PSE&G Public Service Electric and Gas Company

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Robert L. Mittl General Manager
Nuclear Assurance and Regulation

September 21, 1984

Director of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
7920 Norfolk Avenue
Bethesda, MD 20814

Attention: Mr. Albert Schwencer, Chief
Licensing Branch 2
Division of Licensing

Gentlemen:

HOPE CREEK GENERATING STATION
DOCKET NO. 50-354
DRAFT SAFETY EVALUATION REPORT
OPEN ITEM STATUS

Attachment 1 is a current list which provides a status of the open items identified in Section 1.7 of the Draft Safety Evaluation Report (SER). Items identified as "complete" are those for which PSE&G has provided responses and no confirmation of status has been received from the staff. We will consider these items closed unless notified otherwise. In order to permit timely resolution of items identified as "complete" which may not be resolved to the staff's satisfaction, please provide a specific description of the issue which remains to be resolved.

Attachment 2 is a current list which identifies Draft SER Sections not yet provided.

Enclosed for your review and approval (see Attachment 4) are the resolutions to the Draft SER open items listed in Attachment 3.

In addition, pursuant to discussions held on September 20, 1984, between PSE&G and NRC Licensee Qualification Branch, enclosed (see Attachment 5), is revised proposed HCGS Technical Specifications. This information supersedes the proposed HCGS Technical Specifications transmitted on September 14, 1984, and supplements the information contained in FSAR Section 13.4.

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FSAR Section 13.4 will be modified in Amendment 8 to address the attached technical specification requirements.

Also, enclosed (see Attachment 6), is Revision 1 to the response to BWR Core Thermal Hydraulic Stability (supersedes 8/12/84 submittal) as requested by the Core Performance Branch.

A signed original of the required affidavit is provided to document the submittal of these items.

Should you have any questions or require any additional information on these items, please contact us.

Very truly yours,

R J [illegible]

Attachments/Enclosure

C D. H. Wagner
USNRC Licensing Project Manager (w/attach.)

W. H. Bateman
USNRC Senior Resident Inspector (w/attach.)

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION
DOCKET NO. 50-354

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Public Service Electric and Gas Company hereby submits the enclosed responses to DSER open items, proposed Technical Specifications pursuant to Final Safety Analysis Report Section 13.4 and response to BWR Core Thermal Hydraulic Stability for the Hope Creek Generating Station.

The matters set forth in this submittal are true to the best of my knowledge, information, and belief.

Respectfully submitted,

Public Service Electric
and Gas Company

By: Thomas J. Martin
Thomas J. Martin
Vice President -
Engineering and Construction

Sworn to and subscribed
before me, a Notary Public
of New Jersey, this 21st day
of September 1984.

David K. Burd

DAVID K. BURD
NOTARY PUBLIC OF NEW JERSEY
My Comm. Expires 10-23-85

MC 28 02

DATE: 9/21/84

ATTACHMENT 1

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
1	2.3.1	Design-basis temperatures for safety-related auxiliary systems	Complete	8/15/84
2a	2.3.3	Accuracies of meteorological measurements	Complete	8/15/84 (Rev. 1)
2b	2.3.3	Accuracies of meteorological measurements	Complete	8/15/84 (Rev. 1)
2c	2.3.3	Accuracies of meteorological measurements	Complete	8/15/84 (Rev. 2)
2d	2.3.3	Accuracies of meteorological measurements	Complete	8/15/84 (Rev. 2)
3a	2.3.3	Upgrading of onsite meteorological measurements program (III.A.2)	Complete	8/15/84 (Rev. 2)
3b	2.3.3	Upgrading of onsite meteorological measurements program (III.A.2)	Complete	8/15/84 (Rev. 2)
3c	2.3.3	Upgrading of onsite meteorological measurements program (III.A.2)	NRC Action	
4	2.4.2.2	Ponding levels	Complete	8/03/84
5a	2.4.5	Wave impact and runup on service water intake structure	Complete	9/13/84 (Rev. 3)
5b	2.4.5	Wave impact and runup on service water intake structure	Complete	9/13/84 (Rev. 3)
5c	2.4.5	Wave impact and runup on service water intake structure	Complete	7/27/84
5d	2.4.5	Wave impact and runup on service water intake structure	Complete	9/13/84 (Rev. 3)
6a	2.4.10	Stability of erosion protection structures	Complete	8/20/84
6b	2.4.10	Stability of erosion protection structures	Complete	8/20/84
6c	2.4.10	Stability of erosion protection structures	Complete	8/03/84

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ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL T A. SCHWENCER LETTER DATED
7a	2.4.11.2	Thermal aspects of ultimate heat sink.	Complete	8/3/84
7b	2.4.11.2	Thermal aspects of ultimate heat sink	Complete	8/3/84
8	2.5.2.2	Choice of maximum earthquake for New England - Piedmont Tectonic Province	Complete	8/15/84
9	2.5.4	Soil damping values	Complete	6/1/84
10	2.5.4	Foundation level response spectra	Complete	6/1/84
11	2.5.4	Soil shear moduli variation	Complete	6/1/84
12	2.5.4	Combination of soil layer properties	Complete	6/1/84
13	2.5.4	Lab test shear moduli values	Complete	6/1/84
14	2.5.4	Liquefaction analysis of river bottom sands	Complete	6/1/84
15	2.5.4	Tabulations of shear moduli	Complete	6/1/84
16	2.5.4	Drying and wetting effect on Vincentown	Complete	6/1/84
17	2.5.4	Power block settlement monitoring	Complete	6/1/84
18	2.5.4	Maximum earth at rest pressure coefficient	Complete	6/1/84
19	2.5.4	Liquefaction analysis for service water piping	Complete	6/1/84
20	2.5.4	Explanation of observed power block settlement	Complete	6/1/84
21	2.5.4	Service water pipe settlement records	Complete	6/1/84
22	2.5.4	Cofferdam stability	Complete	6/1/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
23	2.5.4	Clarification of FSAR Tables 2.5.13 and 2.5.14	Complete	6/1/84
24	2.5.4	Soil depth models for intake structure	Complete	6/1/84
25	2.5.4	Intake structure soil modeling	Complete	8/10/84
26	2.5.4.4	Intake structure sliding stability	Complete	8/20/84
27	2.5.5	Slope stability	Complete	6/1/84
28a	3.4.1	Flood protection	Complete	8/30/84 (Rev. 1)
28b	3.4.1	Flood protection	Complete	8/30/84 (Rev. 1)
28c	3.4.1	Flood protection	Complete	8/30/84 (Rev. 1)
28d	3.4.1	Flood protection	Complete	8/30/84 (Rev. 1)
28e	3.4.1	Flood protection	Complete	8/30/84 (Rev. 1)
28f	3.4.1	Flood protection	Complete	7/27/84
28g	3.4.1	Flood protection	Complete	7/27/84
29	3.5.1.1	Internally generated missiles (outside containment)	Complete	8/3/84 (Rev. 1)
30	3.5.1.2	Internally generated missiles (inside containment)	Closed (5/30/84-Aux.Sys.Mtg.)	6/1/84
31	3.5.1.3	Turbine missiles	Complete	7/18/84
32	3.5.1.4	Missiles generated by natural phenomena	Complete	7/27/84
33	3.5.2	Structures, systems, and components to be protected from externally generated missiles	Complete	7/27/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
34	3.6.2	Unrestrained whipping pipe inside containment	Complete	7/18/84
35	3.6.2	ISI program for pipe welds in break exclusion zone	Complete	6/29/84
36	3.6.2	Postulated pipe ruptures	Complete	6/29/84
37	3.6.2	Feedwater isolation check valve operability	Complete	8/20/84
38	3.6.2	Design of pipe rupture restraints	Complete	8/20/84
39	3.7.2.3	SSI analysis results using finite element method and elastic half-space approach for containment structure	Complete	8/3/84
40	3.7.2.3	SSI analysis results using finite element method and elastic half-space approach for intake structure	Complete	8/3/84
41	3.8.2	Steel containment buckling analysis	Complete	6/1/84
42	3.8.2	Steel containment ultimate capacity analysis	Complete	8/20/84 (Rev. 1)
43	3.8.2	SRV/LOCA pool dynamic loads	Complete	6/1/84
44	3.8.3	ACI 349 deviations for internal structures	Complete	6/1/84
45	3.8.4	ACI 349 deviations for Category I structures	Complete	8/20/84 (Rev. 1)
46	3.8.5	ACI 349 deviations for foundations	Complete	8/20/34 (Rev. 1)
47	3.8.6	Base mat response spectra	Complete	8/10/84 (Rev. 1)
48	3.8.6	Rocking time histories	Complete	8/20/84 (Rev. 1)

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
49	3.8.6	Gross concrete section	Complete	8/20/84 (Rev. 1)
50	3.8.6	Vertical floor flexibility response spectra	Complete	8/20/84 (Rev. 1)
51	3.8.6	Comparison of Bechtel independent verification results with the design-basis results	Complete	8/20/84 (Rev. 2)
52	3.8.6	Ductility ratios due to pipe break	Complete	8/3/84
53	3.8.6	Design of seismic Category I tanks	Complete	8/20/84 (Rev. 1)
54	3.8.6	Combination of vertical responses	Complete	8/10/84 (Rev. 1)
55	3.8.6	Torsional stiffness calculation	Complete	6/1/84
56	3.8.6	Drywell stick model development	Complete	8/20/84 (Rev. 1)
57	3.8.6	Rotational time history inputs	Complete	6/1/84
58	3.8.6	"O" reference point for auxiliary building model	Complete	6/1/84
59	3.8.6	Overturning moment of reactor building foundation mat	Complete	8/20/84 (Rev. 1)
60	3.8.6	BSAP element size limitations	Complete	8/20/84 (Rev. 1)
61	3.8.6	Seismic modeling of drywell shield wall	Complete	6/1/84
62	3.8.6	Drywell shield wall boundary conditions	Complete	6/1/84
63	3.8.6	Reactor building dome boundary conditions	Complete	6/1/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
64	3.8.6	SSI analysis 12 Hz cutoff frequency	Complete	8/20/84 (Rev. 1)
65	3.8.6	Intake structure crane heavy load drop	Complete	6/1/84
66	3.8.6	Impedance analysis for the intake structure	Complete	8/10/84 (Rev. 1)
67	3.8.6	Critical loads calculation for reactor building dome	Complete	6/1/84
68	3.8.6	Reactor building foundation mat contact pressures	Complete	6/1/84
69	3.8.6	Factors of safety against sliding and overturning of drywell shield wall	Complete	6/1/84
70	3.8.6	Seismic shear force distribution in cylinder wall	Complete	6/1/84
71	3.8.6	Overturning of cylinder wall	Complete	6/1/84
72	3.8.6	Deep beam design of fuel pool walls	Complete	6/1/84
73	3.8.6	ASHSD dome model load inputs	Complete	6/1/84
74	3.8.6	Tornado depressurization	Complete	6/1/84
75	3.8.6	Auxiliary building abnormal pressure	Complete	6/1/84
76	3.8.6	Tangential shear stresses in drywell shield wall and the cylinder wall	Complete	6/1/84
77	3.8.6	Factor of safety against overturning of intake structure	Complete	8/20/84 (Rev. 1)
78	3.8.6	Dead load calculations	Complete	6/1/84
79	3.8.6	Post-modification seismic loads for the torus	Complete	8/20/84 (Rev. 1)

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
80	3.8.6	Torus fluid-structure interactions	Complete	6/1/84
81	3.8.6	Seismic displacement of torus	Complete	8/20/84 (Rev. 1)
82	3.8.6	Review of seismic Category I tank design	Complete	8/20/84 (Rev. 1)
83	3.8.6	Factors of safety for drywell buckling evaluation	Complete	6/1/84
84	3.8.6	Ultimate capacity of containment (materials)	Complete	8/20/84 (Rev. 1)
85	3.8.6	Load combination consistency	Complete	6/1/84
86	3.9.1	Computer code validation	Complete	8/20/84
87	3.9.1	Information on transients	Complete	8/20/84
88	3.9.1	Stress analysis and elastic-plastic analysis	Complete	6/29/84
89	3.9.2.1	Vibration levels for NSSS piping systems	Complete	6/29/84
90	3.9.2.1	Vibration monitoring program during testing	Complete	7/18/84
91	3.9.2.2	Piping supports and anchors	Complete	6/29/84
92	3.9.2.2	Triple flued-head containment penetrations	Complete	6/15/84
93	3.9.3.1	Load combinations and allowable stress limits	Complete	6/29/84
94	3.9.3.2	Design of SRVs and SRV discharge piping	Complete	6/29/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
95	3.9.3.2	Fatigue evaluation on SRV piping and LOCA downcomers	Complete	6/15/84
96	3.9.3.3	IE Information Notice 83-80	Complete	8/20/84 (Rev. 1)
97	3.9.3.3	Buckling criteria used for component supports	Complete	6/29/84
98	3.9.3.3	Design of bolts	Complete	6/15/84
99a	3.9.5	Stress categories and limits for. core support structures	Complete	6/15/84
99b	3.9.5	Stress categories and limits for core support structures	Complete	6/15/84
100a	3.9.6	10CFR50.55a paragraph (g)	Complete	6/29/84
100b	3.9.6	10CFR50.55a paragraph (g)	Complete	9/12/84 (Rev. 1)
101	3.9.6	PSI and ISI programs for pumps and valves	Complete	9/12/84 (Rev. 1)
102	3.9.6	Leak testing of pressure isolation valves	Complete	9/12/84 (Rev. 1)
103a1	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
103a2	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
103a3	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
103a4	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL A. SCHWENCER LETTER DATE
103a5	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
103a6	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
103a7	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
103b1	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
103b2	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
103b3	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
103b4	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
103b5	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
103b6	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
103c1	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
103c2	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
103c3	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
103c4	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
104	3.11	Environmental qualification of mechanical and electrical equipment	NRC Action	

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
105	4.2	Plant-specific mechanical fracturing analysis	Complete	8/20/84 (Rev. 1)
106	4.2	Applicability of seismic andd LOCA loading evaluation	Complete	8/20/84 (Rev. 1)
107	4.2	Minimal post-irradiation fuel surveillance program	Complete	6/29/84
108	4.2	Gadolina thermal conductivity equation	Complete	6/29/84
109a	4.4.7	TMI-2 Item II.F.2	Complete	8/20/84
109b	4.4.7	TMI-2 Item II.F.2	Complete	8/20/84
110a	4.6	Functional design of reactivity control systems	Complete	8/30/84 (Rev. 1)
110b	4.6	Functional design of reactivity control systems	Complete	8/30/84 (Rev. 1)
111a	5.2.4.3	Preservice inspection program (components within reactor pressure boundary)	Complete	6/29/84
111b	5.2.4.3	Preservice inspection program (components within reactor pressure boundary)	Complete	6/29/84
111c	5.2.4.3	Preservice inspection program (components within reactor pressure boundary)	Complete	6/29/84
112a	5.2.5	Reactor coolant pressure boundary leakage detection	Complete	8/30/84 (Rev. 1)
112b	5.2.5	Reactor coolant pressure boundary leakage detection	Complete	8/30/84 (Rev. 1)

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL A. SCHWENCER LETTER DATE
112c	5.2.5	Reactor coolant pressure boundary leakage detection	Complete	8/30/84 (Rev. 1)
112d	5.2.5	Reactor coolant pressure boundary leakage detection	Complete	8/30/84 (Rev. 1)
112e	5.2.5	Reactor coolant pressure boundary leakage detection	Complete	8/30/84 (Rev. 1)
113	5.3.4	GE procedure applicability	Complete	7/18/84
114	5.3.4	Compliance with NB 2360 of the Summer 1972 Addenda to the 1971 ASME Code	Complete	7/18/84
115	5.3.4	Drop weight and Charpy v-notch tests for closure flange materials	Complete	9/5/84 (Rev. 1)
116	5.3.4	Charpy v-notch test data for base materials as used in shell course No. 1	Complete	7/18/84
117	5.3.4	Compliance with NB 2332 of Winter 1972 Addenda of the ASME Code	Complete	8/20/84
118	5.3.4	Lead factors and neutron fluence for surveillance capsules	Complete	8/20/84
119	6.2	TMI item II.E.4.1	Complete	6/29/84
120a	6.2	TMI Item II.E.4.2	Complete	8/20/84
120b	6.2	TMI Item II.E.4.2	Complete	8/20/84
121	6.2.1.3.3	Use of NUREG-0588	Complete	7/27/84
122	6.2.1.3.3	Temperature profile	Complete	7/27/84
123	6.2.1.4	Butterfly valve operation (post accident)	Complete	6/29/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL : A. SCHWENCER LETTER DATED
124a	6.2.1.5.1	RPV shield annulus analysis	Complete	8/20/84 (Rev. 1)
124b	6.2.1.5.1	RPV shield annulus analysis	Complete	8/20/84 (Rev. 1)
124c	6.2.1.5.1	RPV shield annulus analysis	Complete	8/20/84 (Rev. 1)
125	6.2.1.5.2	Design drywell head differential pressure	Complete	6/15/84
126a	6.2.1.6	Redundant position indicators for vacuum breakers (and control room alarms)	Complete	8/20/84
126b	6.2.1.6	Redundant position indicators for vacuum breakers (and control room alarms)	Complete	8/20/84
127	6.2.1.6	Operability testing of vacuum breakers	Complete	8/20/84 (Rev. 1)
128	6.2.2	Air ingestion	Complete	7/27/84
129	6.2.2	Insulation ingestion	Complete	6/1/84
130	6.2.3	Potential bypass leakage paths	Complete	9/13/84 (Rev. 1)
131	6.2.3	Administration of secondary containment openings	Complete	7/18/84
132	6.2.4	Containment isolation review	Complete	6/15/84
133a	6.2.4.1	Containment purge system	Complete	8/20/84
133b	6.2.4.1	Containment purge system	Complete	8/20/84
133c	6.2.4.1	Containment purge system	Complete	8/20/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
134	6.2.6	Containment leakage testing	Complete	6/15/84
135	6.3.3	LPCS and LPCI injection valve interlocks	Complete	8/20/84
136	6.3.5	Plant-specific LOCA (see Section 15.9.13)	Complete	8/20/84 (Rev. 1)
137a	6.4	Control room habitability	Complete	8/20/84
137b	6.4	Control room habitability	Complete	8/20/84
137c	6.4	Control room habitability	Complete	8/20/84
138	6.6	Preservice inspection program for Class 2 and 3 components	Complete	6/29/84
139	6.7	MSIV leakage control system	Complete	6/29/84
140a	9.1.2	Spent fuel pool storage	Complete	9/7/84 (Rev. 2)
140b	9.1.2	Spent fuel pool storage	Complete	9/7/84 (Rev. 2)
140c	9.1.2	Spent fuel pool storage	Complete	9/7/84 (Rev. 2)
140d	9.1.2	Spent fuel pool storage	Complete	9/7/84 (Rev. 2)
141a	9.1.3	Spent fuel cooling and cleanup system	Complete	8/30/84 (Rev. 1)
141b	9.1.3	Spent fuel cooling and cleanup system	Complete	8/30/84 (Rev. 1)
141c	9.1.3	Spent fuel pool cooling and cleanup system	Complete	8/30/84 (Rev. 1)

