OPC	10.0	B	Gate	Air/AC	Spring	Closed	2 Closed	A,F,Z,RM	9,21,27
AO-5033C	Torus Makeup	X-205;OPC	10.0	B	Gate	Air/AC	Spring	Closed	2 Closed	A,B,F,Z,RM	9,27.30
AO-5036A	Torus Purge Inlet	X-205;OPC	5.0	B	Butterfly	Air/AC	Spring	Closed	2 Closed	A,F,Z,RM	27,35
AO-5036B	Torus Purge Inlet	X-205;OPC	5.0	B	Butterfly	Air/AC	Spring	Closed	2 Closed	A,F,Z,RM	27,35
SV-5087A	Post Accident Purge and Vent	X-205;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19
SV-5087B	Post Accident Purge and Vent	X-205;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19

TABLE 5.2-4 (CONT)

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

VALVE #	LINE ISOLATED	PENE. # & OPC/IPC	(NOTE 37) MAX OP TIME (SEC)	CLASS	VALVE TYPE (NOTE 6)	POWER TO OPEN (NOTES 5 & 6)	POWER TO CLOSE	NORMAL POSITION (NOTES 9 & 12)	ISOLATION GRP POSITION	ISOLATION SIGNAL	NOTES
SV-5088A	Post Acc. Purge and Vent	X-205;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19
SV-5088B	Post Acc. Purge and Vent	X-205;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19
MO-1001-36A	RHR to Torus	X-210A;OPC	30.0	B-X	Globe	AC	AC	Closed	-- --	G,RM	2,9,35
MO-1001-18A	RHR Minimum Flow	X-210A;OPC	25.0	B-X	Gate	AC	AC	Open	-- --	RM	9,31
CK-1400-35	Core Spray Recirc	X-210A;OPC	--	B-X	Check	--	Process	Closed	-- --	Rev. Flow	28
MO-1001-36B	RHR to Torus	X-201B;OPC	30.0	B-X	Globe	AC	AC	Closed	-- --	G,RM	2,9,35
MO-1001-18B	RHR Minimum Flow	X-210B,OPC	25.0	B-X	Gate	AC	AC	Open	-- --	RM	9,31
1301-47	RCIC Minimum Flow	X-201B;OPC	--	B-X	Check	--	Process	Closed	-- --	Rev. Flow	28
CK-1400-214	Core Spray Recirc.	X-210B;OPC	--	B-X	Check	--	Process	Closed	-- --	Rev. Flow	28
2301-40	HPCI Minimum Flow	X-210B,OPC	--	B-X	Check	--	Process	Closed	-- --	Rev. Flow	28
10-CK-515	Torus Makeup From CST	X-210B;OPC	--	B-X	Check	--	Process	Closed	-- --	Rev. Flow	28
MO-1001-34A	RHR to Torus "A" Loop	X-211A;OPC	30.0	B-X	Gate	AC	AC	Closed	-- Closed	G,RM	2,9,24
MO-1001-34B	RHR to Torus "B" Loop	X-211B;OPC	30.0	B-X	Gate	AC	AC	Closed	-- Closed	G,RM	2,9,24
MO-1001-37A	RHR to Torus Spray Header "A"	X-211A;OPC	45.0	B-X	Globe	AC	AC	Closed	-- Closed	G,S,RM	2,24,35
MO-1001-37B	RHR to Torus Spray Header "B"	X-211B;OPC	45.0	B-X	Globe	AC	AC	Closed	-- Closed	G,S,RM	2,24,35
MO-2301-33	HPCI Turbine Ex. Vac. Brkr.	X-219/OPC	30.0	B-X	Gate	AC	AC	Open	7 Closed	N,RM	36
MO-2301-34	HPCI Turbine Ex.Vac. Brkr.	X-219/OPC	30.0	B-X	Gate	AC	AC	Open	7 Closed	N,RM	36

TABLE 5.2-4 (CONT)

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

VALVE #	LINE ISOLATED	PENE. # & OPC/IPC	(NOTE 37) MAX OP TIME (SEC)	CLASS	VALVE TYPE (NOTE 6)	POWER TO OPEN (NOTES 5 & 6)	POWER TO CLOSE	NORMAL POSITION (NOTES 9 & 12)	ISOLATION GRP POSITION	ISOLATION SIGNAL	NOTES
MO-1301-25	RCIC Pp. Suction From Torus	X-220;OPC	125.0	B-X	Gate	DC	DC	Closed	-- --	RM	28
MO-2301-36	HPCI Pp. Suction From Torus	X-221;OPC	37.0	B-X	Gate	DC	DC	Closed	4 Closed	L,RM	26,28
MO-1001-7A	RHR Pp. Suction	X-222A;OPC	150	B-X	Gate	AC	AC	Open	-- --	RM	22,28
MO-1001-7B	RHR Pp. Suction	X-222D;OPC	150	B-X	Gate	AC	AC	Open	-- --	RM	22,28
MO-1001-7C	RHR Pp. Suction	X-222B;OPC	150	B-X	Gate	AC	AC	Open	-- --	RM	22,28
MO-1001-7D	RHR Pp. Suction	X-222C;OPC	150	B-X	Gate	AC	AC	Open	-- --	RM	22,28
2301-45	HPCI Turbine Exhaust	X-223; OPC	--	B-X	Check	--	Process	Closed	-- Closed	Rev. Flow	
2301-74	HPCI Turbine Exhaust	X-223;OPC	--	B-X	Check	--	Process	Closed	-- Closed	Rev. Flow	
2301-218	HPCI Low Point Drain	X-223;OPC	--	B-X	Check	--	Process	Closed	-- Closed	Rev. Flow	
CV-9068A	HPCI Gland Seal Condenser	X-223;OPC	--	B-X	Globe	DC	Spring	Closed	4 Closed	L,AA,RM	
CV-9068B	HPCI Gland Seal Condenser	X-223;OPC	--	B-X	Globe	DC	Spring	Closed	4 Closed	L,AA,RM	
MO-2301-33	HPCI Turbine Ex. Vac. Brkr.	X-223;OPC	30.0	B-X	Gate	AC	AC	Open	7 Closed	N,RM	36
MO-2301-34	HPCI Turbine Ex. Vac. Brkr.	X-223;OPC	30.0	B-X	Gate	AC	AC	Open	7 Closed	N,RM	36
2301-217	HPCI Exhaust Line Drain	X-224;OPC	--	B-X	Check	--	Process	Closed	-- --	Rev. Flow	28
1301-64	RCIC Turbine Exhaust	X-225; OPC	--	B-X	Stop Check	--	Process	Closed	-- --	Rev. Flow	28
1301-59	RCIC Vac. Pp. Discharge	X-226; OPC	--	B-X	Check	--	Process	Closed	-- --	Rev. Flow	28
SV-5084A	Post Acc. Purge and Vent	X-227;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19
SV-5084B	Post Acc. Purge and Vent	X-227;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19
SV-5083A	Post Acc. Purge and Vent	X-227;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19
SV-5083B	Post Acc. Purge and Vent	X-227;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19

TABLE 5.2-4 (CONT)

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

VALVE #	LINE ISOLATED	PENE. # & OPC/IPC	(NOTE 37) MAX OP TIME (SEC)	CLASS	VALVE TYPE (NOTE 6)	POWER TO OPEN (NOTES 5 & 6)	POWER TO CLOSE	NORMAL POSITION (NOTES 9 & 12)	ISOLATION GRP POSITION	ISOLATION SIGNAL	NOTES
AO-5040A	Torus Vacuum Bkrs.	X-227;OPC	45.0	B	Butterfly	Spring	Air/DC	Closed	2 Closed	A,F,Z	34,3
AO-5040B	Torus Vacuum Bkrs.	X-227;OPC	45.0	B	Butterfly	Spring	Air/DC	Closed	2 Closed	A,F,Z	34,3
X-212A	Torus Vacuum Bkrs.	X-227;OPC	--	B	Check	Vacuum	Process	Closed	---	Rev. Flow	34
X-212B	Torus Vacuum Bkrs	X-227;OPC	--	B	Check	Vacuum	Process	Closed	---	Rev. Flow	34
AO-5025	Direct Torus Vent	X-227,OPC	--	B	Butterfly	Spring	Air/DC	Closed	---	RM	19
AO-5041A	Torus Exhaust Bypass	X-227;OPC	10.0	B	Globe	Air/AC	Spring	Closed	2 Closed	A,B,F,Z,RM	9,15,27,30
AO-5041B	Torus Exhaust Bypass	X-227;OPC	10.0	B	Globe	Air/AC	Spring	Closed	2 Closed	A,B,F,Z,RM	9,15,27,30
AO-5042A	Torus Main Exhaust	X-227;OPC	5.0	B	Butterfly	Air/AC	Spring	Closed	2 Closed	A,F,Z,RM	27
AO-5042B	Torus Main Exhaust	X-227;OPC	5.0	B	Butterfly	Air/DC	Spring	Closed	2 Closed	A,F,Z,RM	27
SV-5065-22B	$H_2/0_2$ Analyzer Supply	X-228C;OPC	2.0	B	Globe	DC	Spring	Closed	2 Closed	A,F,RM	18
SV-5065-15B	$H_2/0_2$ Analyzer Supply	X-228C;OPC	2.0	B	Globe	AC	Spring	Closed	2 Closed	A,F,RM	18
31-CK-434	Air to D/W to Torus Vacuum Breakers	X-228E;OPC	--	B	Check	Process	Process	Closed	---	Rev. Flow	
CV-5046	Air to D/W to Torus Vac. Breakers	X-228E;OPC	--	B	Globe	Air/AC	Spring	Closed	---	RM	
SV-5065-77	PASS Liquid Return	X-228G;OPC	2.0	B	Globe	DC	Spring	Closed	2 Closed	A,F,RM	18
SV-5065-78	PASS Liquid Return	X-228G;OPC	2.0	B	Globe	AC	Spring	Closed	2 Closed	A,F,RM	18
SV-5065-71	PASS Liquid Return	X-228H;OPC	2.0	B	Globe	DC	Spring	Closed	2 Closed	A,F,RM	18
SV-5065-72	PASS Liquid Return	X-228H;OPC	2.0	B	Globe	AC	Spring	Closed	2 Closed	A,F,RM	18
SV-5065-18A	$H_2/0_2$ Analyzer Supply	X-228J;OPC	2.0	B	Globe	DC	Spring	Closed	2 Closed	A,F,RM	18
SV-5065-11A	$H_2/0_2$ Analyzer Supply	X-228J;OPC	2.0	B	Globe	AC	Spring	Closed	2 Closed	A,F,RM	18

TABLE 5.2-4 (CONT)

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

VALVE #	LINE ISOLATED	PENE. # & OPC/IPC	(NOTE 37) MAX OP TIME (SEC)	CLASS	VALVE TYPE (NOTE 6)	POWER TO OPEN (NOTES 5 & 6)	POWER TO CLOSE	NORMAL POSITION (NOTES 9 & 12)	ISOLATION GRP POSITION	ISOLATION SIGNAL	NOTES
SV-5065-25B	H2/O2 Analyzer Supply	X-228K;OPC	2.0	B	Globe	DC	Spring	Closed	2 Closed	A,F,RM	18
SV-5065-27B	H2/02 analyzer Supply	X-228K;OPC	2.0	B	Globe	AC	Spring	Closed	2 Closed	A,F,RM	18
MO-1400-3A	Core Spray Pump Suction	X-229A;OPC:	--	B-X	Gate	AC	AC	Open	-- --	RM	28
MO-1400-3B	Core Spray Pump Suction	X-229B;OPC	--	B-X	Gate	AC	AC	Open	-- --	RM	28
MO-1001-21	RHR Discharge to RW	None;OPC	40.0	--	Gate	DC	DC	Closed	2 Closed	A,F,RM	8,9
MO-1001-32	RHR Discharge to RW	None;OPC	30.0	--	Gate	AC	AC	Closed	2 Closed	A,F,RM	8,9
Various	Type A Instru. Line (typ.)	--;OPC	--	A-X	Hand Globe	Manual	Manual	Open	-- --	--	
Various	Type A Instru. Line (typ.)	--;OPC	--	A-X	Flow	Spring	Process	Open	-- --	Excess Flow	
Various	Type B Instr. Line (typ.)	--;OPC	--	B-X	Hand Globe	Manual	Manual	Open	-- --	-- --	

TABLE 5.2-4 (CONT)

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

ISOLATION SIGNAL CODES FOR TABLE 5.2-4

Signal	Description
A*	Reactor vessel low water level - scram and close isolation valves except main steam lines.
B*	Reactor vessel low low water level - initiate RCIC, HPCI and close main steam line isolation and drain valves.
C	Deleted
D*	Line break - main steam line (steam line high space temperature or high steam flow).
E	Reactor low low level or high drywell pressure - select LPCI and close other loop valves and initiate HPCI.
F*	High drywell pressure - close RHR/shutdown cooling and head spray, the RHR to radwaste valves, and Torus Vacuum Breaker.
G	Reactor vessel low low water level and coincident low reactor pressure; or high drywell pressure - initiate Core Spray and RHR systems.
J*	Line break in cleanup system - high space temperature, or high flow.
K*	Line break in RCIC system steam line to turbine (high steam line space temperature or high steam flow) or low steam line pressure.
L*	Line break in HPCI system steam line to turbine (high steam line space temperature or high steam flow).
M*	Line break in RHR shutdown and head cooling (high space temperature; alarm only; no auto closure).
N*	High Drywell pressure and Low reactor vessel pressure - close HPCI vacuum breakers.
P*	Low main steam line pressure at inlet to main turbine (RUN mode only).
Q*	Reactor high water level - isolate main steam line (except in run mode).
RM*	Remote manual switch from control room.
Rx	This valve is a Reactor Vessel Isolation Valve only (not a Primary Containment Isolation Valve).
S	Low drywell pressure - close containment spray valves.
T	Low reactor pressure permissive to open core spray and RHR-LPCI valves.
U	High reactor vessel pressure - close RHR shutdown cooling valves and head cooling valves.
W	High temperature at outlet of cleanup system nonregenerative heat exchanger.

TABLE 5.2-4 (CONT)

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

ISOLATION SIGNAL CODES FOR TABLE 5.2-4

Y	Standby liquid control system actuated.
Z	Refuel floor high radiation. This signal is part of the Reactor Building Isolation Control System. See Section 7.18.
AA*	Low reactor pressure - closure of HPCI and RCIC steam to turbine isolation valves.
*	These are the isolation functions of the primary containment and reactor vessel isolation control system; other functions are given for information only.

TABLE 5.2-4 (CONT)

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

Notes for Table 5.2-4

1. Main steam isolation valves require that both solenoid pilots be deenergized to close valves. Accumulator air pressure plus spring act together to close valves when both pilots are deenergized. Voltage failure at only one pilot does not cause valve closure. The valves are designed to fully close in less than 10 seconds, but in no less than 3 seconds.

2. Containment spray and suppression cooling valves have interlocks that allow them to be manually reopened after automatic closure. This setup permits containment spray, for high drywell pressure conditions, and/or suppression pool cooling. When automatic signals are not present, valves may be opened for test and operating convenience.

3. On loss of air, this valve fails open.

4. Control rod hydraulic lines can be isolated by the solenoid valves (directional control) outside the primary containment. Lines that extend outside the primary containment are small and terminate in a system that is designed to prevent outleakage. Solenoid valves (directional control) normally are closed, but they open on rod movement.

5. AC motor operated valves are powered from the AC standby power busses. DC isolation valves are powered from the station batteries.

6. All motor operated isolation valves remain in the last position upon failure of valve power. All air operated valves close on motive air failure or power at the solenoid pilots.

7. Not used.

8. MO1001-21 and MO1001-32 are not primary containment isolation valves. They are included for information only since they receive F and A isolation signals.

9. Valves identified by this note can be opened or closed by remote manual switch for operating convenience during any mode of the reactor except when an automatic signal is present. RHR minimum flow valves receive automatic open signal on low flow; they receive no automatic close signal.

10. RCIC Steam supply turbine valves open on Signal B. Line Break signal K overrides to close valves.

11. Coincident signals "G" and "T" open core spray and selected LPCI valves. Special interlocks permit testing these valves by manual switch except when automatic signals are present.

12. Normal status position of valve (open or closed) is the position during normal power operation of the reactor (see "Normal Position" column).

13. HPCI Steam to turbine valves open on Signal E. Line Break signals L and AA override to close.

14. Not used.

15. Manual switches override all automatic signals on the smaller valves that bypass the suppression chamber and drywell exhaust valves.

TABLE 5.2-4

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

Notes for Table 5.2-4

16. Signal "A" or "F" causes automatic withdrawal of TIP probe. When probe is withdrawn, the valve automatically closes by mechanical action.

17. MO-1001-29A & B isolate on reactor low water level (signal A) OR high drywell pressure (Signal F) if RHR Shutdown cooling supply valves MO-1001-50 and 47 are NOT fully closed AND reactor pressure (signal U) is below 80 psig. Valve position indicating lights are not required at the isolation valve display panel.

18. Isolation signals are overridden with control switch in the "emergency open" position.

19. Key locked switch to operate valves administratively control closed.

20. Deleted.

21. These valves are isolation valves for both penetration X-26 and X205. They are shown twice for clarity.

22. Remote manual actuation to close (key locked)

23. Reactor Sample valves isolate on Group 1 signal or Group 2 signal.

24. Isolates on LPCI initiation Signal.

25. May be manually open for high drywell pressure conditions.

26. These valves open on a low CST, or high torus level, if no isolation signal present.

27. In addition to Group 2 isolation, these valves also receive a Refueling Floor High Radiation isolation.

28. Those Class B lines which terminate below the water line of the suppression pool only require one isolation valve. (See Section 7.3.2).

29. High space temperature (Signal J) activates alarm in the control room. Pumps are signaled to stop as a result of valve closure.

30. These valves also receive a reactor low-low water level signal which cannot be bypassed by utilizing the valves emergency open feature.

31. Open on RHR pump low flow. No automatic close signal.

32. Not used.

33. Not used.

34. Valve opens when suppression chamber pressure is 0.5 psi below reactor building pressure.

35. Throttling type valve.

36. These valves are isolation valves for both penetration X-219 and X-223. They are shown twice for clarity.

37. Maximum operating time for AC powered valves are determined assuming AC power is available to the valve. For loss of AC power scenarios, the diesel start and loading time must be added to the maximum operation time.

TABLE 5.2-4 (CONT)

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

Group Isolation Signals

Group 1:		The valves in this group are closed upon any one of the following conditions.
	B*	Reactor low-low water level
	D*	Main Steam Line high flow
	D*	Main Steam Line tunnel high temperature
	P*	Main Steam Line low pressure (in run mode, only)
	Q	Reactor high water level (not in run mode, below Main Steam Line Low Pressure MSIV Isolation Setpoint)
Group 2:		The valves in this group are closed upon any one of the following conditions.
	A*	Reactor low water level
	F*	High drywell pressure
Group 3:		The valves in this group are closed upon any one of the following conditions.
	A*	Reactor low water level
	U	High reactor pressure
	F*	High drywell pressure
Group 4:		The valves in this group are closed upon any one of the following conditions.
	L*	HPCI steam line high flow
	L*	HPCI steam line area high temperature
	AA*	Low Reactor Pressure
Group 5:		The valves in this group are closed upon any one of the following conditions.
	K*	RCIC steam line high flow
	K*	RCIC steam line area high temperature
	K*	RCIC steam line low pressure
Group 6:		The valves in this group are closed upon one of the following conditions.
	A*	Reactor low water level
	J*	Cleanup area high temperature
	J*	Cleanup inlet high flow
Group 7:		The valves in this group are closed upon any one of the following conditions.
	N*	Reactor Low Pressure and High Drywell Pressure

5.4 CONTROL OF COMBUSTIBLE GAS CONCENTRATIONS IN CONTAINMENT

5.4.1 Introduction

A system for control and monitoring of containment atmosphere is provided as required by 10 CFR 50.44. This system is provided for control of oxygen and hydrogen gases that may be generated following a postulated loss of coolant accident (LOCA) combined with degradation, but not total failure, of core standby cooling systems (CSCS). Degradation, but not total failure of the core standby cooling function means that the performance of the CSCS is postulated, for the purpose of design of the combustible gas control system (CGCS), not to meet the acceptance criteria in 10 CFR 50.46 and that there could be localized clad melting and metal-water reaction. The degree of performance degradation of the CSCS is not postulated to be sufficient to cause core meltdown.

The combustible gas control system was originally designed, built, and maintained as safety-related to control the hydrogen and oxygen that may be generated following a postulated LOCA. However, since the promulgation of Final Rule, 10 CFR 50.44, the regulatory basis of the combustible gas control system has shifted from having to cope with a design basis accident (DBA) LOCA to the mitigation of combustible gas generated by a beyond design basis accident (BDBA). The Final Rule has down graded the system to non-safety related, Reg. Guide 1.97 Category 3 for Hydrogen and Category 2 for oxygen subsystems. The regulatory commitment made in the Pilgrim License Amendment 206 requires Pilgrim to maintain the system at least to the level of Reg. Guide 1.97 Category 3 for hydrogen and Category 2 for oxygen monitoring. With the elimination of the design-basis LOCA hydrogen release, the hydrogen monitors are no longer required to mitigate design-basis accidents, and therefore, the hydrogen monitors do not meet the definition of safety-related component as defined in 10 CFR 50.2. Likewise, the oxygen monitors are also down graded to Reg. Guide 1.97, Category 2.

The containment atmospheric control system (CACS) is provided to obviate the possibility of an energy release within the primary containment from a hydrogen-oxygen reaction following a postulated LOCA combined with degraded CSCS functioning. This is to be accomplished by maintaining an atmosphere containing less than 4% oxygen in the drywell and pressure suppression chamber (torus). The system will:

1. Perform initial purging of the primary containment

2. Provide for a supply of nitrogen makeup gas during normal operation or emergency

3. Provide for normal and purge exhaust lines to the standby gas treatment system (SBGT) for normal operating conditions

4. Provide for emergency exhaust from the drywell and torus for release of contaminated drywell and torus gases to the SBGT

5. Provide pneumatic supply to instruments inside the drywell

An adjunct to the CACS is the direct torus vent line. This line can be used to vent excessive pressure generated inside containment (following a beyond design accident) directly to the main stack, bypassing the SBGT.

5.4.2 Source of Hydrogen and Oxygen Accumulation in Containment

Following the postulated design basis LOCA combined with degraded CSCS function, hydrogen may be produced by the postulated metal-water (zirconium-water) reaction. Hydrogen and oxygen may be produced by radiolysis of reactor coolant. Radiolysis of water is the only source of oxygen in the PNPS inerted containment. Under design basis accident conditions, oxygen would be produced in much more limited quantities than hydrogen and is therefore chosen as the parameter to control.

Procedures are in place to control primary containment atmosphere and to maintain the containment inerted during normal operations and transients. The development and implementation of Emergency Operating Procedures (EOPs) industry-wide has fundamentally changed the way in which operators respond to accidents from an "event-based" approach to a "symptom-based" approach. The EOPs do not specifically differentiate between symptoms that are within design basis and those that are beyond design basis.

The EOPs and support procedures contain specific instructions for maintaining the concentrations of both hydrogen and oxygen below their respective thresholds for combustibility. The procedures are structured to effect containment purging with nitrogen and/or venting as the control method for reducing combustible gas concentrations inside containment. Containment oxygen concentration in excess of 5% in the presence of detectable hydrogen i.e., ≥ 1%, is not credible for design basis accidents and would be considered beyond PNPS design basis. The EOPs and support procedures contain appropriate instructions for implementing the strategies of BWROG Emergency Procedure Guidelines to control combustible gases for events beyond PNPS design basis for the purpose of preserving primary containment integrity.

5.4.3 System Description

10 CFR 50.44(b)(1) requires all containments must have a capability for ensuring a mixed atmosphere. 10 CFR 50.44(b)(2) requires all boiling water reactors with Mark I or Mark II type containments must have an inerted atmosphere. 10 CFR 50.44(b)(4)(i) requires equipment for monitoring oxygen in containments that use an inerted atmosphere for combustible gas control. The equipment for monitoring oxygen must be functional, reliable, and capable of continuously measuring the concentration of oxygen in the containment atmosphere following a significant beyond design-basis accident for combustible gas control and accident management, including emergency planning. 10 CFR 50.44 (b)(4)(ii) requires equipment for monitoring hydrogen in the containment. The equipment for monitoring hydrogen must be functional, reliable, and capable of continuously measuring the concentration of hydrogen in the containment atmosphere following a significant beyond design-basis accident for accident management, including emergency planning.

Pilgrim is a Mark I type containment and is provided with an inerted atmosphere to preclude the possibility of a hydrogen combustion event within the containment. The oxygen deficient atmosphere assures that hydrogen build-up due to metal-water reaction is not a concern for these plants. Combustible gas control for these plants is based on control of oxygen, which is produced in more limited quantities than hydrogen following a LOCA or transient event.

The CACS in conjunction with the SBGT are the systems which Pilgrim Station utilizes for primary containment atmospheric control as required by 10CFR50.44. See Figure 5.4-1 (Drawing M227).

The containment combustible gas control system is used primarily for purging (i.e., inerting) with Nitrogen (N_2) or can be used for containment venting. Exhaust from both the torus and drywell can be routed to the main stack via the redundant trains of the SGTS. Makeup of nitrogen (or air) is supplied via the 1 inch redundant solenoid valve trains. See Figure 5.4-1 (Drawing M227).

The primary method of controlling combustible gas inside the primary containment is by maintaining an oxygen free atmosphere by inerting. When the containment is deinerted oxygen is present, but containment integrity post-LOCA is ensured by monitoring containment for hydrogen. Should hydrogen levels rise when deinerted, purging with air (dilution) or the CACS can be used to maintain containment atmosphere hydrogen gas accumulation below stoichiometric proportions. This is achieved by inerting the drywell and suppression chamber atmosphere with nitrogen. The inerted atmosphere is maintained by the following controls:

1. Technical Specification 3.7.A.5.a and 3.7.A.5.b require that, when the containment is required to be inerted, the containment atmosphere must be less than four percent oxygen.

2. The pneumatic control systems located inside the primary containment use only nitrogen when the containment is required to be inerted. Additional capability to address USI-A46 is provided and available.

3. There are no potential sources of oxygen in containment other than that resulting from radiolysis of reactor coolant when the containment is required to be inerted.

In addition to operating with the primary containment atmosphere inerted with nitrogen, PNPS must maintain a safety grade purge/repressurization system in conformance with the general requirements of Criteria 41, 42, and 43 of Appendix A of 10 CFR 50. This basis for maintaining the purge/repressurization system is given in the "Safety Evaluation by the Office of Nuclear Reactor Regulation Relating to Generic Letter 84-09 on Hydrogen Recombiner Capability Pilgrim Nuclear Power Station, Unit 1" (April 30, 1986). It states

> "...the "Safety Grade" purge/repressurization system is still necessary to control combustible gas mixtures for a narrow range of accident scenarios which have the potential to generate hydrogen and oxygen at rates that are comparable to the radiolysis rates described in Regulatory Guide 1.7".

The Purge/Repressurization System controls oxygen concentration below flammability limits (5 volume percent) by a feed and bleed method. The time required before initiation of purge (vent) of the primary containment is controlled by repressurization techniques consisting of nitrogen (or air) addition to the primary containment.

Sixteen (16) solenoid valves are arranged to provide redundant paths to and from the drywell and torus for Nitrogen makeup/repressurization and venting. Nitrogen makeup/repressurization is provided by:

1. Connecting, to hose connections outside containment, a portable nitrogen supply via truck with vaporizer or using the existing (non-seismic) nitrogen storage tank with vaporizer (requires opening a manual block valve located outside containment in the yard area Reactor Building north wall) (Primary emergency make-up)

2. Alternatively, provide a compressed air supply from service air connections outside the primary and secondary containment or from portable (gasoline driven) air compressors located on site (secondary emergency make-up)

The solenoid valves are designed to remain closed against maximum containment pressure, to vent containment so that the maximum containment pressure will not be exceeded, and to provide a nitrogen flow sufficient to maintain the oxygen concentration inside containment below the flammability limits.

The valves in redundant paths are powered from independent Class IE distribution systems each of which is powered from an emergency diesel generator after a loss of offsite power or from essential DC supply. The control switches for redundant valves are located in separate Class IE control panels in the main control room. Conduit and permanently installed equipment required for purging and repressurization functions are located in seismically designed, missile protected buildings, except all the fill connections which are located outside of secondary containment but separated. Redundant conduit systems are separated commensurate with identified hazards. All conduit and permanently installed equipment required for purging and repressurization functions are supported to meet seismic Category I requirements except for N_2 supply equipment described previously.

The solenoid valves are ASME III Class 2 and are qualified environmentally and seismically to the requirements of IEEE 323-1974, IEEE 382-1973, and IEEE 344-1975 for the expected conditions. The valves are rated at 120V ac and are designed to operate between 80 and 110 percent of rated voltage. This range is compatible with expected bus voltages at Pilgrim Nuclear Power Station. The valves which need to operate the direct torus vent system receive control power from essential 125 volts DC.

The control switches have been qualified to the requirements of IEEE 323-1974 for operation in a control room environment. The switches are mounted on Class IE panels (see Table 7.8-3) and the combination has been qualified to IEEE 344-1975 for the Operating Basis Earthquake. The switch's electrical ratings exceed loading requirements.

The cable and wire used for this modification have been qualified to IEEE 383-1974 for fire and ambient conditions exceeding those required for this installation. The 600 V No. 12 AWG control cable has voltage and current capabilities well above that required.

Control of the solenoid valves is remote manual, there is no automatic isolation capability. Isolation signals have not been provided because:

1. The valves are always keylocked closed during normal operation
2. The valves are required to be operated during a high drywell pressure condition and must be available independent of reactor water level. High drywell pressure and low-low reactor water level are the normal containment isolation signals

Nitrogen makeup and ventilation valves are also provided for use under nonaccident conditions. These will automatically close upon receipt of an accident signal. However, these valves may be used after an accident provided the required power supplies are available and a low-low water level signal is not present. Refer to Section 5.2.3.5 and Tables 5.2-4 and 7.3-1.

Indicator lights are provided to continuously monitor valve position. The indicators are driven by reed-type limit switches mounted within the valve electrical housing. Contacts from all control switches are wired to an annunciator window to provide an alarm when a valve is open.

All containment vent and purge valves receive power from either the onsite or offsite emergency power system.

Hydrogen generation rates and amounts are based upon the guidance of Regulatory Guide 1.7. The amount of hydrogen generated by a fuel cladding and water reaction was obtained by using the larger of:

1. Five times the total amount of hydrogen calculated in a previous Pilgrim reload submittal.

2. An average core wide cladding penetration of 0.23 mils

In a previous Pilgrim Station reload submittal, GE calculated an average metal water reaction percentage of 0.13 percent (Reference 1). Five times 0.13 is 0.65 percent cladding interaction. A 0.23 mil average cladding penetration is equivalent to 0.68 percent cladding interaction. Hence, the 0.23 mil average cladding penetration was used. All hydrogen generated by the core metal water reaction was assumed to be released to the primary containment immediately. Radiolytic hydrogen generation rates and accumulation curves were calculated by GE (Reference 2). GE used AEC Safety Guide 7 to generate their curves. These assumptions are the same as those used in Regulatory Guide 1.7.

Hydrogen inputs from corrosion for Pilgrim (no chemical spray) are minor (Reference 3). Hence, no other significant source exists from this event.

5.4.4 Containment Mixing

Significant combustible gas concentration stratification within the drywell or the torus is not expected. Organizations such as Energy Incorporated and GE have investigated containment mixing. Energy Incorporated has estimated less than 0.1 percent variation in hydrogen concentration in the drywell and expects good mixing will take place in the torus because of thermal gradients (Reference 4). Energy Incorporated's conclusion are supported by GE's evaluation of mixing in the containment around their BWR 6. GE believes that a very small temperature (T) or concentration (C) difference is sufficient to promote good mixing ($T = 2.6 \times 10^{-5}$ °F or $C = 4.3 \times 10^{-8}$ in the containment around a BWR 6).

GE also believes that the analysis used on the containment around a BWR 6 will also apply to a Mark I Containment. Based upon the above analysis, in the open Pilgrim BWR Mark I containment, no significant combustible gas concentration stratification is expected within the drywell or torus.

5.4.5 Combustible Gas Monitoring

The existing containment combustible gas monitoring system (CCGMS) consists of two redundant, remotely operable, seismically qualified hydrogen analyzers. The hydrogen analyzers are capable of continuously monitoring drywell hydrogen concentration for 30 days following their initiation. They initiate 30 minutes after safety injection begins. They have a remote readout in the main control room. System operation requires manual initiation by control room operators when directed by procedures. Additional information regarding the hydrogen analyzers is contained in Section 10.19, "Post-Accident Sampling System."

5.4.6 Radiological Consequences of Containment Venting

An evaluation of offsite doses which would be incurred as a result of containment venting to limit containment pressure has been performed in a manner consistent with Regulatory Guides 1.3, 1.7, and 1.45.

The results of this analysis indicate that the doses to receptors at the LPZ would be well within the limits of 10 CFR 100. This analysis assumed that venting at the rate of 50 standard ft^3/min through the SGTS would be initiated at 80 hours after the reactor was made subcritical and venting would continue for 30 days.

5.4.7 Direct Torus Vent Line

5.4.7.1 Introduction

The consequences of several beyond design basis accident scenarios are more severe than the accidents previously considered herein. The primary containment pressure during these accidents is estimated to exceed its design capacity. Thus, the primary containment fails, releasing reactor fission products to the secondary containment and potentially to the environment as well. The direct torus vent line (DTVL) provides an emergency primary containment vent path to prevent, or at least slow down, the buildup of potentially damaging pressure within the primary containment.

5.4.7.2 System Description

The DTVL is an 8" carbon steel line connecting the 20" torus main exhaust line to the underground 20" main stack exhaust line. The 8" DTVL starts at a branch between the 8" containment isolation valves AO-5042A&B. The DTVL terminates in the 20" main stack exhaust line, several feet downstream of the SBGT outlet valves. The line includes AO-5025, an 8" air-operated, normally-closed butterfly valve which serves as the outboard containment isolation valve for the DTVL upstream of the connection to the 20" main stack exhaust line. Both electrical power and valve operator active gas (air or nitrogen) supply are taken from "essential" or reliable sources, or are backed-up to ensure that the system is available during a station blackout or loss of instrument air event. FSAR Figure 5.4-1 (Drawing M227) shows the DTVL arrangement, but the tie into the 20" main stack exhaust line is shown in FSAR Figure 7.18-2 (Drawing M294).

The DTVL meets ASME B&PV Code (1980 Edition with Winter 1980 Addenda), Section III, Subsection NC for Nuclear Class 2 requirements up to and including the isolation valve. The new piping downstream of the isolation valve meets ANSI B31.1 (1977 Edition through Winter 1979 Addenda) requirements.

During normal or general transient conditions, the DTVL outboard isolation valve would remain closed. In response to a beyond design basis accident, plant management could direct the control room operators to employ the DTVL to relieve excessive pressure within the containment. In this case, the operator would follow a written procedure to perform the following basic actions:

- Close, or confirm closed, the outboard isolation valve for the torus main exhaust line
- Optimally, turn off the SBGT which likely came on automatically in response to a high drywell pressure signal
- Close, confirm closed, the SBGT outlet valves to prevent the high containment pressures from back-pressurizing the SBGT filters
- Open the two DTVL isolation valves
- Close the two DTVL isolation valves to terminate the release.

5.4.7.3 Radiological Consequences of DTVL Use

The exhaust gases released by the DTVL following a beyond design basis accident would have initially been "washed" by the suppression pool water which would reduce the particulates released. These exhaust gases are vented to the highest vent point (main stack), avoiding the groundlevel release of radioactive material from containment failure due to over-pressurization.

5.4.8 References

1. GE Letter No. SSX:79-64.

2. July 13, 1979 Letter, W. J. Neal (GE) to S. A. Giusti (Bechtel).

3. BLE-459 dated September 25, 1975.

4. Supplement No. 1 to Dresden Station Special Report No. 39 and Quad Cities Special Report No. 14.

5. NRC SER Supporting Amendment 55 to Facility License No. DPR-35, Containment Atmospheric Dilution System.

6. NRC SER Relating to Generic Letter 84-09 on Hydrogen Recombiner Capability, PNPS Unit 1.

7. Pilgrim License Amendment No. 206, dated July 22, 2004.

7.3 PRIMARY CONTAINMENT AND REACTOR VESSEL ISOLATION CONTROL SYSTEM

7.3.1 Safety Objective

To provide timely protection against the onset and consequences of accidents involving the gross release of radioactive materials from the fuel and nuclear system process barrier, the Primary Containment and Reactor Vessel Isolation Control System initiates automatic isolation of appropriate pipelines which penetrate the primary containment whenever monitored variables exceed preselected operational limits.

A gross failure of the fuel barrier would allow the escape of fission products from the fuel. A gross failure of the nuclear system process barrier could allow the escape of gross amounts of reactor coolant. The loss of coolant could lead to overheating and failure of the fuel. For a gross failure of the fuel, the Primary Containment and Reactor Vessel Isolation Control System initiates isolation of the reactor vessel to contain released fission products. For a gross breach in the nuclear system process barrier outside the primary containment, the Isolation Control System acts to interpose additional barriers (isolation valve closure) between the reactor and the breach, thus stopping the release of radioactive materials and conserving reactor coolant. For gross breaches in the nuclear system process barrier inside the primary containment, the Primary Containment and Reactor Vessel Isolation Control System acts to close off release routes through the primary containment barrier, thus trapping the radioactive material coming through the breach inside the primary containment.

7.3.2 Definitions

See FSAR Section 5.2.3.5.1 for the primary containment isolation valve classes.

7.3.3 Safety Design Bases

1. To limit the uncontrolled release of radioactive materials to the environs, the Primary Containment and Reactor Vessel Isolation Control System shall, with precision and reliability, initiate timely isolation of penetrations through the primary containment structure which could otherwise allow the uncontrolled release of radioactive materials whenever the values of monitored variables exceed preselected operational limits.

2. To provide assurance that important variables are monitored with a precision sufficient to fulfill safety design basis 1, the Primary Containment and Reactor Vessel Isolation Control Systems shall respond correctly to the sensed variables over the expected range of magnitudes and rates of change.

3. To provide assurance that important variables are monitored with a precision sufficient to fulfill safety design basis 1, an adequate number of sensors shall be

provided for monitoring essential variables that have spatial dependence.

4. To provide assurance that conditions indicative of a gross failure of the nuclear system process barrier are detected with sufficient timeliness and precision to fulfill safety design basis 1, the Primary Containment and Reactor Vessel Isolation Control System inputs shall be derived, to the extent feasible and practical, from variables that are true, direct measures of operational conditions.

5. The time required for closure of the main steam line isolation valves shall be short, so that the release of radioactive material and the loss of coolant as a result of a breach of a steam line outside the primary containment are minimal.

