Pacific Gas and Electric Company

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December 28, 2004

PG&E Letter DCL-04-141

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

Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Response to September 8, 2004, Request for Additional Information Regarding License Amendment Request 03-18, "Revision to Technical Specifications 5.5.9, 'Steam Generator (SG) Tube Surveillance Program,' and 5.6.10, 'Steam Generator (SG) Tube Inspection Report,' for 4-volt Alternate Repair Criteria for Steam Generator Tube Repair"

Dear Commissioners and Staff:

PG&E Letter DCL-03-183, dated January 7, 2004, submitted License Amendment Request (LAR) 03-18, "Revision to Technical Specifications 5.5.9, 'Steam Generator (SG) Tube Surveillance Program,' and 5.6.10, 'Steam Generator (SG) Tube Inspection Report,' for 4-volt Alternate Repair Criteria for Steam Generator Tube Repair." LAR 03-18 proposes to revise the DCPP Technical Specifications (TS) to allow application of 4-volt alternate repair criteria at intersections of SG tube hot-legs with the four lowest SG tube support plates.

PG&E Letter DCL-04-086, "Response to NRC Request for Additional Information Regarding License Amendment Request 03-18, 'Revision to Technical Specifications 5.5.9, 'Steam Generator (SG) Tube Surveillance Program,' and 5.6.10, 'Steam Generator (SG) Tube Inspection Report,' for 4-volt Alternate Repair Criteria for Steam Generator Tube Repair," dated July 23, 2004, responded to the staff's questions dated May 28, 2004. PG&E Letter DCL-04-089, "Response to June 14 and July 6, 2004, NRC Request for Additional Information Regarding License Amendment Request 03-18, 'Revision to Technical Specifications 5.5.9, 'Steam Generator (SG) Tube Surveillance Program,' and 5.6.10, 'Steam Generator (SG) Tube Inspection Report,' for 4-volt Alternate Repair Criteria for Steam Generator Tube Repair," dated July 30, 2004, responded to the staff's questions dated June 14 and July 6, 2004. PG&E Letter DCL-04-110, "Response to August 30, 2004, NRC Request for Additional Information Regarding License Amendment Request 03-18, 'Revision to Technical Specifications 5.5.9, 'Steam Generator (SG) Tube Surveillance Program,' and 5.6.10, 'Steam Generator (SG) Tube Inspection Report,' for 4-volt Alternate Repair Criteria for Steam Generator

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Tube Repair," dated September 3, 2004, responded to a staff question dated August 30, 2004.

On September 8, 2004, a meeting was held with the NRC staff to discuss and clarify the remaining issues associated with LAR 03-18. To support the review, the staff requested PG&E to submit the main steam line leak-before-break analysis calculated critical flaw size, analysis crack sizes for leakage flaws, detailed analysis leakage curves, a steam line damage mechanism assessment, the steam line weld maps, and main steam line weld inspection information. This information is provided in Enclosure 1.

In addition, the NRC staff stated the leakage detection system and the TS proposed for new TS 3.7.19 and 3.7.20 contained in PG&E Letter DCL-04-089, needed to be revised to assure redundancy and diversity are maintained similar to the leakage detection system and the associated TS approved for the Westinghouse AP1000 advanced reactor design. Therefore, revised TS 3.7.19 and 3.7.20 are provided as enclosures to this letter, which supersede those provided in PG&E Letter DCL-04-089. The technical basis for the new TS is provided in Enclosure 1. Enclosure 2 provides marked-up TS pages and Enclosure 3 provides retyped TS pages for new TS 3.7.19 and 3.7.20. Enclosure 4 provides marked-up TS Bases pages for new TS 3.7.19 and 3.7.20 for information only. Enclosure 5 provides the main steam line weld maps.

This information does not affect the results of the technical evaluation or the no significant hazards consideration determination previously transmitted in PG&E Letter DCL-03-183.

If you have any questions, or require additional information, please contact Stan Ketelsen at (805) 545-4720.

Sincerely,

DH Oatley

David H. Oatley
Vice President and General Manager

kjse/4328
Enclosures

cc: Edgar Bailey, DHS
Bruce S. Mallett
David L. Proulx
Diablo Distribution

cc/enc: Girija S. Shukla

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of PACIFIC GAS AND ELECTRIC COMPANY	)	Docket No. 50-275 Facility Operating License No. DPR-80
Diablo Canyon Power Plant Units 1 and 2	)	Docket No. 50-323 Facility Operating License No. DPR-82

AFFIDAVIT

David H. Oatley, of lawful age, first being duly sworn upon oath says that he is Vice President and General Manager – Diablo Canyon of Pacific Gas and Electric Company; that he has executed this response to the NRC request for additional information on License Amendment Request 03-18 on behalf of said company with full power and authority to do so; that he is familiar with the content thereof; and that the facts stated therein are true and correct to the best of his knowledge, information, and belief.

David H. Oatley
Vice President and General Manager

Subscribed and sworn to before me this 28th day of December 2004.

Notary Public
County of San Luis Obispo
State of California

SANDRA L. RECTOR
Commission # 1339380
Notary Public - California
San Luis Obispo County
My Comm. Expires Jan 12, 2006

ENCLOSURE 1

PG&E Response to the September 8, 2004, NRC Request for Additional Information Regarding License Amendment Request 03-18, "Revision to Technical Specifications 5.5.9, 'Steam Generator (SG) Tube Surveillance Program,' and 5.6.10, 'Steam Generator (SG) Tube Inspection Report,' for 4-volt Alternate Repair Criteria for Steam Generator Tube Repair"

Critical Flaw Sizes and Calculated Crack Sizes for Leakage Flaws

Detailed results of the Leak-Before-Break (LBB) analysis for the Diablo Canyon Power Plant Units 1 and 2 (DCPP) main steam lines are contained in Tables 1-A through 1-D for Unit 1 main steam lines 1-1 through 1-4, respectively, and in Tables 1-E through 1-H for Unit 2 main steam lines 2-1 through 2-4, respectively. For each node point modeled for the eight main steam lines inside containment, the LBB analysis moment and critical flaw size are provided for the normal operating procedure (NOP) loads and the normal operating procedure plus dynamic (NOP + DYN) loads. In addition, for the NOP + DYN loads, the leakage flaw size, crack growth, and leakage for the leakage flaw are provided.

The calculated crack growth for the leakage flaw assumed 20 dynamic load cycles (maximum of safe shutdown earthquake (SSE) or main steam isolation valve closure). The crack growth calculation corrects an error in the original LBB analysis report SIR-03-146, Revision 1, provided in Enclosure 7 to PG&E Letter DCL-03-183, dated January 7, 2004, and uses a more accurate stress intensity factor (K) formulation. The calculated crack growth for 20 dynamic cycles is negligible (less than 0.059 inches), thus a leakage size flaw would remain stable for a sufficient amount of time for it to be detected. Using the more accurate K formulation, the 0.4 inch crack length growth calculated for 400 load cycles that was referred to on page 6-6 of SIR-03-146, Revision 1, is 1.14 inches. However, there is no need to consider 400 dynamic load cycles due to a SSE since this is well beyond the design basis of DCPP and greatly exceeds the number of SSE cycles which would occur in the time period before steam generator (SG) replacement.

Detailed Leakage Curves

Figures 1-A and 1-B illustrate the LBB analysis leak rates graphically for Unit 1 and Unit 2, respectively. The figures have also been updated to show additional leakage rate curves from those originally provided on pages 5-21 and 5-22 of the LBB analysis report SIR-03-146, Revision 1.

Table 1-A
Results for Each Piping Node - Unit 1 Main Steam 1-1

Node #	NOP		NOP+DYN				Leakage (gpm)
	Moment (in-kips)	Critical Flaw Size (in.)	Moment (in-kips)	Critical Flaw Size (in.)	Leakage Flaw Size (in.)	Crack Growth in 20 Load Cycles (in.)(1)	
20	232.2	47.71	7437.3	21.60	10.80	0.059	2
20A	721	44.66	5856.3	24.73	12.36	0.038	3.8
40	1439.5	40.60	2752.1	34.42	17.21	0.010	>10
50	1729.8	39.10	2307.6	36.35	18.17	0.003	>10
70B	1928.6	38.12	2812.2	34.17	17.08	0.005	>10
70M	2142.4	37.11	3781	30.53	15.27	0.011	>10
70E	2030.7	37.63	3827.9	30.38	15.19	0.012	>10
80	1848.2	38.51	3481.6	31.59	15.79	0.012	>10
80A	1264.5	41.54	2780.8	34.30	17.15	0.011	>10
90	685.2	44.87	3208.3	32.60	16.30	0.015	8.5
100	515.3	45.91	3180.1	32.71	16.35	0.017	8.1
100A	286.1	47.36	3378.9	31.96	15.98	0.022	7.2
110	142.1	48.30	3795.2	30.49	15.24	0.028	5.9
110A	369.3	46.83	4271.2	28.94	14.47	0.029	5.4
115	697.7	44.80	5030.4	26.76	13.38	0.031	4.8
120	785.6	44.27	4692.8	27.69	13.84	0.027	5.5
120A	1168.2	42.07	3397.6	31.89	15.95	0.013	>10
170	1553.1	40.01	2723.5	34.54	17.27	0.009	>10
180B	2018.3	37.69	4039.2	29.68	14.84	0.013	>10
180M	2095.1	37.33	3628.6	31.06	15.53	0.011	>10
180E	1853	38.49	3228.9	32.52	16.26	0.010	>10
202	1515.7	40.20	2597.3	35.07	17.54	0.008	>10
205	1098.6	42.46	2738.9	34.47	17.24	0.012	>10
210B	1089	42.52	2962.4	33.56	16.78	0.012	>10
210M	1088.7	42.52	3177	32.72	16.36	0.013	>10
212	1104	42.43	3954.2	29.95	14.98	0.017	7.8
215M	1132.5	42.27	4626.2	27.88	13.94	0.022	6.3
220	1158.9	42.12	5407	25.79	12.90	0.028	4.9

(1) 20 Cycles of maximum of SSE or MSIV load superimposed on normal operating loads.