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
141d	9.1.3	Spent fuel pool cooling and cleanup system	Complete	8/30/84 (Rev. 1)
141e	9.1.3	Spent fuel pool cooling and cleanup system	Complete	8/30/84 (Rev. 1)
141f	9.1.3	Spent fuel pool cooling and cleanup system	Complete	8/30/84 (Rev. 1)
141g	9.1.3	Spent fuel pool cooling and cleanup system	Complete	8/30/84 (Rev. 1)
142a	9.1.4	Light load handling system (related to refueling)	Complete	8/15/84 (Rev. 1)
142b	9.1.4	Light load handling system (related to refueling)	Complete	8/15/84 (Rev. 1)
143a	9.1.5	Overhead heavy load handling	Complete	9/7/84
143b	9.1.5	Overhead heavy load handling	Complete	9/13/84
144a	9.2.1	Station service water system	Complete	8/15/84 (Rev. 1)
144b	9.2.1	Station service water system	Complete	8/15/84 (Rev. 1)
144c	9.2.1	Station service water system	Complete	8/15/84 (Rev. 1)
145	9.2.2	ISI program and functional testing of safety and turbine auxiliaries cooling systems	Closed (5/30/84-Aux.Sys.Mtg.)	6/15/84
146	9.2.6	Switches and wiring associated with HPCI/RCIC torus suction	Closed (5/30/84-Aux.Sys.Mtg.)	6/15/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
147a	9.3.1	Compressed air systems	Complete	9/21/84 (Rev. 2)
147b	9.3.1	Compressed air systems	Complete	9/21/84 (Rev. 2)
147c	9.3.1	Compressed air systems	Complete	9/21/84 (Rev. 2)
147d	9.3.1	Compressed air systems	Complete	9/21/84 (Rev. 2)
148	9.3.2	Post-accident sampling system (II.B.3)	Complete	9/12/84 (Rev. 1)
149a	9.3.3	Equipment and floor drainage system	Complete	7/27/84
149b	9.3.3	Equipment and floor drainage system	Complete	7/27/84
150	9.3.6	Primary containment instrument gas system	Complete	8/3/84 (Rev. 1)
151a	9.4.1	Control structure ventilation system	Complete	8/30/84 (Rev. 1)
151b	9.4.1	Control structure ventilation system	Complete	8/30/84 (Rev. 1)
152	9.4.4	Radioactivity monitoring elements	Closed (5/30/84-Aux.Sys.Mtg.)	6/1/84
153	9.4.5	Engineered safety features ventilation system	Complete	8/30/84 (Rev 2)
154	9.5.1.4.a	Metal roof deck construction classificiation	Complete	6/1/84
155	9.5.1.4.b	Ongoing review of safe shutdown capability	NRC Action	
156	9.5.1.4.c	Ongoing review of alternate shutdown capability	NRC Action	

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
157	9.5.1.4.e	Cable tray protection	Complete	8/20/84
158	9.5.1.5.a	Class B fire detection system	Complete	6/15/84
159	9.5.1.5.a	Primary and secondary power supplies for fire detection system	Complete	6/1/84
160	9.5.1.5.b	Fire water pump capacity	Complete	8/13/84
161	9.5.1.5.b	Fire water valve supervision	Complete	6/1/84
162	9.5.1.5.c	Deluge valves	Complete	6/1/84
163	9.5.1.5.c	Manual hose station pipe sizing	Complete	6/1/84
164	9.5.1.6.e	Remote shutdown panel ventilation	Complete	6/1/84
165	9.5.1.6.g	Emergency diesel generator day tank protection	Complete	6/1/84
166	12.3.4.2	Airborne radioactivity monitor positioning	Complete	9/13/84 (Rev. 2)
167	12.3.4.2	Portable continuous air monitors	Complete	7/18/84
168	12.5.2	Equipment, training, and procedures for inplant iodine instrumentation	Complete	6/29/84
169	12.5.3	Guidance of Division 8 Regulatory Guides	Complete	7/18/84
170	13.5.2	Procedures generation package submittal	Complete	6/29/84
171	13.5.2	TMI Item I.C.1	Complete	6/29/84
172	13.5.2	PGP Commitment	Complete	6/29/84
173	13.5.2	Procedures covering abnormal releases of radioactivity	Complete	6/29/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	D&ER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL A. SCHWENCER LETTER DATE
174	13.5.2	Resolution explanation in FSAR of TMI Items I.C.7 and I.C.8	Complete	6/15/84
175	13.6	Physical security	Open	
176a	14.2	Initial plant test program	Complete	8/13/84
176b	14.2	Initial plant test program	Complete	9/5/84 (Rev. 1)
176c	14.2	Initial plant test program	Complete	7/27/84
176d	14.2	Initial plant test program	Complete	8/24/84 (Rev. 2)
176e	14.2	Initial plant test program	Complete	7/27/84
176f	14.2	Initial plant test program	Complete	8/13/84
176g	14.2	Initial plant test program	Complete	8/20/84
176h	14.2	Initial plant test program	Complete	8/13/84
176i	14.2	Initial plant test program	Complete	7/27/84
177	15.1.1	Partial feedwater heating	Complete	8/20/84 (Rev. 1)
178	15.6.5	LOCA resulting from spectrum of postulated piping breaks within RCP	NRC Action	
179	15.7.4	Radiological consequences of fuel handling accidents	NRC Action	
180	15.7.5	Spent fuel cask drop accidents	NRC Action	
181	15.9.5	TMI-2 Item II.E.3.3	Complete	6/29/84
182	15.9.10	TMI-2 Item II.K.3.18	Complete	6/1/84
183	18	Hope Creek DCRDR	Complete	8/15/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
184	7.2.2.1.e	Failures in reactor vessel level sensing lines	Complete	8/1/84 (Rev 1)
185	7.2.2.2	Trip system sensors and cabling in turbine building	Complete	6/1/84
186	7.2.2.3	Testability of plant protection systems at power	Complete	8/13/84 (Rev. 1)
187	7.2.2.4	Lifting of leads to perform surveillance testing	Complete	8/3/84
188	7.2.2.5	Setpoint methodology	Complete	8/1/84
189	7.2.2.6	Isolation devices	Complete	8/1/84
190	7.2.2.7	Regulatory Guide 1.75	Complete	6/1/84
191	7.2.2.8	Scram discharge volume	Complete	6/29/84
192	7.2.2.9	Reactor mode switch	Complete	8/15/84 (Rev. 1)
193	7.3.2.1.10	Manual initiation of safety systems	Complete	8/1/84
194	7.3.2.2	Standard review plan deviations	Complete	8/1/84 (Rev 1)
195a	7.3.2.3	Freeze-protection/water filled instrument and sampling lines and cabinet temperature control	Complete	8/1/84
195b	7.3.2.3	Freeze-protection/water filled instrument and sampling lines and cabinet temperature control	Complete	8/1/84
196	7.3.2.4	Sharing of common instrument taps	Complete	8/1/84
197	7.3.2.5	Microprocessor, multiplexer and computer systems	Complete	8/1/84 (Rev 1)

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
198	7.3.2.6	TMI Item II.K.3.18-ADS actuation	Complete	8/20/84
199	7.4.2.1	IE Bulletin 79-27-Loss of non-class IE instrumentation and control power system bus during operation	Complete	8/24/84 (Rev. 1)
200	7.4.2.2	Remote shutdown system	Complete	8/15/84 (Rev 1)
201	7.4.2.3	RCIC/HPCI interactions	Complete	8/3/84
202	7.5.2.1	Level measurement errors as a result of environmental temperature effects on level instrumentation reference leg	Complete	8/3/84
203	7.5.2.2	Regulatory Guide 1.97	Complete	8/3/84
204	7.5.2.3	TMI Item II.F.1 - Accident monitoring	Complete	8/1/84
205	7.5.2.4	Plant process computer system	Complete	6/1/84
206	7.6.2.1	High pressure/low pressure interlocks	Complete	7/27/84
207	7.7.2.1	HELBs and consequential control system failures	Complete	8/24/84 (Rev. 1)
208	7.7.2.2	Multiple control system failures	Complete	8/24/84 (Rev. 1)
209	7.7.2.3	Credit for non-safety related systems in Chapter 15 of the FSAR	Complete	8/1/84 (Rev 1)
210	7.7.2.4	Transient analysis recording system	Complete	7/27/84
211a	4.5.1	Control rod drive structural materials	Complete	7/27/84
211b	4.5.1	Control rod drive structural materials	Complete	7/27/84
211c	4.5.1	Control rod drive structural materials	Complete	7/27/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL A. SCHWENCER LETTER DATE
211d	4.5.1	Control rod drive structural materials	Complete	7/27/84
211e	4.5.1	Control rod drive structural materials	Complete	7/27/84
212	4.5.2	Reactor internals materials	Complete	7/27/84
213	5.2.3	Reactor coolant pressure boundary material	Complete	7/27/84
214	6.1.1	Engineered safety features materials	Complete	7/27/84
215	10.3.6	Main steam and feedwater system materials	Complete	7/27/84
216a	5.3.1	Reactor vessel materials	Complete	7/27/84
216b	5.3.1	Reactor vessel materials	Complete	7/27/84
217	9.5.1.1	Fire protection organization	Complete	8/15/84
218	9.5.1.1	Fire hazards analysis	Complete	6/1/84
219	9.5.1.2	Fire protection administrative controls	Complete	8/15/84
220	9.5.1.3	Fire brigade and fire brigade training	Complete	8/15/84
221	8.2.2.1	Physical separation of offsite transmission lines	Complete	8/1/84
222	8.2.2.2	Design provisions for re-establishment of an offsite power source	Complete	9/14/84 (Rev. 1)
223	8.2.2.3	Independence of offsite circuits between the switchyard and class IE buses	Complete	9/21/84 (Rev. 2)
224	8.2.2.4	Common failure mode between onsite and offsite power circuits	Complete	9/21/84 (Rev. 1)

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
225	8.2.3.1	Testability of automatic transfer of power from the normal to preferred power source	Complete	9/21/84 (Rev. 1)
226	8.2.2.5	Grid stability	Complete	8/13/84 (Rev. 1)
227	8.2.2.6	Capacity and capability of offsite circuits	Complete	8/1/84
228	8.3.1.1(1)	Voltage drop during transient conditions	Complete	8/1/84
229	8.3.1.1(2)	Basis for using bus voltage versus actual connected load voltage in the voltage drop analysis	Complete	8/1/84
230	8.3.1.1(3)	Clarification of Table 8.3-11	Complete	8/1/84
231	8.3.1.1(4)	Undervoltage trip setpoints	Complete	8/1/84
232	8.3.1.1(5)	Load configuration used for the voltage drop analysis	Complete	8/1/84
233	8.3.3.4.1	Periodic system testing	Complete	9/21/84 (Rev. 2)
234	8.3.1.3	Capacity and capability of onsite AC power supplies and use of administrative controls to prevent overloading of the diesel generators	Complete	8/1/84
235	8.3.1.5	Diesel generators load acceptance test	Complete	9/21/84 (Rev. 2)
236	8.3.1.6	Compliance with position C.6 of RG 1.9	Complete	8/1/84
237	8.3.1.7	Decription of the load sequencer	Complete	9/21/84 (Rev. 1)
238	8.2.2.7	Sequencing of loads on the offsite power system	Complete	9/21/84 (Rev. 1)

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
239	8.3.1.8	Testing to verify 80% minimum voltage	Complete	8/15/84
240	8.3.1.9	Compliance with BTP-PSB-2	Complete	8/1/84
241	8.3.1.10	Load acceptance test after prolonged no load operation of the diesel generator	Complete	9/21/84 (Rev. 3)
242	8.3.2.1	Compliance with position 1 of Regulatory Guide 1.128	Complete	9/13/84 (Rev. 1)
243	8.3.3.1.3	Protection or qualification of Class 1E equipment from the effects of fire suppression systems	Complete	9/13/84 (Rev. 1)
244	8.3.3.3.1	Analysis and test to demonstrate adequacy of less than specified separation	Complete	9/13/84 (Rev. 2)
245	8.3.3.3.2	The use of 18 versus 36 inches of separation between raceways	Complete	8/15/84 (Rev. 1)
246	8.3.3.3.3	Specified separation of raceways by analysis and test	Complete	8/1/84
247	8.3.3.5.1	Capability of penetrations to withstand long duration short circuits at less than maximum or worst case short circuit	Complete	9/13/84 (Rev. 1)
248	8.3.3.5.2	Separation of penetration primary and backup protections	Complete	8/1/84
249	8.3.3.5.3	The use of bypassed thermal overload protective devices for penetration protections	Complete	8/1/84
250	8.3.3.5.4	Testing of fuses in accordance with R.G. 1.63	Complete	8/1/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
251	8.3.3.5.5	Fault current analysis for all representative penetration circuits	Complete	9/21/84 (Rev. 2)
252	8.3.3.5.6	The use of a single breaker to provide penetration protection	Complete	9/21/84 (Rev. 2)
253	8.3.3.1.4	Commitment to protect all Class 1E equipment from external hazards versus only class 1E equipment in one division	Complete	9/13/84 (Rev. 1)
254	8.3.3.1.5	Protection of class 1E power supplies from failure of unqualified class 1E loads	Complete	9/14/84 (Rev. 1)
255	8.3.2.2	Battery capacity	Complete	8/1/84
256	8.3.2.3	Automatic trip of loads to maintain sufficient battery capacity	Complete	9/13/84 (Rev.1)
257	8.3.2.5	Justification for a 0 to 13 second load cycle	Complete	9/13/84 (Rev. 1)
258	8.3.2.6	Design and qualification of DC system loads to operate between minimum and maximum voltage levels	Complete	8/1/84
259	8.3.3.3.4	Use of an inverter as an isolation device	Complete	8/1/84
260	8.3.3.3.5	Use of a single breaker tripped by a LOCA signal used as an isolation device	Complete	9/13/84 (Rev. 1)
261	8.3.3.3.6	Automatic transfer of loads and interconnection between redundant divisions	Complete	9/13/84 (Rev. 1)
262	11.4.2.d	Solid waste control program	Complete	8/20/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL A. SCHWENCER LETTER DATE
263	11.4.2.e	Fire protection for solid radwaste storage area	Complete	8/13/84
264	6.2.5	Sources of oxygen	Complete	8/20/84
265	6.8.1.4	ESF Filter Testing	Complete	8/13/84
266	6.8.1.4	Field leak tests	Complete	8/13/84
267	6.4.1	Control room toxic chemical detectors	Complete	8/13/84
268		Air filtration unit drains	Complete	9/13/84 (Rev. 1)
269	5.2.2	Code cases N-242 and N-242-1	Complete	8/20/84
270	5.2.2	Code case N-252	Complete	8/20/84
TS-1	2.4.14	Closure of watertight doors to safety-related structures	Open	
TS-2	4.4.4	Single recirculation loop operation	Open	
TS-3	4.4.5	Core flow monitoring for crud effects	Complete	6/1/84
TS-4	4.4.6	Loose parts monitoring system	Open	
TS-5	4.4.9	Natural circulation in normal operation	Open	
TS-6	6.2.3	Secondary containment negative pressure	Open	
TS-7	6.2.3	Inleakage and drawdown time in secondary containment	Open	
TS-8	6.2.4.1	Leakage integrity testing	Open	
TS-9	6.3.4.2	ECCS subsystem periodic component testing	Open	

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL A. SCHWENCER LETTER DATE
TS-10	6.7	MSIV leakage rate		
TS-11	15.2.2	Availability, setpoints, and testing of turbine bypass system	Open	
TS-12	15.6.4	Primary coolant activity		
LC-1	4.2	Fuel rod internal pressure criteria	Complete	6/1/84
LC-2	4.4.4	Stability analysis submitted before second-cycle operation	Open	

N P84 80/12 25- gm

ATTACHMENT 2 **DATE:** 9/21/84

DRAFT SER SECTIONS AND DATES PROVIDED

SECTION	DATE
3.1	
3.2.1	
3.2.2	
5.1	
5.2.1	
6.5.1	See Notes 1&5
8.1	See Note 2
8.2.1	See Note 2
8.2.2	See Note 2
8.2.3	See Note 2
8.2.4	See Note 2
8.3.1	See Note 2
8.3.2	See Note 2
8.4.1	See Note 2
8.4.2	See Note 2
8.4.3	See Note 2
8.4.5	See Note 2
8.4.6	See Note 2
8.4.7	See Note 2
8.4.8	See Note 2
9.5.2	See Note 3
9.5.3	See Note 3
9.5.7	See Note 3
9.5.8	See Note 3
10.1	See Note 3
10.2	See Note 3
10.2.3	See Note 3
10.3.2	See Note 3
10.4.1	See Note 3
10.4.2	See Notes 3&5
10.4.3	See Notes 3&5
10.4.4	See Note 3
11.1.1	See Notes 1&5
11.1.2	See Notes 1&5
11.2.1	See Notes 1&5
11.2.2	See Notes 1&5
11.3.1	See Notes 1&5
11.3.2	See Notes 1&5