6. The time required for closure of the main steam isolation valves shall not be so short that inadvertent isolation of steam lines causes excessive fuel damage or excessive nuclear system pressure. This basis ensures that the main steam isolation valve closure speed is compatible with the ability of the Reactor Protection System (RPS), and Pressure Relief System to protect the fuel and nuclear system process barrier.

7. To provide assurance that closure of Class A and Class B automatic isolation valves is initiated, when required, with sufficient reliability to fulfill safety design basis 1, the following safety design bases shall be specified for the systems controlling Class A and Class B automatic isolation valves:

   a. No single failure within the Isolation Control System shall prevent isolation action when required to satisfy safety design basis 1

   b. Any one intentional bypass, maintenance operation, calibration operation, or test to verify operational availability shall not impair the functional ability of the Isolation Control System to respond correctly to essential monitored variables

   c. The system shall be designed for a high probability that, when any essential monitored variable exceeds the isolation setpoint, the event shall either result in automatic isolation or shall not impair the ability of the system to respond correctly as other monitored variables exceed their trip points

   d. Where a plant condition that requires isolation can be brought on by a failure or malfunction of a control or regulating system, and the same failure or malfunction prevents action by one or more Isolation Control System channels designed to provide protection against the unsafe condition, the remaining portions of the Isolation Control

System shall meet the requirements of safety design bases 1, 2, 3, and 7a

e. The power supplies for the Primary Containment and Reactor Vessel Isolation Control System shall be arranged so that loss of one supply cannot prevent automatic isolation when required

f. The system shall be designed so that, once initiated, automatic isolation action goes to completion. Return to normal operation after isolation action shall require deliberate operator action

g. There shall be sufficient electrical and physical separation between trip channels monitoring the same essential variable to prevent environmental factors, electrical faults, and physical events from impairing the ability of the system to respond correctly

h. Earthquake ground motions shall not impair the ability of the Primary Containment and Reactor Vessel Isolation Control System to initiate automatic isolation. See Section 7.1.6

8. To assure that the timely isolation of main steam lines is accomplished, when required, with extraordinary reliability, the following safety design bases are specified:

a. The motive force for achieving valve closure for one of the two tandem mounted isolation valves in an individual steam line shall be derived from a different energy source than that for the other valve

b. At least one of the isolation valves in each of the steam lines shall not rely on continuity of any variety of electrical power for the motive force to achieve closure

9. To reduce the probability that the operational reliability and precision of the Primary Containment and Reactor Vessel Isolation Control System will be degraded by operator error, the following safety design bases are specified for Class A and Class B automatic isolation valves:

a. Access to all trip settings, component calibration controls, test points, and other terminal points for equipment associated with essential monitored variables shall be under the control of the control room operator or other supervisory personnel

b. The means for bypassing channels, logics, or system components shall be under the control of the control room operator. If the ability to trip some essential part of the system has been bypassed, this fact will be continuously indicated in the control room

10. To provide the operator with means independent of the automatic isolation functions to take action in the event of a failure of the nuclear system process barrier, it shall be possible for the control room operator to manually initiate isolation of the primary containment and reactor vessel.

11. To provide the operator with the means to assess the condition of the primary containment and Reactor Vessel Isolation Control System, and to identify conditions indicative of a gross failure of the nuclear system process barrier, the following bases shall be specified:

    a. The Primary Containment and Reactor Vessel Isolation Control System shall be designed to provide the operator with information pertinent to the status of the system

    b. Means shall be provided for prompt identification of channel and trip system responses

12. It shall be possible to check the operational availability of each essential channel, logic, and trip system during reactor operation.

7.3.4 Description

7.3.4.1 Identification

The primary containment and reactor vessel isolation control system includes the sensors, channels, switches, and remotely activated valve closing mechanisms associated with the valves, which, when closed, effect isolation of the primary containment or reactor vessel, or both. It should be noted that the control systems for those Class A and B isolation valves which close by automatic action pursuant to the safety design bases are the main subjects of this section. However, Class C remotely operated isolation valves are included because they add to the operator's ability to effect manual isolation. Testable check valves are also included because they provide the operator with an ability to check that the valve disk can respond to reverse flow. The primary containment and reactor vessel isolation control system is designed to comply with the intent of IEEE-279 and the Commission's Proposed General Design Criteria. Refer to Appendix F and Appendix J for additional details.

7.3.4.2 Power Supply

The power for the channels and logics of the isolation control system is supplied from the RPS motor generator sets, the station batteries and the unit preferred power system. Isolation valves receive power from standby power sources. Power for the operation of two valves in a pipeline is fed from different sources. In most cases one valve is powered from an ac bus of appropriate voltage, and the other valve is powered by dc from the station batteries. The main steam isolation valves, described in detail later, use ac, dc, and pneumatic pressure in the control scheme. Table 5.2-4 lists the power supply for each isolation valve.

7.3.4.3 Physical Arrangement

Table 5.2-4 lists the pipelines that penetrate the primary containment and indicates the types and locations of the isolation valves installed in each pipeline. Figure 4.3-2 (BECo M252) identifies some of these pipelines. Pipelines which penetrate the primary containment and directly communicate with the reactor vessel generally have two Class A isolation valves, one inside the primary containment and one outside the primary containment. Pipelines which penetrate the primary containment and which communicate with the primary containment free space, but which do not communicate directly with the reactor vessel, generally have two Class B isolation valves located outside the primary containment. Class A and Class B automatic isolation valves are considered essential for protection against the gross release of radioactive material in the event of a breach in the nuclear system process barrier. Process pipelines that penetrate the primary containment, but do not communicate directly with the reactor vessel, the primary containment free space, or the environs, have at least one Class C isolation valve located outside the primary containment which may close either by process action (reverse flow) or by remote manual operation. Table 5.2-4 presents information about all piping penetrations in the primary containment. Only the controls for the automatic isolation valves are discussed in this part of the safety analysis report. The valves, which are the subject of this text, are specifically identified in the detailed descriptions which follow.

Power cables are run in conduits or trays from appropriate electrical sources to the motor or solenoid involved in the operation of each isolation valve. The control arrangement for the main steam line isolation valves includes pneumatic piping and an accumulator for those valves for which air is considered the emergency source of motive power for closing. Pressure and water level sensors are mounted on instrument racks in either the reactor building or the turbine building. Valve position switches are mounted on the valve for which position is to be indicated. Switches are enclosed in cases to protect them from environmental conditions. Cables from each sensor are routed in conduits and cable trays to the control room. All signals transmitted to the control room are electrical; no pipe from the nuclear system or the primary containment penetrates the control room. Pipes used to transmit level information from the reactor vessel to sensing instruments terminate inside the secondary containment (reactor building). The sensor cables and power supply cables are routed to cabinets in the cable spreading room and control room where the logic arrangement of the system is formed.

To ensure continued protection against the uncontrolled release of radioactive material during and after earthquake ground motions, the control systems required for the automatic closure of Class A and Class B valves are designed as Class 1 equipment as described in Section 12 and Appendix C. This meets safety design basis 7h.

7.3.4.4 Logic

The basic logic arrangement for essential trip functions is one in which an automatic isolation valve is controlled by two trip systems. Where many isolation valves close on the same signal, two trip systems control the entire group. Where just one or two valves must close in response to a special signal, two trip systems may be formed from the instruments provided to sense the special condition. Valves that respond to the signals from common trip systems are identified in the detailed descriptions of isolation functions.

Each trip system has a pair of logics. Each logic receives input signals from at least one channel for each monitored variable. Thus, two channels are required for each essential monitored variable to provide independent inputs to the logic of one trip system. A total of four channels for each essential monitored variable is required for the logics of both trip systems. This description is not applicable to the HPCI and RCIC steam supply low pressure isolation logics. These logics provide an operational interlock and are not intended to perform a primary containment isolation function. Figures 7.3-2 and 7.3-3 illustrate typical isolation control arrangements for motor-operated valves and for the main steam line isolation valves.

The actuators associated with one logic pair provide inputs into each of the actuator logics for that trip system. Thus, either of the two logics associated with one trip system can produce a trip system trip. The logic is a 1-out-of-m arrangement, where m may be 2 or more.

To initiate valve closure, the actuator logics of both trip systems must be tripped. The overall logic of the system could be termed one-out-of-two taken twice.

The basic logic arrangement just described does not apply to Class C isolation valves and testable check valves. Exceptions to the basic logic arrangement are made in several instances for certain Class A and Class B isolation valves as described below.

7.3.4.5 Operation

During normal operation of the station, when isolation is not required, sensor and trip contacts essential to safety are closed; channels, and trip logics are normally energized. Whenever a channel sensor contact opens, its auxiliary relay deenergizes, causing contacts in the trip logic to open. The opening of contacts in the logic deenergizes its actuator. When deenergized, the actuator trip relay opens a contact in an actuator logic. If a trip then occurs in either of the logic pairs of the other trip system, another actuator logic is deenergized. With both trip systems tripped, appropriate contacts open or close in valve control circuitry to actuate the valve closing mechanism. Automatic isolation valves that are normally closed receive the isolation signal as well as those valves that are open. This fail safe logic is not applicable to the HPCI and RCIC systems since these systems may be required to perform a safety function during a loss of AC power. HPCI and RCIC isolation logics are therefore DC powered and energize to actuate. Additionally, RHR isolation (Group III) is not entirely fail-safe since it must perform its safety function during a loss of AC power and therefore isolation logic is DC powered and energize to actuate. The control system for each Class A isolation valve is designed to provide closure of the valve in time to prevent uncovering the fuel as a result of a break in the pipeline which the valve isolates. The control systems for Class A and Class B isolation valves are designed to provide closure of the valves with sufficient rapidity to restrict the release of radioactive material to the environs below the guideline values of applicable regulations.

All automatic Class A and Class B valves and remotely operable Class C valves can be closed by manipulating switches in the control room, thus providing the operator with means independent of the automatic isolation functions to take action in the event of a failure of the nuclear system process barrier. This meets safety design basis 10.

Once isolation is initiated, the valve continues to close, even if the condition that caused isolation is restored to normal. The operator must manually operate switches in the control room to reopen a valve which has been automatically closed. Unless manual override features are provided in the manual control circuitry, the operator cannot reopen the valve until the conditions which initiated isolation have cleared. This is the equivalent of a manual reset and meets safety design basis 7f.

A trip of an isolation trip system channel is annunciated in the control room so that the operator is immediately informed of the condition. The response of isolation valves is indicated by "open-closed" lights. All motor-operated Class A and Class B isolation valves whose primary function is to isolate, have two sets of "open-closed" lights. One set is located near the manual control switches for controlling each valve from the control room panel. A second set is located in a separate central isolation valve position display in the control room. The positions of air-operated isolation valves are displayed in the same manner as motor-operated valves.

Inputs to annunciators, indicators, and the computer are arranged so that no malfunction of the annunciating, indicating, or computing equipment can functionally disable the system. Signals directly from the isolation control system sensors are not used as inputs to annunciating or data logging equipment. Isolation is provided between the primary signal and the information output. The arrangement of indications pertinent to the status and response of the primary containment and reactor vessel isolation control system satisfies safety design bases 11a and 11b.

The control room indication provided to assess the condition of the isolation control system satisfies IEEE-279 paragraphs 4.19 and 4.20 in the following manner:

1. Identification of Protection Actions (IEEE-279 paragraph 4.19)

Protective actions (here interpreted to mean dropout of a single sensor relay) are directly indicated and identified by action of the sensor relay. The relay has an identification tag and a clear glass front window that permits convenient visible verification of the relay position. Any one of the sensor relays also actuates an annunciator, so that no single channel "trip" (relay dropout) will go unnoticed. Either of these indications (annunciation and visible verification relay actuation) fulfills the requirements of this criterion

2. Information Readout (IEEE-279 paragraph 4.20)

The information presented to the operator by the primary containment and reactor vessel isolation control system are:

a. Annunciation of each process variable which has reached a trip point

b. Relay position for trips on main steam line tunnel temperature or main steam line excess flow

c. Control power failure annunciation on each channel

d. Annunciation of steam leaks in each of the five systems monitored, i.e., main steam, reactor water cleanup, residual heat removal (RHR), high pressure coolant injection (HPCI), and reactor core isolation coolant (RCIC)

e. Open and closed position lights for each isolation valve

f. Drywell pressure and temperature indicators

g. Torus water temperature

h. Torus water level

Additional information is available to the operator for monitoring reactor vessel pressure, reactor vessel water level, neutron flux, and control rod positions

7.3.4.6 Isolation Valve Closing Devices and Circuits

Table 7.3-1 itemizes the type of closing device provided for each isolation valve intended for use in automatic or remote manual isolation of the primary containment or reactor vessel. To meet the requirement that automatic Class A valves be fully closed in time to prevent the reactor vessel water level from falling below the top of the active fuel as a result of a break of the pipeline which the valve isolates, the valve closing mechanisms are designed to give the closing rates specified on Table 7.3-1. In many cases a "standard" closing rate is adequate to meet isolation requirements. Because of the relatively long time required for fission products to reach the containment atmosphere following a break in the nuclear system process barrier inside the primary containment, a "standard" closure rate is adequate for the automatic closing devices on Class B isolation valves.

Motor operators for Class A and Class B isolation valves are selected with capabilities suitable to the physical and environmental requirements of service. The required valve closing rates were considered in designing motor operators. Appropriate torque and limit switches are used to ensure proper valve seating. Handwheels, which are automatically disengaged from the motor operator when the motor is energized, are provided for local manual operation.

Direct solenoid operated isolation valves and solenoid air pilot valves are chosen with electrical and mechanical characteristics which make them suitable for the service for which they are intended. Appropriate watertight or weathertight housings are used to ensure proper operation under accident conditions.

Closure of the isolation valve in the pneumatic supply line to the drywell is annunciated to alert the operator as to the loss of air condition.

The main steam isolation valves are spring closing, pneumatic, piston operated valves designed to close upon loss of pneumatic pressure to the valve operator. This is a fail safe design. The control arrangement is shown on Figures 7.3-3 and 7.3-4. Closure time for the valves is adjusted between 3 and 5 sec. Each valve is piloted by two, three-way, packless, direct acting, solenoid-operated pilot valves: one powered by AC, the other by DC. An accumulator is located close to each isolation valve to provide pneumatic pressure for valve operation to preclude challenges to ECCS due to inadvertent air loss during operation.

The valve pilot system and the pneumatic pipe lines are arranged so that, when one or both solenoid-operated pilot valves are energized, normal air supply provides pneumatic pressure to the air-operated pilot valve to direct air pressure to the main valve pneumatic operator. This overcomes the closing force exerted by the spring. When both pilots are deenergized, as would be the result of both trip systems tripping or placing the manual switch in the closed position, the path through which air pressure acts is switched so that the opposite side of the valve operator is pressurized, thus assisting the spring in closing the valve. In the event of air supply failure, the loss of air pressure will cause the air operated pilot valve to move by spring force to the position resulting in main valve closure. Main valve closure is then effected by means of the air stored in the accumulator and by the spring.

Air pressure, acting alone, and the force exerted by the spring, acting alone, are each capable of independently closing the valve. The isolation valves inside the primary containment (inboard) are designed to close under either pneumatic pressure or spring force with the vented side of the piston operator at the containment peak accident pressure. The outboard valve is exactly the same design, although it will be subjected only to atmospheric pressures. The accumulator volume was chosen to provide enough pressure to close the valve when the pneumatic supply to the accumulator has failed.

The supply line to the accumulator is large enough to make up pressure to the accumulator at a rate faster than the valve operation bleeds pressure from the accumulator during valve opening or closing.

A separate, single, solenoid-operated pilot valve with an independent test switch is included to allow manual testing of each isolation valve from the control room. The testing arrangement is designed to give a slow closure of the isolation valve being tested to avoid rapid changes in steam flow and nuclear system pressure. Slow closure of a valve during testing requires 50 to 60 seconds. The valve mechanical design is discussed further in Section 4.6, Main Steam Line Isolation Valves (MSIVs).

Four additional keylock switches (one for each logic channel) are provided to facilitate testing of the MSIV pilot valve logic circuits.

7.3.4.7 Isolation Functions and Settings

The isolation allowable setpoints of the Primary Containment and Reactor Vessel Isolation Control System are listed on Table 7.3-2. The functions that initiate automatic isolation are itemized on Table 7.3-1 in terms of the pipelines that penetrate the primary containment. This latter table includes all pipelines of concern for isolation purposes. Although this section is concerned with the electrical control systems that initiate isolation to prevent direct release of radioactive material from the primary containment or nuclear system process barrier, the additional information given on Table 7.3-1 can be used to assess the overall (electrical and mechanical) isolation effectiveness of each system having pipelines which penetrate the primary containment. Isolation functions and trip settings used for the electrical control of isolation valves in fulfillment of the previously stated safety design bases are discussed in the following paragraphs. The role each isolation function plays in initiating isolation of barrier valves or groups of valves is illustrated in the functional control diagrams on Figures 7.3-5 and 7.3-6.

1. Reactor Vessel Low Water Level

   A low water level in the reactor vessel could indicate that either reactor coolant is being lost through a breach in the nuclear system process barrier, or that the normal supply of reactor feedwater has been lost and that the core is in danger of becoming overheated as the reactor coolant inventory diminishes. Reactor vessel low water level initiates closure of various Class A and Class B valves. The closure of Class A valves is intended to either isolate a breach in any of the pipelines in which valves are closed or conserve reactor coolant by closing off process lines. The closure of Class B valves is intended to prevent the escape of radioactive materials from the primary containment through process lines which are in communication with the primary containment free space.

Two reactor vessel low water level isolation trip settings are used to complete the isolation of the primary containment and the reactor vessel. See Table 7.3-1, Signals A and B. The first reactor vessel low water level isolation trip setting, which occurs at a higher water level than the second setting, initiates closure of all Class A and Class B valves in major process pipelines except the main steam lines. The main steam lines are left open to allow the removal of heat from the reactor core. The second and lower reactor vessel low water level isolation trip setting completes the isolation of the primary containment and reactor vessel by initiating closure of the main steam isolation valves, and any other Class A or Class B valves that must be shut to isolate minor process lines.

The first low water level setting, which is coincidentally the same as the reactor vessel low water level scram setting, was selected to initiate isolation at the earliest indication of a possible breach in the nuclear system process barrier, yet far enough below normal operational levels to avoid spurious isolation. Isolation of the following pipelines is initiated when reactor vessel low water level falls to this first setting.

Torus Vacuum Breakers

Traversing incore probe

RHR reactor shutdown cooling suction

Reactor water sample lines

Drywell equipment drain sump discharge

Drywell floor drain sump discharge

Reactor water cleanup

Drywell purge inlet and makeup gas*, **

Drywell main exhaust

Suppression chamber exhaust valve bypass*, **

Suppression chamber purge inlet and makeup gas*, **

Suppression chamber main exhaust

Drywell exhaust valve bypass*, **

RHR-LPCI supply

RHR to Radwaste

Containment atmosphere sampling lines

* Containment makeup and ventilation valves are also provided for use following an accident condition. These are remote manual operated. Refer to Section 5.4.3.

** The reactor water low level isolation signal can be bypassed. These valves may be opened anytime provided the low-low water level signal is not present.

The second and lower of the reactor vessel low water level isolation settings was selected low enough to allow the removal of heat from the reactor for a predetermined time following the scram, and high enough to complete isolation in time for the operation of CSCS in the event of a large break in the nuclear system process barrier. This second low water level setting is low enough that partial losses of feedwater supply would not unnecessarily initiate full isolation of the reactor, thereby disrupting normal shutdown or recovery procedures. Isolation of the following pipelines is initiated when the reactor vessel water level falls into this second setting.

All four main steam lines:

Main steam line drain

Reactor water sample line

A high water level in the reactor vessel indicates that the reactor is overfilled and the steam lines are in danger of being flooded with water. The high water level isolation signal is to protect against rapid depressurization due to a malfunction of the pressure regulator system during start-up when pressure is below 782 psig. This high water level isolation is not functional when the mode switch is in the run position. The reactor high water level initiates isolation of:

All four main steam lines:

Main steam line drain

Reactor water sample line

Reactor vessel high water level also shuts down the RCIC and HPCI turbines. Refer to Sections 4.7 and 7.4, respectively.

2. Deleted

3. Main Steam Line Space High Temperature

High temperature in the space in which the main steam lines are located outside of the primary containment could indicate a breach in a main steam line. The automatic closure of various Class A valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. When high temperatures occur in the main steam line space, the following pipelines are isolated. (See Table 7.3-1, Signal D):

All four main steam lines

Main steam line drain

Reactor water sample line

The main steam line space high temperature trip is set far enough above the temperature expected during operations at rated power to avoid spurious isolation, yet low enough to provide early indication of a steam line break.

4. Main Steam Line High Flow

Main steam line high flow could indicate a break in a main steam line. The automatic closure of various Class A valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. Upon detection of main steam line high flow, the following pipelines are isolated:

All four main steam lines

Main steam line drain

Reactor water sample line

The main steam line high flow trip setting is selected high enough to permit the isolation of one main steam line for test at rated power without causing an automatic isolation of the rest of the steam lines, yet low enough to permit early detection of a steam line break. See Table 7.3-1, Signal D.

5. Low Steam Presssure at Turbine Inlet

Low steam pressure at the turbine inlet while the reactor is operating could indicate a malfunction of the nuclear system pressure regulator in which the turbine control valves or turbine bypass valves open fully. See Table 7.3-1, Signal P.

The termal stresses associated with excessive depressurization could result in a significant increase in the nuclear system process barrier's lifetime fatigue usage factor. Also, excessive depressurization would permit sufficient level swell to trap water in the main steamline between the in-board MSIVs and the SRVs, requiring SRVs to discharge either liquid or two-phase flow. SRVs are only designed for saturated steam with less than 1% moisture.

A rapid depressurization of the reactor vessel while the reactor is near full power could also result in undesirable differential pressures across the channel around some fuel bundles of sufficient magnitude to cause mechanical deformation of channel walls. Such depressurizations, without adequate preventative action, could require thorough vessel analysis or core inspection prior to returning the reactor to power operation. To avoid excessive depressurization, the steam pressure at the turbine inlet is monitored and upon falling below a preselected value with the reactor in the RUN mode initiates isolation of the following pipelines:

All four main steam lines

Main steam drain line

Reactor water sample line

The low steam pressure isolation setting is selected far enough below normal turbine inlet pressures to avoid spurious isolation yet high enough to provide timely detection of a pressure regulator malfunction. Although this isolation function is not required to satisfy any of the safety design bases for this system, this discussion is included here to make the listing of isolation functions complete.

An evaluation that demonstrates the adequacy of the isolation setting of 750 psig is included in Reference 1. The actual analytical limit is calculated to be 782 psig.

6. Primary Containment (drywell) High Pressure

High pressure in the drywell could indicate a breach of the nuclear system process barrier inside the drywell. The automatic closure of various Class B valves prevents the release of significant amounts of radioactive material from the primary containment. Upon detection of a high drywell pressure, the following pipelines are isolated. See Table 7.3-1, Signal F.

Torus Vacuum Breakers

Traversing incore probe

RHR shutdown cooling suction

Reactor water sample lines

Drywell equipment drain sump discharge

Drywell floor drain sump discharge

Drywell purge inlet and makeup gas*, **

Drywell main exhaust

Suppression chamber exhaust valve bypass*, **

Suppression chamber purge inlet and makeup gas*, **

Suppression chamber main exhaust

Drywell exhaust valve bypass*, **

RHR-LPCI supply

RHR to Radwaste

Containment atmosphere sampling lines

The primary containment high pressure isolation setting is selected to be as low as possible without inducing spurious isolation trips. See Table 7.3-1, Signal F.

* Containment makeup and ventilation valves are also provided for use following an accident condition. These are remote manual operated. Refer to Section 5.4.3.

** The reactor water low level isolation signal can be by-passed. These valves may be opened anytime provided the low-low water level signal is not present.

7. RCIC System Equipment Space High Temperature

High temperature in the vicinity of the RCIC System equipment could indicate a break in the RCIC steam line. The automatic closure of certain Class A valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. When high temperature occurs near the RCIC System equipment, the RCIC turbine steam line is isolated. The high temperature isolation setting is selected far enough above anticipated normal RCIC system operational levels to avoid spurious operation but low enough to provide timely detection of a RCIC turbine steam line break. See Table 7.3-1, Signal K.

8. RCIC Turbine High Steam Flow

RCIC turbine high steam flow could indicate a break in the RCIC turbine steam line. The automatic closure of certain Class A valves prevents the excessive loss of reactor coolant, and the release of significant amounts of radioactive materials from the nuclear system process barrier. Upon detection of RCIC system turbine high steam flow, the RCIC system turbine steam line is isolated. The high steam flow trip setting is selected high enough to avoid spurious isolation yet low enough to provide timely detection of a RCIC turbine steam line break. See Table 7.3-1, Signal K.

The logic arrangement used for this function is shown on Figure 7.3-7 and is an exception to the usual logic requirement because high steam flow is the second method of detecting a RCIC turbine steam line break.

9. RCIC Turbine Steam Line Low Pressure

RCIC turbine steam line low pressure is used to automatically close the two isolation valves in the RCIC turbine steam line, so that steam and radioactive gases will not escape from the

RCIC turbine shaft seals into the reactor building after steam pressure has decreased to such a low value that the turbine cannot be operated. The isolation setpoint is chosen at a pressure below that at which the RCIC turbine can operate effectively. This isolation is an operational interlock not required for safety. See Table 5.2-4, Signal K.

10. HPCI System Equipment Space High Temperature

High temperature in the vicinity of the HPCI system equipment could indicate a break in the HPCI system turbine steam line. The automatic closure of certain Class A valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. When high temperature occurs near the HPCI system equipment, the HPCI system turbine steam supply line is isolated. The high temperature isolation setting is selected far enough above anticipated normal HPCI system operational levels to avoid spurious isolation, but low enough to provide timely detection of a HPCI turbine steam line break. See Table 5.2-4, Signal L.

11. HPCI Turbine High Steam Flow

HPCI turbine high steam flow could indicate a break in the HPCI turbine steam line. The automatic closure of certain class A valves prevents the excessive loss of reactor coolant, and the release of significant amounts of radioactive materials from the nuclear system process barrier. Upon detection of HPCI turbine high steam flow the HPCI turbine steam line is isolated. The high steam flow trip setting is selected high enough to avoid spurious isolation, yet low enough to provide timely detection of a HPCI turbine steam line break. See Table 5.2-4, Signal L.

The logic arrangement used for this function, shown on Figure 7.3-7, is an exception to the usual logic requirement, because high steam flow is the second method of detecting a HPCI turbine steam line break.

12. Low Reactor Vessel Pressure

Low reactor vessel pressure is used to automatically close the two isolation valves in the HPCI turbine steam line, so that steam and radioactive gases will not escape from the HPCI turbine shaft seals into the reactor building after steam pressure has decreased to such a low value that the turbine cannot be operated. The isolation setpoint is chosen at a pressure below that where the HPCI turbine can operate efficiently. This isolation is an operational interlock not required for safety. See Table 5.2-4, Signal AA.

13. Reactor Water Cleanup System Space High Temperature

High temperature in the vicinity of the reactor water cleanup (RWCU) equipment and piping could indicate a break in a RWCU line. The automatic closure of certain Class A valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. When high temperature occurs near the RWCU equipment, the RWCU system is isolated. The high temperature isolation setting is selected far enough above anticipated normal system operational levels to avoid spurious isolation, yet low enough to provide timely detection of a line break. See Table 5.2-4, Signal J.

14. Reactor Water Cleanup System High Flow

RWCU high flow could indicate a break in a RWCU line. The automatic closure of certain Class A valves prevents the excessive loss of reactor coolant, and the release of significant amounts of radioactive materials from the nuclear system process barrier. Upon detection of RWCU high flow, the RWCU line is isolated. The high flow trip setting and time delay setting were selected high enough to avoid spurious isolation, yet low enough to provide timely detection of line break. See Table 5.2-4, Signal J.

15. High Reactor Vessel Pressure

High reactor vessel pressure is used to automatically close the two isolation valves in the RHR pumps' shutdown cooling suction piping and the two isolation valves in the shutdown cooling head spray line so that the RHR low pressure piping will not be threatened by overpressurization. The isolation setpoint is chosen at a pressure below where the RHR piping could be overpressurized and the maximum differential pressure associated with the suction isolation valves is not exceeded. The RHR inboard injection valve control circuit uses the negation of this signal as a permissive for the shutdown cooling mode. See Table 5.2-4, Signal U.

16. Low Reactor Vessel Pressure AND High Drywell Pressure

Low reactor vessel pressure AND high drywell pressure are used to automatically close the two isolation valves in the HPCI turbine exhaust vacuum breaker line. The low reactor vessel pressure isolation setpoint was chosen to coincide with the pressure at which the HPCI system would trip. See Table 5.2-4, Signal N.

7.3.4.8 Instrumentation

Sensors providing inputs to the Primary Containment and Reactor Vessel Isolation Control System are not used for the automatic control of process systems, thus separating the functional control of protection systems and process systems. Channels are physically and electrically separated to assure that a single physical event cannot prevent isolation. Channels for one monitored variable that are grouped near to each other provide inputs to different isolation trip systems. Figures 7.3-2, 7.3-3, and 7.3-7 through 7.3-12 illustrate typical arrangements of channels, logics, and valve closing mechanism circuitry for Isolation Control Systems. Figures 7.3-5 and 7.3-6 illustrate in detail the functional arrangement of channels used to initiate isolation of various groups of valves. Table 7.3-2 lists instrument characteristics. Figures 7.3-14 through 7.3-24 illustrate how the many different channels and logics are typically combined to form the Isolation Control System. On Figures 7.3-14 through 7.3-24, the key contacts and relays have been consistently identified so that tracing the action of the isolation control circuitry from sensor through valve control is possible. Not all isolation valve controls are illustrated on Figures 7.3-14 through 7.3-24; however, sufficient illustration of typical controls is given that the general arrangement for any isolation valve control circuit is included.

1. Reactor vessel low water level signals are initiated from four differential pressure transmitters which sense the difference between the pressure due to a constant reference column of water, and the pressure due to the actual water level in the vessel. An analog trip unit actuated by each of the four transmitters is used to indicate that water level has decreased to the first and higher low water level isolation setting; another analog trip unit actuated by each of the four transmitters is used to indicate that water level has decreased to the second and lower of the two low water level isolation settings. Reactor vessel high water level signals are initiated from analog trip units activated from the same transmitters. The four transmitters and respective trip units for each level setting are arranged in pairs; each transmitter/trip unit in a pair provides a signal to a different trip system. Two pipelines, attached to taps above and below the water level on the reactor vessel, are required for the differential pressure measurement for each pair of transmitters. The two pairs of pipelines terminate outside the primary containment in the Reactor Building; they are physically separated from each other and tap off the reactor vessel at widely separated points. The reactor vessel low water level transmitters sense level from these pipes. This arrangement assures that no single physical event can prevent isolation when required. Cables from the level sensors are routed to the analog trip cabinets in the Cable Spreading Room. Level instrumentation sensing lines inside the drywell have been designed with a minimum vertical drop to reduce error due to high drywell temperature.

2. Deleted.

3. High temperature in the vicinity of the main steam lines is detected by bimetallic temperature switches located in the main steam line tunnel ventilation exhaust duct and in the turbine basement area. The detectors are located or shielded so that they are sensitive to air temperature and not the radiated heat from hot equipment. An additional temperature sensor is located near each set of four detectors for remote temperature readout and alarm. The temperature sensors activate an alarm at high temperature and upon loss of power, operate to give the alarm condition. The main steam line space temperature detection system is designed to detect leakage greater than 10 gal/min in the main steam tunnel and 150 gal/min in the condenser compartment. Figure 7.3-8

illustrates in general terms the instruments used to detect high temperatures in the main steam line space. Figure 7.3-9 illustrates how temperature switches are combined to form a typical single channel. A total of four main steam line space high temperature channels are provided. Each main steam line isolation logic receives an input signal from one main steam line space high temperature channel. See Section 7.3.4.8.1.

4. High flow in each main steam line is sensed by four differential pressure transmitters which sense the pressure difference across the flow restrictor in that line. Figure 7.3-10 illustrates the general arrangement of instruments used to sense the flow in a single main steam line. Figure 7.3-11 illustrates how the 16 differential pressure transmitters and respective trip units are combined to form four channels. Each main steam line isolation logic receives an input signal from one main steam line high flow channel.

5. Main steam line low pressure is sensed by four pressure transmitters which sense pressure downstream of the outboard main steam isolation valves. The sensing point is located at the header that connects the four steam lines upstream to the turbine stop valves. Each transmitter and respective trip unit is part of an independent channel. Each channel provides a signal to one isolation logic.

6. Primary containment pressure is monitored by four non-indicating pressure transmitters which are mounted on instrument racks outside the drywell. Pipes that terminate in the reactor building connect the transmitters with the drywell interior. Cables are routed from the transmitter to the analog trip cabinets. The transmitters and respective trip units are grouped in pairs, physically separated, and electrically connected to the isolation control system so that no single event will prevent isolation due to primary containment high pressure.

7. High temperature in the vicinity of the RCIC equipment is sensed by two sets of four bimetallic temperature switches. Each set is arranged as two trip systems. Figure 7.3-7 illustrates how temperature switches are combined to form a typical temperature channel. Each trip system receives input signals from two temperature trip channels. Both trip channels in either one of two trip systems must trip to initiate isolation. An additional temperature sensor is located near each set of four detectors for remote temperature read out and alarm. Figure 7.3-8 illustrates in general terms the instruments used to detect high RCIC area temperatures. See Section 7.3.4.8.1.

8. High flow in the RCIC turbine steam line is sensed by two differential pressure switches which monitor the differential pressure across an elbow installed in the RCIC turbine steam supply pipeline. The arrangement is illustrated on Figure 7.3-12. The tripping of either trip channel initiates isolation of the RCIC turbine steam line. This exception to the usual channel arrangement is because high steam flow is the second

method of detecting a steam line break, high RCIC equipment space temperature being the first.

9. Low pressure in the RCIC turbine steam line is sensed by four pressure switches from the RCIC turbine steam line upstream of the isolation valves. The four switches are arranged in a one-out-of-two taken twice logic in a single trip system. This trip is not considered a PCIS function. The logic is one-out-of-two taken twice to preclude inadvertent system isolation due to instrument failure, and to insure isolation even if a single instrument fails.

10. High temperature in the vicinity of the HPCI equipment is sensed by two sets of four bimetallic temperature switches. Each set is arranged as two trip systems. Figure 7.3-7 illustrates how temperature switches are combined to form a typical temperature channel. Each trip system receives input signals from two temperature trip channels. Both trip channels in either one of two trip systems must trip to initiate isolation. An additional temperature sensor is located near each set of four detectors for remote temperature read out and alarm. Figure 7.3-8 illustrates in general terms the instruments used to detect high HPCI area temperature. See Section 7.3.4.8.1.

11. High flow in the HPCI turbine steam line is sensed by two differential pressure switches which monitor the differential pressure across an elbow installed in the HPCI turbine steam pipeline. The arrangement is illustrated on Figure 7.3-12. The tripping of either switch initiates isolation of the HPCI turbine steam line. This exception to the usual sensor arrangement is because high steam flow is the second method of detecting a steam line break, high HPCI equipment space temperature being the first.

12. High temperature in the spaces occupied by the RHR (shutdown cooling) and piping outside the primary containment is sensed by temperature detectors that provide readout and activate alarms only, indicating possible pipe breaks.

    A typical arrangement is shown on Figure 7.3-8. Automatic isolation on high temperature is not required since the reactor vessel low water level isolation function is adequate in preventing the release of significant amounts of radioactive material in the event that either of these two systems suffers a breach.

13. High temperature in the vicinity of the RWCU system is sensed by four sets of two bimetallic temperature switches. A set of two temperature switches is installed in each of the four areas to be monitored; each set is a one-out-of-two trip system and capable of initiating isolation.

14. High flow in the RWCU system supply line is sensed by two differential pressure switches which monitor the pressure difference across an elbow installed in the RWCU system supply line. The arrangement of the differential pressure switches

is similar to that shown on Figure 7.3-12. The tripping of either switch initiates isolation of the RWCU system.

15. Reactor high pressure is sensed by two pressure transmitters which monitor reactor pressure at the steam portion of the reactor vessel. These transmitters provide analog signals to the rosemount analog trip units which are used to automatically isolate the shutdown cooling. These switches are also used as a permissive in the Group III isolation of the RHR injection inboard valves.

16. Low reactor pressure is sensed by four pressure transmitters which are mounted on instrument racks outside the drywell. The transmitters provide electrical signals to analog trip units located in the cable spreading room. The tripping of either the "A" or "B" division of these trip units will initiate isolation of the HPCI steam line, HPCI pump suction line, and turbine exhaust drain pot line. When in conjunction with the high drywell pressure, the HPCI turbine exhaust vacuum breaker line will also isolate.

Channel and logic relays are high reliability relays equal to type GP and EGP relays made by Agastat and HFA and CR120A relays made by the General Electric Company. The relays are selected so that the continuous load will not exceed 50 percent of the continuous duty rating.

7.3.4.8.1 High Temperature Sensors

The location, spatial independence, and resistance to spurious tripping of the high temperature sensors in the main steamline, HPCI turbine steamline and RCIC turbine steamline are detailed in this section.

Table 7.3-3 lists the areas outside the primary containment where main steam, HPCI, and RCIC steam lines are routed. This table also lists the leak detection sensors, summarizes the physical separation of sensors, and specifies the set points at which isolation of the respecting steam line would be initiated.

Potential leak sources and rates which would initiate isolation are as follows:

Main Steam Tunnel

This area contains feedwater, cleanup, and main steam piping. Isolation of the main steam lines will be initiated at ventilation exhaust temperatures from the main steam tunnel of 160°F to 170°F, which would result from steam leaks equivalent to 10 gal/min and greater. The feedwater and cleanup systems normally operate at approximately 1,000 psig with 400°F water. Leakage of about 40 gal/min from either of these water systems would cause an area temperature increase and initiation of main steam isolation. If ventilation exhaust temperatures did not decrease following main steam line isolation, then the presence of leakage from another system would be suspected and further actions taken to identify the source of the suspected leak.

Condenser Compartment Leak

This area contains main steam piping, extraction steam piping, and feedwater piping. Temperature sensors are provided in the main ventilation exhaust from this area to isolate the main steam lines at temperatures of 140°F to 150°F. This would correspond to steam leaks of approximately 150 gal/min or greater.

HPCI Turbine Area

This area contains only HPCI system components. Isolation of the HPCI steam line will be initiated at ventilation exhaust temperatures of 160°F to 170°F. This would result from a steam leak equivalent to approximately 10 gal/min or greater.