Table 1-B
Results for Each Piping Node - Unit 1 Main Steam 1-2

Node #	NOP		NOP+DYN				Leakage (gpm)
	Moment (in-kips)	Critical Flaw Size (in.)	Moment (in-kips)	Critical Flaw Size (in.)	Leakage Flaw Size (in.)	Crack Growth in 20 Load Cycles (in.)(1)	
20	623.4	45.25	7877.9	20.85	10.43	0.057	2.2
20A	862.9	43.81	6159.1	24.06	12.03	0.039	3.7
20B	1170.5	42.06	4437.6	28.43	14.22	0.020	6.8
40	1446.6	40.56	2776.3	34.32	17.16	0.010	>10
50	1709	39.21	2523.6	35.39	17.69	0.005	>10
70 B	1875.2	38.38	2918.2	33.74	16.87	0.007	>10
70 M	2004.6	37.76	3575.4	31.25	15.63	0.011	>10
70 E	1877.7	38.37	3748.3	30.65	15.32	0.013	>10
80	1713.1	39.19	3403	31.87	15.94	0.012	>10
80A	1388.8	40.87	2827.9	34.11	17.05	0.011	>10
80B	1107.8	42.41	3077.7	33.11	16.55	0.013	>10
90	910.9	43.53	3705.8	30.79	15.40	0.017	8
100	775.2	44.33	3830.3	30.37	15.18	0.020	7.3
110	527.2	45.84	4406.6	28.53	14.26	0.028	5.5
110A	615.4	45.29	4332	28.75	14.38	0.026	5.9
120	886.6	43.68	4322	28.78	14.39	0.022	6.5
150	1086.8	42.53	4367	28.65	14.32	0.020	6.8
170	1602.7	39.75	2887.5	33.86	16.93	0.009	>10
180 B	2056.1	37.51	3341.1	32.10	16.05	0.009	>10
180 M	2167.3	36.99	3772.6	30.56	15.28	0.011	>10
180 E	2016.4	37.70	3538.9	31.38	15.69	0.011	>10
202	1884.7	38.34	3240.5	32.48	16.24	0.010	>10
202A	1587.2	39.83	2657	34.82	17.41	0.008	>10
205	1497.7	40.29	3002.7	33.40	16.70	0.011	>10
210 B	1507.1	40.25	3257.7	32.41	16.21	0.012	>10
210 M	1511.2	40.22	3453.4	31.69	15.84	0.013	>10
212	1490.9	40.33	3800.2	30.47	15.23	0.014	9
215 M	1450.3	40.54	4251.2	29.00	14.50	0.015	7.8
220	1391.9	40.85	4509	28.22	14.11	0.018	7

(1) 20 Cycles of maximum of SSE or MSIV load superimposed on normal operating loads.

Table 1-C
Results for Each Piping Node - Unit 1 Main Steam 1-3

Node #	NOP		NOP+DYN				Leakage (gpm)
	Moment (in-kips)	Critical Flaw Size (in.)	Moment (in-kips)	Critical Flaw Size (in.)	Leakage Flaw Size (in.)	Crack Growth in 20 Load Cycles (in.)(1)	
20	655.8	45.05	7192.6	22.03	11.01	0.051	2.5
20A	520.4	45.88	5144	26.46	13.23	0.035	4.2
20B	888.4	43.67	3721.9	30.74	15.37	0.017	7.8
40	1314.1	41.27	2381.3	36.02	18.01	0.008	>10
50	1662.6	39.44	2206.9	36.81	18.40	0.002	>10
70 B	1856.1	38.48	2704.6	34.62	17.31	0.005	>10
70 M	2071.7	37.44	3554.6	31.32	15.66	0.010	>10
70 E	1982.3	37.86	3634.7	31.04	15.52	0.012	>10
80	1813.1	38.69	3268.1	32.37	16.19	0.010	>10
80A	1350.8	41.07	2802.9	34.21	17.10	0.011	>10
90	1019.2	42.91	3437.9	31.74	15.87	0.014	8.8
100	882.6	43.70	3458.4	31.67	15.84	0.015	8.4
105	589.5	45.45	3761.6	30.60	15.30	0.021	7
110	562.5	45.62	3827.2	30.38	15.19	0.022	6.8
110A	558.5	45.64	3849.8	30.30	15.15	0.023	6.9
120	783	44.29	4090.3	29.51	14.76	0.022	6.8
130	1009.6	42.97	4329.6	28.76	14.38	0.021	6.7
170	1564.6	39.95	2830.5	34.09	17.05	0.009	>10
180 B	2012.6	37.72	3321.1	32.18	16.09	0.009	>10
180 M	2093.3	37.34	3644.6	31.01	15.50	0.011	>10
180 E	1879.2	38.36	3315.9	32.20	16.10	0.010	>10
202	1789	38.81	3125.3	32.92	16.46	0.010	>10
202A	1390	40.86	2339.6	36.20	18.10	0.007	>10
205	1325.7	41.21	2778.2	34.31	17.16	0.011	>10
210 B	1345.4	41.10	2945.5	33.63	16.81	0.012	>10
210 M	1384.5	40.89	3236.6	32.49	16.25	0.013	>10
212	1415.2	40.73	3792.7	30.49	15.25	0.013	8.9
215 M	1433.1	40.64	4485.1	28.29	14.15	0.017	7.2
220	1429.9	40.65	4880	27.17	13.58	0.021	6.4

(1) 20 Cycles of maximum of SSE or MSIV load superimposed on normal operating loads.

Table 1-D
Results for Each Piping Node - Unit 1 Main Steam 1-4

Node #	NOP		NOP+DYN				Leakage (gpm)
	Moment (in-kips)	Critical Flaw Size (in.)	Moment (in-kips)	Critical Flaw Size (in.)	Leakage Flaw Size (in.)	Crack Growth in 20 Load Cycles (in.)(1)	
20	136.5	48.34	6556	23.24	11.62	0.053	2.6
30	173.8	48.09	6239.2	23.89	11.94	0.050	2.8
30A	825.2	44.04	5173.8	26.38	13.19	0.031	4.8
40	1372.6	40.96	2545.4	35.30	17.65	0.009	>10
50	1670.2	39.40	2487.1	35.55	17.77	0.005	>10
70 B	1856	38.48	2848.6	34.02	17.01	0.007	>10
70 M	2022.8	37.67	3480.6	31.59	15.79	0.010	>10
70 E	1903.3	38.25	3513.3	31.47	15.74	0.011	>10
80	1717.3	39.17	3098.2	33.03	16.51	0.010	>10
80A	1356.9	41.04	2707.9	34.60	17.30	0.010	>10
80B	998	43.03	2879	33.90	16.95	0.012	>10
90	642.8	45.13	3301.7	32.25	16.12	0.017	8.1
100	488.4	46.08	3354.6	32.05	16.03	0.019	7.8
110	158.3	48.20	3966.2	29.91	14.96	0.029	5.5
110A	408.7	46.58	4183.3	29.22	14.61	0.028	5.7
120	757.5	44.44	4615.9	27.91	13.95	0.027	5.6
150	861.5	43.82	4790.2	27.41	13.71	0.027	5.5
150A	1221.1	41.78	3624	31.08	15.54	0.013	8.9
170	1582.6	39.85	2974.6	33.51	16.76	0.010	>10
180 B	2019.7	37.68	3425.1	31.79	15.90	0.010	>10
180 M	2108.9	37.26	3790.6	30.50	15.25	0.012	>10
180 E	1921.3	38.16	3395.2	31.90	15.95	0.011	>10
202	1795.9	38.77	3115.8	32.96	16.48	0.010	>10
202A	1471.6	40.43	2639.1	34.89	17.45	0.009	>10
205	1273.2	41.49	3155.2	32.80	16.40	0.013	>10
210 B	1250	41.62	3334.5	32.13	16.06	0.013	>10
210 M	1200.6	41.89	3596	31.18	15.59	0.013	8.9
212	1145.6	42.20	4218.8	29.10	14.55	0.018	7.2
215 M	1094.5	42.48	4629.3	27.87	13.94	0.022	6.3
220	1048.5	42.74	4819.1	27.33	13.67	0.025	5.8

(1) 20 Cycles of maximum of SSE or MSIV load superimposed on normal operating loads.

Table 1-E
Results for Each Piping Node - Unit 2 Main Steam 2-1

Node #	NOP		NOP+DYN				Leakage (gpm)
	Moment (in-kips)	Critical Flaw Size (in.)	Moment (in-kips)	Critical Flaw Size (in.)	Leakage Flaw Size (in.)	Crack Growth in 20 Load Cycles (in.)(1)	
5	1104.9	42.43	3956.6	29.95	14.97	0.017	7.7
7 B	1104.9	42.43	3996.2	29.82	14.91	0.017	7.7
7 M	1099.3	42.46	3996.2	29.82	14.91	0.017	7.7
8	1094.5	42.48	3686	30.86	15.43	0.015	8.3
9 B	1094.5	42.48	3688.3	30.85	15.43	0.015	8.3
9 M	1101.3	42.45	3175.5	32.73	16.36	0.013	>10
19	1117.6	42.35	3063.7	33.16	16.58	0.013	>10
20	1129.1	42.29	2841.8	34.05	17.02	0.012	>10
24	1140.6	42.23	2764.4	34.37	17.18	0.012	>10
28	1440.2	40.60	2495.7	35.51	17.76	0.008	>10
29	1687.1	39.32	2742.9	34.46	17.23	0.007	>10
30	1743	39.04	2815.2	34.16	17.08	0.008	>10
35 B	1810.6	38.70	2906.1	33.79	16.89	0.008	>10
35 M	2031.4	37.63	3139.4	32.87	16.43	0.008	>10
35 E	1950.2	38.02	2777.8	34.31	17.16	0.005	>10
40	1919.9	38.16	2725.3	34.53	17.27	0.005	>10
41	1874.5	38.39	2649.6	34.85	17.42	0.004	>10
45	1466.6	40.46	2264.8	36.54	18.27	0.005	>10
45A	1156.5	42.14	2458.6	35.67	17.84	0.010	>10
50	847.6	43.90	2708.3	34.60	17.30	0.012	>10
55	802.7	44.17	2746.4	34.44	17.22	0.012	>10
58	659.9	45.02	2867.4	33.94	16.97	0.013	>10
59	497.7	46.02	3013.7	33.36	16.68	0.016	8.7
60	157.9	48.20	3700.4	30.81	15.41	0.027	6.1
70	450.7	46.31	3658.3	30.96	15.48	0.022	7.1
71	494.3	46.04	3658.5	30.96	15.48	0.022	7
80	626.8	45.23	3667	30.93	15.46	0.020	7.3
85	790.7	44.24	3695.7	30.83	15.41	0.018	7.7
85A	1164.6	42.09	3139.6	32.86	16.43	0.013	>10
85B	1540.3	40.07	3273.4	32.35	16.18	0.012	>10
90	1916.9	38.18	3784.4	30.52	15.26	0.013	>10
95 B	2057.2	37.51	3947.4	29.98	14.99	0.013	10
95 M	2169	36.98	3072.3	33.13	16.56	0.005	>10
95 E	1966.3	37.94	5146.9	26.45	13.23	0.017	6.8
101	1775.3	38.88	5865	24.71	12.35	0.024	5.3
105	1442.7	40.58	4689.4	27.70	13.85	0.019	6.8
110	1373.4	40.95	4449.2	28.40	14.20	0.018	7
120	1309	41.30	4227.6	29.08	14.54	0.017	7.7
120A	710.7	44.72	2628.7	34.94	17.47	0.012	>10
120B	134.3	48.36	3252	32.44	16.22	0.023	7.1
121	702.7	44.77	4825.3	27.32	13.66	0.029	5
125	795.1	44.21	5038.7	26.74	13.37	0.030	5

(1) 20 Cycles of maximum of SSE or MSIV load superimposed on normal operating loads.