SECTION	DATE
11.4.1	See Notes 1&5
11.4.2	See Notes 1&5
11.5.1	See Notes 1&5
11.5.2	See Notes 1&5
13.1.1	See Note 4
13.1.2	See Note 4
13.2.1	See Note 4
13.2.2	See Note 4
13.3.1	See Note 4
13.3.2	See Note 4
13.3.3	See Note 4
13.3.4	See Note 4
13.4	See Note 4
13.5.1	See Note 4
15.2.3	
15.2.4	
15.2.5	
15.2.6	
15.2.7	
15.2.8	
15.7.3	See Notes 1&5
17.1	8/3/84
17.2	8/3/84
17.3	8/3/84
17.4	8/3/84

Notes:

1. Open items provided in letter dated July 24, 1984 (Schwencer to Mittl)

2. Open items provided in June 6, 1984 meeting

3. Open items provided in April 17-18, 1984 meeting

4. Open items provided in May 2, 1984 meting

5. Draft SER Section provided in letter dated August 7, 1984 (Schwencer to Mittl)

CT:db

DATE: 9/21/84

ATTACHMENT 3

DSER ITEM	DSER SECTION	SUBJECT
147	9.3.1	Compressed air system
223	8.2.2.3	Independence of offsite circuits between the switchyard and Class 1E buses
224	8.2.2.4	Common failure mode between onsite and offsite power circuits
225	8.2.3.1	Testability of automatic transfer of power from the normal to preferred power source
233	8.3.3.4.1	Periodic system testing
235	8.3.1.5	Diesel generators load acceptance test
237	8.3.1.7	Description of the load sequencer
238	8.2.2.7	Sequencing of loads on the offsite power system
241	8.3.1.10	Load acceptance test after prolonged no load operation of the diesel generator
251	8.3.3.5.5	Fault current analysis for all representative penetration circuits
252	8.3.3.5.6	The use of a single breaker to provide penetration protection

ATTACHMENT 4

DSER Open Item No. 147~~a, b, c, d~~ (DSER Section 9.3.1)

COMPRESSED AIR SYSTEMS

The service air system consists of two 100 percent capacity trains of compressors, aftercoolers, moisture separators, receivers, and associated piping and valves. Cooling is provided by the turbine auxiliary cooling system. One compressor runs automatically with the other compressor on standby. The standby compressor starts automatically on failure of the first system or failure of the first system to meet the demand for compressed air. This system maintains a constand pressure in the instrument air system. [The applicant has not provided an FSAR figure which identifies each air user, the location of each user, and all accumulators, check valves, and other appurtenances associated with safety related components, systems, and equipment, such as the ADS. The applicant has not provided readable figures in the FSAR, due to the drawing scale factor.] The service air compressor supplies air for the instrument air system by means of an intertie between the service air system and the instrument air system before the instrument air dryer package. The isolation between the two air systems is supplied air from the emergency air supply system (consisting of one compressor, filter, aftercooler, moisture separator, and receiver) for all accidents except a LOCA. Cooling is provided by the reacotr auxiliaries cooling system.

[The applicant has not identified the location of the equipment and the component classifications on the FSAR figures. Therefore, we cannot conclude that air systems satisfy the requirements of General Design Criterion 2, "Design Basis for Protection Against Natural Phenomena," and the guidelines of Regulatory Guide 1.29, Positions C.1 and C.2, "Seismic Design Classification.]

A scheduled program of testing and inspection of the system will be provided to ensure operability of the system components and control systems. For compliance with the requirements of GDC 1, see Section 3.2 of this SER.

The service air system has no functions necessary for achieving safe reactor shutdown condition nor for accident prevention or mitigation. [The applicant has not identified and demonstrated that all instruments, controls and services required for safe shutdown of the plant such as the MSIV and ADS valves are provided with seismic Category I passive air accumulators to assure their proper function in a loss of the air system.] All other air-operated valves including the scram discharge inlet and outlet valves and other devices are designed to move to a safe position on loss of instrument air and do not require a continuous air supply under emergency or abnormal conditions.

[Additionally, the applicant has not verified that all station air system containment penetrations are provided with redundant seismic Category I, Quality Group B isolation valves. Therefore, we cannot conclude the requirements of General Design Criterion 2 and the guidelines of Regulatory Guide 1.29, Position C.2, are satisfied.]

The service instrument air systems will initially meet the requirements of American National Standards Institute (ANSI) MC11.1-1976, using non-oil-lubricated air compressors. [The applicant has not committed to perform periodic air quality testing of the air systems to assure compliance with the requirements of ANSI-MC11.1-1976.]

[Based on the above, we cannot conclude that the safety-related and non safety-related compressed air systems meet the requirements of General Design Criterion 2 regarding the protection against natural phenomena and the guidelines of Regulatory Guide 1.29, Positions C.1 and C.2. We will report resolution of this item in a supplement to this SER. The compressed air system does not meet the applicable acceptance criteria of SRP Section 9.3.1.]

RESPONSE

The information for each air user, and all accumulators, check valves and other appurtenances associated with safety-related components, systems and equipment is provided in the response to Question 410.89

The ADS valve actuators are supplied with nitrogen (air) from the primary containment instrument gas system (see Section 9.3.6 for details of nitrogen (air) supply to ADS valves).

As described in FSAR Section 9.3.1.3 except for the containment isolation valves and penetration, whose location and classification is shown in Table 3.2-1 (Item XVII.a.3), the service air system is not safety related. Therefore, General Design Criteria 2 and Regulatory Guide 1.29, positions C.1 ~~and C.2~~ do not apply. Insert B

As described in Section 6.2.4.3.2.4, "Containment Isolation System the Compressed Service Air Line" and Table 3.2-1 (Item XVII.a.3) the contaiment penetration is provided with redundant Seismic Category I, Quality Group B isolation valves.

As described in revised Section 9.3.1.~~2~~4, the quality of air supplied to the instrument air system will be periodically tested to see that it meets the requirements of ANSI MC11.1-1976 "Quality Standard for Instrument Air".

In addition, the instrument air system afterfilter is designed to remove 0.4 micrometre particles with a 98 per cent efficiency. The system is designed to permit preventive or corrective maintenance on one air dryer and after filter train without effecting system operability. Therefore, quarterly inspection of ~~the~~ afterfilter assures that the maximum particle size in the air stream at the instrument is 3.0 micrometres. This satisfies requirement 4.2 of ANSI MC 11.1-1975.

Category I and ASME B&PV Code, Section III, Class 2, requirements as defined in Sections 3.7 and 6.2.

9.3.1.4 Tests and Inspections

The containment penetration portions of the compressed air systems are preoperationally tested in accordance wth the requirements of Chapter 14. The instrument air system is tested in accordance with Regulatory Guide 1.68.3, Preoperational Testing of Instrument Air Systems. Compressors and dryers shall be tested in accordance with ASME and manufacturers' test procedures.

INSERT A →

9.3.1.5 Instrumentation Application

Instrumentation is provided for each instrument air and service air compressor train to monitor and automatically control each compressor's operation.

The compressors are tripped on the following signals: low oil pressure, high oil temperature, high cooling water discharge temperature, high air pressure in the receiver, high outlet air temperature, and high vibration. Most of these signals are annunciated in the main control room by common trouble alarms. High air temperature in the aftercooler and moisture separators, low pressure in the air receivers, and high intake filter differential pressure are also alarmed on a local control panel and the main control room by a common trouble alarm. Instrumentation is also provided locally for each instrument air dryer package train to monitor the packages operation.

Service air compressor and emergency instrument air compressor trouble are individually annunciated and alarmed on the local common service air compressor control panel. These alarms also indicate on the main control room computer, along with the air dryer trouble alarms.

9.3.2 PROCESS AND POST-ACCIDENT SAMPLING SYSTEMS

The process sampling system (PSS) is designed to monitor and provide grab samples of both radioactive and nonradioactive fluids used in the normal operation of Hope Creek Generating Station (HCGS).

DSER OPEN ITEM NO. 147

INSERT "A"

The instrument air dew point will be tested in accordance with ANSI MC11.1-1975, Quality Standard For Instrument Air, at a frequency of once per quarter as specified in the air dryer technical manual.

The Instrument Air System afterfilter is designed to remove .04 micrometre particles with a 98% efficiency. The system is designed to permit preventive or corrective maintenance on one dryer and afterfilter train without affecting system operability. Therefore quarterly inspection of the afterfilter assures that the maximum particlea size in the air stream at the instrument is 3.0 micrometres. This satisfies requirement 4.2 of ANSI MC 11.1-1975.

Insert B

the non safety related portion of the service air system is included in the siesmic II/I program described in Section 3.2.1 and as indicated in table 3.2-1. Thus the requirements of Regulatory Guide 1.29, position C.2 are satisified.

Principal Components	FSAR Section	Source of Supply (1)	Location (2)	Quality Group Classification (3)	Principal Construction Codes and Standards (5)	Seismic Category (6)	QA Requirements (7)	Comments
XVII. Auxiliary Systems								
a. Compressed air (service and instrument) systems:	9.3.1							
1. Compressors		P	T	NA	None	II/I ~~NA~~	~~N~~	(50)
2. Pressure vessels, not for safety-related equipment		P	All	D	VIII-1	II/I ~~NA~~	~~N~~	(50)
3. Piping and valves, containment penetration and isolation		P	C,A	B	III-2	I	Y	(48)
4. Piping and valves, reactor building penetration and isolation		P	C	C	III-3	I	Y	(48)
5. Piping and valves, other		P	All	D	B31.1.0	II/I ~~NA~~	~~N~~	(50)
b. Primary containment instrument gas system:	9.3.6							
1. Compressors		P	C	B	III-2	I	Y	(45)
2. Filter housings, dryers, & coolers (air side)		P	C	B	III-2	I	Y	
3. Coolers (water side)		P	C	C	III-3	I	Y	
4. Receiver tanks		P	C	B	III-2	I	Y	
5. Piping and valves, air with safety function		P	C	B	III-2	I	Y	(48)
6. Piping and valves, cooling water		P	C	C	III-3	I	Y	(48)
7. Piping and valves, air with safety function (inside drywell)		P	A	C	III-3	I	Y	(48)
8. Piping and valves, containment penetration and isolation		P	A,C	B	III-2	I	Y	(48)
9. Piping and valves, air, other		P	A,C	D	B31.1.0	N	N	
10. Motors, compressors		P	C	N/A	IEEE-323/344	I	Y	

Rev. 2
#3

DSER Open Item No. 223 (DSER Section 8.2.2.3)

INDEPENDENCE OF OFFSITE CIRCUITS BETWEEN THE SWITCHYARD AND THE CLASS 1E BUSSES

The Hope Creek design provides two immediate access offsite circuits between the switchyard and the 4.16 kV Class 1E busses. It is the staff position that these two circuits be physically separate and independent such that no single event can simultaneously affect both circuits in such a way that neither can be returned to service in time to prevent fuel design limits or design conditions of the reactor coolant pressure boundary from beng exceeded. The physical separation and independence of these two circuits from and including station service transformers 1AX501 and 1BX501 to the 4.16 kV Class 1E busses has not been described or analyzed in the FSAR.

By Amendment 4 to the FSAR, the applicant implied, in response to a request for information, that the offsite circuits are non-Class 1E and thus do not have to be physically separated in accordance with the requirements of Criterion 17 of Appendix A of 10CFR50. The staff finds this interpretation to be unacceptable.

RESPONSE

FSAR Section 8.2.2.2 has been added to provide a discussion of the physical separation and independence of the two offsite power circuits from the station service transformers to the 4.16 kV Class 1E buses.

QUESTION 430.4 (Section 8.2)

The Hope Creek design provides two immediate access offsite circuits between the switchyard and the 4.16 kV Class 1E buses. It is the staff position that these two circuits be physically separate and independent such that no single event can simultaneously affect both circuits in such a way that neither can be returned to service in time to prevent fuel design limits or design conditions of the reactor coolant pressure boundary from being exceeded. The physical separation and independence of transformers 1AX501 and 1BX501 to the 4.16 kV Class 1E buses has not been described or analyzed in the FSAR. Provide the description and analysis and justify areas of noncompliance with the above staff position. The analysis should include separation and independence of control and protective relaying circuits as well as the power circuits.

RESPONSE

FSAR Section 8.2.2.2 has been added to provide the required information.

8.2.2.2 SEPARATION OF OFFSITE POWER SUPPLIES WITHIN THE PLANT

The circuits for the offsite power supply located within the plant are designed to comply with the requirements of GDC 17. Refer to FSAR Section 8.3.1.2.1 for a detailed description.

NT

groups remain intact to provide for 1. and 2. above.

INSERT A

Each 4.16-kV Class 1E bus has access to the two physically independent offsite power sources. Upon LOP, the Class 1E system is automatically isolated from the offsite power system and the onsite non-Class 1E distribution system. The isolation of the offsite and Class 1E onsite power systems is accomplished by tripping of the incoming offsite source breakers to the 4.16-kV Class 1E buses. This tripping is accomplished through the undervoltage relays connected on the source side of these breakers. The tripping of these incoming offsite source breakers to the 4.16-kV Class 1E buses also isolates one power supply channel from redundant power supply channels. The combination of these factors considered in the design of the electric power system minimizes the probability of losing electric power from the onsite power supplies as a result of the loss of power from the offsite sources or any disturbances of the non-Class 1E ac system.

The voltage analysis performed in accordance with Branch Technical Position PSB-1, Item 3, indicates that the onsite distribution system voltages are adequate to support Class 1E loads within the equipment ratings during LOCA and plant shutdown with the offsite system voltages at anticipated minimum or maximum voltage and with only the offsite source being considered available. The analysis also confirmed that the setting of the undervoltage relays on the source side of the incoming offsite source breakers on the Class 1E 4.16-kV buses will protect Class 1E loads from degraded voltages resulting from sustained low offsite system voltage condition.

The voltage analysis is based on the simplified single line diagram shown on Figure 8.3-15 which represents one half of station distribution buses and one of the two offsite sources. Because of similarity in the redundant Class 1E buses and similarity of non-Class 1E buses, the voltage analysis conducted is applicable to all of the station distribution buses. This single line

Insert A

Figure 8.3-5 shows that each of the four 4.16 kV Class 1E switchgear buses is supplied from two offsite (preferred) power sources and one onsite standby diesel generator (SDG). The offsite power to these buses is supplied from station service transformers 1AX501 and 1BX501 by non-segregated phase buses that are enclosed in metallic ducts. The non-segregated phase buses from the station service transformers to the 4.16 kV Class 1E switchgear are designated as non-Class 1E.

Figure 8.3-16 shows the routing of these non-segregated phase bus ducts from station service transformers 1AX501 and 1BX501 to 4.16 kV switchgear.

Station service transformers 1AX501 and 1BX501 are provided with individual water spray systems and are separated from each other by a 1-hour fire barrier. Each transformer has a collection dike and drainage outlet for collecting transformer oil spills and fire suppression system water and draining it to the oily waste drainage system. The drainage outlet for each transformer is designed to drain the entire volume of oil from the transformer plus the maximum flow of water from the automatic water spray system.

The non-segregated phase buses are run outside the turbine building wall up to the point where they enter the building. An extension of the station service transformers' water spray sprinkler system provides additional protection in the area of the common bus support and the limited area of crossover of the two non-segregated buses.

The non-segregated bus ducts are designed and constructed for adverse outdoor weather conditions (rain, ice, etc). The bus ducts are designed per ANSI Standard C37.20-1969/C37.20C-1974, Section 8.2.2.4, Watertight Tests, and, therefore, water from the sprinkler system of one transformer will not endanger the operation of the non-segregated bus of the other transformer.

These design features ensure that a station service transformer fire can not damage the bus duct from the other transformer and cause a loss of both offsite sources of power.

Within the turbine building the offsite buses are routed through common areas. Separate supports are provided for the non-segregated phase buses in non-seismic plant areas. In Seismic Class I plant areas Seismic Class I supports are provided for the non-segregrated phase buses. The buses are physically separated from each other and their steel duct enclosures minimize, to the extent practical, the likelihood of their simultaneous failure under operating and postulated accident environmental conditions.

The onsite power feeds to the 4.16 kV Class 1E switchgear are routed in rigid steel conduit from the standby diesel generator rooms. Each train of onsite Class 1E power is compartmentalized such that the four trains are separated from each other by two-hour fire rated concrete walls and each diesel is separated from its associated offsite power bus by a three-hour fire rated wall.

The circuit breakers that connect a 4.16 kV Class 1E switchgear bus to the two offsite power supplies and its associated onsite standby power supply are Class 1E and are qualified to the HCGS seismic and environmental parameters for any design basis event. These breakers are electrically interlocked to prevent the automatic paralleling of the onsite and offsite power supplies.

The only control interface between the onsite Class 1E and offsite power systems is the station service transformer differential relay current transformer (CT) leads in the Class 1E switchgear. The CT leads are classified as non-Class 1E and are enclosed in armored cable or conduit to comply with Regulatory Guide 1.75.

Each of the four SDGs are located in separate rooms of a Seismic Class 1 structure. The SDGs and the associated control panels are qualified for HCGS seismic and environmental parameters for all design basis events. The control panels, power, and control cables for all the four SDGs are separated to comply with Regulatory Guide 1.75 requirements.

Each of the four Class 1E 4.16 kV switchgear buses has its own independent protective relaying schemes. The failure of a protective relay in the 13.8 kV and/or 500 kV systems does not impact any of the four onsite power sources.

The control power supplies for both the offsite and onsite Class 1E infeed breakers are from a 125V dc distribution panel of the same Class 1E channel. Cables of the same Class 1E channel are routed in common raceways but these raceways are separated from their redundant counterpart by two-hour fire rated concrete walls from the switchgear room to the cable spreading room. Within the cable spreading room the redundant Class 1E control raceways are provided with Regulatory Guide 1.75 separation as well as automatic fire suppression systems. Figures 9.5-1 to 9.5-5 show these features.

Common control room panels, where both onsite and offsite control cables terminate, have separation or barriers provided, in accordance with Regulatory Guide 1.75, to eliminate common mode failures between onsite and offsite breaker control.

Protection against common mode fire induced failure of the onsite power trains is addressed as part of the Hope Creek fire protection analysis in Section 9.5.1, and Appendix 9A.