HPCI Valve Station Area

This area contains both HPCI and RHR system piping. Isolation of the HPCI steam line will be initiated at ventilation exhaust temperatures of 160°F to 170°F. This would result from a steam leak equivalent to approximately 10 gal/min or greater. The RHR system piping contains water sufficiently hot to flash and increase ventilation exhaust temperatures to the leak detection setpoint only when operating in the shutdown cooling mode. Therefore, RHR Leakage would not cause isolation of the HPCI system when it is required to be operable. The shutdown cooling mode of RHR operation does not operate above a reactor pressure of about 75 psig, while the HPCI system does not operate below a pressure of about 50 psig.

RCIC Turbine Area

This area contains RCIC system components only. Isolation of the RCIC steam line will be initiated at space temperatures of 160°F to 170°F, which would result from a steam leak equivalent to approximately 10 gal/min or greater.

RCIC Valve Station Area

This area contains RCIC piping and various cold water lines associated with other systems. Isolation of the RCIC steam line will be initiated at a space temperature of 190°F to 200°F, which would result from a steam leak of approximately 10 gal/min. A leak from the other piping in this area would be cold water and would not cause an area temperature increase and spurious isolation of the RCIC steam line.

Torus Compartment Area

This area contains both HPCI and RCIC steam lines in addition to the "cold" water lines associated with other systems. The HPCI and RCIC steam lines are separated by a minimum distance of approximately 65 ft.

Protection against the continued spurious isolation of either the HPCI or RCIC steam supply line due to leakage in the torus compartment is provided by establishing a temperature differential between the initiation setpoints of the temperature switches in the torus compartment ventilation exhaust ducts in combination with operating procedures.

Analytical limits are listed in Table 7.3-2 for the sensors associated with the RCIC steam line and trip settings of 190°F to 200°F are specified for those associated with the HPCI steam line. This difference in trip settings allows preferential isolation of the RCIC steam line in the event of a small leak, and permits the HPCI system to remain operable.

Isolation of the RCIC system due to steam line leakage:

a. If the leak occurs in the RCIC system piping, the RCIC steam line temperature would decrease and thus prevent HPCI system Isolation at the higher exhaust duct temperature

b. If the leak occurs in the HPCI system piping, the HPCI steam line temperature would continue to increase and isolate the HPCI system. The operator would subsequently return the RCIC system to service

Simultaneous isolation of HPCI and RCIC system steam supply lines could be postulated to occur as a result of a large RCIC system leak in the immediate vicinity of the exhaust plenum from the torus compartment, resulting in a rapid temperature increase to the HPCI analytical limit before the RCIC system steam line isolation valves were completely closed. However, analysis indicates that high RCIC steam flow would isolate the RCIC steam line before the HPCI temperature setpoint was reached.

Distinguishing between an RCIC and an HPCI steam line leak, assuming both lines were simultaneously isolated, would be possible by opening each line in succession and observing the temperature effect on the local sensors. The nonleaking system could then be returned to service. The temporary isolation of both the RCIC and HPCI steam supply lines as a result of a steam leak within the torus compartment is acceptable since neither system would be required to perform its function of providing coolant makeup to the reactor vessel. The isolation of the leaking steam line would limit coolant losses from the reactor vessel without disrupting normal plant operation. The specified settings will initiate RCIC isolation upon steam leaks of approximately 40 gal/min and greater.

7.3.4.9 Environmental Capabilities

The physical and electrical arrangement of the Primary Containment and Reactor Vessel Isolation Control System was selected so that no single physical event will prevent isolation. The location of Class A and Class B valves inside and outside the primary containment provides assurance that the control system for at least one valve on any pipeline penetrating the primary containment will remain capable of automatic isolation. Electrical cables for isolation valves in the same pipeline are routed separately. Motor operators for valves inside the primary containment are of the totally enclosed type; those outside the primary containment have weatherproof type enclosures. Solenoid valves, whether used for direct valve isolation or as an air pilot, are provided with watertight enclosures. All cables and operators are capable of operation in the most unfavorable ambient conditions anticipated for normal operations. Temperature, pressure, humidity, and radiation are considered in the selection of equipment for the system. Cables used in high radiation areas have radiation resistant insulation. Shielded cables are used where necessary to eliminate interference from electromagnetic fields.

Special consideration has been given to isolation requirements during a loss of coolant accident inside the drywell. Components of the Primary Containment and Reactor Vessel Isolation Control System that are located inside the primary containment and that must operate during a loss of coolant accident are the cables, control mechanisms, and valve operators of isolation valves inside the drywell. These isolation components are required to be functional in a loss of coolant accident environment.

Electrical cables are selected with insulation designed for this service. Closing mechanisms and valve operators are considered satisfactory for use in the Isolation Control System only after completion of environmental testing under loss of coolant accident conditions or submission of evidence from the manufacturer describing the results of suitable prior tests.

Verification that the isolation equipment has been designed, built, and installed in conformance to the specified criteria is accomplished through quality control and performance tests in the vendor's shop or after installation at the station before startup, during startup, and thereafter during the service life of the equipment.

Control is also exercised through review of equipment design during bid review and by approval of vendor's drawings during the fabrication stage. Purchase specifications require extensive control of materials and of the fabrication procedure.

7.3.5 Safety Evaluation

The Primary Containment and Reactor Vessel Isolation Control System, in conjunction with other protection systems, is designed to provide timely protection against the onset and consequences of accidents involving the gross release of radioactive materials from the fuel and nuclear system process barriers. It is the objective of Section 14, Station Safety Analysis, to identify and evaluate postulated events resulting in gross failure of the fuel barrier and the nuclear systems process barrier. The consequences of such gross failures are described and evaluated in that section.

Tentative trip settings are selected that are far enough above or below normal operating levels that spurious isolation and operating inconvenience are avoided. It is then verified by analysis that the release of radioactive material following postulated gross failures of the fuel and nuclear system process barrier is kept within acceptable bounds by those trip settings. Trip setting selection is based on operating experience and constrained by the safety design basis and the safety analyses.

Section 14 shows that the actions initiated by the Primary Containment and Reactor Vessel Isolation Control System, in conjunction with other safety systems, are sufficient to prevent releases of radioactive material from exceeding the guide values of published regulations. Because the actions of the system are effective in restricting the uncontrolled release of radioactive materials under accident situations, the Primary Containment and Reactor Vessel Isolation Control System meets the precision and timeliness requirements of safety design basis 1.

Because the Primary Containment and Reactor Vessel Isolation Control System met the precision and timeliness requirements of safety design basis 1 using instruments with the characteristics described on Table 7.3-2, it is concluded that safety design basis 2 was met.

Temperatures in the spaces occupied by various steam lines outside the primary containment are the only essential variables of significant spatial dependence that provide inputs to the primary containment and reactor vessel isolation control system. The large number of temperature sensors and their dispersed arrangement near the steam lines requiring this type of break protection provide assurance that a significant break will be detected rapidly and accurately. One of the two groups of four temperature switches is located in the ventilation exhaust from the steam line tunnel between the drywell and the secondary containment ventilation barrier and the other group of four temperature switches is located in the ventilation exhaust from the turbine basement area. This assures that abnormal air temperature increases are detected regardless of leak location in that space. It is concluded that the number of sensors provided for steam line break detection satisfies safety design basis 3.

Because the Primary Containment and Reactor Vessel Isolation Control System meets the timeliness and precision requirements of safety design basis 1 by monitoring variables that are true, direct measures of operational conditions, it is concluded that safety design basis 4 is satisfied.

Section 14 evaluates a gross breach in a main steam line outside the primary containment during operation at full power. The evaluation shows that the main steam lines are automatically isolated in time to prevent a release of radioactive material in excess of the guide values of published regulations and to prevent the loss of coolant from being great enough to allow uncovering of the core. These results are true even if the longest closing time of the valve is assumed. The time required for automatic closure of the main steam isolation valves meets the requirements of safety design basis 5.

The shortest closure time of which the main steam valves are capable is 3 sec. The transient resulting from a simultaneous closure of all main steam isolation valves in 3 sec during reactor operation at full power is considerably less severe than the transient resulting from inadvertent closure of the turbine stop valves (which occurs in a small fraction of 1 sec) coincident with failure of the turbine bypass system.

The RPS is capable of accommodating the transient resulting from the inadvertent closure of the main steam line isolation valve. This conclusion is substantiated by Section 14. This meets safety design basis 6.

The items of safety design bases 7, 8, and 9 must be fulfilled for the Primary Containment and Reactor Vessel Isolation Control System to meet the design reliability requirements of safety design basis 1. It has already been shown that safety design bases 7f and 7h have been met. The remainder of the reliability requirement is met by a combination of logic arrangement, sensor redundancy, wiring scheme, physical isolation, power supply arrangement, and environmental capabilities. These subjects are discussed in the following paragraphs.

Because essential variables are monitored by four channels arranged for physical and electrical independence, and because a dual trip system arrangement is used to initiate closure of automatic isolation valves, no single failure, maintenance operation, calibration operation, or test can prevent the system from achieving isolation. An analysis of the Isolation Control System shows that the system does not fail to respond to essential variables as a result of single electrical failures such as short circuits, ground, and open circuits. A single trip system trip is the result of these failures. Isolation is initiated upon a trip of the remaining trip system. For some of the exceptions to the usual logic arrangement, a single failure could result in inadvertent isolation of a pipeline. With respect to the release of radioactive material from the nuclear system process barrier, such inadvertent valve closures are in the safe direction and do not pose any safety problems. HPCI, RCIC, and RHR primary containment isolation logics are single failure proof with an energize to actuate design. Any single failure can only affect closure of one of two containment isolation valves. This meets Safety Design Bases 7a and 7b.

The redundancy of channels provided for all essential variables provides a high probability that whenever an essential variable exceeds the isolation setting, the system initiates isolation. In the unlikely event that all channels for one essential variable in one trip system fail in such a way that a system trip does not occur, the system could still respond properly as other monitored variables exceed their isolation settings. This meets Safety Design Basis 7c.

The sensors, circuitry, and logics used in the primary containment and reactor vessel isolation control system are not used in the control of any process system. Thus, malfunction and failures in the controls of process systems have no direct effect on the isolation control system. This meets Safety Design Basis 7d.

The various power supplies used for the isolation system logic circuitry and for valve operation provide assurance that the required isolation can be effected in spite of power failures. If AC for valves inside the primary containment is lost, DC is available for operation of valves outside the primary containment. The main steam isolation valve control arrangement is resistant to both AC and DC power failures. Because both solenoid-operated pilot valves must be deenergized, loss of a single power supply will neither cause inadvertent isolation nor prevent isolation if required.

The logic circuitry for each channel is powered from the separate sources available from the reactor protection system buses, the uninterruptible AC power supply, or the 125V DC buses (for HPCI, RCIC, and RHR). A loss of power here results in a single trip system trip. In no case does a loss of a single power supply prevent isolation when required. This meets Safety Design Basis 7e.

All instruments, valve closing mechanisms, and cables of the isolation control system can operate under the most unfavorable environmental conditions associated with normal operation. The discussion of the effects of rapid nuclear system depressurization on level measurement given in Section 7.2, Reactor Protection System, is equally applicable to the reactor vessel low water level transmitters used in the primary containment and reactor vessel isolation control system. The temperature, pressure, differential pressure, and level switches, transmitters, trip units, cables, and valve closing mechanisms used were selected with ratings that make them suitable for use in the environment in which they must operate.

The special considerations (treated in the description portion of this section) made for the environmental conditions resulting from a loss of coolant accident inside the drywell are adequate to ensure operability of essential isolation components located inside the drywell.

The wall of the primary containment effectively separates adverse environmental conditions which might otherwise affect both isolation valves in a pipeline. The location of isolation valves on either side of the wall decouples the effects of environmental factors with respect to the ability to isolate any given pipeline. The previously discussed electrical isolation of control circuitry prevents failures in one part of the control system from propagating to another part. Electrical transients have no significant effect on the functioning of the isolation control system. It is concluded that safety design basis 7g is satisfied.

The design of the main steam isolation valves meets the requirement of safety design basis 8a in that the motive force for closing each main steam line isolation valve is derived from both a source of pneumatic pressure and the energy stored in a spring. Either energy source is capable, alone, of closing the valve. None of the valves relies on continuity of any sort of electrical power to achieve closure in response to essential safety signals. Total loss of the power used to control the valves would result in closure. This meets safety design basis 8b.

Calibration and test controls for pressure and temperature switches, transmitter and analog trip units are located on the devices themselves. These devices are located in the turbine building and reactor building. To gain access to the setting controls on each device, a cover plate, access plug, or sealing device must be removed by operations personnel before any adjustment in trip settings can be effected. The location of calibration and test controls in areas under the control of the control room operator or other supervisory personnel reduces the probability that operational reliability will be degraded by operator error. This meets safety design basis 9a. Because no manual bypasses are provided in the isolation control system, safety design basis 9b is met.

Because safety design bases 7, 8, and 9 have been met, it can be concluded that the Primary Containment and Reactor Vessel Isolation Control System satisfies the reliability requirement of safety design bases 10, 11a, and 11b as shown in the description of the system. The following section on inspection and testing of the system demonstrates that safety design basis 12 is satisfied.

It is concluded that all safety design bases are met.

7.3.6 Inspection and Testing

All essential parts of the primary containment and reactor vessel isolation control system are testable during reactor operation. Isolation valves can be tested to assure that they are capable of closing by operating manual switches in the control room and observing the position lights and any associated process effects. Testing of the main steam line isolation valves is discussed in Section 4.6, Main Steam Line Isolation Valves.

7.3.7 Nuclear Safety Requirements for Plant Operation

Table 7.3-4 presents the operational nuclear safety requirements for the primary containment and reactor vessel isolation control system for boiling water reactor (BWR) operating states C, D, E, and F as proposed for initial plant operation.

The entries on Table 7.3-4 represent an extension of the stationwide BWR systems analysis of Appendix G to the components of the Primary Containment and Reactor Vessel Isolation Control System. The following referenced portions of this safety analysis report provide important information justifying the entries on Table 7.3-4:

Reference	Information Provided
1. Preceding parts of Section 7.3	Description of primary containment and reactor vessel isolation control system hardware; isolation control system sensor setpoints
2. Station Safety Analysis, Section 14	Analysis verifying response of isolation control system to transients and accidents
3. Station Nuclear Safety Operational analysis, Appendix G	Identifies conditions and events for which isolation control system action is required
4. Jacobs, I.M., Guidelines for Determining Safe Test Intervals and Repair Times for Engineering Safeguards, General Electric Company, Atomic Power Equipment Department, April 1969, (APED-5736)	Describes methods used to establish allowable repair times

Each detailed requirement on Table 7.3-4 is referenced, where possible, to the most significant condition originating the need for the requirement by identifying a matrix block on Table G.5-3. The matrix block references, given in parentheses beneath the detailed requirements in the "minimum required for action" columns on Table 7.3-4 are coded as follows:

Example of Matrix Reference:

```
F21-73
|  |
|--|---- F - BWR operating state F
   |---- 21 - Event (row 21)
   |--- 73 - Isolation Control System
                (column 73)
```

In most cases, the basis for an operational nuclear safety requirement is clear from the information provided by the previously noted references. The Isolation Control System requirements in operating states C, D, E, and F result from considerations for the main steam line break accident, the loss of coolant accident, or lesser cases of these two design basis accidents. In general, the requirements for the isolation functions are applicable only when the nuclear system is pressurized, because only under this condition are pipe breaks postulated. In addition, operability of the various isolation components is necessary only when the associated lines are unisolated. The following paragraphs give additional information about some of the less obvious operational nuclear safety requirements.

The requirements of items 7.3.1, 7.3.2, and 7.3.4 of Table 7.3-4 are applicable only when any of the affected lines are unisolated. The requirement for the main steam line low pressure isolation function, item 7.3.6 on Table 7.3-4, is applicable only in operating State F and only when the mode switch is in RUN. If the mode switch is not in RUN, this isolation function is bypassed; operating State F is the only state in which the RUN position is utilized as part of planned operation.

The surveillance test and calibration frequencies for the instrumentation of the Primary Containment and Reactor Vessel Isolation Control System are selected on the same basis as for the Reactor Protection System. See Section 7.2.6. The Radiation Monitoring Systems are treated in Section 7.12.

The surveillance test frequencies for the automatic isolation valves of the Primary Containment and Reactor Vessel Isolation Control System are contained in the Technical Specifications referenced in Appendix B. The frequencies are based upon the need to prevent the uncovering of the core following pipe breaks outside the primary containment, the need to contain released fission products following pipe breaks inside the primary containment, the reliability of the valves, and the potential service experience of the valves. The valves of the system are highly reliable and have low service requirements; many of the valves are normally closed. Successful passing of the surveillance tests for the valves essential to reactor vessel isolation requires that they close within specified closure times.

The full system test at each refueling outage (state A) requires that each initiating function for isolation be tested to demonstrate that all the automatic valves associated with an initiating function actually close upon receipt of the isolation signal.

7.3.8 Current Technical Specifications

The current limiting conditions for operation, surveillance requirements, and their bases are contained in the Technical Specifications referenced in Appendix B.

7.3.9 References

1. NEDO-31296, "Safety Evaluation of MSIV Low Turbine Inlet Pressure Isolation Setpoint Change for Pilgrim Nuclear Power Station," General Electric Company, May 1986.

7.10 FEEDWATER CONTROL SYSTEM

7.10.1 Power Generation Objective

The objective of the Feedwater Control System is to maintain a preestablished water level in the reactor vessel during planned operation.

7.10.2 Power Generation Design Bases

The Feedwater Control System shall regulate the feedwater flow so that the proper water level in the reactor vessel is maintained according to the requirements of the steam separators over the entire operating range of the reactor.

The feedwater flow shall also provide sufficient subcooled water to the reactor vessel during power operation to maintain normal operating temperatures.

7.10.3 Description

The feedwater control system, during planned operation, automatically regulates feedwater flow into the reactor vessel. The system is capable of being manually operated.

The feedwater flow control instrumentation measures the water level in the reactor vessel, the feedwater flow rate into the reactor vessel, and the steam flow rate from the reactor vessel. During automatic operation, these three measurements are used for controlling feedwater flow.

The optimum reactor vessel water level is determined by the requirements of the steam separators which limit the water carryover with the steam going to the turbines and limit the steam carryunder with the water returning to the core. For optimum limitation of carryover and carryunder, the steam separators require a decrease in reactor vessel water level as a function of an increase in reactor power level. The water level in the reactor vessel is maintained within %2 in of the optimum level. This control capability is achieved during plant load changes by balancing the mass flow rate of feedwater to the reactor vessel with the steam flow from the reactor vessel. The feedwater flow regulation is achieved by adjusting the feedwater control valves to deliver the required feedwater flow to the reactor vessel (see Figure 7.10-1, Drawing M1P 2-7).

7.10.3.1 Reactor Vessel Water Level Measurement

Reactor vessel water level is measured by two identical, independent sensing systems. A differential pressure transmitter senses the difference between the pressure due to a constant reference column of water and the pressure due to the variable height of water in the reactor vessel. This differential pressure transmitter is installed on differential pressure taps that serve other systems (see Section 7.8, Reactor Vessel Instrumentation). The differential pressure signal is fed into a proportional amplifier which converts the level signal from 4-20MA to 10-50MA for indication and control. The reactor vessel water level and pressure from each sensing system are indicated in the main control room. The level signal from either sensing system can be selected by the operator as the signal to be used for feedwater flow control. The water level and the reactor vessel pressure are continually recorded in the main control room.

Each level sensing analog instrumentation system is equipped with a bistable device that provides a signal to trip the feedwater pumps and alarm at the main control room when extreme high water level is detected. A coincident detection of both systems is required for initiation of the automatic backup trip protection of the feedwater pumps. A bypass of this function is provided.

7.10.3.2 Steam Flow Measurement

The steam flow is measured across each main steam line flow restrictor by a differential pressure transmitter. A pressure transmitter, multiplier/divider, and proportional amplifier correct the steam flow signal for density to produce an accurate steam flow signal.

The corrected steam flow rate from each main steam line is indicated in the main control room. The steam flow signals are added by a summer to produce a total steam flow signal for indication and feedwater flow control. The total steam flow is recorded in the main control room.

7.10.3.3 Feedwater Flow Measurement

Feedwater flow is measured in each feedwater line on the reactor side of the control valves. A flow element in each feedwater line is provided for flow measurement. The pressure difference across the flow element is sensed by a differential pressure transmitter. Corrections to the feedwater signal are made for water density variations due to temperature changes. These corrections are made by an input from a temperature element through a millivolt/current transmitter and multiplier/divider. The feedwater signal is then linearized by a square root extractor to produce a mass flow rate signal.

A summer is used to add the flow signals from the feedwater lines. The output from the summer is the total corrected feedwater mass flow rate signal. This signal is used for indication and feedwater flow control. The total feedwater flow is recorded in the main control room.

7.10.3.4 Feedwater Control Signal

The feedwater control signal adjusts the feedwater control valves. The components which are manually operated or automatically function to produce the feedwater control signal are the following:

Level Controller

During automatic operation of the feedwater control system, the level controller output is the feedwater control signal. During manual operation the level controller output signal is blocked.

The level controller automatically establishes its setpoint, proportional to the total steam flow signals, at the optimum reactor vessel water level. The level controller receives a three-element control input signal (described in paragraph 7.10.3.4.1) which represents reactor vessel water level. The output from the level controller, resulting from comparison of the setpoint to the signal representing reactor vessel water level, regulates the feedwater flow so that the reactor vessel water level meets the setpoint requirement.

Manual/Automatic Transfer Station
(one for each feedwater control valve)

The manual/automatic transfer station is a manual controller with a transfer switch. While the feedwater control valves are being controlled by the level controller, the transfer switch is positioned so that the manual controller potentiometer is bypassed and the level controller signal goes through the manual/automatic transfer station to a feedwater control valve. During startup or when manual control may be desirable, the level controller signal is blocked by the transfer switch and the feedwater control signal is transmitted and controlled at the manual/automatic transfer station by the operator.

7.10.3.4.1 Automatic Operation

The ability of the Feedwater Control System to maintain reactor vessel water level within a small margin of optimum water level during plant load changes is accomplished by the three element control signal. The three element control signal is the signal fed to the level controller representing reactor vessel water level. Operations determine the optimum water level to be maintained. This is accomplished by adjusting the level controller setpoint.

The three element control signal is obtained as follows: The total steam flow signal and the total feedwater flow signal are fed into a proportional amplifier. The output from this amplifier reflects the mismatch between its input signals and is designated as the steam flow/feedwater flow error signal. If steam flow is greater than feedwater flow, the amplifier output is increased from its normal value until steam and feedwater flows are equal. The reverse is also true. This amplifier output is fed to a second proportional amplifier which also receives the reactor vessel water level signal.

The addition of the reactor vessel water level signal to the steam flow/feedwater flow error signal results in the three element control signal which is fed to the level controller. A lead lag network is provided to improve system response. Its output is fed to the level controller during three element control.

The feedwater control signal is adjusted by the level controller according to the requirements of the three element control signal and the total steam flow signal so that the required reactor vessel water level is maintained.

7.10.3.4.2 Optional Operating Modes

Optional methods of Feedwater Control System operation are available, and are used during ascension to power. A one element signal (reactor vessel water level) is used to replace the three element control signal to the level controller. At high power level when steam flow and feedwater flow signals are large, anticipatory action is effective. At low loads (0-40 percent), single element control is recommended since steam flow measurement signal-to-noise ratio is prohibitive and it has no useful anticipatory action. Manual/automatic transfer stations can be individually operated to transmit feedwater control signals to each of the feedwater control valves.

7.10.3.5 Feedwater Valve Control

During normal power operation feedwater is delivered to the reactor vessel through two feedwater valves arranged in parallel. Another valve, the low flow valve, is used exclusively for plant startup and is manually controlled at the manual loading station. The feedwater pumps are powered by constant speed AC motors. The feedwater valves are air operated.

The feedwater control signal is fed to both Feedwater Regulating Valve (FRV) Electronic Positioner/Controllers. For each FRV, an electronic module installed outside of the Condenser Bay provides a signal to a stepper motor/encoder driving a high capacity pneumatic module that directly controls the air supply to the double-acting piston type pneumatic actuator. A displacement sensor mounted on the actuator provides the valve stem position feedback to the electronic module. The FRV is a stacked disk type throttle valve with a characterized trim that optimizes the control of the feed flow over the full operating range.

Protection is provided against overfilling the vessel when in the flow control mode by separate contacts on reactor water level alarm units. These can be set anywhere throughout the control normal reactor water level range. High water level is annunciated by alarm contacts on the reactor level recorder, and reactor feed pump trip alarm units. Since the high level trip uses 2 out of 2 taken once logic, failure of one channel to indicate high, does not cause the reactor feed pump trip. For this reason, this trip is not used in transient analysis beginning with Cycle 21.

The level controller and its associated manual/balance/auto switching that provide for normal manual or automatic control are located in the control room. The manual/auto stations for the valves are also located in the control room.

Each feedwater regulating valve will pneumatically lock-up in the "as-is" position in the event of a control signal failure, instrument air supply failure, or electronic controller fault condition when in the normal operating mode.

7.10.3.6 Feedwater Pump Trip

The reactor feedwater pump breakers will be tripped on high-high reactor pressure for events that are indicative of an ATWS event. The trip occurs from the feedwater pump trip logic in the ATWS panels as described in 3.9.3.3

7.10.4 Inspection and Testing

All Feedwater Flow Control System components can be tested and inspected according to manufacturers' recommendations. This can be done prior to plant operation and during scheduled shutdowns. Reactor vessel water level indications from the two water level sensing systems can be compared during normal operations to detect instrument malfunctions. Steam mass flow rate and feedwater mass flow rate can be compared during constant load operation to detect inconsistencies in their signals. The level controller can be tested while the feedwater control system is being controlled by the manual/automatic transfer stations.

Figure 7.10-1 has been removed.

Please refer to BECo Controlled Drawing M1P 2-7.

10.2 NEW FUEL STORAGE

10.2.1 Power Generation Objective

The power generation objective of the new fuel storage vault and the new fuel storage racks is to provide a dry location for upright storage of new fuel assemblies which will allow efficient handling of the assemblies during station operations.

10.2.2 Power Generation Design Basis

1. The new fuel storage racks are designed to accommodate greater than 30 percent of the full core loading of fuel assemblies in an upright storage position.

2. The new fuel storage racks and the concrete storage vault are designed to allow efficient handling of the fuel assemblies during station operations.

10.2.3 Safety Design Basis

1. The new fuel racks are designed with sufficient spacing between the new fuel assemblies to assure that the fully loaded array will have a $K_{eff} \leq 0.90$ for normal dry conditions and a $K_{eff} < 0.95$ for abnormal conditions where the assemblies are completely flooded with water.

2. The fully loaded new fuel storage vault and storage racks are designed to Class I standards.

10.2.4 Description

The new fuel storage vault is a reinforced concrete Class I structure, accessible only through top hatches. There is an open drain in the floor of the vault to prevent flooding. New fuel racks are provided for at least 30 percent of the full reactor core load. Each new fuel storage rack holds up to 10 unchanneled fuel assemblies in a row spaced approximately 6.6 in apart center-to-center. The racks are arranged in rows having an 11 in center-to-center spacing that will limit the effective multiplication factor (K_{eff}) of the array to less than 0.90 assuming the fuel to be in the dry condition.

Each space for a fuel assembly has adequate clearance for inserting or withdrawing the assembly from above while enclosed in a protective plastic wrapping. Guides are provided to guide the fuel assemblies for the full length of their insertion into the rack. The design of the racks prevents accidental insertion of the fuel assembly into a position not intended for the fuel. The weight of the fuel assembly is supported at the bottom, and the rack provides full longitudinal support for the new fuel assembly spacers. Removable gratings (approximately 11 in wide and 6 ft 7 1/2 in long) over each fuel rack are provided to minimize the number of uncovered assemblies.

Each new fuel storage rack is designed as a Class I structure. Stresses in a fully loaded rack are designed not to exceed applicable specification requirements of the American Institute of Steel Construction (AISC) or the American Society of Civil Engineers (ASCE) when subjected to a horizontal earthquake load of 0.25g applied in any direction. A safety factor of approximately 2, based upon the material yield strength or local critical buckling, is used where these specifications are not applicable.

The storage rack structure is designed to absorb an impact energy of at least 7,000 ft-lb on an impact surface no larger than 3 inches in diameter. Under this impact force, the members that function to physically maintain the subcritical spacing (to assure that K_{eff} will not exceed 0.95 when flooded) will remain intact. Those members whose local and general strain exceed 25 percent of the material ultimate strain are assumed to be nonexistent for further energy absorption or for spacing purposes. Those members and their connections whose continued presence is required to maintain the subcriticality margin are designed using a minimum safety factor of approximately 1.33 based on the lower of the material yield or buckling stresses.

The storage racks are designed to withstand a pull-up force of 5 tons, and a horizontal force of 1,000 lb applied to the top of the rack. This is necessary in the event that the fuel assembly or grappling device binds during removal. The stress in these members required to maintain the abnormal storage subcriticality conditions will not exceed 75 percent of the material yield strength or 75 percent of that stress at which local buckling occurs.

The new fuel racks are designed to be restrained by hold-down lugs to assure that rack spacing does not vary under specified earthquake loads. Hold-down bolts will restrain the rack in case a stuck fuel assembly is inadvertently hoisted. Each hold-down bolt is designed to withstand 500 lb horizontal shear and an uplift force of 5,000 lb. All materials used in the construction of the new fuel storage racks are specified in accordance with the applicable ASTM specifications, and all welds are in accordance with AWS standards. Materials selected are corrosion resistant or are treated to provide the necessary corrosion resistance.

Criticality monitoring shall be in accordance with the requirements of 10 CFR 50.68(b).

10.2.5 Safety Evaluation

The calculations of K_{eff} are based upon the geometrical arrangement of the fuel array, and subcriticality does not depend upon the presence of neutron absorbing materials. The arrangement of the fuel assemblies in the fuel storage racks results in K_{eff} below 0.90, when dry. In an abnormal condition which assumes the vault is flooded with water and the fuel elements are brought to their most reactive spacing, the rack spacing is designed such that K_{eff} will not exceed 0.95.

Design of the new fuel storage vault to Class I standards effectively eliminates the possibility of vault damage due to earthquake loads.

A floor drain prevents accumulation of water in the vault. A radiation monitor in the vault provides warning of any radiation level increase above normal operating conditions. It is concluded that the safety design bases are met.

10.2.6 Inspection and Testing

The new fuel storage racks do not require any special inspection and testing for nuclear safety purposes.

10.3 SPENT FUEL STORAGE

10.3.1 Power Generation Objective

The power generation objective of the spent fuel storage racks and the spent fuel storage pool is to provide specially designed underwater storage space for the spent fuel assemblies which require shielding during storage and handling.

10.3.2 Power Generation Design Basis

1. Spent fuel storage racks are supplied for the storage of a maximum number of fuel assemblies.

2. The spent fuel storage racks and the spent fuel storage pool are designed to allow efficient handling of the fuel assemblies during refueling and fuel handling operations.

10.3.3 Safety Design Basis

1. The spent fuel storage racks are designed to maintain, when fully loaded with fuel assemblies, a subcritical configuration having a k_{eff} <0.95 for normal and abnormal conditions, as defined in Section 10.3.4.

2. The storage pool and concrete structures provide a sufficient depth of water and sufficient concrete thicknesses to adequately shield station personnel from radiation emitted by a full load of spent fuel assemblies.

3. The fully loaded spent fuel storage racks, supports, and pool concrete structures are designed to Class I standards.

10.3.4 Description

10.3.4.1 General

The spent fuel storage racks provide storage at the bottom of the fuel pool for the spent fuel received from the reactor vessel. See Figure 10.3-1. The racks are full length, top entry, and designed to maintain the spent fuel in a space geometry which precludes the possibility of criticality under normal and abnormal conditions. Normal conditions exist when the spent fuel is stored at the bottom of the fuel pool in the design storage position. Abnormal conditions may result from:

- Increased temperature
- Boiling
- Reduced moderation density
- Fuel assembly positioning (rack bending)
- Assembly placed outside rack
- Dropped fuel assembly
- Lost/Missing absorber plate

The standard spent fuel racks, shown on Figure 10.3-1, are a modular design of varying sizes. Each rack has the capacity to store an average of 260 spent fuel assemblies. The fuel pool has a licensed capacity of 3859 fuel assemblies. With the present inventory of fuel racks in the pool, PNPS only has the capacity to store 3404 fuel assemblies. The racks are free standing.

Nine racks are made up of welded stainless steel assemblies in the shape of cruciforms, angles, and tees. Sheets of Boraflex poison material are sandwiched between the stainless steel sheets creating a welded assembly. The rack assembly is shown on Figure 10.3-1.

The remainder of the racks are made up of welded stainless steel boxes. Sheets of Boral or Metamic poison material have been sandwiched between the box walls and a stainless steel sheath welded to the box walls for the purposes of holding the poison in position. Refer to Figures 10.3-4, 10.3-5 and 10.3-6.

The pool configuration for the existing and new racks plus the future expansion racks are shown in Figure 10.3-7.

The racks are designed to withstand a pull-up force equal to 4,000 lb acting on the rack corner (necessary in the event that a fuel assembly or grappling device acting on the rack corner binds during removal). The maximum allowable stress on the members required to maintain the subcritical condition will not exceed 75 percent of the material yield strength or 75 percent of that stress at which local buckling occurs.

No spaces exist between normal fuel storage positions so that it is not possible to insert a fuel assembly, either deliberately or by accidental drop, in any position not intended as a fuel storage position, except as analyzed. See Section 10.3.5.

Each fully loaded spent fuel storage rack is designed as a Class I structure. The spent fuel racks are designed such that the stresses in a fully loaded rack do not exceed applicable American Institute of Steel Construction or American Society of Civil Engineers specification requirements when subjected to the seismic loads resulting from the Safe Shutdown Earthquake. Both the horizontal and vertical forces due to the earthquakes are considered to act simultaneously. Acceleration time-histories resulting at the spent fuel pool floor during the Safe Shutdown Earthquake are used as input to the dynamic analysis of the racks.

The storage rack structure is designed to absorb the vertical impact force imposed by a fuel assembly dropped from a height of 36 in above a rack onto any location on the rack. Under this impact force, those members, whose function is to physically maintain the normal design subcritical spacing to assure $k_{eff} \leq 0.95$, will remain intact.

All materials used in the construction of the rack are specified in accordance with the latest issue of applicable ASTM specifications, and all welds are in accordance with AWS standards or ASME Section IX for materials used. Materials selected are corrosion resistant or treated to provide the necessary corrosion resistance.

Special brackets have been designed to hang control rod blades from the spent fuel pool curb. Design calculations and administrative controls have been established to identify acceptable radiological limits for storing material in the spent fuel pool. Hanging control rod blades from the spent fuel pool curb is within the plant shielding design as specified in Sections 12.3.1.1 and 12.3.3.2.

The spent fuel storage pool has been designed to withstand earthquake loading as a Class I structure. It is a reinforced concrete structure, completely lined with seam-welded stainless steel plates welded to reinforcing members (channels, I-beams, etc) embedded in concrete. Interconnected drainage monitoring channels are provided behind the liner welds. These channels are designed to (1) prevent pressure buildup behind the liner plate, (2) prevent the uncontrolled loss of contaminated pool water to other relatively cleaner locations within the secondary containment, and (3) provide necessary detection and measurement of liner leaks. These drainage channels are formed in the concrete behind the liner and are designed to permit free gravity drainage to the floor drainage sump. The passage between the spent fuel storage pool and the refueling cavity above the reactor vessel is provided with two double sealed gates with a monitored drain between the gates. This arrangement permits monitoring of leaks and facilitates repair of a gate or seal, if necessary.

To avoid unintentional draining of the pool, there are no penetrations that would permit the pool to be drained below a safe storage level (approximately 10 ft above the top of the fuel). Lines extending below this level are equipped with siphon breakers to prevent siphon backflow. Two epoxy phenolic-lined carbon steel skimmer surge tanks are sized to take into account the placement of large items such as the spent fuel cask into the pool.

Makeup water to the fuel pool is transferred from the condensate storage tanks directly to the skimmer surge tanks to make up for normal fuel pool losses. The available methods of providing makeup water to the spent fuel pool include the following:

1. Condensate transfer system with either of the two condensate transfer pumps operating can provide water through two paths:

   a. 3-inch piping directly to the fuel pool skimmer surge tanks with a maximum flow rate of 200 GPM.

   b. 10-inch piping to the spent fuel pool cooling system (SFPCS) discharging directly to the fuel pool or to the filter-demineralizer train with a flow rate of approximately 1100 GPM.

2. Demineralized water transfer system 4-inch piping to the spent fuel pool, reactor basin, and dryer separator pool service boxes. Either of the two demineralized water transfer pumps can provide 100 GPM to the service boxes which may be connected to discharge to the fuel pool.

3. The fire protection system (FPS) has two hose stations on the refuel floor (Elev. 117 ft). The FPS can be fed from the electric motor driven fire pump or the diesel engine driven fire pump, each rate at 2000 GPM, drawing water from either of the two fire water storage tanks. Each hose station is rated to discharge 150 GPM.

4. After the reactor has been brought to the cold shutdown condition, the RHR/SFPCS intertie may be used to add makeup water to the fuel pool if the other methods described above are not available. The fire protection system is connected to the RHR loop cross-tie to which the RHR/SFPCS intertie is also connected thus delivering water from the FPS directly to the fuel pool. One loop of RHR using one pump may also be used to deliver water from the torus to the fuel pool while the other RHR loop maintains shutdown cooling of the reactor.

The condensate and demineralized water transfer systems include three alternate storage tanks, four pumps, and three separate flow paths to the SFPS. The FPS is configured with a ring header arrangement that provides two independent flow paths to each hose station. During a loss of off-site power, the FPS diesel fire pumps and mobile fire engines, if needed, would be available.

10.3.4.2 Fuel Pool Level Indicators

Low water level alarms are provided locally and in the main control room in the event of water loss from either rupture of the fuel pool wall liner, or the rupture of the reactor basin refueling bellows. (The alarm from the reactor basin is isolated during station operation.) As a backup, flow alarms are provided in the drain lines of the reactor vessel to drywell seal, drywell to concrete seal, and fuel pool gate to detect leakage. See Section 10.4.

NRC Order EA-12-051 required the installation of at least one permanent Spent Fuel Pool (SFP) level indication system. Pilgrim has installed two permanent SFP level indicating systems. The systems were designed and manufactured by MOHR Industries of Richland Washington.

Each of the two systems consist of a probe in the SFP, a power conditioner in the Control Room, a display unit in the Control Room, and a backup battery in the Control Room. The system can measure the level from approximately 6 inches above the top of the fuel racks to approximately 1-1/2 inches below the flange on the probe. Therefore the range is from an elevation of 93 ft. 3 inches to 116 ft. 7-1/2 inches. Reference drawing C2900.