Table 1-F
Results for Each Piping Node - Unit 2 Main Steam 2-2

Node #	NOP		NOP+DYN				Leakage (gpm)
	Moment (in-kips)	Critical Flaw Size (in.)	Moment (in-kips)	Critical Flaw Size (in.)	Leakage Flaw Size (in.)	Crack Growth in 20 Cycles Load (in.)(1)	
5	1401.7	40.80	4441.5	28.42	14.21	0.017	7.1
7 B	1401.8	40.80	4472	28.33	14.17	0.018	7.1
7 M	1431.3	40.64	4426.4	28.47	14.23	0.017	7
8	1441	40.59	3997.4	29.81	14.91	0.013	8.3
9 B	1441	40.59	3996.4	29.82	14.91	0.013	8.3
9 M	1433.4	40.63	3612.5	31.12	15.56	0.013	9.9
9 E	1408.4	40.77	3386.6	31.93	15.97	0.013	>10
20	1390.4	40.86	3186.7	32.68	16.34	0.012	>10
24	1384.5	40.89	3093.3	33.04	16.52	0.012	>10
24A	1460.7	40.49	2560.5	35.23	17.62	0.008	>10
30	1790	38.80	2854.9	33.99	17.00	0.007	>10
40 B	1864.5	38.43	2970.8	33.53	16.76	0.008	>10
40 M	2037.5	37.60	3186.4	32.68	16.34	0.008	>10
41	1936.3	38.08	2886	33.87	16.93	0.006	>10
45	1482.4	40.38	2241.5	36.65	18.32	0.005	>10
50	920.3	43.48	2797.5	34.23	17.12	0.012	>10
55	881.5	43.71	2848.1	34.02	17.01	0.012	>10
59	762.4	44.41	3014.3	33.35	16.68	0.013	9.5
60	696.4	44.80	3120.1	32.94	16.47	0.015	8.1
65	666.1	44.99	3173.8	32.73	16.37	0.015	8.2
70	645.9	45.11	3212.2	32.59	16.29	0.016	8.3
70A	530.9	45.81	3572.7	31.26	15.63	0.021	7.3
75	579.4	45.52	4127.7	29.39	14.70	0.025	6
80	780.8	44.30	4144.5	29.34	14.67	0.022	6.5
85	921.3	43.47	4193.4	29.18	14.59	0.021	6.8
90	1076	42.59	4273.3	28.93	14.47	0.020	6.8
90A	1271	41.51	3512.7	31.47	15.74	0.013	9.2
90B	1543.6	40.06	3539.5	31.38	15.69	0.013	10
95	1860.1	38.46	4057.3	29.62	14.81	0.014	9.1
100 B	2027.3	37.65	4270.5	28.94	14.47	0.014	9
100 M	2134.4	37.14	3082.9	33.08	16.54	0.006	>10
100 E	1959.6	37.97	5814.1	24.82	12.41	0.022	5.5
106	1759.4	38.96	6868.7	22.63	11.31	0.033	3.9
110	1458.7	40.50	5615.8	25.29	12.64	0.026	5.1
112	1386	40.89	5315.7	26.02	13.01	0.025	5.5
115	1318.7	41.25	5037.9	26.74	13.37	0.023	5.8
115A	731.2	44.59	2858.6	33.98	16.99	0.012	7.2
115B	429.9	46.45	3754.9	30.62	15.31	0.024	5.5
120	979.9	43.14	5617.1	25.28	12.64	0.032	4.4

(1) 20 Cycles of maximum of SSE or MSIV load superimposed on normal operating loads.

Table 1-G
Results for Each Piping Node - Unit 2 Main Steam 2-3

Node #	NOP		NOP+DYN				Leakage (gpm)
	Moment (in-kips)	Critical Flaw Size (in.)	Moment (in-kips)	Critical Flaw Size (in.)	Leakage Flaw Size (in.)	Crack Growth in 20 Load Cycles (in.)(1)	
5	1395.8	40.83	4410.6	28.52	14.26	0.017	7.4
7 M	1422	40.69	4370.9	28.64	14.32	0.017	7.4
8	1428.5	40.66	3946.6	29.98	14.99	0.013	8.5
9 M	1418.7	40.71	3541.3	31.37	15.69	0.013	10
9 E	1393	40.85	3310.5	32.22	16.11	0.013	>10
20	1376.7	40.94	3129.6	32.90	16.45	0.012	>10
24	1370.8	40.97	3035.5	33.27	16.64	0.012	>10
24A	1392.8	40.85	2591.6	35.10	17.55	0.009	>10
25	1528.1	40.14	2501.5	35.49	17.74	0.007	>10
30	1594.1	39.79	2551.4	35.27	17.63	0.007	>10
35	1860.3	38.46	2900.1	33.81	16.91	0.007	>10
40 M	2038.4	37.60	3118.4	32.95	16.47	0.007	>10
40 E	1941	38.06	2827.4	34.11	17.05	0.005	>10
40A	1716.8	39.17	2416.6	35.86	17.93	0.004	>10
45	1495.5	40.31	2223.2	36.73	18.37	0.004	>10
45A	1197.3	41.91	2443.7	35.74	17.87	0.009	>10
50	916.7	43.50	2741.4	34.46	17.23	0.012	>10
55	878.2	43.72	2787.9	34.27	17.14	0.012	>10
58	641.8	45.13	3126.9	32.91	16.46	0.015	8.7
58A	526.3	45.84	3458.5	31.67	15.83	0.020	7.5
60	571.9	45.56	3975.3	29.88	14.94	0.024	6.5
65	911.7	43.53	4083	29.54	14.77	0.020	7
70	1072.7	42.61	4169.8	29.26	14.63	0.019	7.1
70A	1265	41.54	3426.9	31.79	15.89	0.013	9.7
70B	1532	40.12	2875.6	33.91	16.96	0.010	>10
75	1841.5	38.55	2997.2	33.42	16.71	0.008	>10
80 B	2016.4	37.70	3187	32.68	16.34	0.008	>10
80 M	2120.6	37.21	3064.4	33.16	16.58	0.006	>10
80 E	1942.9	38.05	3946.7	29.98	14.99	0.013	9.7
86	1734.1	39.08	4408.2	28.52	14.26	0.014	8
90	1444.4	40.58	3623.1	31.08	15.54	0.013	9.5
90A	816.7	44.09	2722.6	34.54	17.27	0.012	>10
90B	418.5	46.52	3628.3	31.06	15.53	0.023	6.9
100	971.6	43.18	5562.8	25.41	12.71	0.032	4.5

(1) 20 Cycles of maximum of SSE or MSIV load superimposed on normal operating loads.

Table 1-H
Results for Each Piping Node - DCPP Unit 2 Main Steam 2-4

Node #	NOP		NOP+DYN				Leakage (gpm)
	Moment (in-kips)	Critical Flaw Size (in.)	Moment (in-kips)	Critical Flaw Size (in.)	Leakage Flaw Size (in.)	Crack Growth in 20 Load Cycles (in.)(1)	
5	1104.7	42.43	4651.8	27.81	13.90	0.023	5.2
7 M	1099.9	42.45	4440.9	28.42	14.21	0.021	6.7
8	1095.3	42.48	3958.5	29.94	14.97	0.017	7.8
9 B	1095.3	42.48	3956.4	29.95	14.97	0.017	7.8
9 M	1101.7	42.44	3321.4	32.17	16.09	0.013	9.7
19	1117.3	42.36	3041.9	33.25	16.62	0.013	>10
20	1133.7	42.26	2828.8	34.10	17.05	0.012	>10
24	1146.7	42.19	2739.2	34.47	17.24	0.012	>10
24A	1274.1	41.49	2497.1	35.51	17.75	0.009	>10
30	1489.5	40.34	2688.3	34.69	17.34	0.009	>10
31	1587.2	39.83	2834	34.08	17.04	0.009	>10
35	1802.5	38.74	3169.9	32.75	16.37	0.010	>10
40M	2023.1	37.67	3434.8	31.76	15.88	0.010	>10
45	1943.1	38.05	2992.7	33.44	16.72	0.007	>10
46	1897.9	38.27	2831.5	34.09	17.05	0.006	>10
47	1492.4	40.32	2585.1	35.12	17.56	0.008	>10
47A	1182.3	41.99	3231	32.51	16.26	0.013	9.6
50	873.4	43.75	4190.3	29.19	14.60	0.022	6.7
55	828.8	44.01	4344.7	28.72	14.36	0.023	6.2
65	690.6	44.84	4839.7	27.28	13.64	0.030	5
70	540.2	45.76	5412.8	25.78	12.89	0.037	4
70A	265	47.50	4933.4	27.02	13.51	0.037	4.2
75	163.5	48.16	4727.6	27.59	13.80	0.036	4.2
79	538.8	45.77	3848.4	30.31	15.15	0.023	7
80	582.6	45.50	3769.8	30.57	15.29	0.022	7
85	744.7	44.51	3503	31.51	15.75	0.017	8
85A	1109.6	42.40	3049.3	33.22	16.61	0.013	>10
85B	1476.9	40.40	2825.5	34.12	17.06	0.010	>10
90	1845.1	38.53	3274	32.35	16.18	0.010	>10
95 B	2040.9	37.58	3488.8	31.56	15.78	0.010	>10
95 M	2151.1	37.07	3123	32.93	16.46	0.006	>10
95 E	1947.8	38.03	4397.6	28.55	14.28	0.014	8.5
101	1724.3	39.13	4958.8	26.95	13.48	0.018	6.8
106	1362.2	41.01	3818.8	30.41	15.20	0.013	8.7
110	1286.8	41.42	3620.6	31.09	15.55	0.013	9
110A	423.6	46.49	3332.7	32.13	16.07	0.020	7.6
120	696	44.81	6047.3	24.30	12.15	0.040	3.5

(1) 20 Cycles of maximum of SSE or MSIV load superimposed on normal operating loads.