These design features minimize the probability of losing electric power from any of the required Class 1E electrical power systems as a result of, or coincident with, loss of the power generated by the main generator, loss of the power from the offsite transmission network, or loss of the power from the onsite electric power supplies, as required by GDC 17.

Rev. 1

#4

DSER Open Item No. 224 (DSER Section 8.2.2.4)

COMMON FAILURE MODE BETWEEN ONSITE AND OFFSITE POWER CIRCUITS

Each of the 4.16 kv Class 1E busses at Hope Creek is supplied power from preferred offsite and standby onsite circuits. It is the staff position that these circuits should not have common failure modes. Physical separation and independence of these circuits has not been described or analyzed in the FSAR. By Amend. 4 to the FSAR, the applicant, in response to a request for information, indicated that a single event can not cause common failure of both onsite and offsite power source circuits because they are separated in accordance with the requirements of Regulatory Guide 1.75. The staff disagrees. Separation in accordance with Regulatory Guide 1.75 by itself is not sufficient for the staff to conclude that there are no common failure modes or to conclude that the probability of coincident loss of both onsite and offsite power sources has been minimized in accordance with the requirements of Criterion 17 of Appendix A to 10 CFR 50.

RESPONSE

FSAR Section 8.3.1.2.1 has been revised to include the results of an analysis to show compliance of the onsite and offsite power systems to GDC 17.

QUESTION 430.5 (SECTION 8.2)

Each of the 4.16 kV Class 1E busses at Hope Creek is supplied power from preferred offsite and standby onsite circuits. It is the staff position that these circuits should not have common failure modes. Physical separation and independence of these circuits has not been described or analyzed in the FSAR. Provide a description and analysis in accordance with Section 5.2.1(5) of IEEE Standard 308-1974.

RESPONSE

FSAR Section 8.3.1.2.1 has been revised to provide the requested information.

NT

groups remain intact to provide for 1. and 2. above.

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Each 4.16-kV Class 1E bus has access to the two physically independent offsite power sources. Upon LOP, the Class 1E system is automatically isolated from the offsite power system and the onsite non-Class 1E distribution system. The isolation of the offsite and Class 1E onsite power systems is accomplished by tripping of the incoming offsite source breakers to the 4.16-kV Class 1E buses. This tripping is accomplished through the undervoltage relays connected on the source side of these breakers. The tripping of these incoming offsite source breakers to the 4.16-kV Class 1E buses also isolates one power supply channel from redundant power supply channels. The combination of these factors considered in the design of the electric power system minimizes the probability of losing electric power from the onsite power supplies as a result of the loss of power from the offsite sources or any disturbances of the non-Class 1E ac system.

The voltage analysis performed in accordance with Branch Technical Position PSB-1, Item 3, indicates that the onsite distribution system voltages are adequate to support Class 1E loads within the equipment ratings during LOCA and plant shutdown with the offsite system voltages at anticipated minimum or maximum voltage and with only the offsite source being considered available. The analysis also confirmed that the setting of the undervoltage relays on the source side of the incoming offsite source breakers on the Class 1E 4.16-kV buses will protect Class 1E loads from degraded voltages resulting from sustained low offsite system voltage condition.

The voltage analysis is based on the simplified single line diagram shown on Figure 8.3-15 which represents one half of station distribution buses and one of the two offsite sources. Because of similarity in the redundant Class 1E buses and similarity of non-Class 1E buses, the voltage analysis conducted is applicable to all of the station distribution buses. This single line

Insert A

Figure 8.3-5 shows that each of the four 4.16 kV Class 1E switchgear buses is supplied from two offsite (preferred) power sources and one onsite standby diesel generator (SDG). The offsite power to these buses is supplied from station service transformers 1AX501 and 1BX501 by non-segregated phase buses that are enclosed in metallic ducts. The non-segregated phase buses from the station service transformers to the 4.16 kV Class 1E switchgear are designated as non-Class 1E.

Figure 8.3-16 shows the routing of these non-segregated phase bus ducts from station service transformers 1AX501 and 1BX501 to 4.16 kV switchgear.

Station service transformers 1AX501 and 1BX501 are provided with individual water spray systems and are separated from each other by a 1-hour fire barrier. Each transformer has a collection dike and drainage outlet for collecting transformer oil spills and fire suppression system water and draining it to the oily waste drainage system. The drainage outlet for each transformer is designed to drain the entire volume of oil from the transformer plus the maximum flow of water from the automatic water spray system.

The non-segregated phase buses are run outside the turbine building wall up to the point where they enter the building. An extension of the station service transformers' water spray sprinkler system provides additional protection in the area of the common bus support and the limited area of crossover of the two non-segregated buses.

The non-segregated bus ducts are designed and constructed for adverse outdoor weather conditions (rain, ice, etc). The bus ducts are designed per ANSI Standard C37.20-1969/C37.20C-1974, Section 8.2.2.4, Watertight Tests, and, therefore, water from the sprinkler system of one transformer will not endanger the operation of the non-segregated bus of the other transformer.

These design features ensure that a station service transformer fire can not damage the bus duct from the other transformer and cause a loss of both offsite sources of power.

Within the turbine building the offsite buses are routed through common areas. Separate supports are provided for the non-segregated phase buses in non-seismic plant areas. In Seismic Class I plant areas Seismic Class I supports are provided for the non-segregrated phase buses. The buses are physically separated from each other and their steel duct enclosures minimize, to the extent practical, the likelihood of their simultaneous failure under operating and postulated accident environmental conditions.

The onsite power feeds to the 4.16 kV Class 1E switchgear are routed in rigid steel conduit from the standby diesel generator rooms. Each train of onsite Class 1E power is compartmentalized such that the four trains are separated from each other by two-hour fire rated concrete walls and each diesel is separated from its associated offsite power bus by a three-hour fire rated wall.

The circuit breakers that connect a 4.16 kV Class 1E switchgear bus to the two offsite power supplies and its associated onsite standby power supply are Class 1E and are qualified to the HCGS seismic and environmental parameters for any design basis event. These breakers are electrically interlocked to prevent the automatic paralleling of the onsite and offsite power supplies.

The only control interface between the onsite Class 1E and offsite power systems is the station service transformer differential relay current transformer (CT) leads in the Class 1E switchgear. The CT leads are classified as non-Class 1E and are enclosed in armored cable or conduit to comply with Regulatory Guide 1.75.

Each of the four SDGs are located in separate rooms of a Seismic Class 1 structure. The SDGs and the associated control panels are qualified for HCGS seismic and environmental parameters for all design basis events. The control panels, power, and control cables for all the four SDGs are separated to comply with Regulatory Guide 1.75 requirements.

Each of the four Class 1E 4.16 kV switchgear buses has its own independent protective relaying schemes. The failure of a protective relay in the 13.8 kV and/or 500 kV systems does not impact any of the four onsite power sources.

The control power supplies for both the offsite and onsite Class 1E infeed breakers are from a 125V dc distribution panel of the same Class 1E channel. Cables of the same Class 1E channel are routed in common raceways but these raceways are separated from their redundant counterpart by two-hour fire rated concrete walls from the switchgear room to the cable spreading room. Within the cable spreading room the redundant Class 1E control raceways are provided with Regulatory Guide 1.75 separation as well as automatic fire suppression systems. Figures 9.5-1 to 9.5-5 show these features.

Common control room panels, where both onsite and offsite control cables terminate, have separation or barriers provided, in accordance with Regulatory Guide 1.75, to eliminate common mode failures between onsite and offsite breaker control.

Protection against common mode fire induced failure of the onsite power trains is addressed as part of the Hope Creek fire protection analysis in Section 9.5.1, and Appendix 9A.

These design features minimize the probability of losing electric power from any of the required Class 1E electrical power systems as a result of, or coincident with, loss of the power generated by the main generator, loss of the power from the offsite transmission network, or loss of the power from the onsite electric power supplies, as required by GDC 17.

#5
Rev. 1

DSER Open Item No. 225 (DSER Section 8.2.3.1)

TESTABILITY OF AUTOMATIC TRANSFER OF POWER FROM THE NORMAL TO PREFERRED POWER SOURCE

Each Class 1E bus is supplied with a normal and alternate off-site power source. On loss of the normal source, the bus is automatically transferred to the alternate power source. The capability to test this transfer of power has not been specifically addressed in the FSAR.

Inclusion of the test capability in the FSAR and justification for not testing while the plant is operating at power will be pursued with the applicant.

RESPONSE

The response to Question 430.6 has been revised to provide the requested information.

QUESTION 430.6 (SECTION 8.2)

Each Class 1E bus is supplied with a normal and alternate offsite power source. On loss of the normal source, the bus is automatically transferred to the alternate power source. The capability to test this transfer of power has not been specifically addressed in the FSAR. Describe the transfer circuitry, how it is tested during normal plant operation, and its compliance with GDC 18.

RESPONSE

A description of the transfer circuitry, its testing, and its compliance with GDC 18 are provided in revised Section 8.2.2.

Under all power flow conditions tested, the station and its transmission arrangements satisfy the MAAC Reliability Principles and Standards.

The stability analysis was conducted for the system configuration using the Philadelphia Electric Company transient stability program TRANSTAB.

The types of faults tested in accordance with the MAAC Criteria, Section IV, were:

a. Three-phase faults with normal clearing time

b. Single-phase-to-ground faults with delayed clearing.

The analysis established that the critical fault condition was a three-phase fault on the Hope Creek to Keeney 500 kV line at HCGS. The single-phase-to-ground fault case with delayed clearing simulated a stuck breaker condition, such that with independent pole tripping of the breakers, the breaker closest to the fault on the faulted phase failed to open. Therefore, backup or delayed clearing is required to isolate the fault. A transient stability case list is given in Table 8.2-1.

The loss of the Hope Creek Unit represents the loss of the largest single generating unit. For this condition, grid stability is maintained. Beyond this criteria, HCGS will remain stable with the loss of both Salem Units 1 and 2.

The circuits from the offsite system to the onsite distribution system are of sufficient capacity and capability to supply the station loads during normal or abnormal operating conditions, accident conditions or plant shutdown conditions independent of the onsite standby power sources. The circuits consist of two paths as shown on Figure 8.3-1. One path is from Station Power Transformers T1 and T3 to the station service transformers as shown. Whereas, the other path begins from Station Power Transformers T2 and T4. In the event that one of the paths is unavailable and/or the offsite system has a degraded voltage condition, automatic transfer of its station distribution buses to the other path is initiated.

On the Class 1E 4 kV buses the transfer circuit has two functions. One is to transfer the bus to the alternate source if the normal source is lost due to transformer fault. The other function is to transfer the bus to the alternate source if the normal source has an undervoltage condition. The transfer circuit is shown in each of the main circuit breaker schematic diagram. The applicable diagrams were submitted under separate cover in accordance with Regulatory Guide 1.70, Revision 3, Section 1.7 and consist of Drawing Numbers E-0068-0 thru E-0075-0 and Sheets 3 and 4 of E-0106-0 together with other drawings referenced thereon.

There are eight main circuit breakers, two for each bus, and the transfer circuit is typical for each breaker. The transfer circuit(s) is described as follows, using Bus 10A401 as an example:

a. Transformer Fault

Bus 10A401 is normally supplied from station service transformer 1AX501 through main circuit breaker (1)52-40108. Drawing Number E-0068-0 shows this breaker's schematic diagram. In the event transformer protective relay operation (differential, ground overcurrent or overcurrent relay), lockout relay (3)86TR-AX501 or (3)86TB1-AX501, shown on Drawing Number E-0112-0, will trip breaker (1)52-40108 and close the alternate feeder breaker (1)52-40101, shown on Drawing Number E-0069-0.

b. Undervoltage of Normal Source Voltage

Undervoltage relays (1)27-40108(A-B) and (1)27-40108(B-C) will pickup auxiliary relays (1)27X-40108(A-B) and (1)27X-40108(B-C) when the normal source voltage is 92% or less of normal bus voltage as shown on Sheet 3 of Drawing Number E-0106-0. Contacts 7-8 of the two auxiliary relays are connected in series to provide a trip signal to breaker (1)52-40108 upon relay actuation - shown as wire number 31 in Drawing Number E-0068-0. The bus is now deenergized since the normal source feeder breaker is tripped. Bus undervoltage relays (1)27A1-401(A-B), (1)27A1-401(B-C), (1)27A2-401(A-B) and (1)27A2-401(B-C) will operate auxiliary relays (1)27AX1-401(A-B), (1)27AY1-401(A-B), (1)27AX1-401(B-C), (1)27AY1-401(B-C), (1)27AX2-401(A-B), (1)27AY2-401(A-b), (1)27AX2-401(B-C), and (1)27AY2-401(B-C) - all shown on Sheet 3 of Drawing Number E-0106-0.

Of the eight auxiliary relays, contacts 9-10 of (1)27AY1-401(A-B), (1)27AY1-401(B-C), (1)27AY2-401(A-B) and (1)27AY2-401(B-C) are connected in a two-out-of-four, twice arrangement to close the alternate source feeder breaker (1)52-40101 - shown as wire number 52 on Drawing Number E-0069-0.

The transfer circuit will be tested during the preoperational test of Class 1E 4.16 kV ac power system as indicated in Section 14.2.12.1.32. This test will include actual loads on the bus if the loads are ready for preoperational test; otherwise the complete bus transfer test will be performed during the ECCS integrated initiation during loss of offsite power preoperational test described in Section 14.2.12.1.47. The protective relays of the transfer circuit are designed for testing during normal plant operation by use of test plugs or test switches to isolate their actuating function. Actual power source transfer testing from the normal source to the alternate sources as required by GDC 18 will be performed in accordance with surveillance requirement 4.8.1.1.1 of the Standard Technical Specifications. Power source transfer testing is not performed during power operation in order to preclude an undesirable transient which may result due to the interruption of normal ac power to an individual bus should the transfer sequence fail.

R Voltage analysis performed indicate that each path is of sufficient capacity and capability to supply all the station loads, Class 1E and non-Class 1E, without exceeding design limits of the station equipment (except during the unlikely event that the offsite system voltage is at maximum with no loads on the station distribution buses which are fed from unit substation transformers with taps of 5% boost.)

8.2.2.1 Outages of Transmission Lines in Vicinity of the Station

To demonstrate the reliability of the transmission line associated with the Hope Creek station, unscheduled outages of existing transmission lines (of similar or identical design) in the geographical area were investigated. Unscheduled outages of these lines for the past 5 years are listed below:

Transmission Lines	1978	1979	1980	1981	1982
Salem - Keeney	0	0	2	1	1
Salem - New Freedom-North	1	0	1	0	0
Salem - New Freedom-South	0	0	0	1	1

Historically, outages in the area have been caused by lightning strikes, fires, and equipment problems.

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#10

DSER Open Item No. 233 (DSER Section 8.3.3.4.1)

PERIODIC SYSTEM TESTING

Description of compliance to Section 6.4, Periodic System Tests, of IEEE Standard 308-1974, had not been included in Section 8.1.4.6 of the FSAR. By Amendment 4 to the FSAR, the applicant provided the following description of compliance: "Periodic system tests shall be performed using written procedures which will be designed to demonstrate system performance. The frequency of testing shall be governed by the frequencies specified in the Technical Specifications."

The following periodic system tests are required by Section 6.4 of IEEE Standard 308-1974 in order to demonstrate:

(1) The Class 1E loads can operate on the preferred power supply.

(2) The loss of the preferred power supply can be detected.

(3) The standby power supply can be started and can accept design load within the design basis time.

(4) The standby power supply is independent of the preferred power supply.

Pending inclusion of each of these tests in the Hope Creek Technical Specifications, the staff concludes that periodic system testing will comply with the guidelines of Section 6.4 of IEEE Standard 308-1974. This testing meets the requirements of GDC 17 and 18 and is acceptable.

RESPONSE

The Hope Creek Generating Station Technical Specifications, when issued, will include the appropriate periodic system tests as required by Section 6.4 of IEEE Standard 308-1974 in order to demonstrate:

(1) The Class 1E loads can operate on the preferred power supply.

(2) The loss of the preferred power supply can be detected.

(3) The standby power supply can be started and can accept design load within the design basis time.

(4) The standby power supply is independent of the preferred power supply.

FSAR Section 8.1.4.6 has been revised to include this commitment.

QUESTION 430.13 (SECTION 8.3.1. AND 8.3.2)

Description of compliance to Section 6.4, Periodic System tests, of IEEE Standard 308-1974, has not been included in Section 8.1.4.6 of the FSAR. Provide the description and justify areas of noncompliance.

RESPONSE

Section 8.1.4.6 describes compliance to Section 6.4, Periodic System Tests, of IEEE Standard 308-1974.

NT

6. The batteries of the dc power supply can meet the design requirements of their connnected load without the chargers in operation.

7. Each battery charger has sufficient capacity to meet the largest combined demands of the various continuous steady-state loads plus the charging capacity to restore the battery from the design minimum charge state to the fully charged state within 12 hours.

c. Periodic equipment tests are performed at scheduled intervals in accordance with the requirements of Chapter 16. These tests are performed to:

1. Detect within prescribed limits the deterioration of the equipment toward an unacceptable condition.

2. Demonstrate that standby power equipment and other components that are not exercised during normal operation of the station are operable.

d. Periodic system tests shall be performed using written procedures which will be designed to demonstrate system performance. The frequency of testing shall be governed by the frequencies specified in the Technical Specifications.

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As HCGS is a single unit generating plant, multiunit station considerations do not apply. Battery testing is described in Chapter 16.

8.1.4.7 Regulatory Guide 1.40, Qualification Tests of Continuous-Duty Motors Installed Inside the Containment of Water-Cooled Nuclear Power Plants, March 1973

HCGS complies with Regulatory Guide 1.40 as discussed in Section 1.8.

Insert "A" to FSAR Section 8.1.4.6:

The HCGS Technical Specifications will also include the appropriate periodic system tests as required by Section 6.4 of IEEE Standard 308-1974 in order to demonstrate:

(1) The Class 1E loads can operate on the preferred power supply.

(2) The loss of the preferred power supply can be detected.

(3) The standby power supply can be started and can accept design load within the design basis time.

(4) The standby power supply is independent of the preferred power supply.