10.3.5 Safety Evaluation

The design of the spent fuel storage provides for a $k_{eff} \leq 0.95$ for both normal and abnormal storage conditions. Normal conditions exist when the fuel storage racks are located at the bottom of the pool covered with a normal depth of water (about 25 ft above the stored fuel) and with fuel assemblies in their design storage positions. Abnormal conditions may result from abnormal location of a fuel assembly adjacent to the fuel storage racks, eccentric positioning of a fuel assembly within a fuel storage cell, zirconium fuel channel distortion, a dropped fuel assembly, or fuel rack lateral movement.

Analysis of the reactivity effects has been completed twice, first for the existing high density racks by Southern Science (Reference 3) and second by Holtec International (References 4 and 10) for the new racks. The Holtec Analysis bounds the existing analysis and, hence, provides acceptance criteria for storage of reactor fuel equally applicable for both the old and new spent fuel racks.

These analyses of the reactivity effects were performed with both the CASMO-3 computer code (a two-dimensional multi-group theory code) and the KENO-5a code (a Monte Carlo code), using the 27 energy group SCALE neutron cross section library. CASMO-3 was used as the primary method of analysis as well as the means of evaluating small reactivity increments associated with manufacturing tolerances. Burn up calculations were also performed with CASMO-3. KENO-5a was used to perform an independent verification of the CASMO-3 results as well as to assess the reactivity consequence of eccentric fuel positioning and abnormal locations of fuel assemblies. Both codes are widely used for the analysis of fuel storage rack reactivity and have been benchmarked against results from numerous critical experiments.

An assessment of the reactivity has also been performed using TGBLA06 in place of CASMO-3 and MCNP-05P in place of KENO-5a. This analysis concluded that acceptance criteria established by the Holtec analysis are also appropriate for use with GNF 10 x 10 fuel.

To ensure that true reactivity will always be less than the calculated reactivity, the following conservative assumptions were made:

1. The racks contain the most reactive fuel authorized to be stored in the facility without any controls or any uncontained burnable poison, and with the fuel at the burn up corresponding to the highest reactivity during its burn up history.

2. Moderator is pure, unborated water at a temperature within the design-basis range corresponding to the highest reactivity.

3. Criticality safety analyses are based on the infinite multiplication factor ($K\infty$); that is, lattice of storage racks is infinite in all directions, except in the assessment of certain abnormal/accident conditions where neutron leakage is inherent.

4. Neutron absorption effects of minor structural material are neglected.

For the design basis reactivity calculations, uncertainties due to tolerances in the following were accounted for: boron loading, Boral thickness, cell lattice spacing, stainless steel cell wall thickness, and fuel enrichment and density. These uncertainties were statistically combined at the 95 percent probability, 95 percent confidence (95/95 probability/confidence) level. In addition, a calculation bias of 0.01 Δk was added to account for possible differences between fuel vendor calculations and those performed here.

The resulting conservative criteria for acceptable storage of fuel in the spent fuel storage racks at Pilgrim Station are:

1) Fuel must have lattice-average enrichment of 4.6% or less.

2) The K_∞ in the standard core geometry, calculated at the burn up of maximum bundle reactivity, must be 1.32 or less.

Together these criteria satisfy the USNRC criteria that K_{eff} of fuel storage racks be maintained less than or equal to 0.95.

The reactivity effects during abnormal and accident conditions due to the effects of temperature and water density, abnormal location of a fuel assembly, eccentric fuel assembly positioning, fuel rack lateral movement or the dropping of a fuel assembly on top of the storage rack were considered. None of the credible conditions resulted in exceeding the limiting reactivity criterion of K_{eff} no greater than 0.95.

Reactivity calculations discussed above assume that the neutron absorbing material incorporated in the design of the fuel storage racks maintains its installed configuration and material properties. However, the older design employs Boraflex, a polymer which has demonstrated shrinkage under irradiated conditions including exposure to gamma fluxes from stored spent fuel. When further exposed to water, the polymer erodes and washes out of the racks. Initial in-situ examinations of highly exposed Boraflex material in the PNPS spent fuel racks has confirmed the expected shrinkage, but did not indicate erosion. The test results are reported in reference 11. Reactivity calculations, as previously described, were repeated to allow evaluation of potential future changes in the condition of various Boraflex parameters to determine the extent of further degradation that may be acceptable. The results are reported in reference 12. For the same fuel criteria discussed above, the K_{eff} remains less than 0.95.

Fuel in the spent fuel storage pool is covered with sufficient water for radiation shielding. Low water level alarms are provided locally and in the main control room in the event of water loss from either rupture of the fuel pool wall liner or the rupture of the reactor basin refueling bellows. As a backup, flow alarms are provided in the drain lines to detect reactor vessel to drywell seal, drywell to concrete seal, and fuel pool gate leakages. An adequate fuel pool water level is maintained even in the unlikely event of a pipe break between the skimmer surge tanks and the fuel pool cooling system pumps, since fuel pool discharge to the skimmer surge tanks is by overflow only. Thus, a pipe break would drain the skimmer surge tank but not reduce the fuel pool level. Siphon-breakers prevent siphon backflow through the fuel pool cooling system discharge pipes.

Criticality monitoring shall be in accordance with the requirements of 10 CFR 50.68(b).

10.3.6 Consequences of a Dropped Fuel Cask

The spent fuel pool is designed as a Class I structure using the design criteria described in Appendix C and Section 12. The loading combinations considered do not include the forces generated by a heavy falling object such as a spent fuel handling cask.

The reactor building crane upgrade modification installed for dry fuel storage cask handling utilizes a reactor building crane main hoist that has been designed as a single-failure-proof component. When used with casks and below-the-hook cask handling equipment designed to function as a single-failure-proof handling system, consideration of a cask drop accident is not required per the guidance of NUREG-0612 (Reference 14).

Use of conservatively designed hoisting equipment, load testing, and examination prior to cask handling to verify sound equipment minimizes the possibility of a dropped cask (see Section 10.3.7).

Pilgrim evaluated a load handling accident involving a cask up to 35 tons in weight being dropped through the refuel floor equipment hatch opening in a submittal letter to the NRC (Reference 15). This letter is cited as an input to the NRC Safety Evaluation supporting Amendment 33 to the Pilgrim Operating License (Reference 16).

This evaluation is associated with NUREG-0612 requirements when a non single-failure-proof handling system is in use. In the unlikely event of a cask drop through the equipment hatch during cask handling operations, it would fall back onto the transport vehicle which could absorb, dissipate, and distribute over a wide area most of the kinetic energy of the cask. Under the most severe postulated conditions, which assume the transport vehicle and the reactor building floor at el 23 ft. may not stop the cask, it could land in the torus compartment at el -17 ft. 6 in. and strike and damage the torus.

Regardless of the degree of penetration of the cask or the location at which it ultimately stops, the ability to safely achieve plant shutdown, cool down, and depressurization is not jeopardized. The reactor would be immediately shut down. Cool down and depressurization would be initiated using the turbine bypass to the condenser and feedwater system. At the appropriate time the shutdown cooling mode of the residual heat removal system (RHR) would be initiated using the RHR and reactor building closed cooling water systems (RBCCW) unaffected by the cask drop.

10.3.7 Inspection and Testing

Leak detection channels are provided on the concrete side of the spent fuel storage pool liner. Surveillance of flow from these leak channels will permit early determination and localization of any leakage.

The spent fuel racks require no special inspection and testing for nuclear safety purposes. A commitment was made in response to Generic Letter 96-04, Boraflex Degradation of Spent Fuel Pools, to a periodic material surveillance of the Boraflex material cell panels installed on spent fuel pool racks. A separate commitment was made to an accelerated surveillance program for Boral test coupons installed in the spent fuel rack area as part of License Amendment 155 (increased spent fuel storage capacity). A similar surveillance program will be used for Metamic poison material.

Prior to cask handling operations a visual inspection of cables, sheaves, hook, yoke, and cask lifting trunnions is made. Following these inspections no-load mechanical and electrical tests are conducted to verify proper operation of crane controls, brakes, and lifting speeds. A load test is then conducted by lifting the empty cask approximately 1 ft off its transport vehicle. Once again all critical elements, controls, and lifting speeds are examined and tested in the loaded condition. Additionally, this test is used to verify that no significant movement occurs after an interval in the loaded condition.

After confirmation of the operational acceptability of the crane, the fuel cask is hoisted to the refueling floor and moved over a prescribed path to its position in the fuel storage pool. Travel over the spent fuel storage pool with the refueling cask is limited to that small area provided for cask use.

Preventive maintenance procedures include inspection and testing of crane controls, brakes, and rigging. Hooks are examined by nondestructive testing methods.

The proper application of prescribed industrial specifications in the design of the reactor building crane provides an adequate safety margin over the designed lifting capacity. Inspection, maintenance, and operating procedures as described in the preceding paragraphs will assure that an adequate safety margin is maintained throughout the lifetime of the plant.

10.3.8 Dry Fuel Storage

The PNPS has established as Independent Spent Fuel Storage Installation (ISFSI) west of the Reactor Building inside the plant protected area. The ISFSI Area includes an ISFSI Pad, an Approach Slab, and a Radiation Control Area (RCA) fence. The ISFSI concrete pad has a capacity for 40 vertical spent fuel storage casks.

The Spent Fuel Dry Cask Storage operations at PNPS will be conducted under a general license in accordance with Subpart K of 10 CFR Part 72. The general license issued by 10 CFR 72.210, "General license issued," authorizes a 10 CFR Part 50 nuclear power plant licensee to store spent fuel at an onsite ISFSI. Subpart K of 10 CFR Part 72 also includes 10 CFR 72.212, "Conditions of general license issued under §72.210," which requires the use of a dry cask storage system that is pre-approved by the Nuclear Regulatory Commission, as evidenced by its listing 10 CFR 72.214.

The PNPS ISFSI uses the Holtec HI-STORM 100S Version B vertical cask storage overpack and the Holtec MPC-68 multi-purpose canister (MPC), as described in the HI-STORM 100 Cask System FSAR (Reference 17) and approved by the Nuclear Regulatory Commission via the HI-STORM Certificate of Compliance No. 1014 (Reference 18).

The MPC provides the confinement boundary for the stored fuel. The MPC is a welded, cylindrical canister with a honeycombed fuel basket. All MPC confinement boundary components are made entirely of stainless steel. The honeycombed basket, which is equipped with neutron absorbers, provides criticality control.

The HI-STORM 100S Version B storage overpack provides shielding and structural protection of the MPC during storage. The HI-STORM 100S Version B overpack design includes a lid which incorporates the air outlet ducts into the lid. The overpack is a heavy-walled steel and concrete, cylindrical vessel. Its side wall consists of plain (un-reinforced) concrete that is enclosed between inner and outer carbon steel shells. The overpack has four air inlets at the bottom and four air outlets at the top to allow air to circulate naturally through the cavity to cool the MPC inside. The inner shell has supports attached to its interior surface to guide the MPC during insertion and removal, and allow cooling air to circulate through the overpack. A loaded MPC is stored within the HI-STORM 100S Version B storage overpack in a vertical orientation.

Loading the MPC with spent fuel assemblies takes place in the Reactor Building. Using the 100-ton Reactor Building crane and a lift yoke, a transfer cask with an empty MPC is lowered into the spent fuel pool. The MPC is then loaded with spent fuel assemblies utilizing the refueling platform. Once loaded, the transfer cask and MPC are transferred by the Reactor Building crane to the Reactor Building decontamination area, where the MPC is decontaminated, welded shut, drained, dried, and backfilled with helium. The transfer cask containing the loaded MPC is again lifted using the Reactor Building crane and lift yoke, lowered through the hoist way and placed on top of the HI-STORM 100 storage overpack inside the Reactor Building truck bay where the MPC is transferred from the transfer cask to the HI-STORM 100 storage overpack. The loaded HI-

STORM 100 storage overpack is then transported out of the Reactor Building to the ISFSI.

10.3.9 References

1. American National Standard, "Design Objectives for Light Water Reactor Spent Fuel Storage Facilities at Nuclear Power Stations", ANS-57.2, ANSI N210-1976.

2. US Nuclear Regulatory Commission "Standard Review Plan", Office of Nuclear Reactor Regulation, NUREG-0800.

3. Southern Science Co., "Criticality Safety Analysis of the High Density Spent Fuel Storage Racks for the Pilgrim Nuclear Power Station", SSA-159 (SUDDS/RF 85-40, March 1985).

4. GE Letter ELH: 85-079, from E. L. Heinlein to R. G. Clough, "Transmittal of K-infinity Calculations", September 23, 1985.

5. Holtec International "PNPS Spent Fuel Storage Capacity Expansion" Licensing Report #HI-92925, (SUDDS/RF 93-01)

6. Holtec International "Single Rack Analysis" Report #HI-92927 (SUDDS/RF 94-23)

7. Holtec International "Spent Fuel Pool Slab Analysis" Report #HI-92952 (SUDDS/RF 94-24)

8. Holtec International "Whole Pool Multi Rack Analysis" Report #HI-92929 (SUDDS/RF 94-27)

9. Holtec International "Thermal Hydraulic Analysis" Report #HI-92936 (SUDDS/RF 94-28)

10. Holtec International "Criticality Safety Analysis" Report #HI-92939 (SUDDS/RF 94-29)

11. Holtec International "Blackness Testing of Boraflex in Selected Cells of the Pilgrim Station Spent Fuel Storage Racks", Report #HI-60935 (SUDDS/RF96-57).

12. Holtec International "Criticality Safety Analyses of the Pilgrim Spent Fuel Storage Racks with Degradation of the Boraflex Neutron Absorber", Report #HI-91709 (SUDDS/RF97-43).

13. Holtec International "In-Situ Neutron Absorber Surveillance Program", HSP-10

14. NUREG-0612, Control of Heavy Loads at Nuclear Power Plants, July 1980 (Enclosure 1 to NRC Letter dated December 22, 1980; Ltr. 1.81.014).

15. Pilgrim Letter #78-109 to NRC dated June 26, 1978 (Ref. ELNRC1.2.78.109).

16. NRC Safety Evaluation Report for Amendment No. 33 to the Pilgrim Operating License (Ref. NRCLE1.1.78.120).

17. Holtec International Final Safety Analysis Report for the HI-STORM 100 Cask System, Revision No. 9, USNRC Docket No. 72-1014, Holtec Report No.: HI-2002444, February 13, 2010.

18. USNRC Certificate of Compliance No. 1014, Docket No. 72-1014, Amendment No. 7, for the HI-STORM 100 Cask System, December 28, 2009.

10.8 FIRE PROTECTION SYSTEM

10.8.1 Power Generation Objective

The power generation objective of the fire protection system is to provide adequate fire protection capability in all areas of the station and to ensure safe shutdown in the event of a fire in any area of the plant.

10.8.2 Power Generation Design Basis

The fire protection system is designed to furnish water, halon, carbon dioxide, and/or dry chemicals as necessary for fire extinguishment in the station. The fire protection system is designed to provide the following:

1. A reliable supply of fresh water for fire fighting

2. A reliable system for delivery of water to potential fire locations

3. Automatic fire detection in selected areas

4. Fire extinguishment or control by fixed equipment activated either automatically or manually for areas with a high fire risk

5. Manually operated fire extinguishing equipment for use by operating personnel at selected points throughout the station

In addition, an alternate shutdown system has been installed to ensure that the station's safe shutdown capability is not adversely affected by a fire (Reference 6).

The requirements contained in the Entergy Quality Assurance Program Manual (QAPM) are applied to those activities affecting fire protection systems and equipment required to limit fire damage to safety-related structures, systems, and components so that the capability to safely shut down the plant is ensured.

10.8.3 Description

The fire protection system, piping and instrumentation diagram is shown on Figure 10.8-1 (BECo M218)..

10.8.3.1 Fire Water System

The site fire water supply is taken from two 250,000 gal, lined carbon steel water tanks which are devoted exclusively to fire protection. The fire water system may also use water from a city water main.

The water supply is delivered by either an electric motor-driven pump (rated at 2,000 gal/min) or a diesel engine driven pump (rated at 2,500 gal/min). The diesel engine driven pump is used for standby and emergency use on loss of ac power. A hydro turbine driven by diesel fire pump P-140 drives the backup diesel fuel transfer pump (P-181). This pump takes suction from the emergency diesel generator fuel oil storage tanks, bypasses diesel transfer pump P141-A and discharges to day tank T-123. The purpose of this hydro turbine driven pump is to provide a redundant (non-electric power dependent) diesel fuel oil transfer pump for the diesel fire pump P-140. This redundant pump will allow extended operation of the diesel fire pump as a water source for the RHR system during extended station blackout and severe accident scenarios beyond design basis. A small jockey pump (rated at 50 gal/min) is provided to maintain a constant pressure for the water system. If the system pressure drops substantially, the motor-driven fire pump will start automatically, and if pressure continues to drop, the diesel-driven pump will also start automatically.

The pumps feed outdoor fire hydrants, interior hose stations, sprinkler systems, and deluge systems for the station.

As part of the Safety Enhancement Program (SEP), a piping connection is provided from the Fire Protection System to the RHR System. This connection will allow water from the Fire Protection System fire pumps to flow to the upper containment spray header, torus spray header, and/or LPCI injection lines during a severe accident or station blackout.

The interconnection of the Fire Protection System and the RHR is manually initiated. Inadvertent admission of fire water to the RHR and or RHR contamination of the FPS is prevented by requiring the operator to install a removable pipe section with couplings and to open two locked closed valves. The removable pipe section is not installed during normal operation.

There are four types of sprinkler or water spray systems used at PNPS: (1) deluge, (2) pre-action, (3) wet pipe, and (4) dry pipe systems.

Deluge and pre-action systems have empty pipes. In these systems, the water is controlled (i.e., held out) by a separate heat detection system. Deluge systems have "open" sprinkler heads or water spray nozzles and pre-action have "closed" automatic heads or nozzles.

Wet pipe systems have pressurized water in their pipes and "closed" sprinkler heads. Dry pipe systems have pressurized air in their pipes and automatic "closed" sprinkler heads.

Deluge systems protect the exterior surface of the following equipment:

1. Main Transformer
2. Auxiliary Transformer
3. Shutdown Transformer
4. Startup Transformer

Wet pipe sprinkler systems protect the following areas:

1. Turbine basement area (west of shield wall)
2. Turbine lube oil reservoir room
3. Turbine lube oil conditioning room
4. Contaminated tool storage area
5. Recirculation motor generator sets room
6. Station heating boiler room
7. Old Machine shop
8. Offices at 37′ elevation radwaste bldg.
9. Diesel fire pump and day tank rooms
10. Offgas Retention Building - charcoal filter room
11. Radwaste hydraulic press (baler) area
12. Access control area and radiological offices
13. Condenser Retubing Building
14. Reactor Building (20 ft wide sprinkler systems only on El. 23'0" and 51'-0")
15. Reactor Auxiliary Building - Water Treatment Room
16. Safety enhancement program (SEP) Pump Building.
17. Redline building (RCA ingress/egress area and trash and laundry area).
18. Trash Compaction Facility

There are pre-action systems provided for the following areas:

1. Hydrogen seal supply oil area (sprinklers)

2. Diesel generator and day tank rooms (sprinklers)

3. Deleted

4. Turbine lube oil reservoir (water spray)

5. Turbine generator bearings (water spray) and oil hazards below the turbine lagging (sprinklers)

There is a dry pipe sprinkler system in the radwaste trucklock and condenser retubing building trucklock areas.

10.8.3.2 Other Extinguishing Systems

Total flooding, automatically actuated Halon 1301 fire suppression systems protect the following areas:

1. Cable spreading room

2. Plant computer room

3. O&M building record storage vault

4. Station blackout (SBO) diesel generator building

Dry chemical wheeled cart fire extinguishers will be provided in the following areas:

1. Diesel generator building

2. HPCI pump and turbine areas

3. Recirculation pump motor generator set room

4. Reactor feedpump area

Portable CO_2 hand extinguishers are provided in the control room and computer room. Portable dry chemical and pressurized water hand extinguishes are provided throughout the plant, as indicated in the Fire Protection System Evaluation and as modified by the Safety Evaluation Reports (References 1, 2, and 3).

10.8.3.3 Other Fire Protection Features

Fire detection systems which alarm in the control room are located in the following areas:

1. Diesel generator building

2. Reactor feed pump area

3. Computer room

4. Recirculation pump motor generator set room

5. Control room air recirculation fan inlet duct

6. Control room cabinets and consoles required for safe shutdown

7. Vital motor generator set room

8. Safety pump rooms (HPCI, RCIC, RHR)

9. CRD modules and MCC areas - east and west elevation 23 ft

10. Switchgear rooms and battery rooms

11. Radwaste trucklock area

12. Reactor Building areas at elevations 51 ft, 74 ft 3 in, 91 ft 3 in, and 117 ft and other areas housing safe shutdown equipment, panels, cable trays, and instrumentation

13. Reactor Building closed cooling water pump rooms A and B

14. Offgas Retention Building

15. The cable spreading room

Fire Detection Systems which do not alarm in the Control Room are located in the following areas:

1. Operation & Maintenance Building

2. EPIC Computer Room

10.8.3.4 Fire Barriers

Three hour rated fire walls, and some that are less than three hour rated in accordance with PNPS Safety Evaluation Report (Reference 4), are identified in the Fire Protection Evaluation Report (Reference 1). Doors, dampers, pipe penetrations, and cable penetrations through these fire walls are also rated 3 hour fire resistant, unless an evaluation demonstrates a fire rating of less than 3 hours is acceptable.

These fire walls separate fire areas containing safety related equipment for safe shutdown of the station in accordance with PNPS Safety Evaluation Reports (References 2, 3, and 4).

There are fire wraps for some safe shutdown raceways routed in certain areas as follows:

- "B" Switchgear Room - Enclosures #1 and #2, three hour rated.
- Cable Spreading Room - Enclosure #3, one hour rated.
- Torus Room (Bay 15) - Fire Wrap, one hour rated for instrumentation raceway M994.
- Control Room, Shift Managers Office - Fire Wrap, Three hour rated for raceway A-260.

Fire exits in the turbine auxiliary building (i.e., access area and time tunnel) are separated by smoke control doors.

Noncombustible shields are installed between the feedwater pumps (i.e., turbine building) to prevent oil from one pump from spraying on the other(s).

The diesel generator day tank room(s) are designed to prevent diesel fuel oil from entering the diesel generator room(s).

Curbs have been installed in the Generator Auxiliaries Area of the Turbine Building to contain potential oil spills and prevent them from spreading into the Lower Switchgear Room. These curbs, in conjunction with the sprinkler system in the area, provide a reasonable means of fire control should an oil fire occur.

10.8.3.5 Alternate Shutdown System

The alternate shutdown system, independent of cabling and equipment in the cable spreading room (CSR) and Control Room, is provided to effect safe shutdown of Pilgrim in the event of a fire in the CSR or the Control Room. This is accomplished by installing isolation switches for safety-related equipment that will provide the capability for the plant operators to reach a safe shutdown condition. These switches will isolate their associated equipment from the CSR cables, thus transferring control from the Control Room to the local emergency shutdown stations outside of the CSR and Control Room. These isolation switches are located in alternate shutdown panels and are located as close as practical to the equipment or switchgear they serve.

Isolation for other components and systems is achieved by manual tripping of switchgear breakers and MCC breakers such that components which are not required to change status between "Normal" and "Shutdown" conditions will not be affected by faults in their control circuitry.

Alternate shutdown panels are provided for the following systems:

a. Core Spray
b. RHR
c. RBCCW
d. Salt Service Water
e. HPCI
f. RCIC
g. Automatic Depressurization System
h. Diesel Generators

An Emergency Lighting System has been installed to provide sufficient illumination for the access routes to each alternate shutdown panel and for operation of the safety related equipment from these panels (References 2, 3, & 4).

10.8.4 Inspection, Testing and Technical Requirements for Fire Protection Equipment

The following provides surveillance frequencies, acceptance criteria and degraded equipment requirements for equipment associated with fire protection. This section reflects the guidance provided in Generic Letters 86-10 and 88-12.

10.8.4.1 Fire Detection Instrumentation

10.8.4.1.1 Fire Detection Instrumentation Technical Requirements

The minimum fire detection instrumentation for each fire detection zone shown in Table 10.8-1 shall be operable at all times when equipment in that fire detection zone is required to be operable.

ACTION: With the number of minimum operable fire detection instruments less than required by Table 10.8-1:

a. Within 1 hour, establish a fire watch patrol to inspect the zone with the inoperable instrument(s) at least once per hour; and

b. Restore the inoperable instrument(s) to operable status within 14 days to assure the minimum operable detectors for each detection zone, or determine the cause of the malfunction and develop plans for restoring the instrument(s) to operable status.

c. For inoperable fire detectors controlling fire suppression systems, see the respective fire suppression system section (i.e., Section 10.8.4.3 for water suppression systems or 10.8.4.4 for gaseous suppression systems).

10.8.4.1.2 Fire Detection Instrumentation Surveillance Requirements

As a minimum, the number of fire detectors noted in Table 10.8-1 shall be demonstrated operable in accordance with NFPA 72 Fire Code by a functional test at least once per year.

EXCEPTION; The detectors in the charcoal vault in the augmented offgas building need to be functionally tested once per refueling outage.

10.8.4.2 Fire Water Supply System

10.8.4.2.1 Fire Water Supply System Technical Requirements

At all times when any safety related equipment is required to be operable, the fire water supply system shall be operable with:

1. One 2000 gpm and one 2500 gpm, 119 psig (95% of the 125 psi rated output), fire pumps which are arranged to start automatically.

2. Two water supplies with a minimum storage quantity of 240,000 gallons of water in each.

3. Two independent water flow paths from 1 and 2 above to each fire water suppression system. (10.8.4.3 and 10.8.4.5)

ACTION: With less than the above required equipment:

a. Restore the inoperable equipment to operable status within 7 days or implement the plans and procedures to be used to provide for the loss of redundancy in this system.

b. With no Fire Water Supply System flow path operable, establish the Backup Fire Water Supply System within 24 hours (in accordance with station procedures) or an orderly shutdown of the reactor shall be initiated and the reactor shall be in the cold shutdown condition within 24 hours.

10.8.4.2.2 Fire Water Supply System Surveillance Requirements

The fire water supply system shall be tested and verified to be operable:

a. by checking the volume of water in each fire water tank at least once every 7 days.

b. by automatically starting each fire pump at least once every month and running the diesel engine driven pump for thirty minutes and the motor driven pump for at least 10 minutes at that time.

c. by visually checking every shutoff valve on the fire water supply system at least once every month for proper position. (Exception - once per cycle for those in Locked High Radiation Areas)

d. by cycling each fire water supply system shutoff valve through its full operation at least once per cycle.

e. by verifying at least once per cycle that one pump starts and delivers at least 2000 gpm and one pump 2500 gpm while maintaining a system pressure of at least 119 psig (95% of the 125 psi rated output).

f. by performing a water flow test on the fire water yard loop at least once every year.

g. by verifying at least once every month that the diesel fire pump fuel storage tank contains a minimum of 175 gallons of fuel oil.

h. at least once per operating cycle by subjecting the diesel to an inspection in accordance with procedures prepared in conjunction with the manufacturer's recommendations for the class of service.

i. by verifying at least once per 3 months that a sample of diesel fuel from the fuel storage tank, obtained in accordance with ASTM D4057-81 or D4177-82, is within the acceptable limits specified in Table 1 of ASTM D975-81 with respect to viscosity, water content, and sediment.

j. by demonstrating that the diesel starting 24-volt battery bank and charger are operable as follows:

    1. at least once per week by verifying that the electrolyte level of each battery is above the plates and battery voltage is at least 24 volts.

    2. at least once per 3 months by verifying that the specific gravity is appropriate for continued service of the battery.

    3. at least once per operating cycle by verifying that the batteries and battery racks show no visual indication of physical damage or abnormal deterioration and the battery-to-battery and terminal connections are clean, tight, free of corrosion, and coated with anti-corrosion material.

10.8.4.3 Spray and/or Sprinkler Systems

10.8.4.3.1 Spray and/or Sprinkler Systems Technical Requirements

The spray and/or sprinkler systems located in the following areas shall be operable at all times when equipment in the spray/sprinkler protected area is required to be operable:

1. Diesel generator room preaction sprinkler systems (including detectors).

2. Diesel fire pump fuel oil storage room wet pipe sprinkler system.

3. Auxiliary boiler room wet pipe sprinkler system.

4. Recirculation pump MG set room wet pipe sprinkler system.

5. Hydrogen seal oil supply unit preaction sprinkler system (including detectors).

6. Turbine basement addition wet pipe sprinkler system.

7. Reactor building elevation 23'-0", north side wet pipe sprinkler system.

8. Reactor building Elevation 51'-0", north and south side wet pipe sprinkler systems.

9. Reactor auxiliary building, water treatment area, wet pipe sprinkler system.

10. Health physics access area wet pipe sprinkler system.

ACTION: From and after the date that a spray and/or sprinkler system is made or found to be inoperable:

a. Within one hour establish a continuous fire watch with backup suppression, except as specified in 10.8.4.3.1, actions c, d, e, f, and g.

b. Restore the system to operable status within 14 days or determine the cause of inoperability and develop plans for restoring the system to operable status.

c. If the Spray or Sprinkler System is not operable because no Fire Water Supply System flow path is operable, complete actions identified in Section 10.8.4.2.1.

d. If the suppression system of the diesel generator room preaction sprinkler systems (including detectors but excluding the Pilotex portion of the system), is inoperable, establish an hourly fire watch patrol with backup suppression provided that the detection system in that fire area and the detection and suppression system for the redundant fire area is operable.

e. If two or more detectors of the diesel generator room preaction sprinkler system are found or made to be inoperable, within one hour charge that sprinkler system piping with water.

f. If the wet pipe sprinkler system for the reactor recirculation pump MG set room, reactor building auxiliary building water treatment room, auxiliary boiler room, reactor building elevations 23′ & 51′ north side, or reactor building elevation 51′ south side is inoperable, establish an hourly fire watch patrol with backup suppression provided that the detection system in the area is operable. Additional administrative controls will be implemented to further reduce any potential fire hazards while the automatic suppression systems are inoperable.

g. When the entire fire area protected by a spray and /or sprinkler system is designated, "HIGH RADIATION AREA/AIRBORNE RADIOACTIVITY AREA", an hourly fire watch patrol may be established (e.g., for ALARA considerations in lieu of a continuous fire watch). If a zone of the fire area is so designated, one of the following shall apply: (1) If the zone is adequately inspectable from a non-High Radiation Area, the continuous fire watch shall be located in the non-High Radiation Area, or (2) If (1) cannot be accomplished, a fire watch patrol shall enter the High Radiation Area once every eight hours.

It is not necessary to enter areas designate designated as "Locked High Radiation Area".

10.8.4.3.2 Spray and/or Sprinkler Systems Surveillance Requirements

The spray and/or sprinkler systems shall be demonstrated to be operable according to the following:

1. Each sprinkler system and water spray system alarm shall be tested at least once every year by opening the alarm bypass or inspector test valve. Alarms in high radiation areas are to be tested once per cycle.

2. Deleted.

3. Each preaction sprinkler system shall be trip tested at least once per cycle.

4. Each water spray system shall be trip tested automatically by simulated actuation of the heat detectors at least once per cycle.

10.8.4.4 Halon System

10.8.4.4.1 Halon System Technical Requirements

The halon system for the cable spreading room shall be operable with each of the five storage tanks charged to at least 95% of the minimum quantity of halon (217 lbs. per tank) necessary to extinguish a fire, and minus or plus 10% of the pressure stamped on the data plate on the tank corresponding to an ambient temperature of 70°F. Detectors associated with the automatic initiation of the halon system shall be operable, except that an individual detector may be inoperable if the other detector in the same bay is operable and both detectors in all adjacent bays are operable.

The halon system shall be operable at all times when the safety related equipment in the cable spreading room is required to be operable.

ACTION:

a. Within one hour from and after the time that the system is found to be inoperable, establish a continuous fire watch with backup suppression equipment.

10.8.4.4.2 Halon System Surveillance Requirements

The halon system shall be demonstrated operable:

1. At least once per month by verifying the halon storage tank pressure and that the control panel is in the automatic mode.

2. At least once per 6 months by verifying the quantity of halon in the storage tank(s).

3. a. At least once per operating cycle by verifying that the system and associated devices actuate upon receipt of a simulated actuation signal, and

   b. Performance of an inspection to assure the nozzles are unobstructed.

10.8.4.5 Fire Hose Stations

10.8.4.5.1 Fire Hose Stations Technical Requirements

The interior fire hose stations shown in Table 10.8-2 shall be operable at all times when the equipment in the area protected by the fire hose station is required to be operable.

ACTION:

a. With a hose station inoperable, provide an additional equivalent capacity hose for the unprotected area at/from an operable hose station within 1 hour, except as specified in 10.8.4.5.1. Action b.

b. If a fire hose station is not operable because no fire water supply system flow path is operable, complete actions specified in section 10.8.4.2.1.

10.8.4.5.2 Fire Hose Stations Surveillance Requirements

Each interior fire hose station shall be verified to be operable:

1. At least once per month by visual inspection of the station to assure that the hose and nozzle are properly installed. (Exception - Once per cycle for those in Locked High Radiation Areas).

2. At least once per cycle by removing the hose for inspection, replacing any degraded coupling gaskets, and reracking.

3. At least once per two fuel cycles (approximately 4 years) by partially opening each hose station valve to verify valve operability and no obstruction. (Partial flow test).

4. By conducting a hydrostatic test of each hose every three years.

   a. at a pressure 50 psig greater than the maximum available pressure at that hose station, or

   b. at the applicable service test pressure as listed in Table 8-3 of the "Standard for Care, Maintenance of Fire Hose Including Connection and Nozzles." NFPA No. 1962-1979, or

   c. by replacing each nontested hose with a new or used hose which has been hydrostatically tested in accordance with the pressures specified in a or b above.

10.8.4.6 Fire Barrier System

10.8.4.6.1 Fire Barrier System Technical Requirements

All fire barrier systems providing separation of redundant safe shutdown systems shall be functional at all times when the safe shutdown systems are required to be operable.

<u>ACTION</u>: With one or more of the required fire barrier systems nonfunctional:

a. Within one hour either establish a continuous fire watch on one side of the affected barrier or verify the OPERABILITY of an automatic fire detection or suppression system on at least one side of the nonfunctional fire barrier and establish an hourly fire watch patrol, except as identified in 10.8.4.6.1 actions b and c.

b: When the fire areas on both sides of the affected fire barrier are designated "HIGH RADIATION AREAS/AIRBORNE RADIOACTIVITY AREA", an hourly fire watch patrol may be established (e.g. for ALARA considerations) in lieu of a continuous fire watch.

c Certain fire barrier components may be degraded without adversely affecting the fire barrier function of preventing fire damage to redundant trains of safe shutdown equipment. Fire Protection may perform an evaluation to document that no fire watch is necessary or to allow hourly fire watches for circumstances where degraded barriers are still capable of performing their fire protection function.

10.8.4.6.2 Fire Barrier System Surveillance Requirements

Surveillance requirements for penetrations in fire barriers are as follows:

1. Fire Barrier Penetration Seals: Approximately 20% of the fire barrier penetration seals shall be visually inspected once per cycle. The sampling shall ensure that 100% of the seals are inspected within a 10 year period or 5 fuel cycles. If any seal is found to be inoperable, then an additional 10% of the seals shall be inspected. Sampling and inspection shall continue until all of the seals in a sample are found to be operable or until 100% of the seals are inspected.

2. Fire Doors: Each fire door shall be tested once per cycle for operability of closure and latching mechanisms and for integrity.

3. Fire Dampers: Each fire damper shall be tested once per every 2 cycles for operability and integrity. In certain circumstances Fire Protection may determine that it is not necessary to test a damper and may recommend an inspection only. An evaluation will be prepared to document the basis for such determinations.

4. Fire barrier enclosures and fire wrap systems: Each fire barrier enclosure and fire wrap system will be visually inspected for integrity once each operating cycle.

10.8.4.7 Fire Brigade

A fire brigade of 5 members including a fire brigade leader shall be maintained on site at all times. This minimum excludes 3 members of the minimum shift crew necessary for safe shutdown and any personnel required for other essential functions during a fire emergency.

The fire brigade training shall be in accordance with Pilgrim Station's Fire Protection Training Program. The fire protection training of fire brigade members shall be held quarterly.

10.8.4.8 Alternate Shutdown Panels

The operability and surveillance requirements for the alternate shutdown system are in Section 3/4.12 of Pilgrim Station's Technical Specifications. The emergency lighting system for the alternate shutdown system is within the scope of the Maintenance Rule at PNPS. Performance requirements are established and monitored accordingly.

10.8.5 References

1. Pilgrim Station 600, Unit 1, Boston Edison Company, Fire Protection System Evaluation, March 1, 1977.

2. Safety Evaluation Report by the Office of Nuclear Reactor Regulation (Amendment 35 to License No. DPR-35) for Pilgrim Nuclear Power Station-1, December 21, 1978.

3. Safety Evaluation Report (additional Fire Protection Information Review) for Pilgrim Nuclear Power Station-1, October 7, 1980.

4. Safety Evaluation Report by the Office of Nuclear Reactor Regulation Related to Amendment No. 123 to Facility Operating License No. DPR-35, dated October 13, 1988.

5. Report 89XM-1-ER-Q Updated Fire Hazards Analysis.

6. Power System Calculation No. 32, "Appendix R, Safe Shutdown Analysis for PNPS".

7. License Amendment 143 resulting from Generic Letters 86-10 and 88-12.

10.11 INSTRUMENT AND SERVICE AIR SYSTEMS

10.11.1 Power Generation Objective

The power generation objective of the Instrument and Service Air Systems is to provide the station with a continuous supply of oil-free compressed air. This air is directed to station instrumentation and general station services.

10.11.2 Power Generation Design Basis

1. The Instrument Air System is designed to supply clean, dry air to station instrumentation and controls at 70 to 100 psig with a design dewpoint of -40°F at 100 psig.

2. The Service Air System is designed to provide clean air to station services at 70 to 100 psig. The Low Pressure Service Air System is designed to provide clean air at a nominal pressure of 20 psig to station services.

10.11.3 Description

10.11.3.1 General

The air systems are, in general, designed to Class II requirements, although Class I equipment requiring air under accident conditions has Class I air accumulators and piping associated with that equipment. See Figure 10.11-1.

The high pressure air supply (nominal 100 psig with allowance for drops to 90 psig) is developed by three reciprocating (in long term layup) and two rotary screw type air compressors operating in parallel. Each compressor has an after cooler and delivers the compressed air to a bank of receivers. There are five air receivers which are connected to a common discharge header that delivers the air to the high pressure service air system and to two instrument air dryers to provide high quality dry air to the various instrument air headers. There is one coalescing air filter located upstream of each instrument air dryer. There is one particulate air filter downstream of the instrument air dryer X-105 and dryer X-160 A&B. The downstream air filters are to ensure that no desiccant or other foreign material enters the instrument air system. There is also a bypass around the dryers and filters which can be opened by remote manual or automatic means for dryers X-105 and X-160A&B to assure a continued supply of instrument air to the essential instrument air header in the event of an air dryer failure. Normally, use of one of the two rotary compressors will maintain the air receivers at the desired pressure for system supply. The remaining compressors serve as standby units. Actuation of the standby units is automatic and is indicated in the control room.