Figure 1-A
Leak-Before-Break Analysis Leak Rates for Diablo Canyon Unit 1

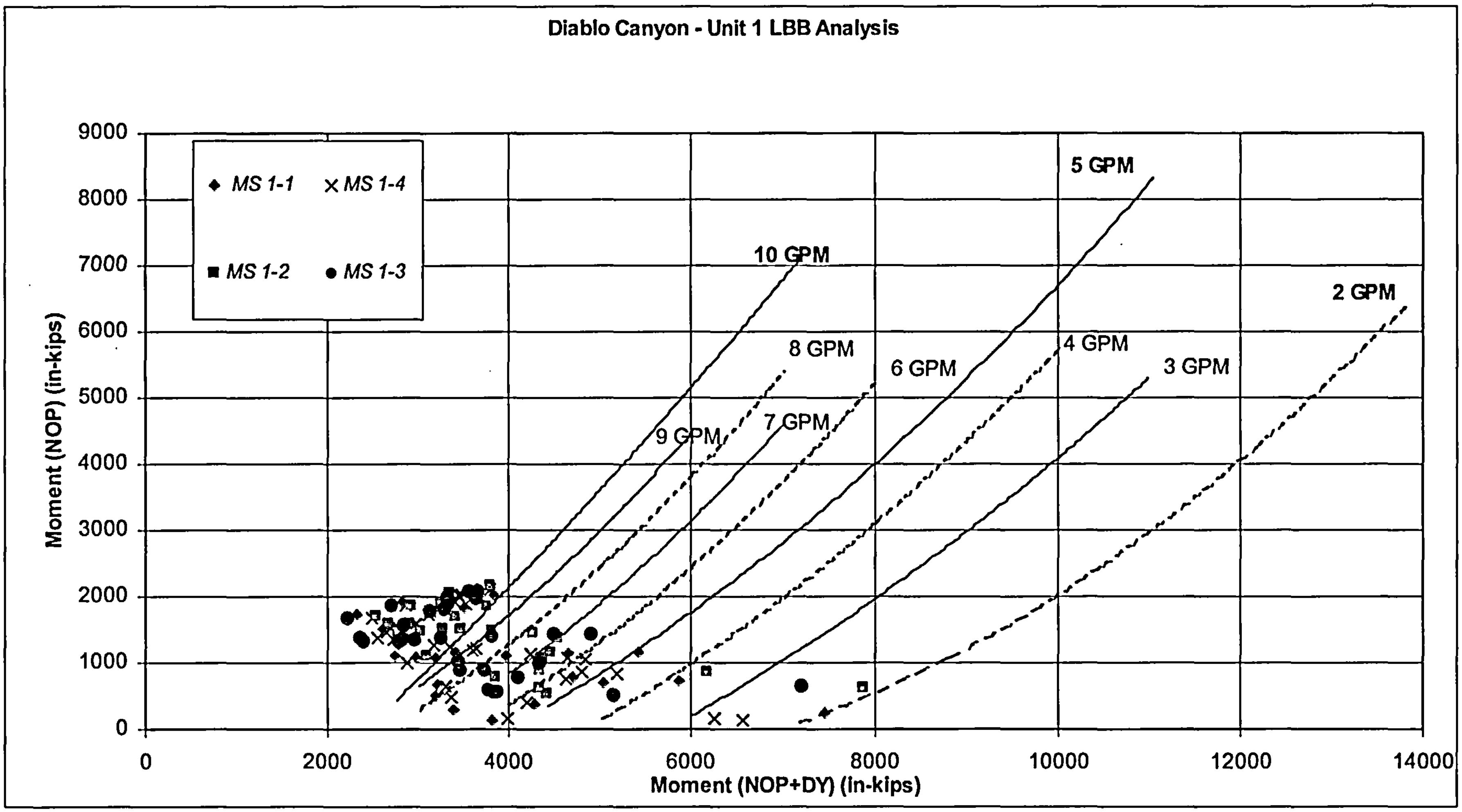
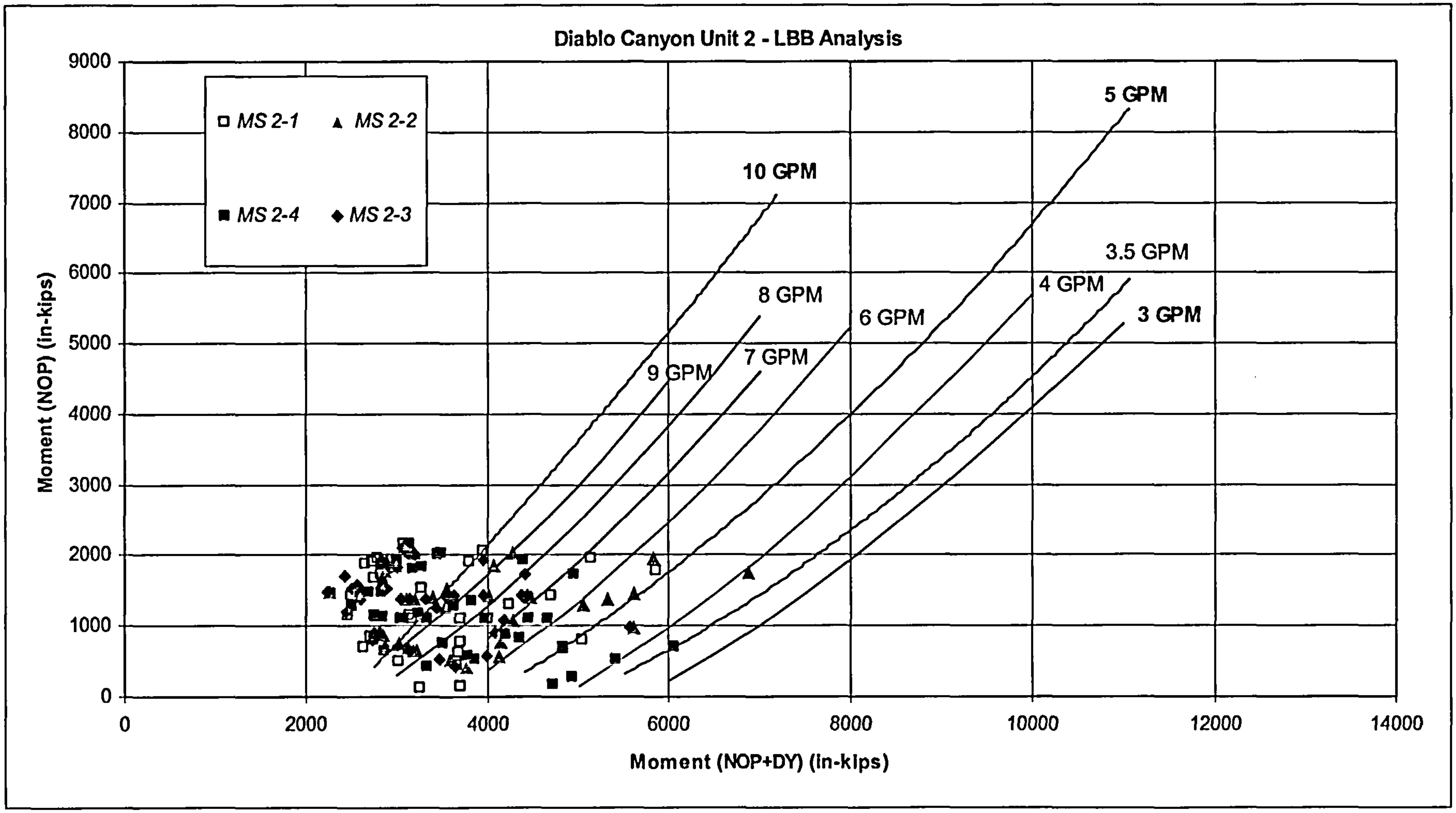


Figure 1-B
Leak-Before-Break Analysis Leak Rates for Diablo Canyon Unit 2



Main Steam Line Damage Mechanism Assessment

All potential main steam line (MSL) damage mechanisms were evaluated for the MSLs inside containment. Fatigue was identified as the only credible mechanism. Evaluated mechanisms include:

- Thermal fatigue
  - Thermal stratification, cycling and striping fatigue
  - Thermal transient fatigue
- Stress corrosion cracking
  - Intergranular stress corrosion cracking
  - Transgranular stress corrosion cracking
  - External chloride stress corrosion cracking
  - Primary water stress corrosion cracking
- Localized corrosion
  - Microbiologically influenced corrosion
  - Pitting
  - Crevice corrosion
- Flow sensitive corrosion
  - Erosion-cavitation
  - Flow accelerated corrosion

It was determined that no additional damage mechanisms existed for the MSLs inside containment. Therefore, fatigue is the only mechanism available to cause flaw propagation.

Steam Line Weld Maps

MSL weld map drawings, which depict the welds in the MSLs are contained in Enclosure 5. Drawings are provided for the DCPP Unit 1 MSLs 1-1, 1-2, 1-3, and 1-4 and DCPP Unit 2 MSLs 2-1, 2-2, 2-3, and 2-4.

MSL Weld Inspections

All circumferential and longitudinal welds of the DCPP Units 1 and 2 MSLs inside containment have been 100 percent volumetrically examined via radiography during plant construction. Periodic volumetric examinations have been conducted on a sampling of these welds since plant construction in accordance with the NRC approved in-service inspection program. The periodic examinations of the MSL welds following original construction are as follows:

UNIT 1	**Weld #**	**Examination type & date**
SG 1-1	WICG 9-1	magnetic particle testing (MT) & ultrasonic testing (UT) 3/1988 MT & UT 4/1997

	WICG 1-1	MT 4/1994
	WICG 18-1	MT & UT 5/1997 8 inches outside containment
SG 1-2	WICG 10-2	MT & UT 4/1997
	WICG 2-2	MT 4/1994
	WICG 1-2	MT 4/1994
SG 1-3	WICG 1-3	MT 4/1994
	WICG 2-3	MT 4/1994
SG 1-4	WICG 1-4	MT 4/1994
	WICG 2-4	MT & UT 4/1994
	WICG 12-4	MT & UT 5/1997 outside containment
	WICG 27-4	on safety valve MT & UT 4/08/04 outside containment

UNIT 2	Weld #	Examination type & date
SG 2-1	WICG 4-1	MT & UT 2/1998
SG 2-1	WICG 9-1	flued head MT 11/1988 UT 03/1990 UT & MT 2/1998
SG 2-1	WICG 11-1	MT & UT 3/1998 8 inches outside containment
SG 2-1	WICG 21-1	MT & UT 2/1998 outside containment

All of the above periodic examinations following start of commercial operation were satisfactory. Note that some of the above examinations were performed on welds outside containment. Although these are not the welds of concern for the MSL LBB license amendment proposal, they are MSL welds that carry the same quality and *construction examination requirements. The satisfactory results of these* examinations thus provide added assurance that no degradation mechanism is active in the MSLs.