NT
Rev. 2

DSER Open Item No. 235 (DSER Section 8.3.1.5)

DIESEL GENERATOR LOAD ACCEPTANCE TEST

Position C.2.a(2), of Regulatory Guide 1.108, requires that the preoperational and periodic tests demonstrate proper operation of the diesel generator for design accident loading sequence to design load requirements. Section 1.8.1.9 of the FSAR states that for preoperational testing actual loads are started but may not duplicate their design basis condition. This statement implies exception to the above position. Justification for non-compliance with the guidelines of Regulatory Guide 1.108 will be pursued with the applicant, and the results of the staff review will be reported in a supplement to this report.

RESPONSE

Section 1.8.1.108 has been revised to provide the required information.

QUESTION 430.15 (SECTION 8.3.1)

In Sections 1.8.1.9 and 8.1.4.2 of the FSAR. You state (1) that preoperational testing at Hope Creek does not meet the guidelines of position C3 of Regulatory Guide 1.9 (revision 1), (2) predicted loads are verified by testing; however, loads that cannot be tested are verified by analysis or by comparison, and (3) for preoperational testing, actual design loads are started but may not duplicate their design basis condition. The above statement imply (1) that the diesel generators at Hope Creek will not be preoperationally or periodically tested to demonstrate their capacity and capability to operate properly when subject to design load, (2) that the guidelines of position C.2.a(2) of Regulatory Guide 1.108 (revision 1) will not be followed, and (3) that the design does not meet the requirements of Criterion 17 of Appendix A to 10 CFR 50. In Section 8.1.4.20 of the FSAR provide justification for noncompliance.

RESPONSE

Section 1.8.1.9 has been revised to delete the clarification to position C.3 of Regulatory Guide 1.9, Revision 1. The preoperational test program at HCGS for diesel generator testing will follow the guidelines of Regulatory Guides 1.9 and 1.108, as shown in Sections 14.2.12.1.30 and 14.2.12.1.47.

Periodic testing of the SDGs, at the required 18 month intervals, will be performed using written procedures in accordance with the requirements of the Hope Creek Technical Specifications. Sections 1.8.1.108 and 8.1.4.20 have been revised to reflect this response.

Position C.2.a(2) of Regulatory Guide 1.108 is met with the exception discussed and justified in FSAR Section 1.8.1.108.

9-13 NT

See Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.107 Conformance to Regulatory Guide 1.107, Revision 1, February 1977: Qualifications for Cement Grouting for Prestressing Tendons in Containment Structures

Regulatory Guide 1.107 is not applicable to HCGS.

1.8.1.108 Conformance to Regulatory Guide 1.108, Revision 1, August 1977: Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants

Although Regulatory Guide 1.108 is not applicable to HCGS, per its implementation section, HCGS complies with it, with the following exception:

1.8.1.109 Conformance to Regulatory Guide 1.109, Revision 1, October 1977: Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I

HCGS complies with Regulatory Guide 1.109.

For further discussion, see Chapter 15.

INSERT A

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Insert "A" to Page 1.8-97

1. During the preoperational test phase, the proper design accident loading sequence will be demonstrated by the test described in Section 14.2.12.1.47. This test will verify the ability of the SDG to start and accept the sequenced design loads as specified in Table 8.3-1 except for certain valves while maintaining voltage and frequency within specified limits. This test will not provide ECCS flows to the reactor vessel. Therefore certain motor operated valves that provide ECCS isolation will not be actuated during the test. These transitory valve loads have been calculated to represent 2 percent of the total load expected under an actual LOCA condition. Since this percentage is minimal, compared to the total load, the SDG load test closely approximates the exact functional loads of an actual LOCA condition.

2. For periodic testing required by the Hope Creek Technical Specifications, the test per this regulatory position will be performed during shutdown. This test will simulate, separately, a loss of offsite power, and a loss of offsite power plus a LOCA condition, to verify the SDGs' ability to start and accept the sequenced design loads.

#15
Rev. 1
#238 (also attached)

DSER Open Item No. 237 (DSER Section 8.3.1.7)

DESCRIPTION OF THE LOAD SEQUENCER

By Amendment 4 to the FSAR, the applicant in response to a request for information, provided a description of the Hope Creek load sequencer. Based on a review of this description, it appears that provisions for shedding of safety loads has not been considered in the design of the load sequencer. Load shedding capacity and inclusion of the description in Section 8.3 of the FSAR will be pursued with the applicant.

RESPONSE

The question 430.19 has been revised to include a description of the load sequencer and load shedding of non-Class 1E loads connected to the Class 1E loads. FSAR section 8.3.1.1.2.7 has been revised to include description of the design features of the load sequencer and the load shedding of the non Class 1E loads.

DSER Open Item No. 238 (DSER Section 8.2.2.7)

SEQUENCING OF LOADS ON THE OFFSITE POWER SYSTEM

It is the staff's position that the offsite power system should have sufficient capacity to supply all required loads without sequencing of loads. By Amendment 4 to the FSAR, the applicant indicated that the Hope Creek design includes provision for sequencing of loads on the offsite as wel1l as the onsite power supply. Thus, the Hope Creek offsite power system may not have sufficient capacity to supply all loads wiithout sequencing. Sequencing of loads on the offsite power system represents an additional source of unreliability and because the same sequencer is used for both onsite and offsite power sources, independence between sources may be compromised. Therefore, it is the staff position that the applicant must perform an analysis with results documented in the FSAR, to demonstrate (1) (1) that there are no credible circuits or common failure modes in the sequencer design that could render both the onsite and offsite power sources unavailable and, (2) that the combined reliability of onsite and offsite power sources has not been compromised. This item will be pursued with the applicant.

RESPONSE

Attached, per your request, is a copy of the ELS system reliability analysis. The response to Question 430.19 has been revised to reflect the submittal of this reliability analysis, description of the load sequencer and results of an analysis for common mode failures. Also the FSAR section 8.3.1.1.2.7 has been revised to describe the load sequencing and the load shedding of non class 1E loads.

\# 15
\# 16 NT

QUESTION 430.19 (SECTION 8.3 1)

A description of the diesel generator automatic load sequencer has not been provided in the FSAR. Provide the description. In addition, provide the results of a reliability analysis for the sequencer that demonstrates the capability of the onsite power system to supply power to safety loads on demand.

RESPONSE

HCGS has four Class 1E automatic emergency load sequencers (ELS), one each for the four Class 1E channel power supplies. The ELSs are designed to provide sequenced starting of ESF and selected non-1E loads, in response to loss of offsite power (LOP) and/or loss of coolant accident (LOCA) The sequenced application of loads minimizes the drop in voltage and frequency at the power supply buses.

Insert B

Control power for the ELSs is provided from their respective channel of uninterruptible power supply source.

The inputs and outputs of the four ELSs are electrically and physically separated to meet the requirements of Regulatory Guide 1.75.

OPERATION:

During normal plant operation, the ELSs are in a standby condition. Each of the four ELSs is supplied inputs from its corresponding channel that represent:

a. LOCA - Low reactor vessel level and/or high drywell pressure condition.

b. LOP - Undervoltage condition on the ELS's corresponding 4.16 kV Class 1E bus.

c. Standby Diesel Generator (SDG) circuit breaker closed.

d. Remote system reset.

Each ELS provides the following four sets of outputs fanned out to various plant electrical loads within its Class 1E channel system:

a. Sequential start signals to loads required following a LOCA.

b. Sequential start signals to loads required following a LOP.

(Question 430.19)

Insert B

Each channelized ELS consists of two individual solid state sequencers that are housed in a single control panel. These two solid state sequencers are for the LOP sequence and the LOCA sequence. The LOP and LOCA sequencers have two solid state logic timers for each particular sequence powered from redundant internal power supplies. Each of the four channelized ELS has these internal redundant component features.

There are four Class 1E emergency load sequencers, one for each of the four Class 1E power divisions. These four emergency load sequencers are electrically and physically independent of each other. There are no interconnections of electrical cabling between any of the four divisional emergency load sequencers. The individual solid state design circuitry and unique redundant solid state timers and power supplies within each emergency load sequencer minimize the possibility of a sneak circuit or misoperation of an individual ELS. In the event that an ELS did have inadvertent operation as a result of a sneak circuit, only one Class 1E ELS would be impacted since each ELS is electrically and physically independent of each other. There would be three Class 1E ELS available for plant shutdown if any single ELS failed.

There are no credible sneak circuits or common failure modes in the sequencer design that could impact the availability of the onsite and offsite power sources. The HCGS sequencer design does not degrade the combined reliability of the onsite and offsite power sources.

c. One set of process start inhibit signals (PSIS) to the LOCA Loads to prevent inadvertant starting of LOCA equipment due to automatic signals while ELS is in operation.

d. One set of PSIS to prevent inadvertant starting of the LOP equipment due to automatic signals while the ELS is in operation.

The ELSs respond to the receipt of LOCA and/or LOP signals in the following manner:

a. <u>LOP ONLY</u>

The LOP input to the sequencer resets the logic to prevent starting of the ELS timer until the SDG circuit breaker closes. Upon the closing of the SDG circuit breaker, the ELS timer starts applying the LOP loads in the predetermined sequence. The 'LOP Loads' here refers to the loads that are required to shutdown the reactor safely under an LOP event. The LOP sequencer is manually reset after the end of the LOP sequence.

b. <u>LOCA ONLY</u>

The LOCA signal sheds a non-Class 1E loads (independent of ELS) and initiates the ELS logic to start applying the LOCA loads in the predetermined sequence. The LOCA loads here refers to the loads that are required to shutdown the reactor safely under LOCA condition. The LOCA sequence is manually reset after the end of LOCA sequence.

c. <u>LOCA DURING LOP SEQUENCING</u>

The LOCA signal sheds non-Class 1E loads (independent of ELS), and overrides the LOP sequencer and starts the LOCA sequencer to apply LOCA loads in the predetermined sequence.

d. <u>LOP DURING LOCA SEQUENCING</u>

The LOCA sequencer stops and resets. When the power is restored to the 4.16 kV Class 1E bus associated with the ELS, the LOCA signal overrides the LOP timer initiated signal. The LOCA sequencer restarts applying LOCA loads.

e. <u>LOCA AFTER LOP SEQUENCING COMPLETED</u>

The LOCA signal sheds the non-Class 1E loads (independent of ELS) and starts the LOCA sequencer to apply LOCA loads in a predetermined sequence.

(NT)

f. LOP AFTER LOCA SEQUENCING COMPLETED

If a LOCA signal is still present when the SDG circuit breaker is closed, the LOCA signal overrides the LOP sequencer and starts the LOCA sequencer to apply LOCA loads in the predetermined sequence.

For scenarios '2a' through '2f' above, the PSIS signals are present to prevent the inadvertant starting of equipment before its predetermined sequenced time.

ELS TESTING:

Provisions exist at each of the sequencer cabinets to test the ELSs for 2a through 2f scenarios described above. An alarm is provided in the main control room to indicate that an ELS is being tested. If an actual LOP or LOCA occurs during the testing of an ELS, the sequencer resets automatically and responds to LOP and/or LOCA event.

The ELS system reliability analysis will be provided by July, 1984.

Insert A

(Question 430.19)

Insert A

The load shedding of non-Class 1E loads connected to Class 1E busses occurs upon a loss of offsite power and upon LOCA. During a LOP without LOCA condition, each Class 1E electrical bus has undervoltage relays that energize auxiliary relays which trip the non-Class 1E loads connected to the Class 1E buses. The emergency load sequencer has no electrical interconnection with the load shedding of the non-Class 1E loads.

If offsite power is available and LOCA occurs, then individual LOCA signals will go directly to the Class 1E unit substation breakers feeding the non-Class 1E loads and trip these breakers. Any Class 1E loads that are running during the condition will remain running.

The emergency load sequencer has no electrical interconnection with the tripping of the non-Class 1E loads by the LOCA signal and in addition, has no electrical interties with the offsite power sources.

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d. 120-V ac distribution panels

1. Buses: 225 A continuous rating, 10,000 A bracing

2. Breakers: 100 A frame size, 10,000 A interrupting rating.

e. 120-V ac UPS panels

1. Buses: 225 A continuous rating, 10,000 A bracing

2. Fuses: 10,000 A interrupting rating.

8.3.1.1.2.7 Automatic Load Shedding and Sequential Loading

Load shedding of the loads off the Class 1E buses is achieved by tripping the 4.16-kV breakers as described below:

a. Upon LOP, undervoltage relays monitoring the voltage on the Class 1E buses, trip all the breakers on their respective buses except the two breakers on each bus, which supply power to 480-V unit substations.

b. Upon the occurrence of a LOCA, the 480-V unit substation breakers feeding the non-Class 1E loads are tripped.

Insert A and B

Sequential loading is shown in Table 8.3-1.

8.3.1.1.2.8 Physical Identification of Safety-Related Equipment

Section 8.1.4.14 provides information regarding the physical identification of safety-related cables and raceways.

Color-coded nameplates are provided for all Class 1E equipment. Each separation group has its own color. The color codes assigned to identify electrical switchgear, MCCs, control panels,

(Question 430.19)

Insert A

The load shedding of non-Class 1E loads connected to Class 1E busses occurs upon a loss of offsite power and upon LOCA. During a LOP without LOCA condition, each Class 1E electrical bus has undervoltage relays that energize auxiliary relays which trip the non-Class 1E loads connected to the Class 1E buses. The emergency load sequencer has no electrical interconnection with the load shedding of the non-Class 1E loads.

If offsite power is available and LOCA occurs, then individual LOCA signals will go directly to the Class 1E unit substation breakers feeding the non-Class 1E loads and trip these breakers. Any Class 1E loads that are running during the condition will remain running.

The emergency load sequencer has no electrical interconnection with the tripping of the non-Class 1E loads by the LOCA signal and in addition, has no electrical interties with the offsite power sources.

Insert B

Each channelized ELS consists of two individual solid state sequencers that are housed in a single control panel. These two solid state sequencers are for the LOP sequence and the LOCA sequence. The LOP and LOCA sequencers have two solid state logic timers for each particular sequence powered from redundent internal power supplies. Each of the four channelized ELS has these internal redundant component features.

There are four Class 1E emergency load sequencers, one for each the four Class 1E power divisions. These four emergency load sequencers are electrically and physically independent of each other. There are no interconnections of electrical cabling between any of the four divisional emergency load sequencers. The individual solid state design circuitry and unique redundant solid state timers and power supplies within each emergency load sequencer minimize the possibility of a sneak circuit or misoperation of an individual ELS. In the event that an ELS did have inadvertent operation as a result of a sneak circuit, only one Class 1E ELS would be impacted since each ELS is electrically and physically independent of each other. There would be three Class 1E ELS available for plant shutdown if any single ELS failed.

There are no credible sneak circuits or common failure modes in the sequencer design that could impact the availability of the onsite and offsite power sources. The HCGS sequencer design does not degrade the combined reliability of the onsite and offsite power sources.

(*20) Rev. 3

DSER Open Item No. 241 (DSER Section 8.3.1.10)

LOAD ACCEPTANCE TEST AFTER PROLONGED NO LOAD OPERATION OF THE DIESEL GENERATOR

Section 6.4.2 of IEEE Standard 387-1977 requires, in part, that the load acceptance test consider the potential effects on load acceptance after prolonged no load or light load operation of the diesel generator. This capability should be demonstrated over the full range of ambient air temperatures that may exist at the diesel engine air intake.

By Amendment 4 to the FSAR, the applicant indicated that this diesel generator capability is being reviewed by the diesel engine manufacturer and that additional information with respect to the diesel generators capability will be provided at a later time. This item will continue to be pursued with the applicant.

RESPONSE

See the response to Question 430.145 for the information requested above regarding diesel generator operation under ambient conditions, including low ambient temperatures.

The Hope Creek diesel generators can accommodate a full load acceptance test per IEEE 387-1977 after a no load operation of the diesel generator.

During pre-operational testing, a full load acceptance test per IEEE 387-1977 will be performed after four hours of intermittent no load operation of a diesel generator. Intermittent operation shall consist of unloaded operating periods of fifteen minutes on an average basis. This test will be conducted in accordance with the diesel generator manufacturer's recommendations. The four hours of unloaded operation is considered to be a realistic time based on expected operation of the diesel generators.

Station operating procedures will be provided to assure that after a cumulative four hours of operation at light load, i.e., less than 20% of rated, on any diesel, that diesel will be operated for one hour at a minimum of 50% rated load as per the diesel manufacturer's recommendations.

Section 8.3.1.1.3.10 of the HCGS FSAR has been revised to incorporate the information provided above.

QUESTION 430.22 (SECTION 8.3.1)

Section 6.4.2 of IEEE Standard 387-1977 requires, in part, that the load acceptance test consider the potential effects on load acceptance after prolonged no load or light load operation of the diesel generator. Provide the results of load acceptance tests or analysis that demonstrates the capability of the diesel generator to accept the design accident load sequence after prolonged no load operation. This capability should be demonstrated over the full range of ambient air temperatures that may exist at the diesel engine air intake. If this capability cannot be demonstrated for minimum ambient air temperature conditions, describe design provision that will assure an acceptable engine air intake temperature during no load operation.

RESPONSE

See the response to Question 430.145 for the information requested above regarding operationunder ambient conditions, including low ambient temperatures.

Section 8.3.1.1.3.10 has been revised to provide the information requested regarding load acceptance tests in accordance with IEEE 387-1977.

b. Start the SDG

c. Trip and lockout the 4.16-kV feeder breakers that connect the Class 1E bus to the offsite power supplies.

On an undervoltage condition at a unit substation bus, the undervoltage relays on the unit substation bus trip the Class 1E motor feeders fed from the bus.

As the SDG reaches rated voltage and frequency, logic is provided to generate a permissive interlock for the closing of the SDG circuit breaker.

8.3.1.1.3.7 Periodic Testing of SDGs

Periodic testing of SDGs is discussed in Section 16.

8.3.1.1.3.8 Fuel Oil Storage and Transfer System

The fuel oil storage and transfer system associated with the SDGs is discussed in Section 9.5.4.

8.3.1.1.3.9 SDG Cooling Water System

The SDG cooling and heating system, including engine keepwarm, is described in Section 9.5.5.