The High Pressure Service Air System delivers air to various plant services which do not require drying, such as air powered tools.

The low pressure air supply (nominal 20 psig) is developed by two centrifugal air blowers. The blowers discharge for distribution through a moisture separator and a mist eliminator. Blower usage is intermittent. No dewpoint control is provided. The Low Pressure Service Air System interfaces with several plant systems which contain radioactivity. As a result of aging of system isolation components, unintentional cross-contamination of the Low Pressure Service Air System has occurred. While it is impractical to decontaminate the system and maintain it free of detectable radioactivity, this system should be operated and maintained so as to keep the levels of radioactivity contained within at a minimum commensurate with the goals of the station ALARA program.

A normally closed pressure reducing cross-over line is provided between the high pressure distribution header upstream of the air dryers and the low pressure distribution header. This cross-over may be used to continue low pressure service in the event of blower failure.

Pressure loss in the high pressure system, sensed by several pressure switches, will cause valves in the service air header, the low pressure service air cross-around line, and the non-essential instrument air header to close in a cascading sequence thus leaving the essential instrument air header as the only header drawing air from the receivers in the event that supply pressure decreases.

Instrumentation is provided to monitor the dew point downstream of each air dryer. Flow meters are provided for each air dryer train.

A 3″ back-up air supply system was added to the Instrument Air system, tying into the permanent plant hardpipe connection from the outside of the turbine building where it is connected to a diesel driven oil-free air compressor. This back-up source of instrument air is used for station black-out conditions and/or to provide additional air for times when the system is not available due to maintenance.

The backup nitrogen system consists of two banks of ten cylinders each, a cylinder rack and manifold (X-169), associated piping and valves. The cylinders are arranged to automatically maintain the nitrogen supply to drywell instrumentation once the existing nitrogen supply is not available. The cylinders deliver nitrogen gas through 2 inch piping which ties into the existing drywell instrument supply header. A differential pressure indication switch with annunciator is connected between the cylinder supply and the existing supply which provides control room indication of switchover to the cylinders.

10.11.3.2 Equipment Description

Compressors

The three reciprocating air compressors are vertical, single stage, double acting reciprocating compressors. They are each rated to deliver 159.5 standard ft^3/min at 105 psig. The two rotary compressors are each rated to deliver 655 standard ft^3/min at 102 psig.

The diesel air compressor is sized to accommodate station air loads in a black-out or maintenance condition.

Each reciprocating compressor has a pressurized lubrication system for the power-end parts. The cylinders are non-lubricated having Teflon piston rings. They also have water cooled cylinders and have a displacement of 261 in^3. All intake valves have pneumatic operators which depress the valves allowing the cylinder to unload by venting to the atmosphere each time the motor starts and each time the receiver pressure reaches the top of its operating range.

Each of the three reciprocating compressors is belt-driven (4 belts) by a 40 hp drip proof induction motor. The compressor speed is 514 rpm.

The two rotary screw type compressors are direct driven by an electric motor which provides a shaft output of 156 hp at a compressor discharge pressure of 102 psig. The compressor speed is 3,550 rpm.

The accumulator charging compressor (K-203) and dryer (X-285) are powered by a 5 hp, 460 V/3 phase/60 Hz motor and supplies dry air, with a dew point of (-) 50°F, at 130 psig. This compressor serves as the alternate means of charging the Standby Gas Treatment and Torus Vacuum Breaker accumulators.

Aftercoolers

The reciprocating compressor aftercoolers are shell and tube counter current coolers with air passing through the tubes and water flowing around the tubes. They have an integral moisture separator equipped with an automatic drain trap to remove condensed moisture from the cooled air. Cooling water is supplied by the Turbine Building Closed Cooling Water System.

The rotary screw compressors are provided with intercoolers and aftercoolers, integral with each unit. Cooling water is supplied by the Turbine Building Closed Cooling Water System.

Air Receivers

The air receivers are vertical vessels built to the ASME code for a design pressure of 125 psig. Each receiver is equipped with two relief valves and an automatic drain trap. The volume of each receiver is 151 ft^3.

Air Dryers

The two air dryers are each rated to pass 100% of normal station air demand at 100 psig dried to a dewpoint of -40 F. Each drier has twin towers built to the ASME code for a design pressure of 150 psig. The air is dried by passing it through a desiccant. Moisture is removed from the desiccant by a heated purge air flow.

Class I Accumulators

Class I accumulators, associated piping, and check valves of appropriate size are provided for the following equipment:

1. Torus to Secondary Containment Vacuum Breaker Butterfly Valves

   The torus to secondary containment vacuum breaker butterfly valves are powered by Class I air accumulators. These accumulators are sized for a 30 day mission time without operator action and a design leakage rate of 0.1 SLM. A Class I manual make-up system allows the accumulators to be recharged from outside secondary containment and thus maintain the vacuum breakers valve function for an indefinite period of time. The vacuum breaker and make-up air supply are shown on Figure 10.11-1 (Drawing M220).

2. Main Steam Isolation Valves

3. Main Steam Relief Valves

   A Class I, seismic piping system allows two accumulators to be recharged from outside the Drywell, and thus maintain the RPV pressure control capability for an indefinite period of time.

4. Emergency Diesel Generator Ventilation System Dampers.

10.11.4 Inspection and Testing

The Instrument and Service Air System operates continuously and is observed and maintained during normal operation. No special inspection and testing will be required following preoperational testing.

Figure 10.11-1 has been removed.

Please refer to BECo Controlled Drawing M 220.

10.21 Hydrogen Water Chemistry Extended Test System

10.21.1 Design objective

The hydrogen water chemistry extended test system (ETS) is non-safety related. The ETS is designed to suppress the dissolved oxygen level in the reactor coolant system and mitigate intergranular stress corrosion cracking (IGSCC).

10.21.2 Design Basis

1. The ETS is designed to inject up to 15 SCFM hydrogen into the suction of the feedwater pumps for oxygen suppression in the reactor coolant system.

2. The ETS is designed to inject up to 10 SCFM oxygen into the offgas recombiner to recombine with the hydrogen carry-over produced with hydrogen injection into the feedwater.

3. The ETS is designed to inject oxygen into the suction of the condensate pumps for erosion corrosion protection.

4. The ETS is designed to provide redundant features to key components to improve reliability and has been designed to ANSI B31.1. However, it is not designed to Seismic Class I requirements.

10.21.3 Description

10.21.3.1 General

Boiling water reactors use high purity water as the primary recirculation coolant in the direct cycle production of steam. This water contains a steady state value of 100 to 300 ppb of dissolved oxygen and stoichiometrically related dissolved hydrogen because of the simultaneous action of radiolysis and stripping within the core. It is well known that this is sufficient oxygen in the coolant to cause, in conjunction with the presence of high stresses, intergranular stress corrosion cracking (IGSCC) of stainless steels.

Full scale testing at Pilgrim has shown that both the dissolved oxygen concentration in the recirculation water and the electrochemical potential (ECP) of sensitized type 304SS (304SS is the material of construction of the reactor pressure vessel lining) vary inversely with the rate of hydrogen addition to the feedwater.

As the dissolved oxygen concentration drops, so does the ECP; it is the ECP that determines the susceptibility of 304SS to IGSCC.

IGSCC of sensitized Type 304SS does not occur below -0.230V standard hydrogen electrode scale (SHE) (as measured by a standard hydrogen electrode). This critical value was identified and verified by a series of constant extension rate tests (CERTS) run in both laboratory and operating plant facilities while concurrently measuring the ECP.

During RFO 16 (Spring 2007), the initial application of noble metals was performed. The deposition of noble metal compounds on the wetted surfaces of reactor internal systems has been determined to enhance the effect of hydrogen water chemistry in controlling IGSCC. The intent is to deposit noble metal on the material surfaces of the reactor vessel internal components and recirculation system piping to significantly reduce the ECP in the presence of excess hydrogen concentration. (Reference 6). This has the effect of requiring a much lower hydrogen addition rate; the ETS design was modified to permit injection of up to 15 SCFM hydrogen. The exact level of hydrogen injection flow rate is determined as required to establish the required ECP.

The ETS also provides the capability to inject oxygen into the condensate system (suction of each condensate pump). This maintains condensate/feedwater dissolved oxygen levels in accordance with the BWR water chemistry guidelines for erosion-corrosion protection of the condensate/feedwater piping systems.

10.21.3.2 System Description

A flow diagram of the ETS system is given in Figures 10.21-2, 10.21-3, and 10.21-4 (drawings M257, 258, and 260).

The hydrogen water chemistry (HWC) extended test system (ETS) injects hydrogen into the feedwater at the suctions of the feedwater pumps to mitigate IGSCC in the recirculation system. The injected hydrogen forces a reduction in dissolved oxygen within the recirculation piping and lowers the radiolytic production of hydrogen and oxygen exiting the vessel (main steam) and eventually in the main condenser.

The injected hydrogen basically passes through the coolant cycle unreacted. This leaves an "excess" of hydrogen in the main condenser that would not have an equivalent of oxygen to recombine in the Offgas System. To maintain the Offgas System near its normal operating characteristics, a flow rate of oxygen equal to one half the injected hydrogen flow rate is put in the Offgas System upstream of the recombiner. Oxygen is also being injected into the condensate pump suctions to prevent erosion corrosion in carbon steel piping due to low PPM oxygen.

Three sample subsystems are included in the ETS package to measure: 1) feedwater water chemistry, 2) main steam water chemistry, and 3) % oxygen exiting the offgas recombiner. The ETS also uses signals from the CAVS and the MMS to measure Reactor water chemistry. All three subsystems contain built-in gas calibrators and sample stream conditioning controls.

A computer Data Acquisition System (DAS) is included to summarize the performance of the ETS for various report requirements. It is set up to accept analog input and digital alarm signals.

A block diagram indication the relationship of the ETS subsystems is shown in Figure 10.21-1.

Redundant features are incorporated into the ETS to improve reliability. These are:

- Hydrogen Flow Meters
- Oxygen Flow Meters
- Hydrogen Flow Controllers
- Oxygen Flow Controllers
- Oxygen Flow Control Valves
- Hydrogen Isolation Valves
- Offgas % Oxygen Meters
- Reactor Water Dissolved Oxygen Meters
- Reactor Water Conductivity Meters
- Main Steam Dissolved Oxygen Meters
- Feedwater Dissolved Oxygen Meters
- Recording
- Excess Flow Check Valves

Automatic or control features in the ETS minimize the need for operator attention and improve performance. These are:

a) Automatic variation of hydrogen and oxygen flow rate with power level.

b) Automatic offgas oxygen injection rate change delay. This function is also augmented as a function of power level.

c) Automatic shutdown on several alarms (See Table 10.21-1).

d) Isolation on power loss, operator restart.

e) Reprogrammable alarms and controller electronics.

f) Hydrogen and oxygen flow monitor correction functions to compensate for nonlinearities.

The majority of ETS process valving is grouped into three subsystems (modules). One for the hydrogen injection subsystem, the second for the oxygen injection subsystem to the recombiner, and the third for the oxygen injection subsystem to the condensate system. The hydrogen and oxygen gas sources are from high pressure hydrogen gas storage tanks and the liquid oxygen storage tank.

HWC ETS Hydrogen Supply

The gaseous hydrogen supply sub-system is located in the upper parking lot southwest of the Indoctrination and Support Facility.

The equipment consists of a permanent twelve tube bulk modular assembly, equipped with pressure indication, pressure relief, and temperature indication. The twelve tube assembly nominal gas capacity at 70°F is:

Pressure	Standard Cubic Feet
2640 psi	99,247

The storage vessels and system piping, valves and controls are designed and constructed in accordance with all applicable codes and standards including EPRI NP-5283SR-A, (Reference 1).

Provisions have been made at the storage facility to accept up to three (3) additional transportable hydrogen tube trailers to supply the extended test system and the generator cooling system.

HWC ETS Oxygen Supply

The liquid oxygen supply sub-system is located outside of the turbine building west wall near the southwest corner of the building.

The equipment consists of a 1500 gallon liquid oxygen tank (T-125) with pressure indication, level indication, and pressure, temperature control manifolds. Temperature control valves TCV-58 A&B are set at -20°F to close automatically to prevent any liquid oxygen from entering the system.

The storage vessels and system piping, valves and controls are designed and constructed in accordance with all applicable codes and standards including EPRI NP-5283SR-A, (Reference 1).

ETS Safety Features

The ETS process design incorporates several key safety features:

Non-flammable Offgas

Oxygen is injected into the offgas system upstream of the recombiner in stoichiometric or greater proportion to the hydrogen present to produce a non-flammable offgas through catalytic recombination of all hydrogen.

A built-in delay in the ETS control system insures that the oxygen injection rate decrease lags the hydrogen decrease (excess oxygen is present); and there is no oxygen delay during a hydrogen increase, again insuring excess oxygen in the offgas. This delay period is automatically adjusted for power level.

Low Power Isolation

There are two modes of operations for this system. The first mode of operation is to allow the ETS to automatically shutdown; as the reactor percent power decreases to a preset level (30%), the ETS automatically shuts down. Since the lower level is normally seen only during a reactor shutdown, this feature insures a low power isolation which would normally be accomplished by the reactor operating personnel. It also protects against loss of power level signal to the controllers.

The second mode of operation is to control the shutdown manually by implementing a bypass switch. This mode will allow the ETS to inject hydrogen below 30% reactor power, but will require the system to be secured manually. The ETS is operational while the AOG is in-service.

Automatic Reset of Hydrogen and Oxygen Flow Rates to Zero During ETS Shutdown

The hydrogen external and internal setpoints are disabled and are given a zero value immediately on system shutdown.

The oxygen flow will automatically follow the hydrogen flow rate with a delay and decay. A zero setpoint value is also input to the hydrogen rate limiter on shutdown so system restart with an external or internal setpoints proceeds from zero flow. Restart of the system can proceed only if the shutdown condition is cleared and the annunciator panel is reset. Systems restart should also be delayed fifteen minutes to allow for the ramp rate decay in the external or internal setpoint.

Valves

The flow control and remote isolation valves fail closed upon loss of instrument air or control power, insuring that flow does not proceed in an uncontrolled fashion.

Alarms and Shutdowns

The ETS incorporates numerous alarm and automatic shutdown functions. All alarm and shutdown signals have normally closed continuity, thus alarming or shutting the system down on an electrical wire break.

The ETS control hardware and control logic is designed to insure safe and accurate control of hydrogen and oxygen injection. Primary control of the system takes place at the HWC ETS control panel C613 on the turbine deck, but the system can be shutdown, though not adjusted or re-started, from the control room (Panel CP600).

All the parameters monitored are recorded regularly at a pre-set interval by the data acquisition system (DAS). The DAS also records all alarms and automatic and manual shutdowns. In addition to recording of various parameters at the control panel and DAS, the control room panel continuously displays the hydrogen and oxygen flow rates and the offgas percent oxygen.

10.21.4 Codes, Standards, and Regulations

The mechanical and electrical aspects of the ETS are designed and selected in accordance with the applicable sections of the codes, standards, and regulations referenced below:

The ETS equipment and services are classified non-safety related.

ANSI B31.1 American National Standards Institute, Power piping
ANSI A13.1 Identification of Piping Systems
ANSI/ASTM G63 Evaluating Nonmetallic Materials for Oxygen Service
NEPA 70 National Fire Protection Association National Electrical Code
NFPA 50A Gaseous Hydrogen System
CGA G-4 Compressed Gas Association, Oxygen
CGA G-4.1 Cleaning Equipment of Oxygen Services
CGA G-4.4 Industrial Practices for Gaseous Oxygen Transmission and Distribution Piping Systems
CGA G-5 Hydrogen
ASME Boiler and Pressure Vessel Code, Section IX, Welding and Brazing Qualifications
Mass Building Code
EPRI NP-5283-SR, Dated September 1987, "Guidelines for Permanent BWR Hydrogen Water Chemistry Installations", 1987 Revision

10.21.5 System Evaluation

The ETS consists of the equipment described above and is non-safety related. The ETS is designed not to affect the safe operation of existing safety related systems. The ETS is operational only when the Augmented Offgas is inservice.

Shielding has been added on the turbine deck for on-site and off-site personnel radiation protection. ALARA procedures and maintenance practices have been designed to limit exposure.

10.21.6 References

1. EPRI NP5283SR-A "Guidelines of Permanent BWR Hydrogen Water Chemistry Installations", 1987 Revision.

2. GE-NE-B13-01805-03, "Pilgrim HWC Ramping Test Final Report", December 1995.

3. NESD 95-241, "Optimum HWC Injection Rate for In Core Components IGSCC Protection"

4. PDC 02-122, "Licensing Issues - Thermal Power Uprate"

5. Safety Evaluation 2974, "Increase the ETS H_2 Injection Rate up to 50 SCFM"

6. ER 05117404, "Engineering Evaluation - Plant Configuration & Operation After Noble Metals Application".

12.2 STRUCTURAL DESIGN

12.2.1 Classification of Structures and Equipment

12.2.1.1 General

The most severe environmental phenomena which could affect the site have been evaluated in Section 2. Based on these evaluations, the station structures and equipment have been classified with respect to systems which must remain functional during and following the most severe natural phenomena which can be postulated to occur at this site. For the purpose of categorizing the mechanical structural strength designs for loading conditions due to environmental events, the following definitions have been established:

1. Class I

   This class includes those structures, equipment, and components whose failure or malfunction might cause or increase the severity of an accident which would endanger the public health and safety. This category includes those structures, equipment, and components required for safe shutdown and isolation of the reactor

2. Class II

   This class includes those structures, equipment, and components which are important to reactor operation, but are not essential for preventing an accident which would endanger the public health and safety, and are not essential for the mitigation of the consequences of these accidents. Class II designated structures and/or equipment shall not degrade the integrity of any structures and/or equipment designated Class I

The only exception to these definitions is that a system, whose failure or malfunction might increase the severity of an accident, is not designed to withstand the effects of a tornado if the failure of the system will not cause an accident. The probability of the occurrence of a design basis loss of coolant accident or a design basis tornado during the life of a plant is small. Therefore, the probability of the simultaneous occurrence of these two independent events is relatively small.

12.2.1.2 Class I Structures and Equipment

Nuclear Steam Supply System (NSSS)

Reactor vessel and supports

Control Rod and Drive System including equipment necessary for scram operation

Control rod drive housing supports

Fuel assemblies

Core shroud

Core supports

Steam separator assembly

Steam dryer assembly

Reactor Coolant Recirculation System including valves and pumps

All piping connectors from the reactor vessel up to and including the first isolation valve external to the drywell

Main steam piping when located inside a Class I structure

Isolation valves

Reactor Core Isolation Cooling System

High Pressure Coolant Injection System

Standby Liquid Control System

Residual Heat Removal System

Core Spray Systems

Primary Containment System

Drywell

Pressure suppression chamber

Vent System

Vacuum Relief System

Pressure suppression pool

Isolation valves

Containment penetrations

Secondary Containment System

Reactor Building (with the exception of access locks which are Class II structures)

Reactor Auxiliary Bay Pipe Vaults

Standby Gas Treatment System

Main stack

Reactor Building Isolation Control System

NOTE:

The Secondary Containment System is not designated to be functional during or after a tornado; however, the Reactor Building does protect all the Class I equipment located inside the building from the effects of a tornado.

Station Standby Cooling Systems

Reactor Building Closed Cooling Water System (portion serving Class 1 equipment)

Salt Service Water System (portions serving Class I equipment)

Intake structure (housing the Salt Service Water System)

Equipment Area Cooling System (portions serving Class I equipment)

Standby Electrical Power Systems

Standby AC Power System

DC Power System (125/250 V)

DC Power System (24 V)

Emergency service buses and other electrical gear to power Class I equipment

Station battery rooms

Diesel Generator Building and Underground Fuel Storage Tanks

Reactor Building Fuel Storage Facilities

Spent fuel storage equipment

Spent fuel pool

New fuel storage equipment

New fuel storage vault

Main Control Room System

Main control room

Main Control Room Environmental Control System

All instrumentation and controls required for operation of Class I equipment except the Reactor Manual Control System

Parts of structures housing or supporting Class I equipment

Reactor Building Auxiliary Bay Substructure

12.2.1.3 Class II Structures and Equipment

Reactor Building auxiliary bay superstructure and Reactor Building access locks

Reactor Building (truck) access lock

Turbine Building

Radwaste Building
(Except areas housing or supporting Class I equipment)

Old Administration Building

New Administration/Service Building

Intake and discharge structures
(Except areas housing or supporting Class I equipment)

Trash Compaction Building

Turbine Generator System

Main Condenser System

Reactor and Turbine Building cranes

Reactor Feedwater and Condensate Systems

Main Steam System (outside Reactor Building)

Reactor Cleanup System

Radwaste System

Fire Protection System

Condensate Storage and Transfer Systems

Normal Heating and Ventilating System

Station auxiliary power buses

Electrical controls and instrumentation (for above systems) and the Reactor Manual Control System

Other structures, piping, and equipment not listed under Class I

12.2.2 Description of Principal Structures

12.2.2.1 Reactor Building Structure and Crane

The Reactor Building, with its associated auxiliary bays, houses the reactor, the Reactor Coolant System, and auxiliaries associated with the Nuclear Steam Supply System. It also houses the refueling facilities, spent fuel storage pool, steam separator and dryer storage pool, new fuel storage vault, control rod drive hydraulic equipment, and the Reactor Primary Containment System. The Reactor Building is basically a reinforced concrete structure with structural steel framing, consisting of the following major structural components:

1. The foundation consists of an 8 ft thick heavily reinforced concrete mat

2. Elevated floors consist of concrete slabs simply supported by conventional type structural steel framing

3. The interior walls are reinforced concrete or concrete block

4. The spent fuel storage pool, the reactor well, and the dryer separator storage pool consist of reinforced concrete deep girder walls and base slabs. The pool structures are supported by the drywell shield and the exterior walls. The pools are lined with stainless steel plates on their inside surface

5. The reactor support is a reinforced concrete pedestal. It also serves as a support for the "biological" shield and two steel service platforms. Access through the biological shield is provided in selected areas by means of removable blocks

6. The exterior walls above the refueling floor consist of columns of structural steel and precast concrete wall panels with structural steel bracing

7. The exterior walls below the refueling floor are reinforced concrete with precast panels on the exterior face

8. The roof is an insulated steel deck system supported by structural steel framing and bracing

9. Major structural appurtenances consist of the crane runway, elevator shaft, stairways, and hatches

Load handling over the Refueling Floor and hoist-way down to ground grade is conducted utilizing the Reactor Building crane. The Reactor Building crane is a Class II component upgraded to meet the guidance of NUREG-0554 (reference 8) for single-failure-proof cranes and the guidance of NUREG-0612 Appendix C (reference 1) for the modification of existing cranes. The upgraded crane includes a new trolley with a single-failure-proof 100 tone main hoist, designed and qualified in accordance with the appropriate requirements of ASME NOG-1-2004 (reference 9). The trolley also includes a 10 ton non single-failure-proof auxiliary hoist which conforms to the requirements of Crane Manufacturers Association of America Specification #70 (reference 10). The Reactor Building crane has been evaluated for earthquake loading to meet NUREG-0554 seismic design requirements, and the Reactor Building structure has been evaluated to ensure its integrity for the associated crane reactions.

Notes

1) Use of the Reactor Building Crane Main Hoist as part of a single-failure proof handling system for casks containing irradiated fuel, requires that crane operations be limited to the bridge runway area west of column line 9, and that the ambient air temperature in the vicinity of the bridge girders be ≥65°F.

2) The Reactor Building Crane will not become a missile in the event of an earthquake. Anti-derailment devices installed on the wheel trucks of original crane bridge remain in place but are not required by the upgraded design.

In the area of the reactor well and the storage pools, if the reactor cavity is drained, and the dryer separator pool is filled no higher than el 106.5 ft, the shield block wall has sufficient strength to withstand the hydrostatic head of water, assuming all shield blocks are in place.

Using a mylar sheet over the pool and filling the pool up to the first fixed shield block will reduce airborne contamination. In addition, an area around the pool will be declared an exclusion area and roped off for protection against shine.

12.2.2.2 Turbine Building

The Turbine Building, with its auxiliary bays, houses the turbine generator and associated auxiliaries, the Condensate and Feedwater Systems, switchgear, some radwaste tankage, the Turbine Building crane, and other auxiliary equipment. The Turbine Building is a rigid steel structure with precast concrete siding consisting of the following major structural components:

1. The foundation is a reinforced concrete mat stiffened by the basement walls

2. Elevated floors are concrete slabs simply supported on structural steel framing

3. The interior walls are reinforced concrete or concrete block

4. The turbine pedestal is a heavily reinforced concrete structure resting on the concrete foundation

5. The exterior walls consist of structural steel columns and bracing with precast concrete wall panels

6. The roof is an insulated steel deck system supported by structural steel framing and bracing

12.2.2.3 Radwaste Building

The Radwaste Building houses the radioactive waste treatment equipment, the control room, the cable spreading and computer room, the warehouse, and miscellaneous offices and shops. The Radwaste Building is a reinforced concrete structure with structural steel framing consisting of the following major structural components:

1. The foundation is a reinforced concrete mat

2. Elevated floors are concrete slabs simply supported on structural steel framing

3. The interior walls are reinforced concrete or concrete block

4. Exterior walls are reinforced concrete below grade, and in Class I areas above grade. Other exterior walls above grade consist of structural steel columns and bracing with precast concrete wall panels

5. The roof consists of an insulated steel deck system supported by structural steel framing. In areas requiring missile protection, the metal decking is covered with a reinforced concrete slab

12.2.2.4 Trash Compaction Building

The Trash Compaction Facility processes dry compactable contaminated and non-contaminated waste at Pilgrim Station. The structure is founded on a continuous footing and consists of poured concrete exterior and interior walls and floors. The exterior is surfaced with architectural concrete stock.

12.2.2.5 Diesel Generator Building

The Diesel Generator Building houses two emergency diesel generators and their accessories. The Diesel Generator Building is a reinforced concrete structure with steel framing consisting of the following major structural components:

1. The foundation is reinforced concrete wall footings which are separated from the diesel generator foundation blocks

2. The walls are reinforced concrete with precast reinforced concrete panels on the exterior face

3. The roof is a reinforced concrete slab supported by structural steel framing

12.2.2.6.1 Old Administration Building

The Administration Building provides an office facility for the administrative and clerical personnel. The structure is founded on a continuous footing and consists of a structural steel frame with metal and glass curtain walls, precast concrete panels, and masonry panels. The interior walls are steel stud and plaster. The floors are reinforced concrete on steel framing.

12.2.2.6.2 New Administration/Service Building

The New Administration/Service Building provides an office facility for the administrative and clerical personnel as well as a warehouse, laboratories, and shops. The structure is founded on a continuous footing and consists of a structural steel frame with metal and glass curtain walls. The interior walls are steel stud and plaster. The floors are reinforced concrete on steel framing. The connecting corridor to the process building is located at elevation 23'-0 of the Radwaste Building.

12.2.2.7 Guardhouse

The Main Guardhouse is a facility which houses security equipment and security personnel. It serves as the main entrance and exit to the plant. The structure is founded on spread and continuous footings and consists of a structural steel frame with metal and glass curtain walls and precast concrete panels. Interior walls are masonry block.

The floors are reinforced concrete. The roof is structural steel roof deck with built-up roofing.

12.2.2.8 Intake Structure

The intake structure houses the Salt Service Water System pumps, the Circulating Water System pumps, Fire Protection System pumps, the Chlorination System equipment, stop logs, trash racks, and the traveling screens with their wash pumps. The intake structure consists of a reinforced concrete substructure, and a superstructure of steel framing enclosed with precast panels. Enclosed within the superstructure are the Service Water System pump compartments which are constructed of reinforced concrete and concrete block walls. The four circulating water bays have steel struts on the walls to allow dewatering of the bays. See Figure 12.2-2.

12.2.2.9 Main Breakwater

The main breakwater is of rubble mound construction with the outer layer protected by heavy capstone. The breakwater protects the intake structure against wave attack and damage. In particular, the breakwater is designed to protect the intake structure against wave damage during the design basis storm (see FSAR Section 2.4.4.3.).

12.2.2.10 Main Stack

The main stack is a pipe with a top elevation of 400 ft msl. The main stack is supported by the Filter Building. The Filter Building is a reinforced concrete structure which houses the dilution fans, offgas filters, and heaters. See Figure 12.2-3. The main stack is located 700 ft NW of the Reactor Building as shown on Figure 1.6-1.

12.2.2.11 Gas Bottle Storage Facility

This facility provides a safe and permanent high pressure gas cylinder storage area facilitating control, inventory management and dispensation of gas cylinders. This facility is constructed of concrete block walls, a poured concrete floor and a metal roof. It is open at one side to provide venting in case of a leak. It contains concrete stalls which separate and individually store various gas cylinders used at the Station.

12.2.2.12 Governing Codes and Regulations

The design of all structures and facilities conforms to the applicable code or specification listed below, except where specifically stated otherwise:

1. Uniform Building Code (UBC) 1967

2. American Institute of Steel Construction (AISC) Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, Sixth Edition (for original design), latest edition for modifications

3. American Concrete Institute (ACI) Building Code Requirements for Reinforced Concrete (ACI 318-63)

4. American Welding Society (AWS) Standard Code for Arc and Gas Welding in Building Construction (AWS D.1.0-66)

5. API Specification No. 620 for Welded Steel Storage Tanks

6. ASME Boiler and Pressure Vessel Code, Section III, Class B, governs the design and fabrication of the drywell and suppression chambers

7. AEC Publication TID 7024, Nuclear Reactors and Earthquakes, governs the seismic design of all Class I structures

8. American Water Works Association (AWWA) AWWA M 11 Steel Pipe Manual and Standard D100

9. Regulations of the Commonwealth of Massachusetts as follows:

a. Standard Specifications for Highways, Bridges, and Waterways (1967) for construction

b. Regulations of the Department of Health and Sanitary Water Board with respect to water

c. Department of Labor and Industry Regulations

d. Massachusetts State Police Department Bureau of Fire Protection Regulations for storage of combustible materials

10. Standard Specifications for Highway Bridges by the American Association of State Highway Officials (AASHO) for design

11. U.S. Army Corps of Engineers regulations with respect to dredging and construction of offshore structures for the Bay of Cape Cod

12. American Society of Civil Engineers Paper No. 3269, for wind design requirements

13. American Iron and Steel Institute Specifications for the Design of Light Gage Cold-formed Steel Structural Members, 1962

The design of new structures subsequent to plant construction conforms to the latest revision of the code or standard as applicable.

12.2.3 Loading Considerations

12.2.3.1 General

All structures and equipment are designed for dead, live, seismic, and wind loads in accordance with applicable codes and as described in the following paragraphs. The loading conditions are determined by the function of the structure and its importance in meeting the station safety and power generation objectives. The load combinations and limits are given in Appendix C, Structural Loading Criteria.

12.2.3.2 Vertical Loads

Dead Loads

The dead loads include the weight of the framing, roof, floors, walls, platforms, and all permanent equipment and materials.

Live Loads

The live loads include all vertical loads except the dead loads. The live loads that have been used in the design of structures are given on Table 12.2-1.

12.2.3.3 Lateral Loads

Wind Loads

The design wind loads are derived from ASCE Paper 3269. The wind loads given on Table 12.2-2 apply to the site area and are used in the station design. A one-third increase in allowable stress is permitted for the wind loading conditions.

Tornado Loads

All Class I structures are designed to withstand the effects of tornadoes and to protect Class I equipment. The Class I structures are designed in accordance with Appendix H, Tornado Criteria for Nuclear Power Plants. The basic design criteria for tornado effects are as follows:

1. The velocity components are applied as a 300 mph horizontal wind over the full height of the structure

2. The pressure differential is applied as 3 psi internal (bursting) pressure occurring in 3 sec

3. The missiles are applied as a 4,000 lb automobile flying through the air at 50 mph but not more than 25 ft above ground, as a 4 in x 12 in x 12 ft plank (108 lb) traveling end-on at 300 mph over the full height of the structure, or as a 3 in dia Schedule 40 pipe 10 ft long traveling end-on at 100 mph over the full height of the structure

All three loading conditions are applied simultaneously.

In the case of adjacent Class I and II structures, such as the Reactor Building and portions of the Turbine Building, an expansion joint is provided to allow for possible unequal deflections associated with different structural systems.

The only Class II structure attached to a Class I structure and not designed to withstand tornado loading is the building exhaust vent stack. This structure consists of light steel framing attached to the Reactor Building and is covered with metal wall siding. The design of siding is such that it may be partially blown away by the tornado without affecting the adjacent Reactor Building. The steel framing will remain in place.

The offgas stack is a Class I structure not designed to withstand tornado loadings, as stated in Section 12.2.1.1. The stack is located sufficiently far from other Class I structures to preclude any interaction, assuming the stack were to fall as a result of tornado loads.

The Secondary Containment System is not designated to be functional during or after a tornado; however, the Reactor Building does protect all the Class I equipment located inside the building from the effects of a tornado.

Crane Runway Loads

The lateral and longitudinal forces on crane runways are in accordance with the AISC Code.

12.2.3.4 Pressure and Thermal Loads

The pressure and thermal design conditions for the Primary Containment System are given on Table 5.2-1. The Reactor Building is designed for an internal pressure loading of 36.5

lb/ft2 (7 in H_2O). The spent fuel storage pool has a design temperature of 212°F.

12.2.3.5 Seismic Loads

12.2.3.5.1 General

The design of Class I structures and equipment is for horizontal ground acceleration of 0.08g for the Operating Basis Earthquake (OBE) and 0.15g for the Safe Shutdown Earthquake (SSE).

The vertical acceleration is equal to two-thirds of the horizontal ground acceleration. Both the vertical and either of the responses of two horizontal seismic motions are considered to be applied simultaneously. The larger combination controls the design. The combined stresses resulting from operational loadings and from a SSE are such that a safe shutdown can be achieved. The applicable load combinations and stress limits including all operational and seismic loads for Class I equipment are given in Appendix C, Structural Loading Criteria. The derivation of the OBE and the SSE is given in Section 2.

Equipment seismic loadings were determined from amplified floor response spectra for the appropriate locations. These spectra were generated from acceleration time-histories at each floor, derived from the normalized Taft earthquake response spectrum, applied to the base of each building model. All erratic peaks were averaged to give smoothed curves for various values of critical damping as required for the seismic analysis.

Class II structures and equipment are designed in accordance with the provisions of the Uniform Building Code, Seismic Zone 2. Class I to Class II interfaces are designed so that there will be no functional failure in the Class I structure. In order to accomplish this design objective, Class I structures have the capacity of withstanding the forces resulting from possible failures of Class II structures which are either attached or adjacent to the Class I structures. In the case of Class I and Class II structures rigidly interconnected, the Class I structure is designed to support the latter.

The Class I portion is checked to assure it can carry any loads that may be transmitted from the connected Class II structures. For example, the salt service water pump room reinforced concrete structure in the intake structure will act as a support for the rest of the building superstructure. Wherever a Class II structure supports a Class I portion located above it, the supporting structure is analyzed and designed to the Class I requirements. Where relative movement between buildings may endanger the integrity of Class I piping or other connecting elements, or the Class I structures themselves, a dynamic analysis of the interconnected or adjacent buildings and/or equipment systems is performed.

Relative deflections are computed for each structure both parallel and perpendicular to the interface.

The criteria for the relative movements under the SSE loadings require that the combined movement does not exceed the clearance provided. The relative movements under these loadings are accommodated by sliding expansion joints at adjoining structures and by built-in flexibility for piping systems. The dynamic analysis has shown that the cumulative maximum displacement of adjoining concrete structures will be about one-half of the clearance provided.

12.2.3.5.2 Seismic Recording Instrumentation

The seismic recording instrumentation used at Pilgrim Nuclear Power Station is an analog centralized recording magnetic tape acceleration system consisting of a multichannel strong motion accelerograph, remote triaxial accelerometers, peak acceleration recorders, control panel and a magnetic tape playback system.

The system automatically senses, transmits and records seismic responses from three elevation locations, storing the records for quick replay and analysis in response to exceeding a "trigger" acceleration of (.01 g) at plant elevation -17'6". The system automatically resets in preparation for the next seismic event.

The local accelerometers are mounted in the Reactor Building at elevations -17'6", 23'0" and 91'0". Each elevation's local accelerometer will sense and transmit displacements in each of three axes (horizontal, vertical, and lateral). The Main Control Room instrumentation on panel C-911 records the date on cassette tape which may be played back in the form of a chart record by the playback unit. The time history is recorded, as received, from a standard time receiver also located in panel C-911. The seismic monitoring instrumentation does not perform any safety related function.

If an earthquake should occur and the g levels, as recorded by the described instrumentation, are at or below the accelerations corresponding to the OBE (0.08 g ground acceleration), the station will continue in operation. The station design considered these loadings, taking no credit for code allowable increases in stress values. If the recorded accelerations approach the values corresponding to the SSE (0.15 g ground acceleration), an inspection will be undertaken of selected high stress welds in the primary pressure boundary to verify continued system integrity.

12.2.3.5.3 Structural Analysis

A dynamic analysis is performed for Class I structures. The dynamic analysis is performed in four steps; develop a mathematical model, perform the analysis, obtain the structural response, and make spectrum plots.

A mathematical model is developed to represent the structure in order to determine its response to the earthquake. Essentially the weight of the building and major internal elements are concentrated at each of the building floor levels. Provisions are made in the model to account for rocking by means of springs representing the soil stiffness. The stiffness matrix, natural frequencies, and mode shapes are obtained by computer analysis. The technique used in the program to determine natural frequencies and mode shapes is that of tri-diagonalization by successive rotations. The damping values used are given on Table 12.2-3.

For purposes of computer analysis, the time history of the Taft Earthquake of July 21, 1952 is used with the amplitude scaled to 0.08g and 0.15g ground acceleration for the OBE and the SSE, respectively. The earthquake data is placed into digital information with g levels expressed every 0.01 sec over a time interval of 30 sec. The final design is checked to assure that the results are compatible with smoothed response spectra as given on Figures 2.5-5 and 2.5-6.

The Taft time history record generates plots below the ground response spectrum, for frequencies below 1 cps. However, when generating floor response spectra curves from the Taft record for use in equipment seismic design, each curve is compared to the ground response spectrum and corrected so that no points fall below the ground spectrum curve.

The results of the modal analysis are used to represent the structure as a modal system. The technique of modal synthesis is employed to reduce the structural equations to j (number of modes) independent equations.

The modes are further employed to reduce the earthquake forces into j modal forces. The resulting system of equations are then solved independently to obtain the modal coordinates. The solution employs a Runge-Kutta numerical integration scheme. The integration step used is 0.01 sec. Again using the mode shapes, the modal coordinates are operated upon to obtain the physical coordinates of the model; then solved for displacement, velocity, and acceleration. These values are separated point by point for each of the floors as a record of the response time history.