The results of the above periodic examinations found detectable flaws at only one weld since the start of plant operation. The flaws were three linear indications, with a maximum depth of 0.047 inches and with lengths of 2 inches, 7/16 inches, and 1-5/16 inches, separated by short ligaments. They were found on MSL 1-4 at weld number WICG 2-4. Although these flaws met code acceptance criteria and could have remained, PG&E elected to remove them for analysis as well as to examine the similar welds on all other Unit 1 MSLs. No defects were found on the other MSLs inspected. Oxide analysis of the flaw determined that the flaw was not service induced – it had existed since prior to post-weld heat treatment.

The fact that the above flaws had been missed by radiography is understandable. The shallow flaw depth (0.047 inches, less than 0.5 percent throughwall) is well below reliable detection thresholds due to the limited cross section and low contrast in a heavy wall examination radiograph film. Although other similarly small flaws could have escaped detection from initial construction, the potential for such small flaws is recognized and accommodated by code-specified design margins. The possibility of such a pre-existing flaw is similarly recognized and acknowledged in the LBB analysis.

Accommodation of small pre-existing flaws was previously addressed in the LBB analysis by conservatively assuming the presence of an initial circumferential flaw of 15 percent of the pipe thickness, which envelopes with significant margin the shallow flaws identified above. Furthermore, the more conservative crack growth laws for water environment were used in the crack growth evaluation versus air environment. The results of the crack growth analysis were reported in the LBB analysis report SIR-03-146, Revision 1, section 6.5, previously submitted as part of LAR 03-18 in PG&E letter DCL-03-183 dated January 7, 2004. The results of the previously reported crack growth analysis demonstrated that even with the conservative assumptions of a 15 percent crack and crack growth for a water environment, the fatigue crack growth over the design life of the plant remains acceptable.

Future MSL Inspections

To support the application of LBB to the MSLs, PG&E has committed to inspect the most limiting welds of concern. These welds were selected as posing the greatest challenge for detection of 10 percent of the calculated LBB leakage flaw flowrate. The proposed inspection plan addresses all flaws with a calculated leakage flaw flowrate of 5 gpm or less. Additionally, each intersecting seam weld will be examined for a distance of 2.5 times the thickness from the edge of the scheduled circumferential weld.

The proposed weld inspection plan was previously provided to the NRC in PG&E Letter DCL-04-089 dated July 30, 2004. The previously submitted inspection schedule has been revised due to deferring the Unit 2 SG Tube Support Plate (TSP) locking until Unit 2 Refueling Outage 13 (2R13). The inspections previously planned for Unit 2 Refueling Outage 12 will be performed in 2R13. The inspection plans start with the outage when the SG TSP locking is performed. Thus, deferral of SG locking will result in the deferral of any planned inspections to the outage in which the SG TSP locking is performed. Inspections planned for outages after locking will be performed as planned, although inspections will not be performed if SG TSP locking has not been not performed. The modified inspection plan is provided below.

The 15 circumferential welds to be inspected are:

MSL 1-1: Welds WICG10-1/250, RB-228-1, WICG2-1, RB-228-3/251
MSL 1-2: Welds WICG10-2/277, RB-227-3/278
MSL 1-3: Weld WICG10-3/315
MSL 1-4: Welds WICG10-4/343, RB-225-3/344
MSL 2-1: Weld WICG9-1/343

MSL 2-2: Welds RB-227-12/360, RB-227-10
MSL 2-3: Weld RB-226-12/375
MSL 2-4: Welds RB-225-8/327, RB-225-12/325

The nine Unit 1 circumferential welds will be inspected according to the schedule contained in the following table:

MSL for Unit 1	MSL Weld Inspection Schedule			
	Outage # 1R13	Outage # 1R14	Outage # 1R15	Outage # 1R16
1-1	WICG10-1/250	WICG2-1 **	RB-228-1*	RB-228-3/251*
1-2	WICG10-2/277	-	RB-227-3/278*	-
1-3	WICG10-3/315	-	-	-
1-4	WICG10-4/343	RB-225-3/344	-	-

* This weld will not be inspected if the Steam Generators are replaced prior to or during the outage.
** This will include the adjacent pipe to nozzle weld (WICG1-1).

The six Unit 2 circumferential welds will be inspected according to the schedule contained in the following table:

MSL for Unit 2	MSL Weld Inspection Schedule	
	Outage # 2R13	Outage # 2R14
2-1	WICG9-1/343	-
2-2	RB-227-10, RB-227-12/360	-
2-3	RB-226-12/375	-
2-4	RB-225-12/325	RB-225-8/327*

* This weld will not be inspected if the Steam Generators are replaced during the outage.

<u>Required Response Time of the Leakage Detection System Based on the Fracture Mechanics Analysis of Leakage Flaw Growth Rate</u>

It was determined that fatigue is the only mechanism available to cause flaw propagation. Therefore the LBB analysis considered flaw propagation due to fatigue.

Although not required by the LBB analysis guidance of NUREG-1061, the LBB analysis determined maximum stable crack sizes based on NOP loads only (no SSE/MSIV closure loads). As expected, these flaws were determined to be substantially larger than the maximum stable flaw sizes in the NOP + SSE/MSIV

(NOP + DYN) loads cases. For the most limiting leakage flaw locations the flaws were at least 1.6 times the critical flaw size for the NOP + DYN load cases. This information is provided in Tables 1-A through 1-H for each MSL pipe node modeled in the LBB analysis.

As shown in Section 6.5.2 of Report SIR-03-146, Revision 1, a fracture mechanics evaluation was performed by applying 400 SSE cycles to the most limiting leakage flaw of the DCPP analysis – Node 10 in the flued-head of SG 1-2. This evaluation conservatively combined the higher SSE loading with the higher number of cycles equivalent to the design operating basis earthquake. With an initial leakage flaw of 9.24 inches, the 400 cycles resulted in a flaw growth of only 1.14 inches, substantially less than the critical flaw size of 2 times the leakage flaw. This limiting leakage flaw has a corresponding leakage flowrate of 2 gpm. The required detection threshold is 10 percent of this, or 0.2 gpm.

Similarly, all leakage flaws were subjected to 20 cycles of the most limiting SSE/MSIV loads and the flaw growths are provided in Tables 1-A through 1-H. The results illustrate that flaw growth from design basis SSE/MSIV loads are of no significance in propagating a flaw to pipe failure.

Based on the above, a postulated leakage flaw in the DCPP MSLs inside containment, leaking at 0.2 gpm, has no mechanism to propagate to a flaw of unstable size. Consequently, 7 days to detect a 0.2-gpm leak and place the plant in a safe condition is considered a conservative time in which to identify the leak and take action. A system capable of detecting a 0.2-gpm leak and allowing a controlled plant shutdown within 7 days is considered a sufficiently sensitive system to assure the integrity of the MSL pressure boundary is maintained.

In summary, other than fatigue, there are no other mechanisms to propagate a postulated leakage flaw in the DCPP MSLs inside containment, leaking at a minimum of 0.2 gpm. Flaw growth was determined to be of no risk in creating an unstable crack as described in Section 6.5.2 of Report SIR-03-146, Revision 1, contained in Enclosure 7 of PG&E Letter DCL-03-183 dated January 7, 2004. Consequently, 7 days is considered to be sufficient time in which to identify a 0.2-gpm leak and take action to place the plant in a safe condition.

<u>Description of MSL Leakage Detection Instrumentation</u>

The TS 3.7.19 MSL leakage detection instrumentation consists of two containment sump level detection systems and one containment sump flow monitor system. Each of the two containment sumps used to collect containment leakage are instrumented with two different types of level detectors. Each of the level detection systems provide an alarm in the control room for increases of greater than or equal to 0.2 gpm in the normal leakage inside containment. The two containment sump level detection systems provide redundant means to detect MSL leakage while the containment sump flow monitor system provides a diverse means to detect MSL leakage.

Standard Review Plan (NUREG-0800) Section 3.6.3, item 3 of Section III "Review Procedures," states in part that leakage detection systems are evaluated to determine that they are sufficiently reliable, redundant, and sensitive and that systems equivalent to Regulatory Guide (RG) 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems," dated May 1973, are required for the piping under evaluation inside the containment. Standard Review Plan Section 3.6.3, Section V, "Implementation," states in part "Except in those cases in which the applicant proposes an acceptable alternative method for complying with specific portions of the Commission's regulations, the methods described herein will be used by the staff in its evaluation of conformance with Commission regulations." Therefore, Standard Review Plan 3.6.3 allows an applicant to propose an acceptable alternative method for complying with specific portions of the Commission's regulations.

NUREG-1061, Volume 3, "Report of the U.S. Nuclear Regulatory Commission Piping Review Committee, Evaluation of Potential Pipe Breaks", dated November 1984, provides regulatory recommendations for application of LBB. Section 2.4, "Technical Specification," of NUREG-1061, Volume 3, states (page 2-5) that the recommendations of RG 1.45 are not mandatory.

The MSL leakage detection instrumentation meets the intent of the primary guidelines of RG 1.45, in that it is redundant, diverse, reliable, sensitive, and controlled by the TS. The MSL leakage detection instrumentation for the MSL piping inside containment does not meet RG 1.45 because RG 1.45 was created for reactor coolant system (RCS) piping leakage detection systems, to meet 10 CFR 50 Appendix A General Design Criterion 30, and provides guidelines for use of an airborne particulate radioactivity based monitor for leakage detection. Although DCPP has an airborne particulate radioactivity monitor, since radioactivity levels are very low or nonexistent in the secondary system, radioactivity based monitors cannot be relied upon to detect leakage in MSL piping.

The proposed DCPP MSL leakage detection instrumentation provides the following features that are sufficient to ensure the system is reliable, redundant, sensitive, and meets the intent of the reliability, redundancy, and sensitivity requirements of RG 1.45:

- Three detection systems, which employ different detection methods, are used consisting of two different sump level detection systems and a sump flow monitoring system

- Each of the two sump level detection systems will require an operating containment fan cooler unit (CFCU) aligned to each sump, a level transmitter in each sump, and a level monitoring computer that provides a control room alarm

- The detection systems are required to be operable by the TS during Modes 1 to 4

- Each sump level detection system will have continuous data quality monitoring and alarming on failures

- The sump level transmitters have an availability over 99 percent and are considered reliable

- The plant process computer used for the level monitoring and control room alarm in the first sump level detection system has an availability of over 99 percent, is considered reliable, and can be backed up with an equivalent level monitoring computer with control room alarm capability.

- The control system process computer used for the level monitoring and control room alarm in the second sump level detection system is widely used in the process industry and has an availability on the order of 99.9 percent or greater excluding power loss failures, and can be backed up with an equivalent level monitoring computer with control room alarm capability.