8.3.1.1.3.10 Loading of Standby Diesel Generators

The SDGs are designed to start and attain rated voltage and frequency within 10 seconds of the receipt of the starting signal. The generator exciter, and voltage regulator are designed to permit the unit to accept the load and to start the motors in the sequence and time requirements shown in Table 8.3-1. When the automatic load sequencing of Class 1E loads is completed, the operator may manually add additional loads as shown in Table 8.3-1. The application of these additional loads does not exceed the SDG capacity.

The Hope Creek diesel generators can accommodate a full load acceptance test per IEEE 387-1977 after a no load operation of the diesel generator.

During pre-operational testing, a full load acceptance test per IEEE 387-1977 will be performed after four hours of intermittent no load operation of a diesel generator. Intermittent operation shall consist of unloaded operating periods of fifteen minutes on an average basis. This test will be conducted in accordance with the diesel generator manufacturer's recommendations. The four hours of unloaded operation is considered to be a realistic time based on expected operation of the diesel generators.

Station operating procedures will be provided to assure that after a cumulative four hours of operation at light load, i.e., less than 20% of rated, on any diesel, that diesel will be operated for one hour at a minimum of 50% rated load as per the diesel manufacturer's recommendations.

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Rev. 2

DSER Open Item No. 251 (DSER Section 8.3.3.5.5)

FAULT CURRENT ANALYSIS FOR ALL REPRESENTATIVE PENETRATION CIRCUITS

By Amendment 4 to the FSAR, the applicant indicated that coordinated fault-current versus time curves for representative penetration conductors and their protective devices are included in Figures 420.46-1 of the FSAR. Based on a review of these figures, the staff concludes that representative curves for motor differential relay, current transformer, and instrumentation circuits were not included in Figure 430.46-1. Inclusion of these circuits as well as other circuits such that the coordinated fault-current versus time curves is representative of all penetration circuits will be pursued with the applicant.

RESPONSE

FSAR Section 8.1.4.12 has been revised in response to Question 430.46, and to address this concern.

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QUESTION 430.46 (SECTION 8.3.1 and 8.3.2)

Section 8.1.4.12 of the FSAR simplies, through the use of the term "penetration conductor", that primary and backup circuit protection is provided to protect the circuit conductor versus the penetration. This design for containment electrical penetration protection does not meet the guidelines of position 1 of Regulatory Guide 1.63. Position 1 requires primary and backup protection where maximum available fault-current exceeds the current-carrying capability of the penetration versus capability of the conductors.

a. Provide justification for noncompliance with the guidelines of position 1 of Regulatory Guide 1.63.

b. Provide coordinated fault-current versus time curves for each representative type cable that penetrates primary containment. For each cable, the curves must show the relationship of the fault carrying capability between the electric penetrations, the primary overcurrent protective device, and the backup overcurrent protective device.

c. Provide the test report with results that substantiates the capability of the electrical penetration to withstand the total range of time versus fault current without seal failure for worst case environmemental conditions.

RESPONSE

FSAR Section 8.1.4.12 has been revised to provide the requested information.

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Figure 430.46-1

Sheets 1 to 15

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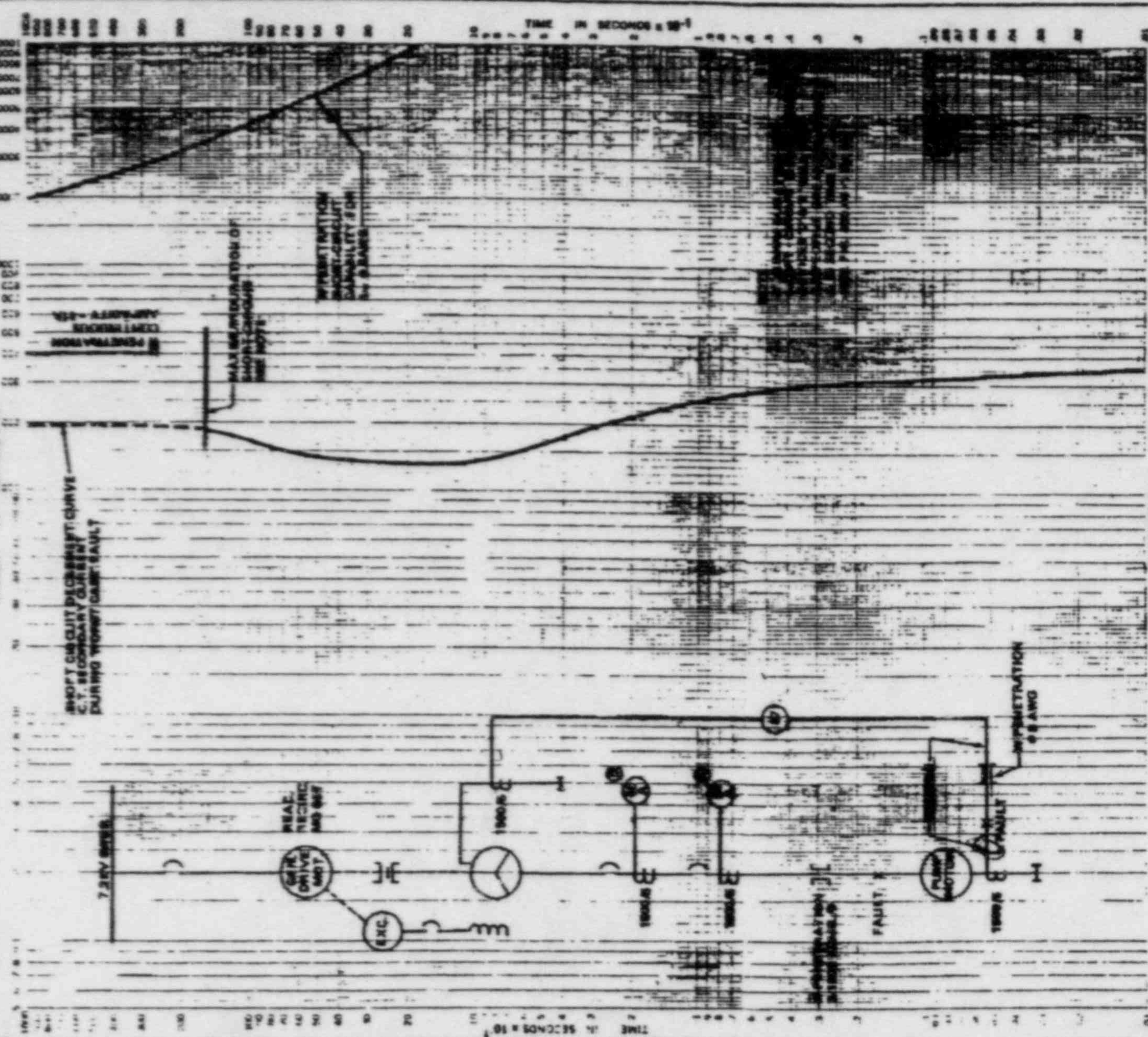
DSER ITEM 251

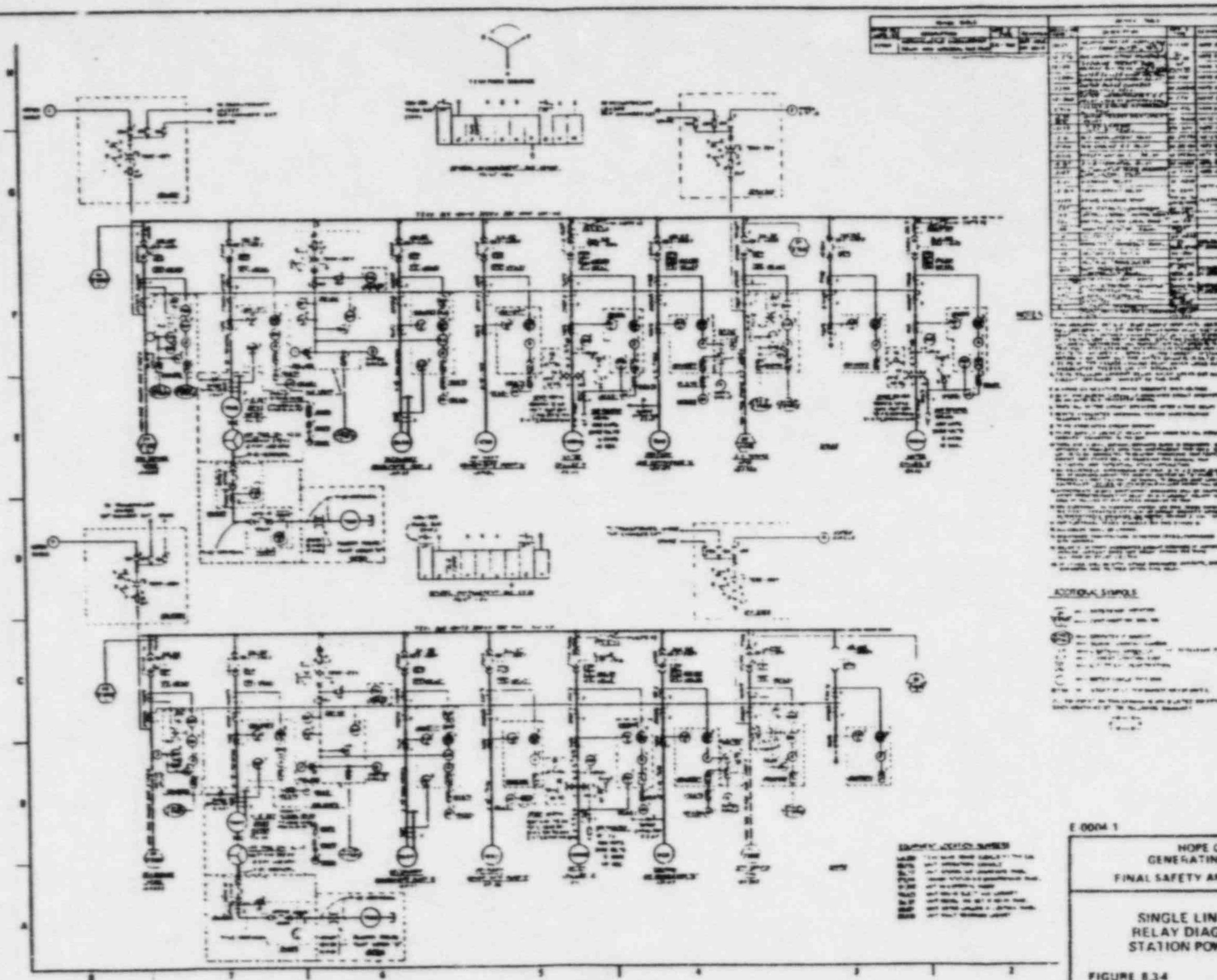


HOPE CREEK
GENERATING STATION
FINAL SAFETY ANALYSIS REPORT

PENETRATION CONDUCTOR
OVERCURRENT PROTECTION

FIGURE 430.48-1
SHEET 12 OF 21

AMENDMENT



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HOPE CREEK
GENERATING STATION
FINAL SAFETY ANALYSIS REPORT

SINGLE LINE METER &
RELAY DIAGRAM 7.2 KV
STATION POWER SYSTEM

FIGURE 8.3-4 Amendment 7, 08/84

DSER OPEN ITEM 251

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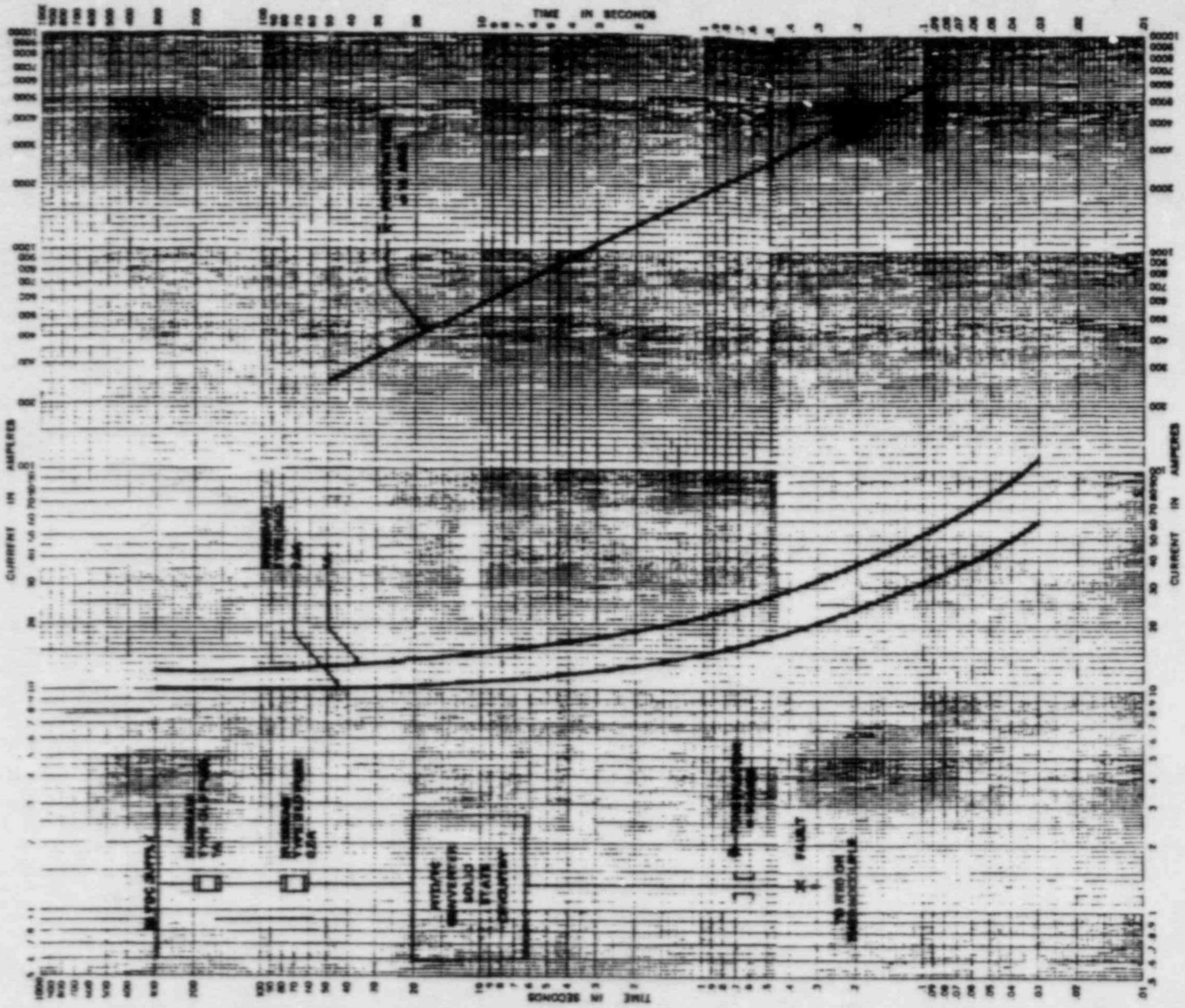

DSER ITEM 251

HOPE CREEK
GENERATING STATION
FINAL SAFETY ANALYSIS REPORT

PENETRATION CONDUCTOR
OVERCURRENT PROTECTION

FIGURE 430-46-1
SHEET 21 OF 2[illegible]

AMENDMENT

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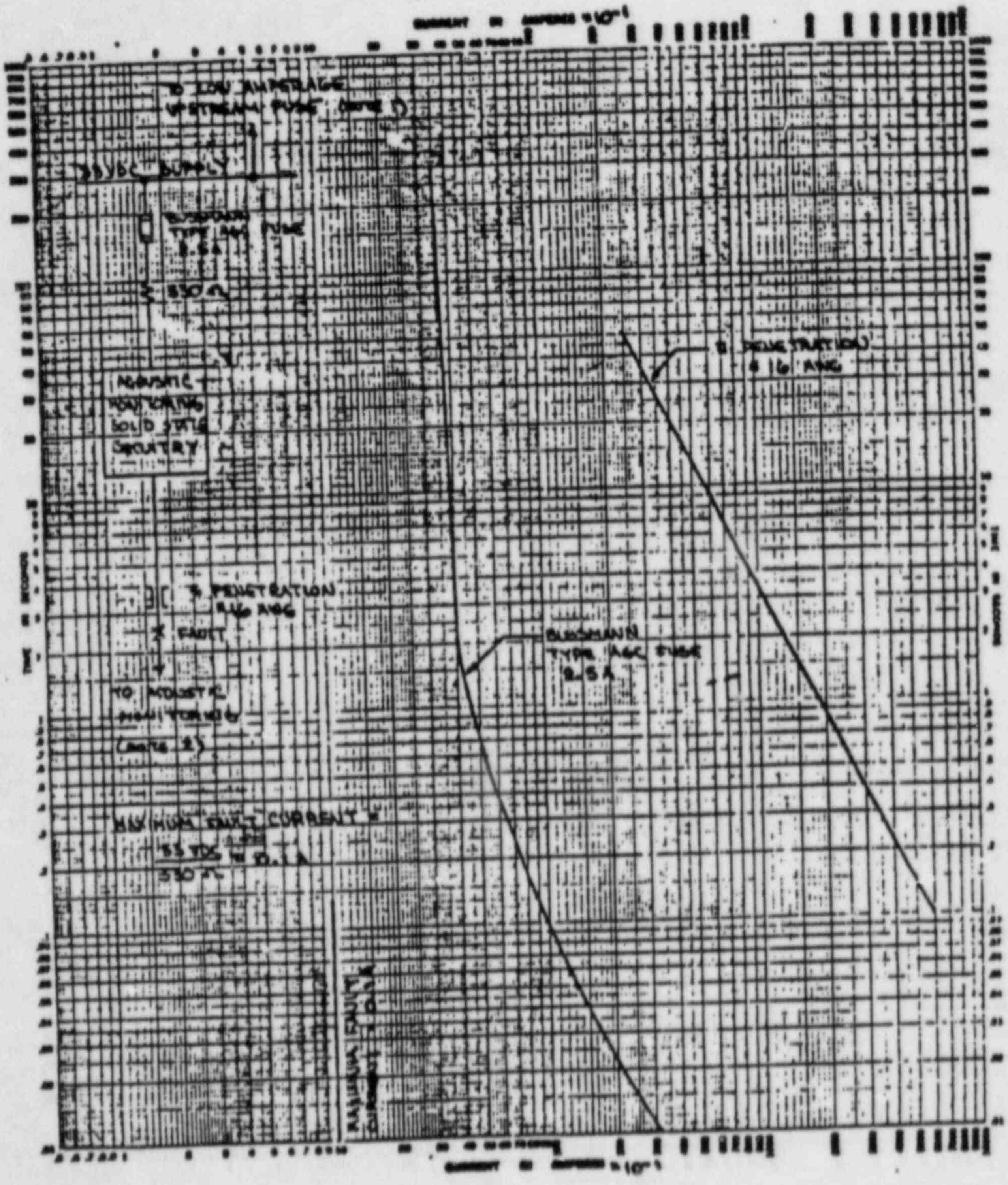

NOTES:

1) THE UPSTREAM FUSE PROVIDES OVERCURRENT PROTECTION OF THIS POWER SUPPLY AND OTHER POWER SUPPLIES OF THIS SYSTEM.
2) THIS CIRCUIT IS SIMILAR TO OTHER INSTRUMENTATION CIRCUITS THAT HAVE LOW CURRENT POWER SUPPLIES AND LOW SIGNAL LEVELS.