For each of the floors a spectrum plot is made. The technique for the plots makes use of determining the response of a single mass system. The natural frequency of this system is varied from 0.1 cps to 30 cps. The maximum response, as acceleration, is then plotted for each frequency.

Class I systems and equipment at the supplier's option may be analyzed dynamically to establish the natural frequency of the equipment and accessories complete with supports. If the natural frequency is less than 20 Hz, then the corresponding particular value of the floor response spectrum is used. For all natural frequencies greater than 20 Hz, an appropriate value of the respective zero period (ZPA) floor acceleration is used.

The equipment supplier is also given the choice, in lieu of performing a dynamic analysis for equipment design, to use the peak value of the applicable floor response spectrum curve.

For the Class I mechanical and electrical equipment, dynamic tests may be carried out, or evidence may be submitted of satisfactory performance through environments of equal or higher dynamic intensity. For such environmental data the levels sustained are required to be greater than the applicable floor response spectrum curve. See paragraph C.3.3.2, Appendix C.

For dynamic test, various approaches may be used. For example, the Class I equipment may be taken at the applicable critical damping curve peak level from 5 Hz to 20 Hz. Alternately, the equipment may be shaken to determine its natural frequency, and the appropriate g level then applied to determine its functional adequacy.

A structure or structural system that cannot be satisfactorily included in the lumped mass structural model analysis are analyzed separately, such as masonry blockwalls and the cable tray and conduit support systems. The analytical technique for the seismic loads induced is similar to that for Class I structures, but is based on response spectrum developed at the structure's support point. The damping values used for the evaluation are based on Table 12.2-3. They are derived from the test results and inherent in the structural system.

12.2.3.5.4 Piping Analysis

For critical piping systems, a dynamic analysis is performed, as described in paragraph C.3.3.1, Appendix C.

Class I piping and associated miscellaneous Class I equipment, instruments, and controls that cannot be satisfactorily included in the lumped mass model representing a structure, are analyzed individually. The analysis is similar to that for Class I structures, but is based on response spectrum developed for points of pipe or equipment supports. These spectra are computed from time history analysis of the structure model, subjected to the north-south horizontal component of the earthquake, normalized to the maximum acceleration associated with the OBE and SSE. Stops, guides, and snubbers are added where necessary to avoid critical natural periods, and to make the system as rigid as practical. Displacements of the piping are checked to assure that there will be no interference with any other equipment or piping.

Essentially the same method of analysis for seismic inertia loads is used on Class I piping, whether located outside or inside the containment structure. To determine the effect of relative differential end displacements on Class I piping systems, the following method is used: The seismic displacements at the ends and at restraints are known from the seismic analysis of the structures. The displacements applied to the piping restraints and anchors correspond to the maximum differential displacements which could occur. The analysis is made twice; once for north-south differential displacements and once for east-west differential displacements. For each response quantity considered (i.e., moments or displacements at a point, and restraint force or moment), the largest value of the two analyses is chosen. The displacements, restraint forces, and moments due to differential displacement are combined with the corresponding quantity from the inertia load analysis of the piping. The basis of combination is SRSS, since the maximums of the two quantities would not occur at the same time. For recirculation, RWCU and RHR replacement piping the basis of combination is absolute sum. The stresses due to relative support displacements in piping are combined with stresses caused by other secondary effects, and the resulting secondary stresses are compared with the applicable, allowable stresses in USAS B31.1.0. For recirculation, RHR and RWCU replacement piping, stresses due to secondary effects were combined in accordance with ASME B&PV Code Section III Subsection NB 1980 Edition through Winter 1981 Addenda. Allowable stresses were referenced from ASME B&PV Code Section III Division I, Appendix I 1980 Edition through Winter 1980 Addenda.

The results of the differential displacement analysis are usually insignificant compared to those of the inertia force analysis. This is because the differential displacements are usually very small, and most piping systems (especially hot ones) have enough flexibility so that these small displacements have little effect.

Since the movement of buried piping is essentially the same as that of the surrounding soil, piping strains due to seismic ground motion are equated to soil strains, which are calculated from the assumed seismic ground motions. Piping stresses, obtained from the strains, are within the allowable stresses defined in USAS B31.1.0.

Where Class I buried piping enters a structure, the magnitude of the relative movements is expected to be insignificant, because the backfill supporting the piping has been compacted to a relative density of 85 percent. Any differential settlement will be small and readily accommodated by the welded steel pipe.

12.2.3.5.5 Recirculation RHR and RWCU Piping Replacement Seismic Analysis

The recirculation piping replacement seismic analysis uses the multi-support excitation response spectrum methodology in which the individual response spectra are applied to each support degree-of-freedom. The individual input spectra are peak broadened $\pm 15\%$ to account for the potential variation in the primary structure eigenvalues due to modeling, analysis and material property uncertainties.

Piping structural damping is provided in Table 12.2-3 and is 2.0% and 3.0%, respectively, for the OBE and SSE analyses.

The colinear contributions due to the 3 spatial components of seismic excitation are combined by the square root of the sum of the squares (SRSS) method.

Peak modal responses are combined by the Double Sum method which accounts for the effects of closely spaced modes. The Double Sum method is identical to the SRSS method if there are no closely spaced modes. Both combination methods; i.e., for 3D spatial effects and for modal confirmation, are consistent with Regulatory Guide 1.92, Revision 1, February 1976.

Recirculation RHR and RWCU piping differential anchor displacements are evaluated and the primary (inertia) and secondary (anchor displacement) stresses combined as described in Paragraph 12.2.3.5.4.

The piping multi-support input spectra are generated from the acceleration time history responses at the primary structure/piping attachment points obtained from the primary structure time history seismic analysis.

12.2.3.5.6 Protective System Instrumentation

Each type of protective system instrument and its supporting panel or cabinet is analyzed, tested, or investigated to confirm that it will withstand the interaction effects of the floor acceleration from the SSE without loss of function. The interaction effects on a protective system instrument are determined by the dynamic response of its supporting control panel or cabinet, static analysis or test.

12.2.3.5.7 Damping Values

The damping factors used in the seismic analysis are based upon deformations or stresses of various materials, and are shown on Table 12.2-3. These damping values are the lower limits of commonly accepted ranges for the stress levels associated with the respective earthquakes based on recommendations by Newmark and Hall in NUREG/CR-0098.

12.2.3.6 Primary Containment Loading Considerations

The primary containment system is designed to withstand all forces associated with a postulated loss of coolant accident (LOCA). In addition to the pressure and thermal loading conditions shown on Table 5.2-1, the primary containment is designed to withstand the jet forces associated with a LOCA, and a post accident flooded condition. The jet forces given on Table 12.2-5 are assumed to result from the impingement of steam and/or water at 300°F. For the flooded condition, the primary containment is assumed to be filled with water up to the normal refueling level.

12.2.3.7 Handling of Heavy Loads

The Pilgrim Station heavy load handling program provides a defense-in-depth approach to reduce the probability of accidents, or the consequences of such accidents, from handling heavy loads (loads in excess of 1500 lbs). The program establishes administrative controls to address safe load paths, safe load handling procedures, crane and hoist operator training, standards for lifting devices and cranes, and special requirements when handling heavy loads in areas where fuel or safe shutdown equipment could be damaged. The program provides reasonable assurance that heavy load lifts will be performed safely and meet applicable guidance contained in NUREG 0612, "Control of Heavy Loads at Nuclear Power Plants," July 1980 (reference 1). Program details are described in references 2, 3, 4, and 5. NRC evaluation of the program is documented in references 6 and 7.

The approach to NUREG 0612 compliance for Dry Fuel Storage heavy loads differs from the above description. The Pilgrim Heavy Load Handling Program details described in references 1,2,3,4, and 5, and evaluated by the NRC in references 6 and 7, are based on the use of non-single-failure-proof hoisting equipment, hence requiring evaluations to demonstrate acceptable load drop consequences. An upgraded Reactor Building crane with a single-failure-proof main hoist is being used with Dry Fuel Storage components and ancillaries designed to the augmented safety factors ANSI N14.6 for critical loads. This approach does not require postulating and analyzing load drop accidents for Dry Fuel Storage operations involving the handling of heavy loads. Dry Fuel Storage is described in FSAR Section 10.3.8.

12.2.4 Foundation Analysis

12.2.4.1 General

The foundation investigation and analysis for the construction of the station was performed in three parts:

1. Field explorations
2. Laboratory Tests and analyses
3. Establishment of foundation design criteria

The field explorations and laboratory tests led to the conclusions that the subsurface conditions in the station area are somewhat variable especially in the upper 35 to 40 ft. The borings encountered erratic and discontinuous layers of silty fine sand, fine sand, clayey silts, and clayey sands. The soils within about 35 ft of the ground surface range in density from loose to compact and are compressible. Beneath the upper variable strata, dense and relatively incompressible poorly graded to well graded sands with varying amounts of gravel and cobbles are found. Bedrock is generally encountered at a depth of about 80 ft in the station area. See Figure 12.2-4.

The foundation design criteria were established on the basis of these conclusions.

12.2.4.2 Field Exploration

In addition to the overall site geologic and seismic explorations, detailed foundation investigations, including borings and field permeability tests, were carried out for use in establishing the foundation criteria for the station structures. Prior to construction, a series of test borings was drilled in the general station area. Altogether a total of 58 borings were drilled to determine the subsurface condition. The locations of some of the test borings and test wells are shown on Figure 12.2-5. In addition to borings for the station, a number of borings was scattered over the site. Borings were made to various depths from 16 to 130 ft. Bedrock was generally encountered at a depth of about 80 ft in the station area as determined by a seismic refraction survey. Disturbed and undisturbed soil samples, suitable for laboratory testing, were extracted from the test borings, examined, and subjected to the laboratory tests listed in Section 12.2.4.3. Figures 12.2-6 through 12.2-10 are some of the boring logs for borings taken in the station area.

A series of pumping and percolation tests were performed to obtain estimates of the permeability of the onsite materials at predetermined depths. The data obtained from these tests were used in the foundation analysis to establish de-watering requirements during the excavation for the foundations.

12.2.4.3 Laboratory Tests

Representative undisturbed soil samples extracted from the test borings were subjected to a comprehensive laboratory testing program to evaluate the physical and chemical characteristics of the soil encountered at the site. The laboratory tests included:

- Direct shear tests
- Unconfined compression tests
- Confined compression tests
- Triaxial compression tests
- Moisture and density determinations
- Particle size analysis
- Shockscope

12.2.4.4 Foundation Design Criteria for Structures

12.2.4.4.1 General

This section describes the foundation conditions for the major and auxiliary station structures.

12.2.4.4.2 Design Considerations

The major station facilities include the reactor building, turbine building, and radwaste building. The auxiliary structures include the diesel generator building, main stack, administration building, and intake structure. A description of foundations provided for the structures is given in the following sections. Figure 12.2-5 shows the locations of structures in relation to the test borings drilled.

An analysis of the liquefaction potential of cohesionless soil fill materials indicated that a granular material compacted to an average relative density of 80 percent at station grade, and 75 percent under the surcharge of the turbine building, would have a factor of safety of at least 1.5 against initial liquefaction, with earthquake motions producing a maximum ground surface acceleration of 0.15g. All Class I structures and the turbine building are founded on undisturbed soil, or on select granular fill compacted to a minimum of 85 percent relative density. The relative density tests were performed in accordance with ASTM Standard D-2049, March 1968, Tentative Method of Testing for Relative Density of Cohesionless Soils.

12.2.4.4.3 Major Structures

Reactor Building

The lowest floor of the reactor building is founded at el -25.5 ft msl on dense to very dense silty sand and sand and gravel. At the center of the reactor, bedrock is about el -60 ft msl. Groundwater in-leakage is designed to be prevented or minimized by a waterproof membrane. The estimated total settlement that this structure will experience is 2 to 4 in of uniform elastic compression at the design loads. The differential settlements are expected to be less than 1 in. Since this structure consists primarily of dead load, most of the elastic deformation will occur during construction. Post construction settlement is expected to be on the order of 1/2 in. A survey traverse of points on the building has been established to monitor settlement. The settlement at approximately 30 percent of the load was negligible.

Turbine Generator Building

The subsurface soil below the founding elevation of the turbine building was found to consist of erratic layers of clayey sand, silty sand, and sand and gravel. This soil was excavated to el -27 ft msl, 13 ft below the founding elevation, to remove these undesirable pockets of less dense compressible soils. The excavated area was then backfilled with suitable granular material and compacted to a minimum relative density of 85 percent.

The Turbine Building is protected below grade by a waterproof membrane designed to prevent or minimize ground water in-leakage.

Radwaste Building

The radwaste building rests partially on undisturbed dense relatively incompressible sand, gravel, and cobbles, and partially on structural backfill compacted to 85 percent relative density. This structure has a waterproof membrane designed to prevent or minimize ground water in-leakage.

12.2.4.4.4 Auxiliary Structures

Diesel Generator Building

The diesel generator building has a reinforced concrete foundation mat founded on a structural backfill, compacted to 85 percent relative density.

Main Stack

The main stack and filter building structure rests on undisturbed dense relatively incompressible sand, gravel, and cobbles.

Administration Building

This structure is founded on structural fill compacted to 75 percent relative density.

Intake Structure

This structure rests on undisturbed very dense incompressible silty sand and gravel.

Guardhouse

This structure is founded on spread and continuous footings and consists of a structural steel frame with metal and glass curtain walls and precast concrete panels. Interior walls are masonry block. The floors are reinforced concrete. The roof is structural steel roof deck with built-up roofing.

12.2.4.4.5 Foundation Settlement Measurements

Table 12.2-6 summarizes the results of foundation settlement measurements taken at various stages of dead load application during construction at points shown on Figure 12.2-11.

Total differential settlements are predicted to be 1 in or less. Measured values of settlement are acceptably low.

12.2.5 Design Organization and Procedures

12.2.5.1 Design Organization

The GE-APED organizations having responsibility for the seismic design of safety related systems and structures in the NSSS were Power Plant Projects, Requisition Engineering, Component Engineering, Seismic Design Engineering, and Plant and Equipment Engineering. The seismic design responsibility was assigned to the functional group, Component Engineering or Plant and Equipment Engineering, responsible for the equipment and/or structure design. These functional groups are responsible to the Manager, Design Engineering.

The Bechtel Corporation Pilgrim Nuclear Power Station Project design organization consisting of the Mechanical Group, Layout Group, Civil Group, and the Electrical Group, in parallel with the Bechtel Corporation Power and Industrial Division's Structural Dynamics Group, and the Piping Stress Group, had the responsibility for the seismic design of all balance of plant structures, systems, and components related to safety.

Dames and Moore performed the site seismology studies. These studies were reviewed and checked by Bechtel's Soils and Geology Department. Chicago Bridge and Iron performed the primary containment stress analyses.

12.2.5.2 Design Responsibilities

Design organizations of GE-APED have been responsible for proper application of seismic design loads and conditions to the design of equipment components and piping in the NSSS scope. Analytical assistance was available within Design Engineering from analytical components specialized in seismic design. An Engineering Practices and Procedures Manual defined explicitly in writing, all Design Engineering responsibilities, including seismic. The Manager, Design Engineering, had overall responsibility for the adequacy of the seismic design of the General Electric product. Overall coordination of this work was assigned to the Seismic Design Component.

The dynamic analysis of station structures was performed by the Bechtel Structural Dynamics Group after the location of major component masses was determined by the involved Bechtel Project groups. The Civil group had responsibility for station structural design. See Appendix C. The Mechanical and Electrical Groups had responsibility for obtaining vendor seismic design analyses or test results of safety-related equipment and instrumentation; the Layout Group provides input on station piping layout to the Piping Stress Group which performs piping stress calculations for Class I piping systems.

The Structural Dynamics Group performed the dynamic structural analyses. The resulting floor response spectrum curves were promulgated in writing to the Bechtel project groups and to the GE- APED Pilgrim Project Organization through the Civil Group which coordinates, and has overall responsibility for, the balance of plant station seismic design.

12.2.5.3 Documentation and Control Procedure

The mechanism for the interchange of needed design information and changes thereto and the coordination of the various facets of the seismic design among the involved design organizations components, and/or groups is shown on Figure 12.2-12.

The system shown on Figure 12.2-12 is a pattern of interrelationships and checks from which an iterative process evolves which ensures proper station seismic design for structures, systems, and components related to safety.

Within GE-APED Design Engineering, the design engineer was ultimately responsible for implementation of the seismic design requirements. Within the Bechtel Pilgrim Project organization, the engineer responsible for the safety-related equipment, supported by the engineers qualified in seismic analysis within the Structural Dynamics Group, were responsible for the implementation of the seismic design requirements.

For GE-APED components, the adequacy of seismic design was the responsibility of the individual design engineer. Within the Bechtel Corporation, the seismic certification of safety-related equipment was the responsibility of the design group procuring the equipment. Within each group, one or more engineers coordinated the transfer of vendor seismic certification (analyses, tests, or documentation of suitable performance in comparable vibrational environments) to the Civil Group for engineering review and approval by the Structural Dynamics Group.

12.2.5.4 Purchase of Safety-Related Equipment

Class I Systems and equipment at the supplier's option may be analyzed dynamically to establish the natural frequency of the equipment and accessories complete with supports. If the natural frequency is less than 33 Hz, then the corresponding particular value of the floor amplified response spectrum is used. For all natural frequencies greater than 33 Hz, the zero period acceleration value of the respective amplified floor spectrum is used.

The equipment supplier is also given the choice, in lieu of performing a dynamic analysis for equipment design, to use the peak value of the corresponding floor amplified response spectrum curves for the seismic analysis.

For the Class I mechanical and electrical equipment, dynamic tests may be carried out, or evidence may be submitted of satisfactory performance through environments of equal or higher dynamic intensity. For such environmental data, the g levels sustained are required to be greater than the 2 and 3 percent critical damping curves for OBE and SSE respectively. See paragraph C.3.3.2, Appendix C for further requirement.

For dynamic test, various approaches may be used. For example, the Class I equipment may be taken at the associated critical damping curve push level. Alternately, the equipment may be shaken to determine its natural frequency and the appropriate g level then applied to determine its functional adequacy.

The above three procedures are consistent with the seismic qualification requirements of IEEE 344-1975.

Seismic qualification documentation of electrical and/or mechanical equipment purchased prior to 1983, for initial use or for replacement-in-kind service, may comply to the requirements of IEEE 344-1987 in lieu of IEEE 344-1975.

12.2.6 References

1. NUREG-0612, Control of Heavy Loads at Nuclear Power Plants, July 1980 (Enclosure 1 to NRC Letter dated December 22, 1980; Ltr. 1.81.014).

2. PNPS Letter 2.81.141, A. Morisi to D.G. Eisenhut (NRC), Subject: NUREG-0612, Control of Heavy Loads, dated June 25, 1981.

3. PNPS Letter 2.81.242, A. Morisi to D.G. Eisenhut (NRC), Subject: NUREG-0612, Control of Heavy Loads, dated October 8, 1981.

4. PNPS Letter 2.83.181, W.D. Harrington to D.G. Eisenhut (NRC), Subject: NUREG-0612, Control of Heavy Loads, dated July 13, 1983.

5. PNPS Letter 2.85.017, W.D. Harrington to D.B. Vassallo (NRC), Subject: Additional Information on NUREG-0612, Factors of Safety for Reactor Building Lifting Devices, dated January 25, 1985.

6. NRC Letter dated March 6, 1985 (Ltr 1.85.069), D.B. Vassello (NRC) to W.D. Harrington, Subject: Control of Heavy Loads (Phase 1).

7. NRC Generic Letter 85-11 (Ltr. 1.85.202), Completion of Phase II on "Control of Heavy Loads at Nuclear Power Plants," NUREG-0612, dated June 28, 1985.

8. NUREG-0554, Single Failure Proof Cranes for Nuclear Power Plants, May 1979.

9. ASME NOG-1, Rules for Construction of Overhead and Gantry Cranes (Top Running Bridge, Multiple Girder), 2004 Edition.

10. Crane Manufacturers Association of America (CMAA) Specification #70, Specifications for Top Running Bridge and Gantry Type Multiple Girder Electric Overhead Traveling Cranes, 2010 Edition.

12.4 RADIOACTIVE MATERIALS SAFETY

12.4.1 Materials Safety Program

Use, Handling, and Storage of Licensed Radioactive Sources

When not in use, all licensed radioactive sources shall be stored in a locked container, cabinet, or room. The sources will normally be stored in the radiochemistry lab and the radiation protection lab.

Other controls for the storage, possession, and use of these sources are presented in PNPS Radiation Protection Operating Procedures and are as follows:

1. Each source and/or source container shall be labeled with a radiation sign and a control number. For each source there will be a Radioactive Source Record Sheet with the following information:

   (a) source control number

   (b) source type

   (c) quantity

   (d) date quantity measurement was made

2. Sources will be controlled by the Radiation Protection Manager (or designee) and will be in a locked container, cabinet, or room when not in use.

3. Sign out logs on which to record the removal of various sources from the assigned storage area and to authorize such removals are provided to the radiation protection lab and radiochemistry lab. The user's signature is required on this record.

4. Sources are to be used, transported, and stored in such a way as to minimize personnel exposure to them. Shielded sources shall be kept in their shielded containers except when they are in use.

5. Each sealed source containing radioactive material either in excess of 100 micro curies of beta and/or gamma emitting material or 5 micro curies of alpha emitting material shall be free of > 0.005 micro curies of removable contamination at all times.

   Each sealed source with removable contamination in excess of the above limit shall be immediately withdrawn from use and:

A. Either decontaminated and repaired, or

B. Disposed of in accordance with Commission Regulations.

6. Each sealed source shall be tested for leakage and/or contamination by:

   A. The licensee, or

   B. Other persons specifically authorized by the Commission or an Agreement State.

   The test method shall have a detection sensitivity of at least 0.005 micro curies per test sample.

7. Each category of sealed sources, excluding startup sources and fission detectors previously subjected to core flux, shall be tested at the frequency described below.

   A. Sources in use - At least once per six months for all sealed sources containing radioactive material:

      1. With a half-life greater than 30 days, excluding Hydrogen 3, and

      2. In any form other than gas.

   B. Stored sources not in use - Each sealed source and fission detector shall be tested prior to use or transfer to another licensee unless tested within the previous six months. Sealed sources transferred without a certificate indicating the last test date shall be tested prior to being placed into use.

   C. Startup sources and fission detectors - Each sealed startup source and fission detector shall be tested within 31 days prior to being subjected to core flux or installed in the core and following repair or maintenance to the source.

NOTE - If a vendor or source supplier furnishes a certificate indicating that a test has been made within 6 months, the source need not be tested for 6 months and may be made available for immediate use.

The Radiation Protection Department shall assure compliance with provisions of 10CFR20, 10CFR30 and applicable conditions of the Facility Operating License.

A complete inventory of radioactive materials in possession shall be maintained current at all times by the Radiation Protection Department. All such sources shall be inventoried at intervals not

to exceed 6 months. Reactor Engineering shall maintain a complete inventory of all special nuclear material maintained on site. A report shall be prepared and submitted to the Commission on an annual basis if sealed source or fission detector leakage tests reveal the presence of $\geq$0.005 micro curies of removable contamination.

Records will be kept of all receipts, transfers, disposal, leak test, and other information pertinent to by-product licensed material.

Records required to be maintained for two years:

A. Test results, in units of micro curies, for leak test performed pursuant to Section 12.4.1

B. Record of annual physical inventory verifying accountability of sources on record.

Unsealed sources will be stored in a locked location in the radiochemistry lab.

Liquid sources will be used in accordance with the PNPS radiation protection procedures and general rules of good practice in radioactive material handling when they are unsealed.

Use, Handling and Storage of Nuclear Fuel

The new and used fuel storage facilities are described in FSAR Sections 10.2 and 10.3. The multiplication constants for fuel in both the new and spent fuel racks are specified in the Pilgrim I Technical Specifications.

The new fuel storage vault, the spent fuel storage pool, and other locations on the refueling floor where fuel assemblies will be handled or stored are monitored by a Radiation Monitoring System complying with the requirements of 10 CFR 70.24.

All spent fuel handling shall be with cranes and hoists designed specifically for that purpose.

The probability of fire in the inspection and preparation area will be minimized by restricting the allowable quantities of flammable materials in the area. Solvents, such as acetone, are required for cleaning and will be handled in small quantities.

Access to the refueling floor and to the overhead bridge crane shall be permitted only to authorized personnel. Fuel loading and unloading operations will be performed by qualified personnel (including contractors) under the direct supervision of a licensed Senior Reactor Operator or Senior Reactor Operator restricted to fuel handling. "Qualified" within the context of the training rule (10 CFR 50.120) means training in, and testing of, site specific refueling procedures to include demonstration of equipment operation (reference NRC Information Notice 94-13).

New fuel inspection shall be performed by Pilgrim Station or contractor personnel. Entry to the refueling floor will be restricted by locked gates or doors any time that full time surveillance by guards or authorized personnel is not in effect and fuel handling operations are in progress.

Fuel shall be brought to the refueling floor in metal criticality proof shipping containers. Only one metal container will be opened and placed in an upright position at any one time.

A minimum of nine assemblies in a flooded square arrangement is necessary for a minimum critical array. Therefore, handling only two assemblies and inspecting no more than two additional assemblies at any one time precludes the possibility of criticality during the handling and inspection sequence.

12.4.2 Facilities and Equipment

Laboratory instruments will be provided for measuring alpha, beta, and gamma radiation, and for the analysis of radioactive gaseous, liquid, and solid samples. These will include an instrument for gross beta gamma counting of smear samples used for contamination control, and a multi-channel gamma analyzer for gaseous and liquid samples used for effluent release control.

Portable radiation survey instruments will be available as required for measurement of alpha, beta, gamma, and neutron radiation expected during normal operation, and in emergencies.

12.4.2.1 Method, Frequency, and Standards Used in Calibrating Instruments

All beta-gamma instruments will be calibrated in accordance with PNPS Radiation Protection Procedures. These calibrations will employ a calibration unit with an appropriate calibration source.

Alpha instruments will be calibrated in accordance with PNPS Radiation Protection Procedures using an appropriate alpha source set.

The neutron instruments will be calibrated in accordance with PNPS Radiation Protection Procedures using an appropriate calibration source. In addition, neutron instruments are response checked prior to use.

12.4.2.2 Dosimeters and Bio-Assay Procedures Used

Personal monitoring devices, i.e., TLDs, OSLDs, electronic dosimeters, and pocket dosimeters, will be furnished to and worn by personnel who require radiation dose monitoring in accordance with PNPS station procedures.

Bio-Assay: Whole body counting is normally done onsite by the Licensee. A licensed off-site facility is available for contingency in whole body counting or analysis of in vitro bio-essay materials.

12.4.3 Personnel and Procedures

The Reactor Engineering Superintendent is the custodian of special nuclear materials received, possessed, used, or transferred under authorization of Operating License DPR-35.

The Radiation Protection Manager is the custodian of by-product and source materials received, possessed, used, or transferred under the authorization of Operating License DPR-35 and NRC Materials License 20-07626-04, and Commonwealth of Massachusetts Materials License 07-6262. The health physics aspects of the handling, storage, and use of these materials will be administered by the Radiation Protection Manager as defined by ANSI N18.1, 1971.

Radiation protection procedures assure compliance with applicable regulations and appropriate sections of the Operating License, Technical Specifications, and FSAR.

12.4.4 Required Materials

The Licensee is authorized to receive, possess, use, and transfer materials as required for operation of the facility by License No. DPR-35.

12.4.5 Offsite Materials Safety Program

All radioactive materials fixed or contained within reactor system components and shipped to temporary field locations such as vendor facilities will remain in the custody of PNPS, and will be under direct supervision of a qualified PNPS representative normally on the Radiation Protection staff.

Radiation protection activities shall be conducted at the temporary field locations in order to assure that all Pilgrim radioactive reactor components are appropriately packaged, surveyed, and labeled in accordance with applicable NRC/Massachusetts DOT regulations and PNPS radiation protection procedures.

PNPS shall assume responsibility for all radiation protection activities incident to inspection, repair, and testing of Pilgrim equipment containing radioactive material while such equipment is at temporary field locations. These activities shall be conducted in accordance with the requirements of 105 CMR 120, Massachusetts Regulations for the Control of Radiation, at temporary field locations within the borders of Massachusetts, or the requirements of 10 CFR 20, Standards for Protection Against Radiation for temporary field locations outside the borders of Massachusetts but within the borders of the continental United States, as applicable. Radiation monitoring instrumentation and personnel monitoring devices such as those used at Pilgrim Station will be utilized at the offsite location.

The maximum total activity of mixed corrosion products contained within and/or fixed upon the surface of the reactor system components shipped to temporary field locations within the borders of Massachusetts or temporary field locations outside the borders of Massachusetts but within the borders of the continental United States, provided that the state has a reciprocity agreement with Massachusetts shall be limited to the values indicated in Massachusetts Materials License No. 07-6262.

All handling of Pilgrim equipment containing radioactive material at vendor's facilities shall be conducted in such a manner as to preclude the onsite release or disposal of any radioactive materials. All radioactive waste from temporary field stations shall be appropriately packaged, surveyed, and labeled and either returned to Pilgrim Station for ultimate disposal through a licensed contractor, or directly transferred to a licensed waste disposal contractor at the field location.

All vendor company employees shall receive radiation protection orientation prior to their assignment of work on radioactive reactor components in any area controlled by PNPS. The orientation will cover all pertinent radiation protection practices, and procedures to the degree sufficient to allow an employee to perform his assignment without incurring unnecessary radiation exposure.

PNPS shall maintain records of all licensed activities conducted at temporary field locations including records showing the transfer of radioactive materials to and from the location, records of radiation surveys, and records of personnel radiation exposure. A report showing individual radiation exposures shall be furnished to the vendor company upon the completion of licensed activities at the temporary location.

13.3 TRAINING

13.3.1 INTRODUCTION

The major operator and technical training programs at Pilgrim Nuclear Power Station are accredited programs of the Institute of Nuclear Power Operations (INPO). Entergy Nuclear is also a member of the National Academy for Nuclear Training in recognition of the quality and accreditation of its training programs.

Accredited programs use an Instructional System Design (ISD) model to develop performance-based training. The process includes five phases: analysis, design, development, implementation and evaluation. The process ensures that training is based on the measurable or observable performance of knowledge and skills required to safely and effectively perform the tasks of the job. The system uses continuous feedback on performance to help identify problems and improve training. Approximately every six years INPO reexamines accredited programs to ensure that they continue to meet accreditation standards.

13.3.2 GENERAL TRAINING

13.3.2.1 Plant Access and Basic Radiation Worker Training

The goal of this INPO certified program is to ensure workers possess the knowledge and skills necessary to work efficiently and safely in a radiological environment with minimum exposure to themselves and other workers.

The scope of the program is designed to address the subject areas common to all employees requiring access to Pilgrim Nuclear Power Station. This program is not applicable to escorted visitors.

13.3.2.1.1 Initial Training

This training course is designed to introduce the new employee to Pilgrim Station and its Boiling Water Reactor operation. Emphasized throughout the course are those personal and plant safety concepts of radiological protection, industrial safety, security, quality assurance, and fitness for duty.

The course is subdivided into two (2) levels of training. Plant Access Training is designed for personnel requiring access to the protected/restricted area. Basic Radiation Worker Training is designed for personnel requiring access to contaminated areas or areas requiring radiation work permits for entry.

13.3.2.1.2 Requalification Training

This training course is required annually for those employees who have held and are required to maintain their unescorted access status at Pilgrim Station. The course provides refresher training in the subject areas included in Initial Training.

13.3.2.1.3 Respiratory Protection Training

This course is designed to qualify and requalify those individuals who perform work using respiratory protection equipment at Pilgrim Station. The purpose of the course is to provide the trainee with the skills and knowledge necessary to work safely and efficiently while utilizing respiratory protection equipment. This course is offered as needed for those employees requiring respiratory protection qualification.

13.3.2.1.4 Priority Access Training

Priority Access Training is a course designed for personnel requiring temporary access to Pilgrim Station to fulfill specific functions.

United States Nuclear Regulatory Commission (USNRC) inspectors, Institute of Nuclear Power Operations (INPO), and contractor escorted radiation workers are provided an overview of general procedures, policies and practices used at PNPS in order to ensure that these individuals can perform required tasks without jeopardizing his/her health and safety and the safety of co-workers.

13.3.2.2 Management and Supervision

The management and supervision training program assists the professional growth of personnel from the time they are newly hired or appointed to exempt status. PNPS department representatives and vendors from the management training field teach various segments of the overall program. The program consists of initial training and continuing training.

13.3.2.2.1 Initial Management and Supervisory Training

Initial management and supervisory training is designed to provide new management/supervisory personnel with an overview of the nuclear organization and its administrative policies and practices, regulatory and safety issues. It further focuses on developing the skills and knowledge required by supervisors to effectively communicate, direct, and evaluate the activities of subordinates.

13.3.2.2.2 Continuing Management and Supervisory Training

Continuing management and supervisory training is designed to provide management/supervisory personnel with refresher training in management and professional development skills. It focuses on the current changes within the organization to ensure that PNPS maintains a viable, effective management work force. Additionally this program provides management/supervisory personnel with specialty training in order to enhance the skills and knowledge required to effectively perform their duties. The duration and sequence of training is based on the operational requirements of the nuclear organization.

13.3.2.2.3 Maintenance Supervisor Initial Training Program

The maintenance supervisor initial training program is designed to provide maintenance supervisors with the skills necessary to perform their duties in a manner which promotes safe and reliable plant operations. The program focuses on the supervisory, leadership and judgment skills as well as the technical and administrative skills necessary to effectively supervise the work of maintenance personnel.

13.3.2.2.4 Shift Manager Initial Training

The Shift Manager program is designed for senior reactor operators with on-shift experience who have been selected as candidates for assuming the duties of the Shift Manager. This program focuses on the higher-level management skills and behaviors and strives for higher levels of understanding built upon the training and experience of the senior reactor operator.

13.3.2.3 Industrial Safety Training

This program is designed to provide station personnel with the skills and knowledge necessary to safely perform their assigned tasks. The program focuses on increasing the trainees awareness of the hazards associated with the industrial environment and with the precautions to be observed and practiced in the performance of daily activities.

13.3.2.3.1 First Aid and CPR Training

This training course is designed to provide the trainee with the skills and knowledge required to provide immediate care to victims of accident and injury situations.

13.3.2.3.2 Safety Awareness

Safety awareness concepts are provided to ensure that line management employees are knowledgeable in the process of identifying and rectifying hazardous conditions.

13.3.2.3.3 Asbestos Associated Worker

This unit is designed to provide the trainee with a working knowledge of asbestos hazards, implementation of special work procedures, and federal, state and local requirements associated with the health effects of asbestos exposure. A refresher training course is available on a non-mandatory basis for qualified asbestos workers who wish to attend.

13.3.3 OPERATOR TRAINING PROGRAMS

13.3.3.1 NRC License Training Programs

13.3.3.1.1 RO/SRO Initial License Training Program

The NRC initial license training program is an INPO accredited program and is designed from a job-task-analysis of the duties and responsibilities of both NRC licensed reactor operators (ROs) and NRC Licensed Senior Reactor Operators (SROs) at Pilgrim Station.

Satisfactory completion of the RO portions of this training program prepares an individual to safely, competently, and efficiently perform all tasks and duties which are the responsibility of an on-watch NRC licensed reactor operator at Pilgrim Station.

Satisfactory completion of the SRO portions of this training program prepares an individual to safely, competently, and efficiently perform all tasks and duties which are the responsibility of an on-watch NRC Licensed Senior Reactor Operator at Pilgrim Station.

Additional details of the RO and SRO Initial License Training Programs are contained within the individual program description.

13.3.3.1.2 Shift Control Room Engineer (SCRE) Qualification Training Program

The SCRE Qualification Training Program is designed from a job-task-analysis of the duties and responsibilities of a qualified SCRE at Pilgrim Station.

The SCRE training program augments the initial SRO training for selected individuals to prepare personnel for the duties and responsibilities formerly performed by Shift Technical Advisor.

Satisfactory completion prepares an individual to safely, competently, and efficiently perform all tasks and duties which are the responsibility of the on-watch SCRE at Pilgrim Station.

13.3.3.1.3 Licensed Operator/Shift Control Room Engineer Requalification Training Program

The Licensed Operator (RO/SRO)/Shift Control Room Engineer (SCRE) Requalification Training Program is an INPO accredited program and was developed in order to maintain the qualifications and competency of NRC licensed operators and qualified SCREs. This program is conducted in accordance with 10CFR55.59 using a systematic approach to training as described in section 55.59(c).

The program reinforces the knowledge and skills acquired in the Initial Training Programs and keeps knowledge and skills up-to-date/current regarding pertinent:

Station equipment/system changes
Station procedure changes
Station instruction/policy changes
Current industry events/lessons learned

Additional details of the Licensed Operator/Shift Control Room Engineer Requalification Training Program are contained within the individual program description.

13.3.3.2 SRO Certification

13.3.3.2.1 Pilgrim Station SRO Certification Training Program

The Pilgrim Station SRO Certification Training Program has been developed in order to provide a senior reactor operator level of knowledge and abilities to selected Nuclear Organization personnel. These personnel require an advanced level of technical understanding of integrated plant operations, but do not require an NRC License to perform their assigned jobs. (For example: Selected Nuclear Training Department staff.)

Additional details of the SRO Certification Training Program are contained within the individual program description.

13.3.3.2.2 SRO Certification Requalification Training Program

The SRO Certification Requalification Training Program was developed to maintain the competency of selected Nuclear Organization personnel who have previously completed initial SRO Certification training. Those individuals that require current SRO level knowledge and abilities due to their position within the organization participate in this program.

This program refreshes and updates those skills and knowledges acquired in initial training. Additional details of the SRO Certification Training Program are contained within the individual program description.

13.3.3.3 Non-Licensed Nuclear Plant Reactor Operator

13.3.3.3.1 Non-Licensed Nuclear Plant Reactor Operator Qualification Training Program

The Non-Licensed Nuclear Plant Operator (NLNPRO) Qualification Training Program is INPO accredited and is designed from a job-task-analysis of the duties and responsibilities of a qualified NLNPRO at Pilgrim Station.

Satisfactory completion prepares an individual to safely, competently, and efficiently perform all tasks and duties which are the responsibility of the on-watch NLNPRO at Pilgrim Station.

Additional information on Pilgrim Station's NLNPRO Qualification Training Program is contained within the individual program description.

13.3.3.3.2 Non-Licensed Nuclear Plant Reactor Operator Requalification Training Program

The NLNPRO Requalification Training Program, an INPO accredited program, was developed in order to maintain the competency of qualified NLNPROs by:

Re-enforcing knowledge and skills acquired in the Initial NLNPRO Qualification Training Program.