- Each of the three detection systems have a response time which is less than the response time required by the fracture mechanics analysis

- Each of the three detection systems has the required sensitivity to detect leakage from the MSLs inside containment prior to a significant failure of the piping. All are capable of detecting a leak that is a factor of 10 less than the leakage flaw flowrate determined by the fracture mechanics analysis in a response time which is less than that required by the fracture mechanics analysis.

First Containment Sump Level Detection System

The first containment (structure) sump level detection system uses a bubbler tube type level detector in each of the two containment sumps. These level detectors are currently credited to provide reactor coolant system leakage detection by TS 3.4.15.a. The first containment sump level detection system consists of two containment sumps, an operating containment fan cooler unit (CFCU) aligned to each sump, a level transmitter in each sump, and a level monitoring computer that provides a control room alarm. The operation of the containment sump level detection system is based on the collection of water condensed from the containment atmosphere. The containment atmosphere is circulated through the CFCUs to remove heat and moisture from the containment. Cooling coils cool air passing through the CFCUs. Water vapor contained in the air will condense onto the cooling coils. This condensation, in turn, will accumulate in the CFCU drains and drain to the containment sumps where the levels will be continuously monitored for accumulation and accumulation rate by the plant process computer (PPC) or equivalent computer device.

The condensation from the CFCUs is directed to the containment sumps via a drain line. Individual drain lines may be closed via remote manual valves to determine the condensation rate from its associated CFCU. Only one CFCU condensate collection monitor can be placed in service at a time. During normal operation these valves are left open because the frequent alarms would constitute an operator distraction. Placing a CFCU condensate collection monitor in service will cause a delay in the response of the level detection system to a 0.2 gpm steam leak. This delay is considered in the response time of the level detection system and is less than 11 minutes.

A design change was made to DCPP in September, 2004, to allow the PPC to monitor the containment sump levels continuously and to provide a control room alarm in the event of a 0.2-gpm leak. Based on testing in progress at this time, the first containment sump level detection system can detect a 0.2 gpm leak in less than 2 hours.

The level of each sump is continuously indicated in the control room and will alarm if it reaches the high-high level. Additionally, the rate of level change of each sump, and the combined sumps, will be continuously monitored for a change in the rate of increase. The timeliest response is assured by monitoring the change in each sump level independently. This reduces the potential for the response to be biased by the steam line crack location with respect to the CFCUs that are operating. The monitoring system will initiate a control room alarm if either sump level changes by a specified amount. This amount will be set to assure the ability to detect a 1.0-gpm leak within one hour, and to detect a 0.2-gpm leak.

Second Containment Sump Level Detection System

The second containment sump level detection system will use a direct immersion sensor type level detector in each of the two containment sumps. Similar to the first containment sump level detection system, the second containment sump level detection system consists of the two containment sumps, an operating containment fan cooler unit (CFCU) aligned to each sump, a level transmitter in each sump, and a level monitoring computer that provides a control room alarm.

The second containment sump level detection system consists of a differential pressure transmitter with a direct immersion sensor connected via a capillary tube to the transmitter. The instrument loop is connected to a control system process computer (CSPC) that uses the level signal with time to produce an alarm signal for annunciation of increased flow. The CSPC will monitor the calculated flow rates and generate a digital output (DO) alarm if the flow rate in either sump or the combined sumps exceeds the 0.2 gpm specified as the setpoint. The alarm from the second containment sump level detection system is independent from the first containment sump level detection system. The CSPC also provides the calculated sump flow rates to the PPC for informational purposes. The flow rates are derived and calculated within the CSPC and sent to the PPC as a separate input from the existing containment sump level system. Additionally, the CSPC will be accessible and can be connected to a portable or local computer to display levels, alarms, a short history of values, and the calculated flow rates. The only common equipment between the first and second containment sump level detection system is the PPC (only used for display of the calculated sump flow rate of the second system) and Plant Main Annunciator System (MAS, with common Alarm Window). Figure 2 illustrates the control loop for one sump. The second sump is identical and uses a common loop power supply and common CSPC.

The design change to install the second containment sump level detection system will be performed on a schedule to support locking of the SG tube support plates and prior to crediting the requested 4-volt alternate repair criteria. The design change is required to provide a control room alarm in the event of a 0.2-gpm leak using the second containment sump level detection system.

Containment Sump Flow Monitor System

The containment sump flow monitor system consists of an integrated flow measurement device (totalizer) on each containment sump. This flow monitor system is already in use to satisfy TS 3.4.15.a. The containment sump flow monitor system provides a diverse backup method to the containment sump level detection systems. The containment sump flow monitor system uses a different measuring process than the sump level detection systems.

The containment sump levels are controlled by the containment sump level control system which consists of a level switch in each sump that provides start and stop signals to two sump pumps in each sump. The sump pump discharge flows are indicated at the auxiliary control board while the pumps are operating. The integrated total flow is indicated at the auxiliary control board by the odometer style flow totalizer. The containment sump level control system will start one sump pump at a sump level of 26 inches, start the second sump pump at a sump level of 32 inches, and stop both sump pumps at a sump level of 13 inches. Normally the second sump pump will not start because the first sump pump has sufficient pumping capacity to prevent the sump level from reaching 32 inches. A main control room alarm will sound if the sump level reaches 32 inches.

Containment leakage monitoring is performed by the plant operators recording sump level and sump pump total flow every 12 hours as required by plant surveillance procedure STP I-1A. This surveillance calculates the leakage flowing to the containment sump by dividing the total sump level change and sump pump flow by the time since the previous surveillance. If the sump level transmitters were not

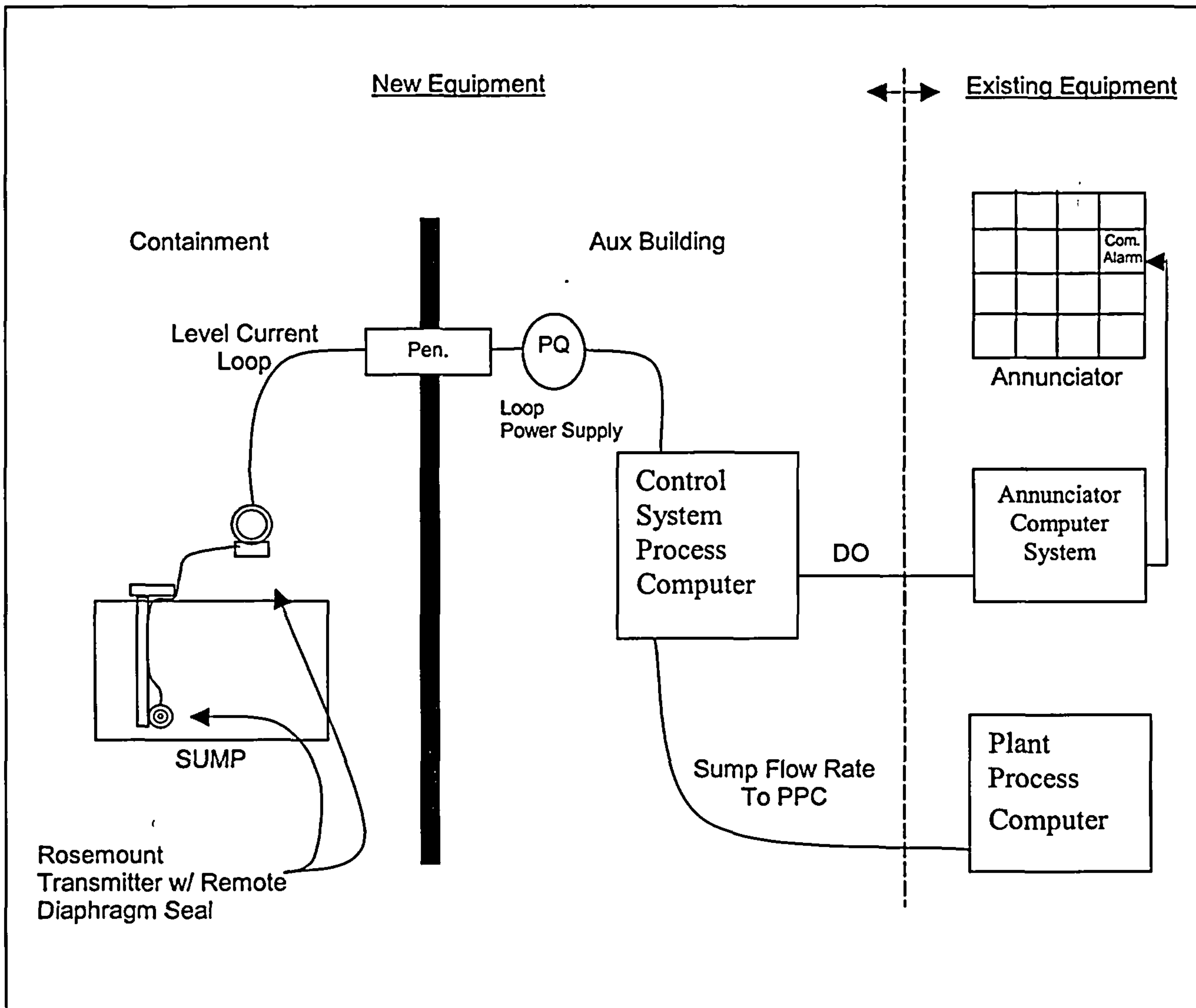

New Equipment
Existing Equipment
Containment
Aux Building
Level Current Loop
Pen.
PQ
Loop Power Supply
Com. Alarm
Annunciator
Control System Process Computer
DO
Annunciator Computer System
SUMP
Sump Flow Rate To PPC
Plant Process Computer
Rosemount Transmitter w/ Remote Diaphragm Seal

FIGURE 2

functioning, the change in the sump pump total flow will still change periodically due to containment leakage increasing the sump levels to 26 inches.

It is noted that the probability that the plant will have to rely on the containment sump flow monitor system instead of the containment sump level detection system is extremely small for the following reasons:

- The probability of failure of both containment sump level detection systems at the same time is low since the only common equipment to detect and generate an alarm between the first and second containment sump level detection system is the plant MAS with common alarm window,
- The chance of undetectable failures is low since each sump level detection system will have continuous data quality monitoring and alarming on failures, and
- Problems with one of the level detection systems can be readily observed by a difference in the indicated sump level for each system on the PPC display. Failures of both systems that would continuously give the same incorrect value are not credible.

Sensitivity and Response Time of MSL Leakage Detection System

Required Sensitivity for MSL Leakage Detection System

A LBB analysis of the MSLs was prepared in support of the SG tube support plate locking and modification of the SG voltage based alternate repair criteria. One of the requirements for an approved LBB methodology is the ability to detect leakage from the affected system prior to significant failure of the piping crediting LBB. The fracture mechanics analysis of the MSLs determined that a flaw of one-half the largest stable crack size in the MSLs would result in a 2.0 gpm steam leak. The design margins for LBB require a leak detection system with capability of detecting a leak that is a factor of 10 less than the leakage flaw flowrate. This factor means the leak detection system must be capable of detecting a 0.2 gpm steam leak. [Note the limiting leakage crack of 2.0 gpm is for Unit 1, the limiting leakage crack for Unit 2 is 3.5 gpm].