DSEI EN ITEM 251

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8.1.4.10 Regulatory Guide 1.53, Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems, June 1973

The electric power system is designed to comply with Regulatory Guide 1.53 as discussed in Section 1.8. All four Class 1E power system channels are designed and located in accordance with the separation criteria for the plant. Routing of cables and location of equipment is designed so that a failure of any kind in any channel cannot propagate to any other redundant channel. Consistent with the single failure criterion, only one failure is assumed to occur in the system following a DBA.

8.1.4.11 Regulatory Guide 1.62, Manual Initiation of Protective Actions, October 1973

HCGS complies with Regulatory Guide 1.62 as discussed in Section 1.8.

8.1.4.12 Regulatory Guide 1.63, Electric Penetration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Power Plants, July 1973

Design of HCGS penetration assembly systems is in compliance with Regulatory Guide 1.63, with the exceptions indicated in g, h, and i below. X

The types of circuits that go through penetration assemblies are as follows:

a. Power feeders for medium voltage 3.92-kV motors

b. Power feeders for 480-V ac motors

c. 480-V ac and 208-V ac miscellaneous power feeders

d. 120-V ac control circuits

e. 125-V dc control circuits

f. 120-V ac lighting circuits

g. Motor differential relay current transformer circuits

h. Low voltage instrumentation circuits

i. Communication circuits.

The following system features are provided to ensure compliance with the Regulatory Guide position on single random failures of circuit overload protection devices:

a. Medium voltage penetration assemblies: The only medium voltage circuits routed through the penetration are the 3.92-kV circuits for the two reactor recirculation pump motors. Each motor is supplied from a variable frequency motor-generator set. The maximum fault current available for a fault inside the containment is limited by the generator contribution and the circuit resistance. PRIMARY AND BACKUP PROTECTION FOR THE 1000 Kcmil PENETRATION IS PROVIDED BY TWO CLASS 1E CIRCUIT BREAKERS IN SERIES AS SHOWN IN FSAR FIGURE 8.3-4. EACH CIRCUIT BREAKER IS PROVIDED WITH AN OVERCURRENT RELAY. THESE RELAYS ARE SET TO TRIP THEIR RESPECTIVE CIRCUIT-BREAKERS. Figure 8.3-17, SHEET 11, SHOWS THAT THE TIME-CURRENT CAPABILITY OF THE 1000 Kcmil PENETRATION IS GREATER THAN ANY MAXIMUM SHORT CIRCUIT CURRENT VS. TIME CONDITION THAT COULD OCCUR.

DSER OPEN ITEM 351

b. 480-V ac motor feeder circuits: The 480-V ac loads inside the containment consist of Class 1E and non-Class 1E motor-operated valves and non-Class 1E continuous-duty motors. All these loads are supplied from 480-V motor control centers (MCCs).

The magnetic-only circuit breaker used in the combination starter for the motor provides primary protection for penetration conductors. A thermal-

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magnetic breaker in series with the starter breaker provides backup protection for these penetration conductors. These primary and backup breakers used for the protection of penetration conductors are both located in the same cubicle of the MCC. The primary breaker is set to provide only short circuit protection. It does not provide locked-rotor protection, which is provided by overload relays in the MCCs for non-Class 1E motor-operated valves and continuous-duty motors.

For Class 1E motor-operated valves (MOVs), the overload relay is bypassed for emergency plant operation to increase the availability of these valves in accordance with Regulatory Guide 1.106. For these Class 1E MOVs, the backup breakers are selected to allow for sustained locked rotor current and penetration conductors are selected to ensure that the thermal limits of the penetration are not exceeded during this condition.

The thermal-magnetic backup breaker has a nonadjustable trip setting, which is rated on the following basis:

1. The time-current characteristic curve remains under the thermal damage curve of the penetration conductor over the range of postulated temperatures so that the breaker trips on overcurrent before the thermal limit of the penetration conductor is reached.

2. The breaker allows locked rotor current of non-Class 1E motors for at least 10 seconds and 1000 seconds for Class 1E motors. These breaker settings prevent nuisance tripping of non-Class 1E motors during starting and allows ample time for the motors to start.

c. 480-V and 208-V miscellaneous feeders: Non-Class 1E 480-V MCCs provide power for hoists, reactor recirculation pump motor space heaters, and welding outlets in the drywell. The primary and backup protections for these feeders are provided by two thermal magnetic breakers in series. Both the breakers have the same ratings and are located in the same cubicle of the MCC. The ratings of both the breakers

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are selected so that on overcurrent, the breakers trip before the thermal limit of associated penetration conductor is reached.

208-V ac miscellaneous feeders from a 208/120-V ac power panel provide power for source range monitoring (SRM) and intermediate range monitoring (IRM) systems. The primary protection for the 208-V ac circuit is provided by fuses in each circuit conductor. These fuses are located in GE control panels. The main 20-ampere thermal-magnetic breaker, located in the power panel, provides the backup protection for these circuits. The time-current characteristics of both the fuses and circuit breakers are selected so that both the devices trip before the thermal limit of the associated penetration conductor is reached.

d. 120-V ac control circuits: 120-V ac circuits are powered from 480/120-V ac control transformers located in the MCC cubicles. Two fuses, with the same rating in series for each circuit, located in the associated cubicles of MCCs, provide both the primary and backup protection. For a fault, the fuses blow before the thermal limit of the associated penetration conductor is reached.

120-V ac control circuits fed from uninterruptible power supply (UPS) distribution panels are provided with two fuses in series for each circuit. Primary protection is provided by the fuses located in GE control panels. Backup protection is provided by the main fuse with a rating higher than the primary fuse located in the UPS panel. For a fault, the fuses blow before the thermal limit of the penetration conductor is reached.

e. 125-V dc control circuits: Each circuit powered from the 125-V dc control bus in the switchgear is provided with two fuses of the same rating located in the associated switchgear cubicle. These two fuses wired in series provide both primary and backup protection for the associated penetration conductor.

Each circuit powered from the control bus in the GE control panels is provided with a fuse in that panel to ensure primary protection for the penetration

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conductor. Backup protection is provided by the feeder breaker supplying the control bus.

In both cases above, either the primary or backup protection is capable of clearing the fault before the thermal limit of the associated penetration conductor is reached.

f. 120-V ac lighting circuits: All lighting circuits going through the penetrations are 120-V ac. Each circuit is provided with two thermal-magnetic breakers in series. The primary protection for the penetration conductor is provided by breakers located in breaker panels. Breakers located in the lighting panels wired in series circuit with breaker panels provide the backup protection for the penetration conductor.

Both the primary and backup protection are capable of clearing the fault before the thermal limit of the penetration conductor is reached.

g. Motor differential relay current transformer circuits: The only circuits in this category are the current transformer circuits for differential protection of the reactor recirculation pump motors. No protection is necessary for the penetration conductors associated with these current transformer leads because the maximum possible relay current for a sustained fault in the medium voltage cable is only 37 amperes. The ampacity of the penetration conductor is 41 amperes. Furthermore, the relay current decays to 1.7 amperes after 80 seconds because of the fault current decrement. These current transformer circuit cables are designated control cables and are routed in separate raceways from power cables. This eliminates the possibility of a short circuit between power and control cables.

INSERT "A"

h. Instrumentation circuits: Instrument circuits are all low-energy circuits carrying only a few milliamperes. Also, these circuits are routed in separate raceways from power cables to eliminate the possibility of a short between power and instrument circuits. The SHORT CIRCUIT current in the instrument circuits CAN not exceed the ampacity of penetration conductors under any faulted condition. In addition,

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Insert A

The differential relay fails safe for shorts or opens in the current transformer circuits. If the differential leads were to short while carrying their normal load of 3.17 amperes, the differential relay would operate and trip the generator drive motor in 144 milliseconds and the 3.17 amperes load would drop down to 1.7 amperes in 80 seconds. The penetration is rated for 41 amperes continuously.

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the instrumentation circuits are protected from overloads by primary overcurrent protective devices which are integral with their power supply and by backup overcurrent protective devices located upstream of the power supplies.

INSERT "B"

i. Communication circuits - Communication circuits consist of 120-V ac power and signal circuits. Each power circuit has two fuses in series. One located in the distribution panel provides the primary protection, and another located in a terminal box near the penetration provides backup protection for the associated penetration conductors. Both of these are capable of clearing the fault before the penetration conductor reaches its thermal limit.

INSERT "C"

8.1.4.13 Regulatory Guide 1.73, Qualification Tests of Electric Valve Operators Installed Inside the Containment of Nuclear Power Plants, January 1974

HCGS complies with Regulatory Guide 1.73 as discussed in Section 1.8.

8.1.4.14 Regulatory Guide 1.75, Physical Independence of Electric Systems, September 1978

HCGS complies with Regulatory Guide 1.75. Clarifications and exceptions are noted in Section 1.8.

8.1.4.14.1 General Separation Criteria

Electrical equipment and wiring for the engineered safety feature systems (ESF), reactor protection system (RPS), and neutron monitoring system (NMS) are segregated into separated channels/divisions as shown in Table 8.1-1, so that under DBAs no single credible event is capable of disabling sufficient equipment to prevent reactor shutdown, decay heat removal from the core, or mitigation of accidents. The ESF systems, RPS, and NMS are separated electrically and physically from one another, and each is further separated into four channels. The degree of separation provided is commensurate with the potential hazards in a given area.

Insert B

The only penetrations with instrument class circuits that are protected by a single circuit breaker or fuse are as follows:

1. Vibration Monitoring

   (a) Circuit breaker is 7 amperes.
   (b) Maximum short circuit current is 0.8 amperes.
   (c) Penetration is #16 AWG wire with a continuous rating of 15 amperes.
   (d) These penetrations have a continuous rating in excess of 18 times the maximum short circuit current they may be expected to experience.

2. Neutron Monitoring System

   (a) Circuit protected by a 1/4 ampere fuse.
   (b) Maximum short circuit current is 0.2 amperes.
   (c) Penetration is #16 AWG wire with a continuous rating of 15 amperes.
   (d) These penetrations have a continuous rating in excess of 75 times the maximum short circuit current they may be expected to experience.

3. Acoustical Monitoring System

   (a) Circuit protected by a 2.5 ampere fuse.
   (b) Maximum short circuit current <0.1 ampere. (The 330KΩ resistor would limit the short circuit to 0.1 ampere even if the rest of the circuit impedance was zero.)
   (c) Penetration is #16 AWG wire with a continuous rating of 15 amperes.
   (d) These penetrations have a continuous rating in excess of 150 times the maximum short circuit current they may be expected to experience.

4. Thermocouple Circuits

   (a) Thermocouples cannot generate any conceivable short circuit challenge to a penetration.

Insert C

The P.A. voice circuits carry millivolt signals only when they are actually transmitting a voice communication. The system cannot generate any conceivable short circuit challenge to a penetration.

In addition, the penetration assemblies are designed to withstand, without loss of mechanical integrity, the maximum short-circuit current vs. time conditions that could occur, given single random failures of circuit overload protection devices. Time current characteristic curves, based on tests, of the penetration conductors have been established by the penetration supplier; these curves show the maximum duration of symmetrical short circuit current. Based on these curves the primary and backup protective devices are selected to ensure that the mechanical integrity of the penetrations is maintained. Coordinated fault-current versus time curves for representative penetration conductors and the protective devices are shown in Figures 8.3-17, Sheets 1 to 22.

The test report that substantiates the capability of the electrical penetration to withstand fault current without seal failure for worst case environmental conditions has been submitted under a separate cover.

The testing of all penetration over-current protective devices will be incorporated in the HCGS Technical Specifications.

#33 Rev. 2

DSER Open Item No. 252 (DSER Section 8.3.3.5.6)

THE USE OF A SINGLE BREAKER TO PROVIDE PENETRATION PROTECTION

By Amendment 4 to tne FSAR, the applicant has indicated that penetration protection for the two reactor recirculation pump motor circuits is provided by a single breaker that is tripped by primary and backup relaying. This design does not meet the requirements of position 1 of Regulatory Guide 1.63. Justification for noncompliane will be pursued with the applicant.

RESPONSE

Figure 8.3-17, Sheet 11, has been provided to show two breakers.

The only penetrations with instrument class circuits that are protected by a single circuit breaker or fuse are as follows:

1. Vibration Monitoring

   a. Circuit Breaker is 7 amperes.
   b. Maximum short circuit current is 0.8 amperes.
   c. Penetration is #16 AWG wire with a continuous rating of 15 amperes.
   d. These penetrations have a continuous rating in excess of 18 times the maximum short circuit current they may be expected to experience.

2. Neutron Monitoring System

   a. Circuit protected by a 1/4 ampere fuse.
   b. Maximum short circuit current is 0.2 amperes.
   c. Penetration is #16 AWG wire with a continuous rating of 15 amperes.
   d. These penetrations have a continuous rating in excess of 75 times the maximum short circuit current they may be expected to experience.

3. Acoustical Monitoring System

   a. Circuit protected by a 2.5 ampere fuse
   b. Maximum short circuit current <0.1 ampere. (The 330kΩ resistor would limit the short circuit to 0.1 ampere even if the rest of the circuit impedance was zero.)
   c. Penetration is #16 AWG wire with a continuous rating of 15 amperes.
   d. These penetrations have a continuous rating in excess of 150 times the maximum short circuit current they may be expected to experience.

4. Thermocouple Circuits

   a. Thermocouples cannot generate any conceivable short circuit challenge to a penetration.

5. P.A. Voice Circuits

   a. These circuits carry millivolt signals only when they are actually transmitting a voice communication. The system cannot generate any conceivable short circuit challenge to a penetration.

6. Differential Relaying Current Transformer Secondary Leads

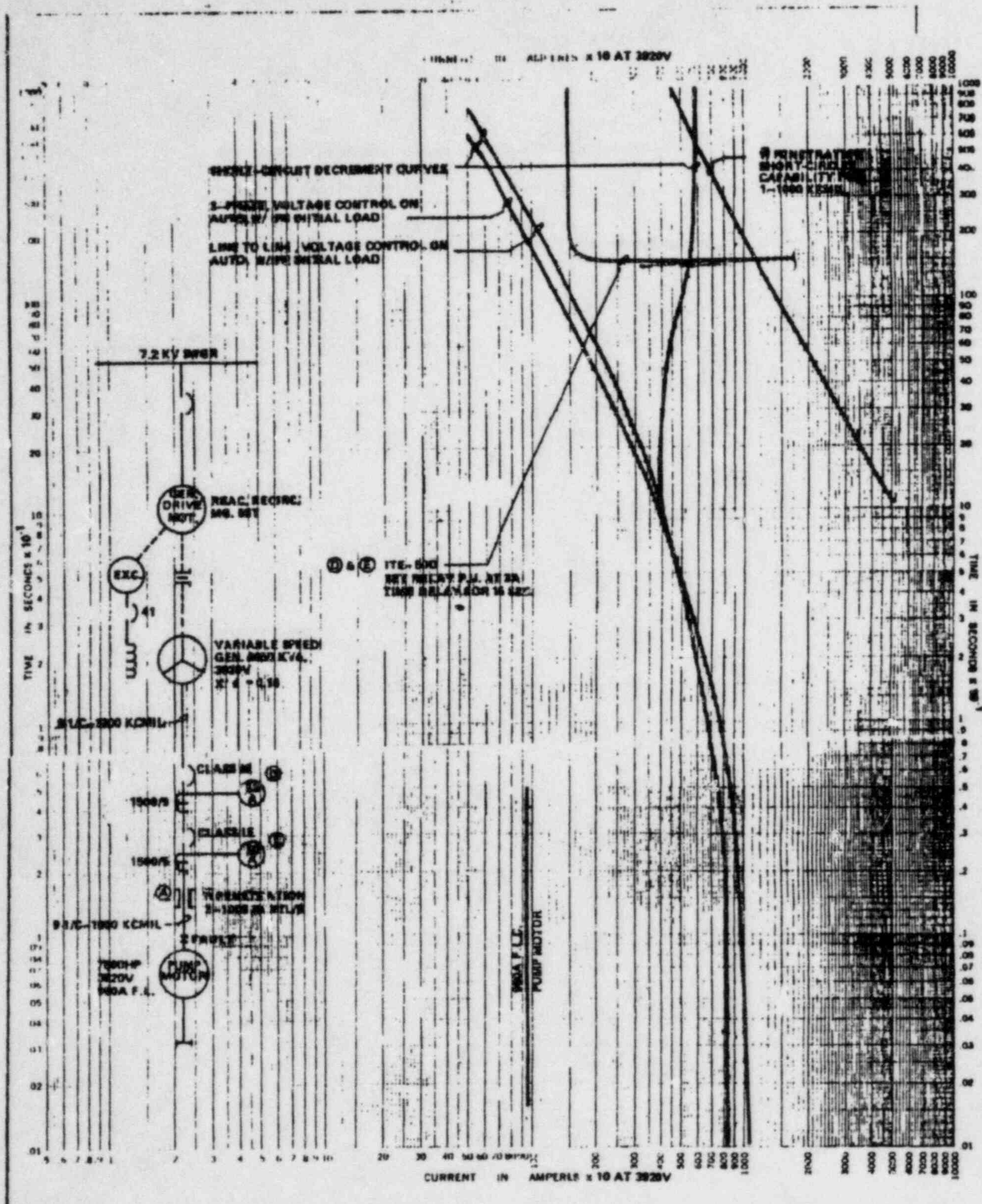
   a. These circuits carry current the equivalent of 1/300 of the current in the conductors of the reactor primary recirculation pump motor. The maximum current flowing in the differential leads under primary short circuit conditions is 37 amperes, while the normal load current in the differential leads is 3.17 amperes. The penetration is sized for 41 amperes continuous.

   b. For a primary fault of the recirculation pump motor, and assuming failure of the differential relay, the maximum duration of the 20 amperes short circuit current in the current transformer leads is 15 seconds. This is the amount of time that the back-up overcurrent relays would take to trip the dual recirculation pump motor breakers. The penetration is sized to carry 41 amperes continually and can carry 370 amperes for the same 15 seconds.

   c. The differential relay fails safe for shorts or opens in the current transformer circuits. If the differential leads were to short while carrying their normal load of 3.17 amperes, the differential relay would operate and trip the generator drive motor in 144 millisecond and the 3.17 amperes load would drop down to 1.7 amperes in 80 seconds. The penetration can carry 41 amperes continuous.