Keeping the NLNPRO's knowledge and skills up-to-date/current regarding pertinent:

Station equipment/system changes
Station procedure changes
Station instruction/policy changes
Current industry events/lessons learned

Additional details of the NLNPRO Requalification Training Program are contained within the individual program description.

13.3.3.4 Plant Specific Simulator

Pilgrim Station Operator Training programs extensively utilize the PNPS plant-specific control room simulator. Simulator time is integrated into the programs to emphasize operations techniques, procedural adherence, control room operations, Emergency Operations Procedure performance, communications techniques, and other specialized training functions. The simulator meets ANS/ANSI 3.5, 1985 standards and incorporates advanced system modeling software allowing accurate simulator fidelity with the actual plant.

The simulator is capable of responding, in real time, to almost all functions an operator would perform in the PNPS Control Room under any condition. It also has the capability to be used during Emergency Plan Drills and has all required communications equipment installed for full drill performance.

13.3.3.5 (deleted)

13.3.4 TECHNICAL TRAINING PROGRAM

13.3.4.1 Nuclear Maintenance Mechanic

13.3.4.1.1 Initial Training

Initial Training for Nuclear Maintenance Mechanics is conducted to ensure that newly assigned Nuclear Maintenance Mechanics can perform at the desired competency level without detailed supervision. This training ensures maintenance of equipment is performed in accordance with station procedures, regulatory and industry standards.

Training is provided for both an orientation and duty area qualification.

A description of the training program can be found within the individual program description.

13.3.4.1.2 Continuing Training

Continuing Training for the nuclear maintenance mechanics provides for the continuous updating of skills and knowledge via a planned training program conducted on a periodic bases. Operating experience, procedure change, changes in plant configuration and manufacturer's recommendations are included in this program. In addition, advanced skills training is provided to selected personnel, as necessary, to meet the needs of the station.

Continuing Training uses the systematic approach to training and is evaluated and scheduled on periodic bases. Periodic training requirements are incorporated into this schedule.

A description of the program can be found within the individual program description.

13.3.4.2 Nuclear Maintenance Electrician

13.3.4.2.1 Initial Training

This program is applicable to newly assigned Entergy Nuclear Maintenance Electricians. Initial Training for the Nuclear Maintenance Electrician is conducted to ensure performance at the desired competency level without detailed supervision. This training ensures maintenance of equipment is performed in accordance with station procedures, and regulatory and industry standards.

This training is provided for both an orientation and duty area qualification

A description of the training program can be found within the individual program description.

13.3.4.2.2 Continuing Training

Continuing Training for the Nuclear Maintenance Electrician provides for continuous updating of skills and knowledge via a planned training program conducted on a periodic basis. Operating experience, procedure changes, changes in plant configuration and manufacturer's recommendations are all included in this program. In addition, advanced skills training is provided to selected personnel, as necessary, to meet the needs of the station.

The description of the training program can be found within the individual program description.

13.3.4.3 Nuclear Control Technician

13.3.4.3.1 Initial Training

Initial training for Nuclear Control Technicians is conducted to ensure that newly assigned technicians can perform at the desired competency level without detailed supervision. This training ensures maintenance of equipment is performed in accordance with station procedures, and regulatory and industry standards.

The description of the training program can be found within the individual program description.

13.3.4.3.2 Continuing Training

Continuing training for Nuclear Control Technicians provides for the continuous updating of skills and knowledge via a planned training program conducted on a periodic basis. Operating experience, updated procedures, changes in plant configuration and manufacturer's recommendations are all included in this program. In addition, advanced skills training is provided to selected personnel to meet the needs of the station.

Continuing training uses the systematic approach to training and is evaluated and scheduled on a periodic bases. Periodic training requirements are incorporated into this schedule. A description of the training program can be found within the individual program description.

13.3.4.4 Radiation Protection Technician

13.3.4.4.1 RP - Technician Initial Training

The purpose of this program is to train newly assigned Entergy radiological protection (RP) technicians who meet the following entry level requirements:

Job description requirements for RP Technician
ANSI N18.1

The program, developed using a systems approach to training, is designed to produce highly competent RP technicians who are able to respond to actual or simulated plant situations, performing all tasks required in accordance with the guidelines and procedures established at the station.

The initial RP Technician Training Program is made up of three qualification phases:

PHASE I - Job Coverage Qualification
PHASE II - Watch Stander Qualification
PHASE III -Full Qualification

Successful completion of the program is demonstrated by passing course quizzes, milestone exams, practical exams.

13.3.4.4.2 RP Technician - Requalification Training

This program, developed using a systems approach to training, is designed to assure the availability of qualified RP technicians, who have maintained their skills through a program of continuous training and evaluation, the content of which is regularly based upon an on-going analysis.

Requalification Training for RP Technicians is conducted to ensure that the detailed and plant-specific knowledge of RP Technicians will be such that they perform at the desired competence level. This program was designed to:

Maintain and enhance the skills and knowledge necessary to accomplish routine, abnormal and emergency duties.

Emphasize lessons learned from industry and plant operating experience to prevent repetition of errors.

Correct performance deficiencies related to training, while enhancing professionalism.

Improve knowledge and skills when changes in responsibilities are identified.

Systematically evaluate individual and team performance to identify areas for improvement.

Ensure that technicians receive information on plant modifications, industry events and procedural changes in a timely manner.

Increase the level of understanding of fundamental principles obtained in initial training, including an emphasis in areas of demonstrated weakness.

Maintain awareness of responsibilities for safe operation of the plant including consequences of incorrect job performance.

Provide input to station management for improvements in operation, practices and procedures.

This program is applicable to all Entergy RP technicians and supervisory personnel with RP responsibilities.

13.3.4.4.3 Radiation Protection Technician - Contractor

Contractor RP Technicians are assigned to PNPS to supplement the Entergy staff during periods of peak workloads. Contractor RP Technicians are often well trained and have extensive experience in Radiation Protection at several facilities.

The purpose of this program is to train contractor RP technicians in PNPS specific procedures and radiological protection practices. The Program is applicable to all experienced contractor RP Technicians assigned to PNPS. The program is developed using the systems approach to training.

13.3.4.5 Chemistry Technician

13.3.4.5.1 Initial Training

Initial training for Chemistry Technicians is conducted to ensure that the detailed and plant-specific knowledge of Chemistry Technicians will be such that they can perform at the required level of competence.

The purpose of the program is to train newly-assigned Entergy Chemistry Technicians who meet the following entry-level job description requirements:

Job description requirements for Chemistry Technicians ANSI N18.1

The program, developed using a systems approach to training, is designed to produce highly competent Chemistry Technicians who are able to perform their assigned responsibilities during routine and emergency conditions in accordance with guidelines and procedures established at PNPS.

Successful completion of the program is demonstrated by passing quizzes, milestone exams, and performance exams.

13.3.4.5.2 Requalification Training

This program, developed using a systems approach to training, is designed to ensure the availability of qualified Chemistry Technicians who have maintained their skills through a program of continuous training and evaluation, the content of which is regularly updated based upon an on-going analysis.

Requalification Training for Chemistry Technicians is conducted to ensure that the detailed and plant-specific knowledge of Chemistry Technicians will be such that they perform at the desired competence level. This program was designed to:

Maintain and enhance the skills and knowledge necessary to accomplish routine, abnormal, and emergency duties;

Emphasize "lessons learned" from industry and plant operating experience to prevent repetition of errors;

Correct performance deficiencies related to training, while enhancing professionalism;

Improve knowledge and skills when changes in responsibilities are identified;

Systematically evaluate individual and team performance to identify areas for improvement;

Ensure that Technicians receive information on plant modifications, industry events, and procedural changes in a timely manner.

Increase the level of understanding of fundamental principles obtained in initial training, including an emphasis in areas of demonstrated weakness;

Maintain awareness of responsibilities for safe operation of the plant, including consequences of incorrect job performance;

Provide input to station management for improvements in operation, practices and procedures.

This program is applicable to all Entergy Chemistry Technicians and Supervisory personnel with Chemistry responsibilities. Requalification Training for Chemistry personnel will be scheduled to meet various regulatory requirements on the basis of an assessment of training needs and/or the need to impart knowledge and/or skills caused by plant configuration of procedure changes.

13.3.4.5.3 Chemistry Technician - Contractor

Contractor Chemistry Technicians are assigned to PNPS to supplement the Entergy staff during periods of peak work loads. Contractor Chemistry Technicians are often well trained and generally have had extensive experience in Chemistry at several facilities.

The purpose of this Program, developed using a systems approach to training, is to train the Contractor Technicians on site-specific procedures and practices. This program is applicable to all Contractor Chemistry Technicians assigned to PNPS.

13.3.4.5.4 Chemistry Supervisory Training

Chemistry Supervisory Training is designed to ensure that a sufficiently trained staff is available to manage and supervise the PNPS Chemistry Division at the desired competence level.

The program is designed to meet requirements for updating and retraining of Chemistry supervisory personnel to assure safe operations at PNPS. This ensures that the individual Chemistry Supervisor is able to respond to actual or simulated plant situations, performing all tasks required in accordance with the guidelines and procedures established at the station.

This program is applicable to all Chemistry Supervisors assigned to PNPS. Retraining for Chemistry Supervisors is scheduled to meet regulatory requirements to assess training needs, and/or to impart knowledge or skills needed due to plant configuration and procedure changes. As required, retraining includes results of industry experience and "lessons learned" as a result of continuing operation.

The Chemistry Supervisory Training Program consists of two parts.

Phase One is the Supervisory Orientation program which is intended as an initial orientation to various "administrative" practices for which the Chemistry Supervisor will have some responsibility. The program is delivered using a combination of monitored, self-study, and formal courses, as well as examiner review of various program elements.

Phase Two is intended to address the ongoing training needs of Chemistry Supervisors and Managers who have already satisfied the requirements of Phase One (through either completion of the orientation program or on-the-job experience). Lessons are available for numerous supervisory and management skill areas. Training for individual supervisors is based on an assessment of their needs.

13.3.5 OTHER TECHNICAL TRAINING

13.3.5.1 Fire Brigade Training

The Fire Brigade Training Program is comprised of Initial and Requalification Training. The Initial Training consists of approximately 80 hours. The Requalification Training consists of one session (training session) per quarter. The session length varies depending on subject(s) to be taught. The training program meets or exceeds the requirements of NFPA standard No. 27-1975 "Private Fire Brigade" (Reference 14).

The program is designed for those personnel assigned to perform Fire Brigade duties at Pilgrim Station.

The goal of the Fire Brigade Training program is to provide education and training in order to ensure that workers have the knowledge and skills necessary to work efficiently and safely in a fire or smoke filled environment.

The training is divided into eight areas:

Fire Protection Systems
Self-Contained Breathing Apparatus
Fire Water Supply
Fire Behavior
Plant Fire Protection
Fire Brigade Equipment
Advanced Training
Recruit Training

13.3.5.2 Engineering Support Personnel

The Engineering Support Personnel Training Program is INPO accredited and is designed to ensure safe and reliable plant operation by providing a training and qualification process for plant personnel responsible for engineering and support functions. The program is comprised of both initial and continuing training components.

13.3.5.3 Emergency Preparedness

This program is designed to qualify specified individuals of the PNPS Emergency Response Organization to properly perform their assigned functions of protecting health and safety of the general public in the event of an accident at PNPS.

13.3.6 REFERENCES

1. Regulatory Guide 1.8 (ANSI N18.1, Section 5.4)
2. Regulatory Guide 1.70.38, Section 13.2.2.3
3. 10CFR50, Appendix B, Criteria II (ANSI N18.7, Section 3.3)
4. 10 CFR 19.12
5. 10 CFR 20.101, 20.102
6. 10CFR50.73
7. INPO Guideline 82-004
8. Regulatory Guide 1.8 (ANSI N18.1, Section 5.3.4)
9. 10CFR50, Appendix B, Criteria II (ANSI N18.7, Section 5.2.10; ANSI N45.2.3, Section 2.4)
10. 10CFR50, Appendix B, Criteria II
11. 10CFR50, Appendix B, Criteria VI
12. 10CFR50, Appendix B, Criteria III
13. 10CFR50, Appendix B, Criteria VI (ANSI N18.7, Section 5.2.15)
14. NFPA Standard No. 27-1975 "Private Fire Brigade"
15. 10CFR26 (54FR24468), Published June 7, 1989.

14.5 POSTULATED DESIGN BASIS ACCIDENTS

The abnormal operating transients documented in Section 14.4 are evaluated to determine the normal plant operating MCPR limit and compliance with the LHGR 1% plastic strain limit. In addition to these analyses, evaluations of less frequent postulated events are made to assure an even greater depth of safety. Accidents are events which have a projected frequency of occurrence of less than once in every one hundred years for every operating BWR. The broad spectrum of postulated accidents is covered by four categories of design basis events. These events are as follows:

1. Decrease in Reactor System Flow Rate - Recirculation Pump Seizure,

2. Reactivity and Power Distribution Anomalies - Control Rod Drop Accident and Loading Error Accident,

3. Decrease in Reactor Coolant Inventory - Steam Line Break and Loss of Coolant Accident, and

4. Radioactive Release from Subsystem or Component - Fuel Handling Accident.

The recirculation pump seizure and misplaced fuel bundle events were analyzed as abnormal operating transients in the initial core evaluation. Since that time, these events have been recategorized as accidents.

As documented in Reference 1, only some of the above accidents are reanalyzed for each reload cycle. These include control rod drop accident and misoriented fuel bundle. The loss of coolant accident analysis is performed only when a new bundle enrichment or new fuel is placed in the core. These three events, the steam line break accident, and the fuel handling accident are addressed below.

14.5.1 Control Rod Drop Accident

There are many ways of inserting reactivity into a boiling water reactor; however, most of them result in a relatively slow rate of reactivity insertion and therefore pose no threat to the system. It is possible, although unlikely, that a rapid removal of a high worth control rod could result in a potentially significant excursion. Therefore, the accident which encompasses the consequences of a reactivity excursion is the control rod drop accident.

The drop of the control rod results in a high local reactivity in a small region of the core and for large, loosely coupled cores like PNPS, significant shifts in the spatial power generation during the course of the excursion. Therefore, the method of analysis must be capable of accounting for any possible effects of the power distribution shifts.

Analysis of this accident is performed at various reactor operating states; the key reactivity feedback mechanism affecting the termination of the initial prompt power burst is the Doppler Reactivity Coefficient. Final shutdown is achieved by scramming all but the dropped rod. The methods utilized to evaluate the rod drop accident are documented in Reference 1. The limit for this event is 280 cal/gm.

14.5.1.1 Sequence of Events

For this accident, the reactor is assumed to be at a control rod pattern corresponding to the maximum incremental rod worth. The rod worth minimizer or operators are functioning within the constraints of the Banked Position Withdrawal Sequences (BPWS). The control rod that will result in the maximum incremental reactivity worth addition at any time in core life, under any operating condition while employing the BPWS, becomes decoupled from the control rod drive.

The operator selects and withdraws the drive of the decoupled rod along with the other control rods assigned to the Banked-Position group such that the proper core geometry for the maximum incremental rod worth exists. The decoupled control rod sticks in the fully inserted position.

The control rod then becomes unstuck and drops at the maximum velocity determined from experimental data (3.11 fps). The reactor goes on a positive period and the initial power burst is terminated by the Doppler Reactivity Feedback. The APRM 120% power signal scrams the reactor. The MSIV's, Steam Line Drain Isolation Valves, and Reactor Water Sample Valves remain open. The Mechanical Vacuum Pump receives an auto trip signal.

14.5.1.2 Analytical Methods and Results

Techniques and models used to analyze the control rod drop accident (CRDA) are documented in Reference 1. Analytical results from BPWS plants like PNPS have been statistically analyzed. The results of this statistical analysis show that, in all cases, the peak fuel enthalpy in a CRDA would be much less than the 280 cal/gm event limit even with a maximum incremental rod worth corresponding to 95% probability at the 95% confidence level. The details of this analysis are given in Reference 1.

14.5.1.3 Radiological Consequences

The analysis for removing the MSIV isolation function was performed by General Electric in NEDO-31400A, Safety Evaluation for Eliminating the Boiling Water Reactor Main Steam Line Isolation Valve Closure Function and Scram function of the Main Steam Line Radiation Monitor. Input values were collected from all participating utilities (includes PNPS) to consider the most bounding case of the effects of removing the MSIV isolation function. The analysis considered the offsite dose consequences for 2 release scenarios.

1) A CRDA where the source term is not reduced, even though the MSIVs close, and the radionuclides enter the condenser at atmospheric pressure to leak directly to the environment.

2) A CRDA where the MSIVs do not close and the activity is processed through the AOG and released via the main stack.

The consequences for the CRDA at PNPS were evaluated using PNPS-specific assumptions and parameter values. The source term is based on the failure of 1200 rods for GE14 fuel. Conservatively, the maximum radial peaking factor that is expected during the operating fuel cycle was applied to all affected rods. The approach is as used in NEDO 31400 and as outlined in Standard Review Plan (SRP) 15.4.9 "Spectrum of Rod Drop Accidents (BWR)."

For the first scenario in which the radioactivity leaks directly from the condenser to the environment, the estimated consequences are 3.7 rem to the thyroid and 0.03 rem to the whole body.

In the event of the second scenario, in which the MSIVs do not close, the offgas pre-treatment or post-treatment monitors would automatically isolate the main stack prior to any release. The off-gas monitors are required by Technical Specifications and the Offsite Dose Calculation Manual to be in continuous operation to isolate the main stack in the event of a noble gas release rate greater than the setpoint value used for normal plant effluent releases. In the event of a CRDA the activity release rate would be significantly greater than that allowed during normal plant operation. The monitors would, therefore, isolate the main stack. The accident activity released from the fuel would be contained in the condenser and the consequences would be as determined for the condenser release scenario.

The CRDA activity release via the AOG system and main stack is highly unlikely at PNPS. However, since the off-gas monitors are not safety-related, a conservative evaluation assuming such a scenario was performed. It was assumed that the AOG system is in service but that the monitors fail to isolate the main stack. Conservatively, the AOG charcoal delay bed hold-up times for noble gases was assumed to be zero. A conservative AOG system flow rate was also used. For this scenario the estimated consequences are still well below the limits established in SRP 15.4.9, which were used in the safety evaluation report as the bases for accepting NEDO 31400. Therefore, the AOG system is not required to mitigate the consequences of a CRDA.

NEDO-31400A recognized that early vintage BWRs like Pilgrim operate at power levels above the mechanical vacuum pump capability while AOG is bypassed. NEDO-31400A states that this operating mode is acceptable because the pretreatment radiation monitors' set points are established to automatically isolate the effluent pathway before Technical Specification dose rate limits are exceeded. If a CRDA occurred while operating in the AOG bypass mode, the resulting offsite dose is expected to be similar to the condenser leakage scenario discussed in this section (i.e., that dose would be a small fraction of 10 CFR 100 dose limits).

The NEDO-31400A safety evaluation did not address removing any other trip functions from the Main Steam Line Radiation Monitors. The other possible trip functions from the Main Steam Radiation monitoring are as follows:

1) Trip the Mechanical Vacuum Pump.
2) Close the Main Steam Line Drain Isolation Valves
3) Close the Reactor Sample Isolation Valves

The Mechanical Vacuum Pump trip function is operable at PNPS. The other trip functions are not operable at PNPS as explained below.

There is no effect on the off-site dose as a result of the main steam line drain valves remaining open during a CRDA since the piping is also routed to the condenser. The source term in the condenser is unaffected because no plate out or condensation of the source term from the reactor to the condenser is assumed in the NEDO-31400A analysis. The occurrence of these phenomena in the drain lines would tend to diminish the condenser source term.

The reactor water sample enters the Reactor Building as a 1-inch line in the Reactor Water Cleanup Heat Exchanger Room. The line splits off to a 1/2-inch line to the Crack Arrest Verification System (CAVS) and 1/2-inch line to the Reactor Water Sample Panel (C121). There is a 1/2-inch line from the CAVS that goes to a sample panel (C136) and drains to the Reactor Water sample panel drain.

The conservative assumptions used in calculating the dose contribution from the open reactor water sample valves are as follows:

1. The valves are assumed to be open for 2 hours before action is taken by the operator.

2. The same fraction of halogens get vented to the atmosphere from the sample line as from the condenser. This assumes no condensation occurs. However, the process stream that goes to the drain first goes to a sample panel cooler and has an outlet temperature of approximately 77°F. Therefore, the actual fraction of halogens that get vented to the atmosphere will be very small.

The estimated contributing doses from this drain are 20.1 rem thyroid and 7.0 E-03 rem whole body.

Another contribution to offsite dose during a CRDA is from the Turbine Gland Seal Condenser Exhausters. This source draws steam from the steam chest of the Main Steam System and supplies it to the gland seals of the turbine. There is a separate condenser for this steam that is mixed with air and then exhausted to the same effluent path as the mechanical vacuum pump. The amount of steam existing through this path depends on the clearances of the packing on the turbine seals. The maximum seal clearance was assumed when considering the offsite dose contribution during a CRDA. Also, no condensation of the steam is assumed after it leaves the exhausters and is released to the environment. The actual process flow is through piping that contains 2 loop seals to collect condensation before being released to the stack. The estimated dose contribution from this source was 0.64 Rem thyroid and 1.3E-02 Rem whole body.

The offsite dose from all sources during a CRDA is totaled below (reference 14.7.11):

Source	Thyroid	WB
Condenser	3.7	3.0E-02
RX Sample Line	20.1	7.0E-03
Gland Seals	0.64	1.3E-02
TOTAL	24.4	5.0E-02

At PNPS, the worst case CRDA most probably would occur during mechanical vacuum pump operation. The mechanical vacuum pump would trip and the radionuclides would be trapped in the condenser. Therefore the condenser leakage scenario is bounding for PNPS.

The CRDA whole body dose for PNPS is less than the NEDO-31400A of 0.31 Rem. The PNPS CRDA thyroid dose is greater than the NEDO-31400A value of 4.3 Rem because of the PNPS site specific added contributions from the reactor sample line and gland seals. However, the total offsite dose for a CRDA is less than the SRP 15.4.9 limits of 75 Rem thyroid and 6 Rem whole body.

NEDO-31400A considered the failure of 850 fuel rods of the 8x8 configuration. For 9x9 fuel, approximately 1000 fuel rods are expected to fail at the same level of deposited energy due to the postulated accident. However, the radiological consequences for the 9x9 fuel designs are the same as for 8x8 fuel designs due to an offsetting lower plenum activity (per rod).

14.5.2 Loading Error Accident

One of the events which is evaluated each cycle is the fuel bundle loading error. The probability of a significant fuel assembly loading error is much less than once in a plant lifetime and requires multiple operator errors to occur. A loading error in the core configuration is defined as one of the following:

1. A fuel bundle is inserted in an improper location (mislocated bundle accident); or

2. A fuel bundle is loaded in an improper orientation, i.e., rotated 90 or 180 degrees (misoriented bundle accident).

The results of this accident must not exceed the Fuel Cladding Integrity MCPR Safety Limit; therefore, there are no radiological consequences.

14.5.2.1 Mislocated Bundle Accident

Mislocated bundle analyses are not performed for reload cores because, based on an analysis of data available from past reloads, the probability that a mislocated fuel bundle loading error will result in a CPR less than the safety limit is sufficiently small that plant/cycle specific analyses are not necessary. Details of this analysis are provided in Reference 1.

14.5.2.2 Misoriented Bundle Accident

Proper orientation of fuel assemblies in the reactor core is readily verified by visual observation and assured by verification procedures during core loading. Five separate visual indications of proper fuel assembly orientation exist:

1. The channel fastener assemblies, including the spring and guard used to maintain clearances between channels, are located at one corner of each fuel assembly adjacent to the center of the control rod.

2. The identification boss on the fuel assembly handle points toward the adjacent control rod.

3. The channel spacing buttons are adjacent to the control rod passage area.

4. The assembly identification numbers which are located on the fuel assembly handles are all readable from the direction of the center of the cell.

5. There is cell-to-cell replication.

Experience has demonstrated that these design features are clearly visible so that any misoriented fuel assembly would be readily identifiable during core loading verification.

Analysis methods for the misoriented fuel assembly are given in Reference 1. A penalty of 0.02 CPR to account for tilting of the misoriented bundle is added to the calculated CPR used in determining the operating limit MCPR. The misoriented bundle accident is evaluated on a cycle specific basis.

14.5.3 Loss of Coolant Accident

Break of a large recirculation pipe represents the limiting pipe break inside the containment. This event has been analyzed quantitatively in Section 6.5. The following is a discussion of the containment analysis and radiological consequences. Assumptions used in these analyses are given in Appendix R.6 and below.

Two ultimate heat sink (UHS) temperatures (65°F and 75°F) are presented in Loss-of-Coolant-Accident, Primary Containment and ECCS Pump NPSH analysis contained Section 14.5.3. The 65°F analysis represents the original design and licensing value. The 65°F analysis information was retained in the FSAR for its historical value and because it was the original basis for the sizing and selection of the containment heat removal systems.

By license amendment (Ref. 12 & 13), the design and licensing basis maximum UHS temperature was raised from 65°F to 75°F. The current operational limit in the Technical Specifications is 75°F. Therefore, the design and licensing value for the maximum UHS temperature is defined at 75°F, to ensure plant operation is not limited below 75°F and that all safety functions directly or indirectly dependent on UHS temperature can be satisfied up to 75°F.

14.5.3.1 Primary Containment Response

14.5.3.1.1 Initial Conditions and Assumptions

The following assumptions and initial conditions were used in the calculation of the effects of a LOCA on the primary containment. The plant response to the accident can be separated into two distinct phases: the short term response and the long-term recirculation phase. The short-term response includes that period of time in the accident up to 600 seconds when initiation of containment cooling is assumed. The peak drywell and wetwell airspace temperatures occur in this period of time and are not influenced by the performance of containment cooling. The long-term recirculation phase of the accident response is defined to begin at 600 seconds with the initiation of containment cooling and continue past the peak suppression pool temperature to the point of minimum NPSH margin.

Historically, the primary containment response has been established using the design value of 65°F for the SSW inlet temperature to the RBCCW heat exchanger. The following discussion of containment response includes analysis performed for the DBA LOCA using a site maximum SSW injection temperature of 75°F. In the following discussion the analysis that used a 75°F SSW injection temperature is referred to as the 75°F SSW Case, likewise the analysis based on 65°F SSW injection temperature is referred to as the 65°F SSW Case.

1. The reactor is operating at full power with all valves in the recirculation system open. Initial power for the 75°F SSW Case was increased to 102% consistent with the current standard based on the requirements of Regulatory Guide 1.49.

65°F SSW Case	75°F SSW Case
1998 MWt	2038 MWt

2. The reactor is assumed to go subcritical at the time of accident initiation due to void formation in the core region. Scram also occurs in less than 1 sec from receipt of the high drywell pressure signal, but the difference in shut down time between 0 and 1 sec is negligible.

3. The sensible heat released in cooling the fuel to 545°F (the normal primary system operating temperature) and the core decay heat were included in the reactor vessel depressurization calculation. The rate of energy release was calculated using a conservatively high heat transfer coefficient throughout the depressurization. Because of this assumed high energy release rate, the vessel is maintained at near rated pressure for almost 6 sec. The high vessel pressure increases the calculated flow rates out of the break; this is conservative for containment analysis purposes. With the vessel fluid temperature remaining near 545°F, however, the release of sensible energy stored below 545°F is negligible during the first 6 sec. The later release of this sensible energy does not affect the peak drywell pressure. The small effect of this energy on the end of transient suppression pool temperature is included in the calculations.

4. The main steam line isolation valves were assumed to start closing at 0.5 sec after the accident, and the valves were assumed to be fully closed in the shortest possible time of 3 sec following closure initiation. Actually, the closures of the main steam line isolation valves are expected to be the result of reactor low-low water level, so these valves may not receive a signal to close for over 4 sec, and the closing time could be as high as 10 sec. By assuming rapid closure of these valves, the reactor vessel is maintained at a high pressure, which maximizes the discharge of high energy steam and water into the primary containment, which in turn maximizes the loading on the containment.

5. For both the short and long-term analysis in the 65°F SSW Case, the feedwater flow was assumed to stop instantaneously at time zero. This conservatism is used because the relatively cold feedwater flow, if considered to continue, tends to depressurize the reactor vessel, thereby reducing the discharge of steam and water into the primary containment.

   Short-term containment response in the 75°F SSW Case is consistent with the 65°F SSW Case. For the 75°F SSW Case long-term analysis, feedwater flow into the RPV continues until the high-energy feedwater (above feedwater enthalpy of 201 BTU/lbm) is injected into the reactor vessel. This assumption is conservative for the long-term suppression pool temperature analysis because additional energy is added to the reactor vessel and containment.

6. The vessel depressurization flow rates were calculated using Moody's critical flow model[2] assuming "liquid only" outflow because this maximizes the energy release to the containment. "Liquid only" outflow means that all vapor formed in the vessel due to bulk flashing rises to the surface rather than being entrained in the exiting flow. Some entrainment of the vapor would occur and would significantly reduce the reactor vessel discharge flow rates. Moody's critical flow model, which assumes annular, isentropic flow, thermodynamic phase equilibrium, and maximized slip ratio, accurately predicts vessel outflows through small diameter orifices. However, actual flow rates through larger flow areas are less than the model indicates due to the effects of a near homogeneous two phase flow pattern and phase nonequilibrium. These effects are in addition to the reduction due to vapor entrainment discussed above.

   For the 75°F SSW Case, the vessel depressurization rates were calculated using the homogeneous equilibrium critical flow model described in NEDO-21052, "Maximum Discharge of Liquid-Vapor Mixtures from Vessels." (Reference 6).

7. The pressure response of the containment is calculated assuming:

   a. Thermodynamic equilibrium in the drywell and suppression chamber. Because complete mixing is nearly achieved, the error introduced by assuming complete mixing is negligible and in the conservative direction.

   b. The constituents of the fluid flowing in the drywell to suppression chamber vents are based on a homogeneous mixture of the fluid in the drywell. The consequences of this assumption result in complete liquid carryover into the drywell vents. Actually, some of the liquid will remain behind in a pool on the drywell floor so that the calculated drywell pressure is conservatively high.

c. The flow in the drywell suppression pool vents is compressible except for the liquid phase. In the development of the drywell flow model, it is noted that the mass fraction of liquid in the drywell is on the order of 0.60, while the volumetric fraction is only about 0.005. This fact resulted in the following interpretation of the flow pattern. The liquid is in the form of a fine mist that is carried along by the predominately steam air flow and does not affect the flow except to add inertia to the flowing fluid. Except for the corrections to account for the liquid inertia, flow is treated as compressible flow of an ideal gas in a duct with friction. The loss coefficients of the Vent/Header/Downcomer System are lumped as an equivalent length of pipe.

The accuracy of this interpretation of the effects of liquid carryover is supported primarily by a series of tests performed as part of the Humboldt Bay series of pressure suppression tests.[3] In this series of tests, changes in the drywell geometry resulted in variation in the amount of liquid carryover achieved. The liquid remaining in the drywell at the end of the test was measured and recorded. These tests were performed with a relatively small diameter orifice in the reactor vessel so that the reactor vessel outflow can be calculated accurately using Moody's critical flow model.[2] On Figure 14.5-1 the calculated and measured pressure responses for these tests are shown. Note that with 100 percent carryover the agreement is excellent. In this test, the drywell was preheated to 184°F before the steam water mixture was introduced to the drywell; the preheating prevented any condensation on the drywell walls. A calculated response assuming condensation but no carryover is also shown on Figure 14.5-1, and the agreement with the measured response with no carryover is excellent.

d. No heat loss from the gases inside the primary containment is assumed. The model is compared against the Bodega Bay test data for two of the smaller orifices tested on Figures 14.5-2 and 14.5-3. As can be seen in the figures, the reactor vessel depressurization model accurately predicted the results of these tests. However, the predicted drywell pressure response is slightly higher than the test results. The over prediction is believed to be due to a combination of:

No condensation assumed in calculated response,

Slight over prediction of reactor vessel discharge flow rates, and

Incomplete liquid carryover into the drywell vents.

As the chosen size of the vessel orifice increases, the vessel depressurization rate is over-predicted and the over prediction of drywell pressure increases. This trend is illustrated on Figure 14.5-4, where calculated and measured drywell peak pressure is compared. In no case did the model underpredict the test data.

14.5.3.1.2 Containment Response

65°F SSW Case

The calculated pressure and temperature responses of the containment are shown on Figures 14.5-5, 14.5-6, and 14.5-7. Figure 4.5-5 shows that the calculated drywell peak pressure is 45 psig, which is well below the maximum allowable pressure of 62 psig. After the discharge of the primary coolant from the reactor vessel into the drywell, the temperature of the suppression chamber water approaches 130°F (Figure 14.5-7), and the primary containment pressure stabilizes at about 27 psig, as shown on Figure 14.5-5. Most of the noncondensible gases are forced into the suppression chamber during the vessel depressurization phase. However, the noncondensibles soon redistribute between the drywell and the suppression chamber via the vacuum-breaker system as the drywell pressure decreases due to steam condensation.

The core spray system removes decay heat and stored heat from the core, thereby controlling core heatup and limiting metal water reaction to less than 0.1 percent. The core spray water transports the core heat out of the reactor vessel through the broken recirculation line in the form of hot water. This hot water flows into the suppression chamber via the drywell to suppression chamber vent pipes. Steam flow is negligible. The energy transported to the suppression chamber water is then removed from the primary containment system by the residual heat removal system (RHR) heat exchangers.

Prior to activation of the RHR containment cooling mode (arbitrarily assumed at 600 sec after the accident), the RHR pumps (low pressure coolant injection (LPCI) mode) have been adding liquid to the reactor vessel along with the core spray. After the reactor vessel is flooded to the height of the jet pump nozzles, the excess flow discharges through the recirculation line break into the drywell. This flow, in addition to cooling the fuel, offers considerable cooling to the drywell and causes a depressurization of the containment as the steam in the drywell is condensed. At 600 sec, the RHR pumps are assumed to be switched from the LPCI mode to the containment cooling mode. The containment spray would normally not be activated at all and the changeover to the containment cooling mode need not be made for several hours. There is considerable time available to place the containment cooling system in operation because about 8 hr will pass before the containment design pressure is reached, assuming no containment cooling.

To access the primary containment long term response after the accident, an analysis was made of the effects of various containment spray and containment cooling combinations. For all cases, one of the core spray loops is assumed to be in operation. The long term pressure and temperature response of the primary containment was analyzed for the following containment spray and cooling conditions:

Case A - Operation of both RHR cooling loops with two residual heat removal (RHR) pumps and two RHR heat exchangers in suppression pool cooling mode. No containment spray.

Case B - Operation of one RHR cooling loop with one RHR pump and one RHR heat exchanger in suppression pool cooling mode. No containment spray.

Case C - Operation of one RHR cooling loop with one RHR pump and one RHR heat exchanger in containment spray mode.

The initial pressure response of the containment (the first 30 sec after break) is the same for each of the conditions. During the long term containment response (after depressurization of the reactor vessel is complete) the suppression pool is assumed to be the heat sink in the containment system. The effects of decay energy, stored energy, and energy from the metal water reaction on the suppression pool temperature are considered.

Case A

This case assumes that both RHR loops are operating at design heat removal capacity. This includes two RHR heat exchangers, two RHR pumps, and design values of cooling water flow to both RHR loops operating in the suppression pool cooling mode. The RHR pumps draw suction from the suppression pool and pump water through the RHR heat exchangers and back into the suppression pool. This forms a closed cooling loop with the suppression pool. This suppression pool cooling condition is arbitrarily assumed to start at 600 sec after the accident. Prior to this time the RHR pumps are used to flood the core (LPCI mode).

The containment pressure response to this set of conditions is shown as curve "a" on Figure 14.5-5. The corresponding drywell and suppression pool temperature responses are shown as curves "a" on Figures 14.5-6 and 14.5-7. After the initial rapid depressurization, energy addition due to core decay heat results in a gradual pressure and temperature rise in the containment. When the energy removal rate of the RHR exceeds the energy addition rate from the decay heat, the containment pressure and temperature begin to decrease. Table 14.5-1 summarizes the peak containment pressure following the initial blowdown peak, the peak suppression pool temperature, and a summary of the equipment capability assumed in the analysis.

Case B

This case assumes that one RHR loop is operating at design heat removal capacity (one RHR heat exchanger, one RHR pump, and design value of cooling water flow to one RHR loop operating in the suppression pool cooling mode). As in the previous case, there is no containment spray operation and the suppression pool cooling mode is assumed to be activated at 600 sec after the accident. The containment pressure response to this set of conditions is shown as curve "b" on Figure 14.5-5. The corresponding drywell and suppression pool temperature responses are shown as curves "b" on Figures 14.5-6 and 14.5-7. A summary of this case is shown on Table 14.5-1, including a summary of the equipment capability assumed in the analysis.

Case C

This original case assumes the same equipment operability as Case B except that the entire discharge from the RHR heat exchanger is routed to the containment spray headers in the drywell and wetwell. It assumed that the containment spray is established at 600 sec after the accident.

The containment response to this set of conditions is shown as curve "c" on Figure 14.5-5. The corresponding drywell and suppression pool temperatures are shown as curves "c" on Figures 14.5-6 and 14.5-7. A summary of this case is shown on Table 14.5-1, including a summary of the equipment capability assumed in the analysis.

Comparing the "containment spray" Case C with the "no spray" Case B, it is seen that the suppression pool temperature response is the same because the same amount of energy is removed from the pool via the RHR heat exchanger. The total flow rate through the RHR heat exchanger is the same for Case B & C. However, the post blowdown containment pressure is higher for the "no spray" case, as shown by Figure 14.5-5. This, however, is of no consequence since the pressure is still much less than the containment design pressure of 56 psig. Figure 14.5-8 illustrates the slight effect on calculated containment leakage rate, due to the higher pressure.

The containment spray flowrate used in the original FSAR containment analysis (based on a 65°F SSW inlet temperature) was substantially reduced from its design value of 5,000 gpm down to 1,100 gpm by capping the majority of the drywell spray nozzles. The Case C, containment pressure and temperature response curves shown on Figure 14.5-5 and Figure 14.5-6 were not recalculated using the current containment spray flow rate of approximately 1,100 gpm. The spray reduction will increase the drywell temperature and pressure between 600 seconds when spray is initiated and 1 X 10^6 seconds, the time at which the analysis is terminated. Although, drywell temperature and pressure increase, that increase is bounded by the results for Case B which is based on one loop of RHR in the suppression pool cooling mode and no spray.

To assure the suppression pool temperature response is the same as that shown on Figure 14.5-7, the RHR heat exchanger flowrate must be maintained consistent with values in Table 14.5-1. Operating procedures require that a portion of the discharge from the RHR heat exchanger be routed to the containment spray headers and the remaining portion return to the suppression pool via the suppression pool bypass line.