Sump Level Detection System Response Time

A summary of the evaluation conducted to estimate the response time required for operators to detect a 0.2 gpm steam leak inside containment using the containment sump level detection system is provided below. The evaluation was performed for the first containment sump level detection system and bounds the second containment sump level detection system since the level detectors which will be used in the new second containment sump level detection system will be required to be as accurate or more accurate than those used in the current first containment sump level detection system. The repeatability of the level detectors is the only parameter in the evaluation which is different for the two containment sump level detection systems.

DCPP has a large dry containment. Conditions within the containment are controlled by the operation of up to five CFCUs. Each CFCU is cooled by the component cooling water (CCW) system.

The ventilation system inside containment is designed to provide cooling to heat loads throughout containment and to provide distributed air flow to minimize the possibility of localized hot spots. This is achieved via a distribution network consisting of five CFCUs that discharge into a common annular header and ducting to various discharge points throughout containment. Under normal operation (three CFCUs in service), the containment air turnover rate is approximately one containment free volume in 8 minutes.

Cooling of the containment atmosphere will result in condensation on the CFCU cooling coils when the containment dew point is above the cooling coil temperature. The rate of condensation will be determined by the moisture content and flow rate of containment air through the CFCUs.

Condensation is collected in the CFCUs and routed to the two containment structure sumps. Three CFCUs drain to one sump and two CFCUs drain to the other sump. Water accumulation in the structure sumps is monitored and pumped into the liquid radioactive waste processing system when the sumps fill.

The condensation collected in each sump will be detected by the level sensors and monitored by the level monitoring computer. The level monitoring computer will provide an alarm upon the detection of a rate of level change exceeding the alarm setpoint.

Alternately, the rate of CFCU condensation may be monitored through a CFCU condensate collection system in the CFCU drain lines. Operation of this system is manually initiated and allows the operators to monitor the time required to collect condensate on a single CFCU. Operation of the condensate collection system will temporarily interrupt the condensate flow to the sump from the selected CFCU, potentially delaying the sump level detection system alarm as much as 11 minutes. Although use of this system will identify a containment leak more quickly than the level detection system, this system is not credited for MSL leakage detection.

Operation with a steam leak will result in a small increase in containment temperature and humidity and result in an increase in the condensation rate of the operating CFCUs. An assessment of this impact allows estimation of the time required to detect a steam leak.

Methodology

The time required to achieve a given sump level change was evaluated using an iterative solution process. A relationship between leak rate, containment humidity, CFCU flow, CCW temperature, and sump level was established and initial conditions were determined.

The mass of water vapor released to containment is a function of the leak rate and the length of the time step. From this release, an increase in the containment humidity is then determined. Based on the containment humidity, the amount of moisture which is condensed out of the air circulating through the CFCUs is then calculated using CCW temperature, humidity, and air flow rate. The moisture condensed out of the circulating air is then incrementally added to the contents of the containment structure sump. This process is repeated for successive time steps until the inventory of the containment structure sump changes by the amount of the detection threshold.

The time to reach the threshold corresponds to the time required to detect the leak rate of concern. For the purpose of this calculation, both sumps are presumed to be in operation with an even split in the accumulation rates. This will result in both sumps simultaneously reaching their detection thresholds, therefore conservatively maximizing the predicted time to alarm.

This method was also used to assess the effect of varying initial conditions on the detection times. The effects of these variations are summarized in the results section.

Analysis Inputs

- The steam leak rate is 0.2 gpm for Unit 1 and 0.35 gpm for Unit 2 based on the results of the LBB evaluation
- The sump threshold of detection is 4.4 gallons for each sump
- Containment free volume is 2.55E6 ft^3
- CFCU flow rates are 110,000 scfm for operation in high speed and 55,000 scfm for operation in low speed
- The range of CCW temperatures is from a lower design limit of 45 °F to the upper design limit of 95 °F

Assumptions Used:

- Containment Initial Conditions

The initial containment conditions are assumed to be a temperature equal to the CCW temperature, a pressure of 1.2 psig, and dewpoint at the CCW temperature.

At power, the operation of the RCPs and other heat loads provide sufficient heating to containment to require cooling of the containment by the CFCUs. The containment air temperature is limited to less than or equal to 120 degrees by TS 3.6.5 in Modes 1 to 4. Containment pressure is limited to less than or equal to 1.2 psig by TS 3.6.4. The containment environment during normal power operation is maintained with a humidity ratio determined by the temperature of the CFCU cooling coils.

The temperature differential between the CCW cooling water and containment ambient temperatures is approximately 25 °F for normal operation with three CFCUs in service. Since the worst-case detection time occurs with a minimal number of CFCUs in service, it is conservative to use a smaller temperature differential between CCW and containment ambient temperatures. Thus, a containment temperature equal to the CCW temperature is assumed.

For the purpose of this evaluation, the most restrictive combination of these parameters is the minimum number of CFCUs in operation (to minimize the condensation rate), the minumum CCW and containment temperatures (results in a higher containment dry air mass and lower condensation rates) and maximum containment pressure (results in a higher containment dry air mass and lower condensation rates).

- Accumulation of Moisture

The DCPP containment is a large, dry PWR containment. The DCPP design includes five CFCUs which control containment pressure and temperature. These CFCUs contain cooling coils which cool the containment atmosphere. CFCUs cool the containment air to the point where any excess moisture above the dew point corresponding to the CCW temperature is condensed and delivered to the CFCU condensation system and the containment structure sumps.

There are no mechanisms which would result in the diversion of condensate to the reactor cavity sump so it is assumed that there is no accumulation of condensate in the reactor cavity sump.

Condensation onto surfaces other than the CFCU cooling coils is considered to be negligible. At power, almost all containment surfaces are warmer than the dew point. The presence of warm air throughout containment will raise the temperature of these surfaces to containment ambient. The only surfaces which have the potential to condense water out of the atmosphere are those which are cooled by the CCW system. The majority of these surfaces comprise the CFCU cooling coils. The remaining surfaces (CCW piping) constitute a very small portion of the surface area cooled by the CCW system and are assumed to be at an equilibrium condition where no significant steady-state moisture accumulation can occur. In addition, there is a substantial amount of forced airflow over the cooling coils while the airflow over the other cooled surfaces is very limited, resulting in very limited potential for the steady-state accumulation of condensation.

- Transit Time to Sump

  The time for the condensate to travel from a CFCU to the containment structure sump was assumed to be one minute. A review of the piping layout indicates that the longest run of piping is approximately 175 feet. At a flow velocity of 3 feet per second, the delay time associated with the movement of the condensate through the drain piping is conservatively determined to be one minute.

- Minimum detectable change in sump level

  Minimum meaningful level change for sump trending purposes is 4.4 gallons. An evaluation of the repeatability of sump level instrumentation concluded that the instrumentation would be able to identify a change in level corresponding to 0.3 inches or 4.4 gallons.

- CCW flow rate / CFCU heat removal capacity

  The impact of the leakage on CCW flow rate and heat removal capacity is inconsequential for the small leak rates of concern for LBB leak detection. The minimum flow rate to the CFCUs is more than sufficient to remove the latent heat in the recirculated air. The amount of energy deposited into the cooling water from the condensed moisture results in a negligible increase in the water temperature under all normal operating conditions.

- Atmospheric dispersion considerations and mixing considerations

  Uniform, instantaneous mixing was conservatively assumed in the detection time evaluation. This is reasonable because of the proximity of the steam lines to the CFCU inlets relative to the bulk of the containment volume. Consequently, a leak from the MSLs would be expected to result in the intake of higher humidity air by the CFCUs. The humidity in the air at the CFCU intake would be higher than that evaluated since the water vapor would not have been distributed throughout containment before being cooled in the CFCU. The lower humidity at the inlet of the CFCU assumed in the calculation results in a lower condensation rate than would actually be expected and results in a correspondingly longer calculated time to detect the leak.

- Delay Time Due to CFCU Condensate Collection Monitor in Operation

  Placing a CFCU condensate collection monitor in operation will delay delivery of condensate to the sump. The delay time is due to filling of the CFCU drain line standpipe until it reaches the high-high level switch and is emptied.

  The volume of the drain line to be filled is 1.9 gallons, including dead volume above the drain valve and below the lower level switch. Since an operable containment sump level detection system will require at least 2 CFCUs in service, one CFCU is assumed to be aligned to each sump with one in the drain collection mode. The CFCUs are assumed to be operating in low speed, which maximizes the time delay in a sump level alarm due to a CFCU condensate collection monitor in operation.

  A sump level alarm will initiate based on a 4.4 gallon change in one sump or an 8.8 gallon change from both combined sumps. To conservatively bound the various possibilities of which sump has the CFCU condensate collection monitor placed is service, the delay time was calculated based on the time to reach a 8.8 gallon change for the combined sumps. The delay time in the sump level alarm was determined to be 11 minutes with one CFCU condensate collection monitor in service with two CFCUs operating in low speed.

Sump Level Detection System Response Time Analysis Results

The analysis results for the response time required for operators to detect a 0.2 gpm steam leak inside containment using the containment sump level detection system are summarized in Table 2. A 0.2-gpm steam leak can be detected in less than 2 hours using the containment sump level detection system with typical operating conditions once equilibrium conditions have been achieved.

Containment Sump Flow Monitor System Response Time

A containment sumps inventory calculation is performed every operating shift and is required to be performed every 12 hours. The containment sumps inventory calculation determines the gross containment leakage through the change in sump indicated level at the auxiliary board and the total pump discharges from the sump. The total sump discharges from the sump due to operation of the sump pump is provided by an integrated flow monitor (totalizer) for each sump. Conservatively assuming the level detectors do not change due to malfunction, a sump pump operation just after the calculation was performed in the prior shift, the worst case instrument inaccuracy, drift, and calibration, and a procedure acceptance criteria of 0.1 gpm, the containment sump flow monitor system can detect a 0.2 gpm leak within 3 days through the containment sumps inventory calculation performed every 12 hours.