The above cases illustrate that the intent of Reg. Guide 1.63 is met. No single failure of a circuit overcurrent protective device could cause a penetration failure. Refer to the representative curves of Figure 8.3-17.

FSAR Section 8.1.4.12 has been revised to incorporate this information.



HOPE CREEK
GENERATING STATION
FINAL SAFETY ANALYSIS REPORT

PENETRATION CONDUCTOR
OVERCURRENT PROTECTION

FIGURE 430.48-1
SHEET 11 OF 21

AMENDMENT

DSER ITEM 252

ATTACHMENT 5

6.5 REVIEW AND AUDIT

6.5.1 STATION OPERATIONS REVIEW COMMITTEE (SORC)

FUNCTION

6.5.1.1 The Station Operations Review Committee shall function to advise the General Manager - Hope Creek Operations on operational matters related to nuclear safety.

COMPOSITION

6.5.1.2 The Station Operations Review Committee (SORC) shall be composed of:

Chairman:	Assistant General Manager - Hope Creek Operations
Member and Vice Chairman:	Operations Manager
Member and Vice Chairman:	Technical Manager
Member and Vice Chairman:	Maintenance Manager
Member:	Operating Engineer
Member:	I & C Engineer
Member:	Senior Nuclear Shift Supervisor
Member:	Technical Engineer
Member:	Maintenance Engineer
Member:	Radiation Protection Engineer
Member:	Chemistry Engineer
Member:	Manager - On Site Safety Review Group or his designee.

ALTERNATES

6.5.1.3 All alternate members shall be appointed in writing by the SORC Chairman.

a. Vice Chairmen shall be members of Station management.

b. No more than two alternates to members shall participate as voting members in SORC activities at any one meeting.

c. Alternate appointees will only represent their respective department.

d. Alternates for members will not make up part of the voting quorum when the member the alternate represents is also present.

MEETING FREQUENCY

6.5.1.4 The SORC shall meet at least once per calendar month and as convened by the SORC Chairman or his designated alternate.

QUORUM

6.5.1.5 The minimum quorum of the SORC necessary for the performance of the SORC responsibility and authority provisions of these technical specifications shall consist of the Chairman or his designated alternate and five members including alternates. No more than two alternates to members shall participate as voting members in SORC activities at any one meeting.

RESPONSIBILITIES

6.5.1.6 The Station Operations Review Committee shall be responsible for:

a. Review of: (1) Station Administrative Procedures and changes thereto and (2) Newly created procedures or changes to existing procedures that involve a significant safety issue as described in Section 6.5.3.2.d.

b. Review of all proposed tests and experiments that affect nuclear safety.

c. Review of all proposed changes to Appendix "A" Technical Specifications.

d. Review of all proposed changes or modifications to plant systems or equipment that affect nuclear safety.

e. Review of the safety evaluations that have been completed under the provisions of 10CFR50.59.

f. Investigation of all violations of the Technical Specifications including the preparation and forwarding of reports covering evaluation and recommendations to prevent recurrence to the Vice President - Nuclear and to the General Manager - Nuclear Safety Review.

g. Review of all REPORTABLE EVENTS.

h. Review of facility operations to detect potential nuclear safety hazards.

i. Performance of special reviews, investigations or analyses and reports thereon as requested by the General Manager - Hope Creek Operations or General Manager - Nuclear Safety Review.

j. Review of the Plant Security Plan and implementing procedures and shall submit recommended changes to the General Manager - Nuclear Safety Review.

k. Review of the Emergency Plan and implementing procedures and shall submit recommended changes to the General Manager - Nuclear Safety Review.

l. Review of the Fire Protection Program and implementing procedures and shall submit recommended changes to the General Manager - Nuclear Safety Review.

m. Review of all unplanned on-site releases of radioactivity to the environs including the preparation of reports covering evaluation, recommendations, and disposition of the corrective action to prevent recurrence and the forwarding of these reports to the Vice President - Nuclear and to the General Manager - Nuclear Safety Review.

n. Review of changes to the PROCESS CONTROL MANUAL and the OFF-SITE DOSE CALCULATION MANUAL.

SORC REVIEW PROCESS required by Specification 6.8

6.5.1.7 A technical review and control system utilizing qualified reviewers from within the station organization shall be established to perform the periodic or routine review of all procedures and changes thereto. Only those items that have a safety significance will be reviewed by SORC. Details of this technical review process are provided in Section 6.5.3.

~~SORC reviews will concentrate on safe and reliable operation of the station. Independent reviews for determination or verification of USQ shall be performed by the Nuclear Safety Review Department (NSR) and the results of NSR reviews will be provided to SORC.~~

AUTHORITY

6.5.1.8 The Station Operations Review Committee shall:

a. Recommend to the General Manager - Hope Creek Operations written approval or disapproval of items considered under 6.5.1.6 (a) through (e) above.

b. Provide written notification within 24 hours to the Vice President - Nuclear and the General Manager - Nuclear Safety Review of disagreement between the SORC and the General Manager - Hope Creek Operations; however, the General Manager - Hope Creek Operations shall have responsibility for resolution of such disagreements pursuant to 6.1.1 above.

RECORDS

6.5.1.9 The Station Operations Review Committee shall maintain written minutes of each meeting and copies shall be provided to the Vice President - Nuclear, the General Manager - Nuclear Safety Review and the Manager - Off-Site Review.

6.5.2 NUCLEAR SAFETY REVIEW

FUNCTION

6.5.2.1 The Nuclear Safety Review Department (NSR) shall function to provide the independent safety review program and audit of designated activities.

COMPOSITION

6.5.2.2 NSR shall consist of a General Manager, a Manager of the On-Site Safety Review Group (SRG) supported by at least four dedicated, full-time engineers located on-site, and a Manager of the Off-Site Review Group (OSR) supported by at least four dedicated, full time engineers located off-site.* The OSR staff shall possess experience and competence in the general areas listed in Section 6.5.2.4. The General Manager and Managers will determine when technical experts shall be used to assist in reviews of complex problems.

NSR shall establish a system of qualified reviewers from other technical organizations to augment its expertise in the disciplines of Section 6.5.2.4. Such qualified reviewers shall meet the same qualification requirements as the NSR staff, and will not have been involved with performance of the original work.

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*Since the Nuclear Department is located on Artificial Island site, the terms on-site and off-site are intended to convey the distinction between inside and outside of the station fence.

Establishment of the Manager - Off-Site Review and Staff is guided by the provisions for independent review of Section 4.3 of ANSI N18.7 (ANS-3.2), and the qualification requirements for the review staff will meet or exceed those described in Section 4.7 of ANS-3.1. The Manager - On Site Review and staff will meet or exceed the qualifications described in Section 4.4 of ANS 3.1.

CONSULTANTS

6.5.2.3 Consultants shall be utilized as determined by the NSR General Manager to provide expert advice to the NSR.

OFF-SITE REVIEW GROUP

6.5.2.4 The Off-Site Review Group (OSR) shall function to provide independent review and audit of designated activities in the areas of:

a. Nuclear Power Plant Operations

b. Nuclear Engineering

c. Chemistry and Radiochemistry

d. Metallurgy

e. Instrumentation and Control

f. Radiological Safety

g. Mechanical Engineering

h. Electrical Engineering

i. Quality Assurance

j. Nondestructive Testing

k. Emergency Preparedness

It shall also function to examine plant operating characteristics, NRC issuances, industry advisories, Licensee Event Reports, and other sources which may indicate areas for improving plant safety.

REVIEW

6.5.2.4.1 The OSR shall review:

a. The Safety evaluations for

   1) Changes to procedures, equipment, or systems and

   2) Tests or experiments completed under the provision of Section 50.59, 10CFR, to verify that such actions did not constitute an unreviewed safety question.

b. Proposed changes to procedures, equipment, or systems that involve an unreviewed safety question as defined in Section 50.59, 10CFR.

c. Proposed tests or experiments that involve an unreviewed safety question as defined in Section 50.59, 10CFR.

d. Proposed changes to Technical Specifications or to the Operating License.

e. Violations of codes, regulations, orders, Technical Specifications, license requirements, or of internal procedures or instructions having nuclear safety significance.

f. Significant operating abnormalities or deviations from normal and expected performance of plant equipment that affect nuclear safety.

g. All REPORTABLE EVENTS

h. All recognized indications of an unanticipated deficiency in some aspect of design or operation of safety-related structures, systems or components.

i. Reports and meeting minutes of the Station Operations Review Committee.

AUDITS

6.5.2.4.2 Audits of facility activities that are required to be performed under the cognizance of OSR are listed below:

a. The conformance of facility operation to provisions contained within the Technical Specifications and applicable license conditions at least once per 12 months.

b. The performance, training, and qualifications of the entire facility staff at least once per 12 months.

c. The results of actions taken to correct deficiencies occurring in facility equipment, structures, systems, or method of operation that affect nuclear safety at least once per 6 months.

d. The performance of activities required by the Operational Quality Assurance Program to meet the Criteria of Appendix "B", 10CFR50, at least once per 24 months.

e. The Facility Emergency Plan and implementing procedures at least once per 12 months.

f. The Facility Security Plan and implementing procedures at least once per 12 months.

g. Any other area of facility operation considered appropriate by the General Manager - Nuclear Safety Review or the Vice President - Nuclear.

h. The Facility Fire Protection Program and implementing procedures at least once per 24 months.

i. An independent fire protection and loss prevention program inspection and audit shall be performed at least once per 12 months utilizing either qualified off-site licensee personnel or an outside fire protection firm.

j. An inspection and audit of the fire protection and loss prevention program shall be performed by a qualified outside fire consultant at least once per 36 months.

k. The radiological environmental monitoring program and the results thereof at least once per 12 months.

The above audits shall be conducted by the Quality Assurance Department or an independent consultant. Audit results and recommendations shall be reviewed by NSR.

ON-SITE SAFETY REVIEW GROUP

6.5.2.5 The On-Site Safety Review Group (SRG) shall function to provide: the review of plant design and operating experience for potential opportunities to improve plant safety; the evaluation of plant operations and maintenance activities; and advice to management on the overall quality and safety of plant operations.

The SRG will make recommendations for revised procedures, equipment modifications, or other means of improving plant safety to appropriate station/corporate management.

RESPONSIBILITIES

6.5.2.5.1 The SRG shall be responsible for:

a. Review of selected plant operating characteristics, NRC issuances, industry advisories, and other appropriate sources of plant design and operating experience information that may indicate areas for improving plant safety.

b. Review of selected facility features, equipment, and systems.

c. Review of selected procedures and plant activities including maintenance, modification, operational problems, and operational analysis.

d. Surveillance of selected plant operations and maintenance activities to provide independent verification* that they are performed correctly and that human errors are reduced to as low as reasonably achievable.

NSR AUTHORITY

6.5.2.6 NSR shall report to and advise the Vice President - Nuclear on those areas of responsibility specified in Sections 6.5.2.4 and 6.5.2.5.

RECORDS

6.5.2.7 Records of NSR activities shall be prepared and maintained. Reports of reviews and audits shall be distributed as follows:

a. Reports of reviews encompassed by Section 6.5.2.4.1 above, shall be prepared, approved and forwarded to the Vice President - Nuclear, within 14 days following completion of the review.

b. Audit reports encompassed by Section 6.5.2.4.2 above, shall be forwarded to the Vice President - Nuclear and to the management positions responsible for the areas audited within 30 days after completion of the audit.

6.5.3 TECHNICAL REVIEW AND CONTROL

ACTIVITIES All and procedures or changes thereto,

6.5.3.1 Programs required by Technical Specification 6.8 and other procedures which affect plant nuclear safety as

*Not responsible for sign-off function

-changes thereto and any

-proposed

Each Station Department Manager shall be responsible for a pre-designated class of procedures

determined by the General Manager - Hope Creek Operations, ~~and changes thereto~~, other than editorial or typographical changes, shall receive an independent operability and technical review and be subjected to an independent USQ determination.

PROCEDURE RELATED DOCUMENTS

6.5.3.2 Procedures, Programs and changes thereto shall be reviewed as follows:

a. Each newly created procedure, program or change thereto shall be independently reviewed by an individual knowledgeable in the area affected other than the individual who prepared the procedure, program or procedure change, but who may be from the same organization as the individual/group which prepared the procedure or procedure change. Procedures other than Station Administrative procedures will be approved by the appropriate station Department Manager or by the Assistant General Manager - Hope Creek Operations. The General Manager - Hope Creek Operations shall approve Station Administrative Procedures, Security Plan implementing procedures, Emergency Plan implementing procedures, and Fire Protection Program implementing procedures.

b. On-the-spot changes to procedures which clearly do not change the intent of the approved procedures shall be approved by two members of the plant management staff, at least one of whom holds a Senior Reactor Operator's License. ~~For~~ ? revisions to procedures which may involve a change in intent of the approved procedures, ~~the person authorized above to approve the procedure, shall approve the revision~~. shall be reviewed in accordance with section 6.5.3.2.a above.

c. Individuals responsible for reviews performed in accordance with item 6.5.3.2a above shall be members of the station staff previously approved by the SORC Chairman and designated as a Qualified Reviewer. A system of Qualified Reviewers shall be maintained by the SORC Chairman. Each review shall include a written determination of whether or not additional cross-disciplinary review is necessary. If deemed necessary, such review shall be performed by the appropriate designated review personnel.

The Qualified Reviewers shall meet or exceed the qualifications described in Section 4.4 of ANS 3.1.

d. If the Department Manager determines that the documents involved contain significant safety issues, the documents shall be forwarded for SORC review and also to NSR for an independent review to determine whether or not an unreviewed safety question is involved. Pursuant to 10CFR50.59, NRC approval of items involving unreviewed safety questions or Technical Specification changes shall be obtained prior to implementation.

NON-PROCEDURE RELATED DOCUMENTS

6.5.3.3 Tests or experiments, changes to Technical Specifications, and changes to equipment or systems shall be reviewed ~~in a manner similar to that~~ described in items 6.5.3.2a, c, and d above. ~~with the exception that the~~ Recommendations for approval are made by SORC to the General Manager - Hope Creek Operations. ~~Independent safety reviews for determination or verification of unreviewed safety questions will be performed by NSR and the results of NSR reviews will be provided to SORC. NSR reviews will be performed not only by using its own staff, but, when needed, also through the use of a system of qualified reviewers established throughout the corporate organization to support NSR.~~ Pursuant to 10CFR50.59, NRC approval of items involving unreviewed safety questions or Technical Specification changes shall be obtained prior to implementation.

RECORDS

6.5.3.4 Written records of reviews performed in accordance with item 6.5.3.2a above, including recommendations for approval or disapproval, shall be maintained. Copies shall be provided to the General Manager - Hope Creek Operations, SORC, NSR, and/or NRC as necessary when their reviews are required.

6.6 REPORTABLE EVENT ACTION

6.6.1 The following actions shall be taken for REPORTABLE EVENTS:

a. The Commission shall be notified and/or a report submitted pursuant to the requirements of Section 50.73 to 10CFR Part 50, and

b. Each REPORTABLE EVENT shall be reviewed by the SORC and the resultant Licensee Event Report submitted to the NSR and the Vice President - Nuclear.

6.7 SAFETY LIMIT VIOLATION

6.7.1 The following actions shall be taken in the event a Safety Limit is violated:

a. The unit shall be placed in at least HOT STANDBY within one hour.

b. The NRC Operations Center shall be notified by telephone as soon as possible and in all cases within one hour. The Vice President - Nuclear and General manager - NSR shall be notified within 24 hours.

c. A Safety Limit Violation Report shall be prepared. The report shall be reviewed by the SORC. This report shall describe (1) applicable circumstances preceding the violation, (2) effects of the violation upon facility components, systems or structures, and (3) corrective action taken to prevent recurrence.

d. The Safety Limit Violation Report shall be submitted to the Commission, the General Manager - Nuclear Safety Review and the Vice President - Nuclear within 14 days of the violation.

ATTACHMENT 6

CPB OPEN ITEM

BWR CORE THERMAL HYDRAULIC STABILITY

Core thermal hydraulic stability will be assured by compliance with the Stability Technical Specification recommended by GE in a letter dated June 14, 1984, to the BWR Owners Group (BWROG). GE has written this specification to address the concerns of BWR Thermal Hydraulic Stability which are presented in SIL No. 380. This specification will be adopted in the Hope Creek Technical Specifications. The requirements of the limiting condition for operation will be addressed in the integrated operating and abnormal operating procedures. A surveillance test procedure will be developed to establish the baseline APRM and LPRM neutron flux noise levels and to check the existing noise levels against baseline values when required. It is PSE&G's intention at this time, to use double loop operation at Hope Creek.