75°F SSW Case

For the 75°F SSW Case, the calculated pressure and temperature responses of the containment are shown on Figures 14.5-16, and 14.5-17. The short-term response of the drywell, wetwell, and suppression pool is the same as for the Case B from the 65°F SSW Case. The containment response prior to 600 seconds is unaffected by containment cooling and remains the same for both cases. The 65°F SSW Case provides an additional description of the short-term response.

Prior to the activation of containment cooling, the LPCI and core spray pumps have been adding liquid to the reactor vessel. After the vessel is flooded to the height of the jet pump nozzles, the excess flow discharges through the break into the drywell. This flow cools the fuel and flushes sensible heat from the reactor vessel into the drywell. The flow of sub cooled liquid into the drywell causes depressurization of the containment as the steam in the drywell is condensed.

For the 75°F SSW Case, the long-term analysis assumes one RHR loop is available for containment cooling. At 600 seconds, the necessary valves are opened admitting cooling water flow to the RHR heat exchanger. The RHR heat exchanger bypass valve is assumed to remain in its full open normal position and the RHR system is assumed to remain in the LPCI mode with containment cooling by heat rejection through the RHR heat exchanger. No disruption of LPCI flow is required to enter this mode of cooling. This configuration will provide maximum core cooling, but does not provide rated heat removal because more than half of the two pump LPCI flow rate goes through the heat exchanger bypass line and not the heat exchanger.

At two hours after the start of the accident, a transition is made from the two pump LPCI with Heat Rejection mode to the one pump LPCI with Heat Rejection mode to maximize the heat removal function of the RHR System. Rated heat removal from the containment is obtained using the LPCI with Heat Rejection mode by removal of one RHR pump from LPCI service and closure of the RHR heat exchanger bypass valve while maintaining maximum LPCI injection flow from the single RHR pump. One pump LPCI with Heat Rejection mode is assumed to run continuously throughout the remainder of the accident response.

For the design basis LOCA analysis, it is assumed that there is only one loop of containment heat removal (RHR, RBCCW, and SSW) operable. The containment heat removal assumed in the design basis LOCA analysis is that which can be obtained with one loop of the RHR, RBCCW, and SSW Systems operating at the limiting conditions for pump and heat exchanger performance. Suppression pool temperature will continue increasing from the transfer of sensible and decay heat from the reactor core to the suppression pool until reaching the peak approximately 5 to 6 hours after the accident. The design peak suppression pool temperature for the DBA-LOCA is 185°F, which is well below the primary containment design temperature of 281°F. Subsequently, the decreasing decay heat results in a steady cooldown and depressurization of primary containment. The RHR heat transfer parameters at the peak suppression pool temperature are given in Table 14.5-6 and the resulting containment and suppression pool temperature profiles are given in Figure 14.5-17.

14.5.3.1.3 Core Standby Cooling System Pump Net Positive Suction Head

To assure proper operation of the CSCS pumps following a design basis LOCA, the Primary Containment and CSCS system design is such that Net Positive Suction Head (NPSH) margin is available to the pumps at all times.

The NPSH available (NPSHA) at the suction to the CSCS pumps is equal to the total absolute pressure minus the vapor pressure of water at the suppression pool temperature. The NPSH required at the pump suction (NPSHR) is the minimum pressure over and above the vapor pressure that must be present in order to prevent pump cavitation.

NPSH design margin is based on calculations that include the effect from the increase in wetwell vapor pressure and air/nitrogen partial pressure in equilibrium with increasing suppression pool temperature with an accounting for containment initial conditions and leakage.

The design margin for NPSH available to the RHR and core spray pumps is determined using the following assumptions:

1. The primary containment is assumed to contain the minimum credible mass of noncondensible gas (air/nitrogen) prior to the design basis LOCA. The drywell initial condition is 150°F, 80% RH, 1.3 psig, and the wetwell is 85°F, 100% RH, 0 psig.

2. The water vapor pressure in containment increases to be in equilibrium with the suppression pool temperature.

3. The partial pressure of the containment air/nitrogen increases with the pool temperature per the ideal gas laws after the initial mixing of the drywell and wetwell air has occurred.

4. Where stated on the figures, containment leakage has been calculated based on a leak rate of 1% per day for design basis conditions and 5% per day to demonstrate conservative design margin with impaired containment integrity.
The leakage values represent percent mass per day at a reference pressure of 45 psig using the mass leakage formulation described in Appendix R.5.4.2 "Long Term Containment Response."

5. The suppression pool temperature profile is based on minimum primary containment system cooling, i.e., one RHR loop in containment cooling is assumed, with an initial suppression pool temperature of 85°F and a salt service water heat sink temperature of 75°F.

6. Minimum initial water volume in the suppression pool is assumed (84,000 ft^3).

7. Drywell free volume temperature is equal to wetwell temperature following the accident. This is based on the redistribution of noncondensible gases between the drywell and wetwell via the vacuum-breaker system following the vessel depressurization phase.

8. Maximum flow rates are used for the CSCS pumps to maximize the suction line losses and NPSH required by the pumps. The NPSHR is 27 ft at 5670 gpm for the RHR pumps and 29 ft at 4950 gpm for the core spray pumps.

Based on the above conservative assumptions, the margin for NPSH available was evaluated for the limiting accident event which is the design basis LOCA. The NPSH available and NPSH margin for the RHR and core spray pumps were evaluated for both a 75°F SSW injection temperature and 65°F SSW injection temperature. In the following discussion the analysis that used a 75°F SSW injection temperature is referred to as the 75°F SSW Case, likewise the analysis based on a 65°F SSW injection temperature is referred to as the 65°F SSW Case.

The 65°F SSW Case is based on the suppression pool temperature profile in Figure 14.5-7 from the original design basis LOCA analysis as described earlier in this section. The assumed flow rates, head losses, initial containment mass of nitrogen, and NPSH required for the RHR and core spray pumps have been revised from the original 65°F NPSH analysis so that the same values are used for both the original 65°F and updated 75°F NPSH analyses presented in this Section. The 75°F SSW Case uses the suppression pool temperature profile from Figure 14.5-17 that is from the updated design basis LOCA analysis described earlier.

Figure 14.5-9 shows the NPSH available as a function of pool temperature with zero containment leakage which makes this curve independent of time. Since no leakage effect is included, Figure 14.5-9 represents the highest NPSH margin that can be obtained using the above assumptions and as can be seen, a large margin exists for all pool temperatures. NPSH margin for the 65°F SSW Case, with leakage effects included, is present in a different format on Figure 14.5-10 and Figure 14.5-13. Here, the suppression pool temperature and containment pressure are shown as a function of time. Also shown is the primary containment pressure required to provide the required NPSH to the RHR and core spray pumps at their maximum required flow rates. As can be seen, substantial margin exists throughout the duration of the event. Therefore, it can be concluded that adequate NPSH will be available at all times following a design basis LOCA for the 65°F SSW Case.

NPSH margin for the 75°F SSW Case, with leakage effects included, is presented on Figure 14.5-18 and Figure 14.5-19. Here, the suppression pool temperature and containment pressure are shown as a function of time. Also shown is the primary containment pressure required to provide the required NPSH to the RHR and core spray pumps at their maximum required flow rates. As can be seen, substantial margin exists throughout the duration of the event. Therefore, it can be concluded that adequate NPSH will be available at all times following a design basis LOCA for the 75°F SSW Case.

The RHR and Core Spray System design analysis shows that substantial NPSH margin is available at all times following the bounding design basis LOCA. The design margin for NPSH available is that which exists between the minimum containment pressure that provides the required NPSH and the containment pressure that exists due to equilibrium conditions for the gas/vapor mixture with an accounting for containment initial conditions and leakage. This method of analysis for determining NPSH margin is in accordance with the original design basis for Pilgrim and other similar BWRs. The NRC has chosen to impose limits on the amount of containment pressure that may be included in the NPSH margin for CSCS pump suction strainer evaluations. These time-dependent containment pressure limits were selected based on NRC review of plant-specific accident analysis and are considerably less than the calculated equilibrium pressure.

In accordance with the NRC Safety Evaluation Report for License Amendment 185, the amount of containment positive pressure that may be included in a CSCS pump NPSH analysis has been limited to the following:

Time After Accident (sec)	(hour)	Containment Pressure (psig)	(psia)
0 to 1,200	0.00 to 0.33	0.0	14.7
1,200 to 1,800	0.33 to 0.50	1.9	16.6
1,800 to 3,600	0.50 to 1.0	3.0	17.7
3,600 to 57,600	1.0 to 16.0	5.0	19.7
57,600 to 108,000	16.0 to 30.0	2.5	17.2
108,000 to 172,800	30.0 to 48.0	1.0	15.7
172,800 to 864,000	48.0 to 240.0	0.0	14.7

These limits on containment pressure are included in the evaluation of LOCA debris head losses for the RHR and core spray pumps and the resulting NPSH available for long-term containment heat removal. There remains sufficient NPSH margin within these containment pressure limits to accommodate the postulated LOCA debris without affecting pump performance. The limits listed above are included in Figure 14.5-18 along with the calculated amount of containment pressure available. Figure 14.5-18 also includes a curve showing the amount of containment pressure required to provide adequate NPSH to the most limiting core spray pump operating with the maximum suction strainer head loss from the bounding analysis for strainer debris described in Section 6.4.3.

Evaluations of NPSH for reactor isolation events are bounded by the design basis LOCA. Analysis for isolation scenarios such as a fire event, where the high pressure makeup systems are assumed unavailable, are included in the updated containment analysis with a 75°F SSW heat sink. It is assumed that reactor depressurization occurs at 1450 seconds (24 minutes) due to low reactor water level and there is no suppression pool cooling for two hours. The peak pool temperature is less than 185°F while the equilibrium mechanism for containment pressure and NPSH available are the same as for the LOCA. The resulting NPSH available exceeds that for the design basis LOCA due to the lower pool temperature.

During Reactor Core Isolation Cooling System (RCIC) operation, the drywell free air volume cooler will normally remain operational. Due to the reduced heat load on the air coolers caused by the shutdown of the two reactor coolant recirculation system pumps, the drywell temperature could actually be less than the normal operating value in spite of the fact that some of the air cooler capacity may also be shut down. The lower drywell temperature would tend to reduce the primary containment pressure which would reduce the NPSH available. In order to arrive at a conservative lower bound on the total NPSH available, the following model was assumed:

1. No leakage from the primary containment (even at 5 percent free volume per day, leakage would be negligible during the short time period being considered).

2. Drywell and wetwell pressure equal (maintained equal by the vacuum breakers between the wetwell and drywell).

3. Torus air temperature equal to pool water temperature.

4. Drywell temperature during reactor core isolation cooling equal to 110°F, 20 percent rh (very conservative estimates).

5. Initial drywell conditions: 150°F, 0 psig, 100 percent rh

Actually, Assumption 4 and 5 are contradictory. If the heat load during normal operation is large enough to cause a drywell temperature of 150°F and a relative humidity of 100 percent, the air coolers would not be capable of reducing the drywell temperature to 110°F during RCIC operation. Such a heat load implies a small steam leak from the primary system.

This RCIC NPSH evaluation is based on very conservative assumptions for drywell and wetwell conditions during RCIC operation. The drywell atmosphere is assumed to be cooled and dehumidified down to 110°F at 20% rh by operation of the drywell coolers. The wetwell is in thermal equilibrium with the suppression pool, but the drywell and wetwell pressures are equalized due to the drywell vacuum breakers. The reactor is assumed to be scrammed at a suppression pool temperature of 110°F and depressurized when the pool reaches 120°F per the Technical Specifications. Due to the fixed drywell temperature at low humidity and the pressure equalization between the drywell and wetwell, the resulting containment pressure is minimized to a level only slightly above atmospheric pressure.

Figure 14.5-11 plots the NPSH available versus suppression pool temperature and show that there is NPSH margin at pool temperatures up to at least 175°F. The RCIC System is specified for continuous operation up to a suppression pool temperature of 140°F; however, short term operation at up to 170°F is also considered for system design since this represents the temperature at the end of a reactor depressurization that begins at 120°F. Figure 14.5-12 plots the containment pressure and a suppression pool temperature profile for a postulated controlled cooldown and depressurization of the reactor. The peak suppression pool temperature at the end of the reactor depressurization is 163°F, which is well within the range for which sufficient NPSH is available.

Assumptions regarding initial pool temperature, heat sink temperature, and decay heat have a minor effect on this peak pool temperature. The predominant effect on pool temperature is the fixed assumptions of reactor shutdown at 110°F and depressurization at 120°F which ensure the suppression pool temperature will not exceed 170°F during the depressurization.

The conservative assumption that pump NPSH required is 28 feet makes this RCIC analysis bounding for both the RCIC and HPCI pumps for operation through vessel depressurization to less than 200 psig.

Vessel depressurization to 200 psig allows the LPCI and/or Core Spray System to maintain core cooling. The NPSH evaluations for RCIC operation is inherently more limiting than for HPCI since during RCIC operation, there is no assumption of a steam leak to heatup and pressurize the drywell. As can be seen in Figure 14.5-11, there is significantly more NPSH available than required for suppression pool temperatures up to 170°F. Therefore, it can be concluded that adequate NPSH will be available during RCIC and HPCI operation.

14.5.3.1.4 Metal Water Reaction Effects on the Primary Containment

If Zircaloy in the reactor core is heated to temperatures above 2,000°F in the presence of steam, a chemical reaction occurs in which zirconium oxide and hydrogen are formed. This is accompanied by an energy release of about 2,800 Btu/lb of zirconium reacted. The energy produced is accommodated in the suppression chamber pool. The hydrogen formed, however, will result in an increased drywell pressure due simply to the added volume of gas in the fixed containment volume. Although very small quantities of hydrogen are produced during the accident, the containment has the inherent ability to accommodate a much larger amount as discussed.

The basic approach to evaluating the capability of a Containment System with a given Containment System spray design is to assume that the energy and gas are liberated from the reactor vessel over some time period. The rate of energy release over the entire duration of the release is arbitrarily taken as uniform, since the capability curve serves as a capability index only, and is not based on any given set of accident conditions as an accident performance evaluation might be.

It is conservatively assumed that the suppression pool is the only body in the system which is capable of storing energy. The considerable amount of energy storage which would take place in the various structures of the containment is neglected. Hence, as energy is released from the core region, it is absorbed by the suppression pool. Energy is removed from the pool by heat exchangers which reject heat to the station cooling systems. Because the energy release is taken as uniform and the service water temperature and system flow rates are constant, the temperature responses of the pool can be determined. It is assumed that the suppression chamber gases are at the suppression chamber water temperature.

The metal water reaction during core heatup is calculated by the core heatup model described in Appendix R.5. The extent of the metal water reaction thus calculated is less than 0.1 percent of all the zirconium in the core. As an index of the containment's ability to tolerate postulated metal water reactions, the concept of "Containment Capability" is used. Since this capability depends on the time domain, the duration over which the metal water reaction is postulated to occur is one of the parameters used.

Containment capability is defined as the maximum percent of fuel channels and fuel cladding material which can enter into a metal water reaction during a specified duration without exceeding the maximum allowable pressure of the containment. To evaluate the containment capability, various percentages of metal-water reaction are assumed to take place over certain time periods. This analysis presents a method of measuring system capability without requiring prediction of the detailed events in a particular accident condition.

Since the percent metal water reaction capability varies with the duration of the uniform energy and gas release, the percent metal water reaction capability is plotted against the duration of release. This constitutes the containment capability curves as shown on Figure 14.5-14. All points below the curves represent a given metal water reaction and a given duration which will result in a containment peak pressure which is below the maximum allowable pressure. The calculations are made at the end of the energy release duration because the number of moles of gases in the system is then at a maximum, and the suppression pool temperature is higher at this time than at any other time during the energy release.

It should be noted that the curves are actually derived from separate calculations of two conditions: the steaming and the non-steaming situations. The minimum amount of metal water reaction which the containment can tolerate for a given duration is given to the condition where all of the noncondensible gases are stored in the suppression chamber. This condition assumes that steaming from the drywell to the suppression chamber results in washing all of the noncondensible gases into the suppression chamber. This is shown as the flat portion of the containment capability characteristic curve. Activation of containment sprays condense the drywell steam so that no steaming occurs, thus allowing noncondensibles to also be stored in the drywell. This is denoted by the rising spray curve. The intersection between the no spray curve and the spray curve represents the duration and metal water reaction energy release which just raises all the spray water to the saturation temperature at the maximum allowable containment pressures.

For durations to the left of the intersection some steam is generated and all the gases are stored in the suppression chamber. For durations to the right of the intersection, the spray flow is subcooled as it exits from the drywell by increasing amounts as the duration is increased.

The energy release rate to the containment is calculated as follows:

$$qin = \frac{Qo + Qmw + Qs}{T_D}$$

Where:

qin = Arbitrary energy release rate to the containment, Btu/sec

Qo = Integral of decay power over selected duration of energy gas release, Btu

Qmw = Total chemical energy released exothermically from selected metal-water reaction, Btu

Qs = Initial internal sensible energy of core fuel and cladding, Btu

T_D = Selected duration of energy and gas release, sec

The total chemical energy released from the metal water reaction is proportional to the percent metal water reaction. The initial internal sensible energy of the core is taken as the difference between the energy in the core after the blowdown and the energy in the core at a datum temperature of 250°F.

The temperature of the drywell gas is found by considering an energy balance on the spray flows through the drywell as described in Appendix R.5.

Based upon the drywell gas temperature, suppression chamber gas temperature, and the total number of moles in the system, as calculated above, the containment pressure is determined. The containment capability curves on Figure 14.5-14 present the results of the parametric investigation.

14.5.3.2 Radiological Consequences

14.5.3.2.1 Loss of Coolant Accident Assumption

1. The reactor has operated for an extended period at 1,998 MWt. To account for power measurement uncertainty, a 2% allowance was added.

2. One hundred percent of the noble gases and 25 percent of the iodine in the core instantaneously become available for leakage from the primary containment.

3. The primary containment leak rate is a constant 1.25 percent/day for 30 days.

4. For radiological dose considerations, release to the atmosphere was assumed to occur via drywell leakage, main steam isolation valve (MSIV) leakage, and emergency core cooling system (ECCS) leakage. Drywell and ECCS Leakage, flows through the Standby Gas Treatment System without the inherent benefit of mixing in the Secondary Containment Building, and is released to the environment via the Main Stack. Main steam isolation valve leakage is a ground level, unfiltered release through the condenser and high pressure turbine.

5. Ninety-nine percent of the iodine entering the Standby Gas Treatment System is retained by the charcoal filters.

6. Atmosphere dispersion factors were based on Regulatory Guide 1.145 models.

7. The breathing rate is 347 cm^3/sec for the first 8 hr, 175 cm^3/sec for the next 16 hr, and 232 cm^3/sec thereafter.

14.5.3.2.2 Analytical Results

Radiological consequences for the loss of coolant accident based on the above assumptions are given in Table 14.5-2.

14.5.4 Main Steam Line Break Accident

The analysis of the main steam line break accident depends on the operating thermal-hydraulic parameters of the overall reactor (such as pressure) and overall factors affecting the consequences (such as primary coolant activity). Insertion of reload fuel does not change any of these parameters. Therefore the analyses presented for the initial core remains applicable. The results of this analysis based on the initial core thermal-hydraulic basis are given in Appendix R.3.5. The results of the coolant loss and radiological consequences are given below. The loss of coolant due to a main steam line break accident evaluation was not performed for the Pilgrim 10 CFR 50 Appendix K power uprate (1.5% of 1,998 MWt at constant pressure). All safety and operational aspects of MSIV and steam flow restrictors performance are within pre-power uprate evaluations.

14.5.4.1 Coolant Loss Analysis

The steam flow rate through the upstream side of the break increases from the initial value of 550 lb/sec in the line to 1,100 lb/sec (about 200 percent of rated flow for one steam line) with critical flow initially occurring at the flow restrictor. The steam flow rate was calculated using an ideal nozzle model. That the flow model predicts the behavior of the flow limiter has been substantiated by tests conducted on a scale model over a variety of pressure, temperature, and moisture conditions.

The steam flow rate through the downstream side of the break consists of equal flow components from each of the unbroken lines. In each of the unbroken lines, the steam flow rate increases from an initial value of 550 lb/sec to 1,100 lb/sec. Critical flow would be occurring at the flow limiters in these lines.

The total steam flow rate leaving the vessel is thus approximately 4,500 lb/sec, which is in excess of the steam generation rate of 2,200 lb/sec. The steam flow steam generation mismatch causes an initial depressurization of the reactor vessel at a rate of 45 psi/sec. The formation of bubbles in the reactor vessel water causes a rapid rise in the water level. The analytical model used to calculate level rise predicts a rate of rise of about 6 ft/sec. Thus, the water level reaches the vessel steam nozzles at 2 to 3 sec after the break. From that time on a two phase mixture is discharged from the break as shown on Figure 14.5-15. The two phase flow rates are determined by vessel pressure and mixture enthalpy.[4] The vessel depressurization is calculated using a digital computer model in which the reactor vessel is divided into nine major nodes. The model includes the flow resistance between nodes, as well as heat addition from the core.

As shown on Figure 14.5-15, two phase flow is discharged through the break at an almost constant rate until late in the transient. This is the result of not taking credit for the effect of valve closure on flow rate until isolation valves are far enough closed to establish critical flow at the valve locations. The linear decrease in discharge flow rate at the end of the transient is the result of the assumption regarding the effect of valve closure on flow rate after critical flow is established at the valve location.

The following total masses of steam and liquid are discharged through the break prior to isolation valve closure:

Steam	25,000 lb
Liquid	60,000 lb

14.5.4.2 Radiological Consequences

14.5.4.2.1 Steam Line Break Accident Assumptions (Ground Level Release)

1. The reactor has operated for an extended period at 1,998 MWt. To account for power measurement uncertainty, a 2% allowance was added.

2. The concentrations of radionuclides in the reactor water are those corresponding to the maximum reactor coolant iodine concentration permitted by plant Technical Specifications.

3. The total mass of steam and water released from the steam line contains concentrations of radionuclides identical with those in the reactor water.

4. All of the radionuclides contained in the steam and water mass released from the steam line are released to the atmosphere from the top of the Turbine Building. All the radioactivity was assumed to be released to the environment as a puff release.

5. It is assumed that there is no thermal rise of the steam cloud.

6. Atmospheric relative concentration values were based on Regulatory Guide 1.145 models.

7. The breathing rate is 347 cm^3/sec.

14.5.4.2.2 Analytical Results

Radiological consequences for the steam line break accident based on the above assumptions are given in Table 14.5-2.

14.5.5 Fuel Handling Accident

Accidents that result in the release of radioactive materials directly to the containment can occur when the drywell is open. A survey of the various conditions that could exist when the drywell is open reveals that the greatest potential for the release of radioactive material occurs when the drywell head and reactor vessel head have been removed. In this case, radioactive material released as a result of fuel failure is available for transport directly to the containment.

Various mechanisms for fuel failure under this condition have been investigated. With the current fuel design the refueling interlocks, which impose restrictions on the movement of refueling equipment and control rods, prevent an inadvertent criticality during refueling operations. In addition, the reactor protection system can initiate a reactor scram in time to prevent fuel damage for errors or malfunctions occurring during planned criticality tests with the reactor vessel head off. It is concluded that the only accident that could result in the release of significant quantities of fission products to the containment during this mode of operation is one resulting from the accidental dropping of a fuel bundle onto the top of the core.

This event occurs under non-operating conditions for the fuel. The key assumption of this postulated occurrence is the inadvertent mechanical damage to the fuel rod cladding as a consequence of the fuel bundle being dropped on the core in the cold condition. Therefore, fuel densification considerations do not enter into or affect the accident results.

14.5.5.1 Sequence of Events

The assumptions and analyses applicable to this type of fuel handling accident are described below.

(1) The fuel assembly is dropped from 32.95 feet (the maximum height allowed by the fuel handling equipment).

(2) The entire amount of potential energy, including the energy of the entire assemblage falling to its side from a vertical position (referenced to the top of the reactor core), is available for application to the fuel assemblies involved in the accident. This assumption neglects the dissipation of some of the mechanical energy of the falling fuel assembly in the water above the core and requires that the grapple cable break, allowing the grapple head and three sections of the telescoping mast to remain attached to the falling assembly.

(3) None of the energy associated with the dropped fuel assembly is absorbed by the fuel material (uranium dioxide).

(4) All fuel rods, including tie rods, were assumed to fail by 1% strain in compression, the same mode as ordinary fuel rods. For the fuel designs considered here, there is no propensity for preferential failure of tie rods.

14.5.5.2 Fuel Damage

Because of the complex nature of the impact and the resulting damage to fuel assembly components, a rigorous prediction of the number of failed rods is not possible. For this reason, a simplified energy approach was taken and numerous conservative assumptions were made to assure a conservative estimate of the number of failed rods.

The number of failed fuel rods was determined by balancing the energy of the dropped assemblage against the energy required to fail a rod. The wet weight of the dropped bundle is 617 pounds and the wet weight of the grapple component is 350 pounds. The drop distance is 32.95 feet. The total energy to be dissipated by the first impact is

$$E = (617 + 350)\ (32.95) = 31{,}870 \text{ ft-lb}$$

One half of the energy was considered to be absorbed by the falling assembly and one half by the four impacted assemblies.

No energy was considered to be absorbed by the fuel pellets (i.e., the energy was absorbed entirely by the non-fuel components of the assemblies). The energy available for clad deformation was considered to be proportional to the mass ratio:

$$\frac{\text{mass of cladding}}{(\text{mass of assembly} - \text{mass of fuel pellets})}$$

and is equal to a maximum of 0.519 for the fuel designs considered here.

The energy absorbed by the cladding of the four impacted assemblies is

$$(15{,}935 \text{ ft-lb})\ (0.519) = 8270 \text{ ft-lb}$$

Each 7x7 or 8x8 assembly rod that fails is expected to absorb approximately 250 ft-lb before cladding failure, based on uniform 1% plastic deformation of the cladding. The energy required to fail a fuel rod depends on the cladding thickness and is smaller for 9x9 and 10x10 designs.

The number of rods failed in the impacted assemblies is

$$N_F = \frac{(8270 \text{ ft-lb})}{(250 \text{ ft-lb})} = 33 \text{ rods}$$

The dropped assembly was considered to impact at a small angle, subjecting all the fuel rods in the dropped assembly to bending moments. The fuel rods are expected to absorb little energy prior to failure as a result of bending. For this reason, it was assumed that all the rods in the dropped assembly fail. The total number of failed rods on initial impact was 62 + 33 = 95.

The assembly was assumed to tip over and impact horizontally on the top of the core. The remaining available energy was used to predict the number of additional rod failures. The available energy was calculated by assuming a linear weight distribution in the assembly with a point load at the top of the assembly to represent the fuel grapple weight.

$$E = W_G H_G + \int_0^{H_B} \frac{W_B}{H_B} y \, dy = W_G H_G + \frac{1}{2} W_B H_B$$

$$= (350 \text{ lb}) \frac{160}{12} + \frac{1}{2} (617) \frac{160}{12} = 8780 \text{ ft-lb}$$

As before, the energy was considered to be absorbed equally by the falling assembly and the impacted assemblies. The fraction available for clad deformation was 0.519. The energy available to deform clad in the impacted assemblies was

$$E_c = (0.50)\ (8780 \text{ ft-lb})\ (0.519) = 2278 \text{ ft-lb}$$

and the number of failures in the impacted assemblies was

$$N_F = \frac{(2278 \text{ ft-lb})}{(250 \text{ ft-lb})} = 9 \text{ rods}$$

Since the rods in the dropped assembly were considered to have failed in the initial impact, the total failed rods in both impacts are 95 + 9 = 104.

Both the GE8x8EB and the GE8x8NB fuel designs contain 2 fewer fuel rods than the 62 fuel rods assumed in the preceding analysis. Hence, this analysis is conservatively bounding for these fuel types.

The number of rods assumed failed in a Fuel Handling Accident for GE11, GE14, and GNF2 are obtained from the GESTAR Amendment 22 Reports. For GE11, 123 rods are calculated to fail per Ref. 25. For GE14, 151 rods are calculated to fail per Ref. 26. For GNF2 fuel, 150 rods are calculated to fail per Ref. 27.

14.5.5.3 Radiological Consequences

The Fuel Handling Accident (FHA) could occur inside the open reactor vessel or, inside the spent fuel pool, both of which are located inside the reactor building, during shutdown refueling operations.

Of the two possible FHA's, it is the FHA occurring inside the open reactor vessel that would be expected to release more radioactive gaseous material from the gap spaces of fuel bundles containing damaged cladding of spent fuel rods.

14.5.5.3.1 Method and Assumptions

The DBA FHA analysis uses the AST guidelines outlined in NUREG-1465 (Reference 21), Regulatory Guide 1.183 (Reference 22), and Regulatory Guide 1.194 (Reference 23).

The following assumptions and initial conditions are used in calculating the fission product release to the environment:

(a) The accident is assumed to occur 24 hours after shutdown.

(b) The FHA results in 151 rods failing, and the release to the environment from the refueling floor occurs within 2 hours.

(c) A decontamination factor (DF) of 200 was assumed for the scrubbing effects of water on halogen activity release. The DF was based on a minimum of 23 feet of water over the dropped assembly. No DF was applied to noble gases and the DF for other radionuclides were assumed to be infinite.

(d) The core inventory was based on a thermal power level of 2028 MW_t, plus a measurement uncertainty of 0.5% (2038 MW_t). A radial peaking factor of 2.1 was used. The bounding core and FHA inventories are given in Table 14.5-4.

(e) All activity within the gaps of the failed fuel rods is released to the refueling cavity water. The released activity corresponds to 8% of the entire inventory of I-131 in the rods, 10% of the Kr-85, 5% of the remaining halogens and noble gases, and 12% of the alkalis (Cs and Rb).

(f) The reactor building is assumed to be open during the refueling operations, with the normal ventilation on, such that all releases to the environment would be via the reactor building vent.

(g) 5 years of hourly meteorological data was used for atmospheric dispersion factors as shown in Table 14.5-4A.

(h) The control room ventilation system was assumed to remain in the normal operating mode during the entire exposure interval (30 days).

(i) Breathing rates, and control room occupancy factors are as given in Reg. Guide 1.183.

(j) The control room air intake rate was assumed to be 1000 cfm (a low value), and 9000 cfm (a high value).

14.5.5.3.2 Results

The dose evaluations of the postulated fuel handling accident are summarized in Table 14.5-5 and demonstrate that the calculated TEDE values to the control room, EAB, and LPZ are less than the limits set forth in 10CFR50.67 and Reg. Guide 1.183. Reference 24 contains the dose consequences for the Fuel Handling Accident.

14.5.6 Radwaste System Accidents

The reactor building, the radwaste building, and the turbine building contain systems which have significant amounts of radioactive materials. The reactor building, the radwaste building, and the turbine building, where they house or support Class I equipment, are Class I. The condenser hotwell, the offgas system piping, the monitor tanks, the treated water holdup tanks, and the condensate storage tanks contain significant amounts of liquid or gaseous radioactivity not enclosed in a Class I structure. This response analyzes the effects, which would result from the failure of the condenser hotwell, of the offgas system piping (rupture disk failure), or of any radwaste system tank.

14.5.6.1 Assumptions

The following assumptions are made in evaluating the potential effects resulting from condenser hotwell or Radwaste System tank failures inside the Radwaste and Turbine building. This analysis is not based on TID-14844 source terms.

1. The maximum activity concentrations in the reactor water and in the radwaste tanks are those expected, assuming offgas stack release rate of 100,000 microcuries/sec after 30 min holdup and, for the Radwaste System, normal daily liquid volume.

2. The activity concentrations in the condenser hotwell are based upon a reactor water steam separation factor of 10^{+4}.

3. The iodine activity concentration in a Radwaste System tank is equal to the ratio of the iodine activity concentration to total reactor water activity concentration after 8 hr decay, multiplied by the maximum activity concentration in the inlet stream to the particular tank.

4. The partition coefficient, the ratio of the iodine concentration in the liquid phase to the iodine concentration in the gas phase at equilibrium, equals $4.43 \times 10^{+5}$ based upon a pH of 7.0, a temperature of 25°C and a total iodine concentration of less than 1×10^{-9} moles /1.[5] Expected iodine concentrations are at least two orders of magnitude less.

5. The partition coefficient is constant and does not increase with decreasing concentration of iodine in the liquid phase.

6. Instantaneous dynamic equilibrium is maintained between the gaseous and liquid phases. The equilibrium exists between the release liquid and the net free volume of the Radwaste Turbine Building basement area; or between the condenser hotwell condensate and condenser compartment net free volume.

7. The area ventilation fans continue exhausting through the Reactor Building vent at full capacity, resulting in one air change every 6.5 min from the Radwaste Turbine Building basement area and one air change every 10 min from the condenser compartment.

8. An airborne iodine reduction factor of 2 results due to plateout of iodine in the gaseous phase.

9. All releases except from offgas piping failure occur during the following meteorological conditions:

   a. For the first 8 hr, Pasquill Type F, 1 m/s, nonvarying wind direction and a volumetric building wake correction factor of c = 1/2 used with the cross sectional area of the structure with a maximum building wake reduction factor of 1/3

   b. From 8 to 24 hr, Pasquill Type F, 1 m/s with plume meander in a 22 1/2 degree sector

   c. From 1 to 4 days, Pasquill Type F and 2 m/s with a frequency of 60 percent, Pasquill Type D 3 m/s with a frequency of 40 percent with a meander in the same 22 1/2 degree sector

   d. From 4 to 30 days, Pasquill Types C, D, and F each occurring 33 1/3 percent of the time with wind speeds of 3 m/s, 3 m/s, and 2 m/s, respectively, with meander in the same 22 1/2 degree sector 33 1/3 percent of the time

10. A breathing rate of 3.47×10^{-4} m3/s for the first 8 hr, $1.75 \times 10^{-4} m^3/s$ from 8 to 24 hr and $2.32 \times 10^{-4} m^3/s$ thereafter is assumed.

11. The effective release height is 30 m with downwash occurring.

12. No credit is taken for radioactive decay in the environment.

14.5.6.2 Radiological Effects

The above assumptions have been chosen to maximize the initial activities, and overestimate the release rates, total releases, and total doses.

Consider first the failure of the condenser hotwell, or a Radwaste System tank. Each set of tanks is surrounded by waterproof shield walls designed to contain the spillage from the failure of one tank in the immediate vicinity until the liquid can be pumped into another tank. The floors in the Radwaste Turbine Building basement area are sloped such that gross tankage failure in that area, if assumed, would result in fluid flow in direction of the Radwaste Building and the Class I portions of the Turbine Building. Thus, all released liquid from tank failure in that area could be assumed to be contained and enclosed by a Class I structure. Also, the release of radioactivity from the condenser hotwell or a tank failure directly into the environment through the ground water is prevented or minimized by the PVC, waterproof membrane which encloses and forms a continuous seal around the Turbine Building, Reactor Building and Radwaste Building footings below grade and by the hydrostatic head exerted on the foundations by the ground water. The primary release of radionuclides to the environment would be due to the release of gaseous iodine in chemical equilibrium with iodine in the liquid phase of the spillage.

During normal operation, Radwaste System tanks containing high activity liquids are vented directly into the Radwaste Exhaust system and tanks containing low activity liquids, such as the monitor tanks and the treated water holdup tanks are vented directly into their immediate areas which are vented into the Radwaste Ventilation Exhaust System. All Radwaste Building Ventilation System air passes through one of two parallel sets of high efficiency particulate air (HEPA) filter trains and is released through the Reactor Building exhaust vent stack.

The iodine activity released to the Ventilation Exhaust System during normal station operation or from spillage following an assumed tank or condenser hotwell failure is a function of the partition coefficient which is the ratio of the iodine concentration in the liquid phase to the iodine concentration in the gas phase at equilibrium. Because iodine undergoes a series of hydrolysis reactions, the partition coefficient is a function of solution temperature, pH, and concentration. The partition coefficient is not a function of the container, thus the coefficient existing prior to the hypothetical tank failure would continue to be appropriate after the failure.

The calculation model developed to determine the release of iodine from spillage to the air above after postulated tank failure assumes that an instantaneous equilibrium exists between the iodine in the liquid and gaseous phases. Solution of the simultaneous coupled differential equations resulting from the differential activity balances across the liquid gas interface, and between the Radwaste Turbine Building basement air and the environment, yields the total iodine activity released to the environment as a function of time.

Solutions to the differential equations show that the release rate to the environment increases with increasing activity and/or volume of the gaseous phase, and decreases with increasing liquid volume, and with time. Thus the maximum release rate results from the failure of one tank containing a maximum activity in a minimum liquid volume. Application of the assumption that an iodine equilibrium condition exists between the released liquid and the total free volume of the Radwaste Turbine Building basement area yields extremely conservative releases, since the released liquid would normally be contained by the waterproof shield walls, and thus would not have the large surface area with which to communicate and establish equilibrium with the total net free volume of the area.

The resulting maximum iodine release rates, total release, and total doses are shown on Table 14.5-3 for various tank failures and the condenser hotwell failures. The maximum iodine release rate is within the Technical Specification limits for releases from the building exhaust vent.

The dose consequences for the failure of the offgas piping is no more than 2.5 REM total body applied over a 2 hour period at the Exclusion Area Boundary. This limit was endorsed by the NRC in their acceptance of Pilgrim's limit of 500,000 micro curies per second (referenced to a 30 minute hold-up) of noble gases at the steam jet air ejector contained in the Amendment 89 (Reference 15).

The Safety Evaluation Report contained in Reference 15 endorsed Pilgrim's use of the NRC guidance contained in NUREG-0133 to meet the intent of NUREG-0473. In Pilgrim's analysis (Reference 18) an air ejector discharge line break is assumed to release the discharge from the air ejectors for one hour, and from the hold up line and process piping downstream of the break for 2 hours.

The other source of low level activity not enclosed in a Class I structure is the water in the condensate storage tanks. As a worst case, simultaneous nonmechanistic failure of both condensate storage tanks was assumed. Station yard layout and design dictates that the direction of unrestrained surface flow will be towards the intake canal, through the armor stone, and onto the surface of the salt water in the intake canal. The rate and extent of vertical dilution is a function of the relative temperatures and densities of sea water and condensate storage water. The total volume of sea water into which the condensate storage tank would be diluted is a function of: 1) the prevailing wind direction and speed; 2) the wave action inside the intake canal; 3) the tidal cycle; 4) whether or not the circulating water pumps are operating; and 5), the relative temperatures of the ambient air, the sea water, and the condensate storage tank water. Calculations were performed to determine the whole body dose resulting from 30.5 cm, 7.63 cm, and 1 cm, layers of undiluted condensate storage tank water supported by a thermocline between it and the colder salt water below. The estimated doses at the surface of the water were 2.4 x 10^{-2} mrem/hr, 1.4 x 10^{-2} mrem/hr, and 0.3 x 10^{-2} mrem/hr, respectively. These dose rates would be reduced as mixing and dilution occur in the intake channel due to the effects noted previously.