Table 2
Summary of Analysis Results
Response Time of Sump Level Detection System

Case	0.2-gpm Nominal	Unit 1 Worst Case/ High CCW	Unit 1 Worst Case/ Low CCW	Unit 2 Worst Case/ High CCW	Unit 2 Worst Case/ Low CCW
Leak Rate (gpm)	0.2	0.2	0.2	0.35	0.35
T_{CCW} (°F)	66	95	45	95	45
T_{cont} (°F)	91	115	45	115	45
CFCUs	3 High	2 Low	2 Low	2 Low	2 Low
Time to detect (min)	61	74	77	53	55
Drain Line Delay Time (minutes)	1	1	1	1	1
Maximum Delay due to CFCU condensate collect monitor placed in service (minutes)	11	11	11	11	11
Summed Time (minutes)	73	86	89	65	67

Summary of Response Time of MSL Leakage Detection System

Either sump level detection system is capable of detecting a 0.2-gpm steam leak in less than 2 hours. The containment sump flow monitor system can detect a 0.2-gpm leak within 3 days through the containment sumps inventory calculation performed every 12 hours. Based on the fracture mechanics analysis of leakage flaw growth rate, 7 days is a timely and conservative response time of the leakage detection system to detect a 0.2-gpm leak and place the plant in a safe condition. Therefore, the response times of the sump level detection systems and the containment sump flow monitor system are acceptable since they are less than the response time required by the fracture mechanics analysis.

Failure History of MSL Leakage Detection Instrumentation

First Containment Sump Level Detection System

The transmitters in the first containment sump level detection system are part of the containment structure sumps already in use to satisfy TS 3.4.15.a. The availability of each of the current containment sump level transmitters during plant Modes 1 through 4 since January 2000 was reviewed. Each of the transmitters was unavailable approximately 10 hours since January 2000. The worst performance was 99.97 percent available, or 12.6 hours unavailable. Thus, the current containment sump level indicators are considered highly reliable and reliable enough to be credited by proposed Technical Specification 3.7.19.

The PPC was similarly reviewed for availability between January 2000 and October 2004. During this period, the DCPP Unit 1 PPC has had an availability of 99.11 percent (359 hours unavailable) and the DCPP Unit 2 PPC has had an availability of 99.15 percent (344 hours unavailable). The unavailable time is typically comprised of events less than an hour in duration. Only recently have any events been longer than a half day, when major maintenance of the Unit 2 PPC in September 2004 resulted in 235 hours total unavailable time. During such times of PPC unavailability, the sump level monitoring and control room alarm functions can be provided by an equivalent computer device. In addition, when the PPC is unavailable, the second containment sump level detection system or the containment sump flow monitor system will provide timely detection of a MSL leak.

Second Containment Sump Level Detection System

No failure history exists for the second sump level detection system but similar equipment has been used in the process industry and provides data on the system reliability and availability. The second sump level detection system sump level transmitter is similar to the transmitter currently installed in the sump. The transmitter unavailability of 10 hours for the currently installed transmitters was primarily due to bubbler system problems. Therefore the new transmitter with immersion element is expected to exhibit performance of less than 5 hours of transmitter unavailability. This equates to 99.98 percent availability.

The CSPC is widely used in the process industry and has been shown to provide availability in the order of 99.9 percent or greater excluding power loss failures. In addition, the system is designed to alarm upon failure of the CSPC or instability of the transmitter. The alarm is directly input to the MAS which has also exhibited availability of 99.9 percent.

Therefore the second containment sump level detection system is expected to exhibit greater availability than the currently installed sump level detection system.

Containment Sump Flow Monitor System

A review of the unavailability history for the integrated flow measurement device used for the containment sump flow monitor system has determined that the unavailability has been much less than 1 percent. Therefore the integrated flow measurement device is highly reliable. It is noted that the integrated flow measurement device is part of the flow monitor system already in use to satisfy TS 3.4.15.a.

Failure Modes of MSL Leakage Detection Instrumentation

The failure modes of the MSL leakage detection instrumentation are summarized in Table 3. The MSL leakage detection system is designed such that there is no single failure which will simultaneously disable the two containment sump level detection systems and the containment sump flow monitor. The two containment sump level detection systems use separate level detectors, power supplies, and level monitoring computers. The containment sump flow monitor is diverse from the containment sump level detection systems since it uses a different measurement process to detect leakage (monitoring of pumped sump flow versus indicated sump level change) and does not rely on the MAS to alert the control room operators of a problem.

Safety Classification of MSL Leakage Detection Instrumentation

The containment sump level detectors and flow monitors (totalizers) used for the MSL leakage detection instrumentation are nonsafety- related and are not Safety Class 1E. There is no requirement that leakage detection and monitoring equipment be safety-related. The containment sump level detectors and flow monitors (totalizers) used for the MSL leakage detection instrumentation are designated Seismic Class II, which is equipment designed to function under conditions up to a Design Basis Earthquake. This is consistent with the TS 3.4.15 RCS pressure boundary leakage detection instrumentation, used to meet General Design Criteria 30, which has a Seismic Class II classification at DCPP.

TS 3.7.19 for MSL Leakage Detection Instrumentation

New TS are provided to include limiting conditions for operation for the main steam leakage detection instrumentation and MSL leakage. The new proposed TS 3.7.19, "Main Steam Line (MSL) Leakage Detection Instrumentation," provides TS requirements for two containment sump level detection systems and one containment sump flow monitor system. Proposed new TSs 3.7.19 and 3.7.20 are contained in Enclosures 2 and 3 and the associated TS Bases are contained in Enclosure 4.

Table 3

Failure Modes and Effects Analysis

MSL Leakage Detection System

Description or Failure	First Sump Level Detection System (LDS) (Existing)	Second Sump LDS (Redundant)	Containment Sump Flow Monitor
Power Supplies	Loops- 120V alternating current (AC) from non-vital panel PY15, fed from transformer from vital 480V power Main annunciator - 125V direct current (DC) from DC Bus 11 - Backup power 120VAC from vital bus 15 PPC - 480V motor control center 12I CFCUs – Vital 480V bus F/G/H	Instrument loops & CSPC – To be specified by design. Shall be different than first LDS. Main Annunciator - 125VDC from DC Bus 11 - Backup power 120VAC from vital bus 15	Pumps – Primary - Non-vital 480V bus I Backup – Non-vital 480V Bus J Alternator Circuit Non-vital panel PY15/25 Main Annunciator - 125V DC from DC Bus 11 - Backup power 120V AC from vital bus 15
First sump LDS power supply	Fails Low – PPC Alarms on out of range - power supply independent from second sump LDS	No effect	No effect
Droop in loop power	No failure until droop falls below 30 VDC, then the signal may fail low – an alarm is not likely	No effect	No effect
High ripple	Frequent alarms due to erratic indication	No effect	No effect

Table 3

Failure Modes and Effects Analysis

MSL Leakage Detection System

Description or Failure	First Sump Level Detection System (LDS) (Existing)	Second Sump LDS (Redundant)	Containment Sump Flow Monitor
Power Supplies (continued)			
Second sump LDS power supply	No effect	Signal Fails High (inverted signal) – PPC out of range alarm - power supply independent from first sump LDS	No effect
Droop in loop power	No effect	No failure until the loop power falls below 16 VDC – then the CSPC creates alarm on PPC due to low output	No effect
High ripple	No effect	Alarm on both MAS and PPC based on CSPC evaluation of signal stability	No effect
Pump alternator control power	No effect	No effect	MAS alarm on eventual sump hi level. Backup pump still operates.
MAS power	MAS alarming lost – PPC alarm still active	MAS alarming lost	No effect MAS alarming on Hi-Hi level lost, however not required for operability

Table 3
Failure Modes and Effects Analysis
MSL Leakage Detection System

Description or Failure	First Sump Level Detection System (LDS) (Existing)	Second Sump LDS (Redundant)	Containment Sump Flow Monitor
Power Supplies (continued) Primary sump pump	No effect	No effect	Primary pump will not operate. On Hi-Hi level redundant backup pump will run and MAS will alarm if Hi-Hi level is achieved. Primary pump status lights on control board will be out for primary pump.
Backup sump pump	No effect	No effect	Primary pump will operate on Hi level. Backup pump will not start on Hi level. Hi-Hi alarm is still active and will alarm in MAS. Backup pump status lights on control board will be out.
Transmitter			
Drift	Not of concern for application	Not of concern for application	No effect
Partial electronic failure	No effect, no SMART transmitter	Out of range alarm on MAS & CSPC – SMART transmitter with failure detection, fails out of range Hi	No effect

Table 3

Failure Modes and Effects Analysis

MSL Leakage Detection System

Description or Failure	First Sump Level Detection System (LDS) (Existing)	Second Sump LDS (Redundant)	Containment Sump Flow Monitor
Transmitter (continued) Complete failure	Out of range alarm on MAS & PPC	Fails low, MAS alarm and PPC overrange	No effect
Fail as-is	Transmitter failure - Can identify by comparison to level provided by second sump LDS	No effect - Not realistic failure mode due to use of self monitoring transmitter	No effect
Differential pressure sensor			
Diaphragm failure	Erratic performance – Can be detected by comparison to level provided by second sump LDS – erratic performance creates high probability of alarm	Erratic performance – Can be detected by comparison to level provided by first sump LDS – erratic performance creates high probability of alarm	No effect

Table 3

Failure Modes and Effects Analysis

MSL Leakage Detection System

Description or Failure	First Sump Level Detection System (LDS) (Existing)	Second Sump LDS (Redundant)	Containment Sump Flow Monitor
Differential pressure sensor (continued) Capillary tube crimp	No effect, No capillary	Fail High - Out of range signal will result and cause MAS alarm	No effect
Bubbler system			
Air supply clogging	Signal will fail as-is initially then track from actual with a proportional multiplier, may become erratic.	No effect	No effect
Regulator fails open	Indication will initially shift higher but will track afterwards with offset and proportional shift to the high side. This will provide conservative leakrate determination and alarm earlier.	No effect	No effect
Stilling Well			
Clogging	Indication will trend high and may alarm.	No effect	No effect, displacer level switches.

Table 3

Failure Modes and Effects Analysis

MSL Leakage Detection System

Description or Failure	First Sump Level Detection System (LDS) (Existing)	Second Sump LDS (Redundant)	Containment Sump Flow Monitor
Level Switch			
Float sticking	No effect	No effect	Level switches will fail to actuate – will be identified by Hi level on redundant LDS systems
CSPC			
Power supply	No effect	Signal fails hi – PPC out of range alarm	No effect
Analog to digital conversion	No effect	Sensed by CSPC & alarmed on MAS & PPC	No effect
Digital to analog conversion	No effect	Gives bad input to PPC. MAS alarm unaffected.	No effect
Digital output	No effect	MAS alarm disabled but PPC unaffected. CSPC alarm check will drive output to PPC into overrange alarm if MAS alarm is detected.	No effect
Logic failures	No effect	Will provide erratic results to PPC/MAS. PPC trends will not channel check. High likelihood of PPC out of range alarm	No effect
System failure	No effect	Results in PPC out of range alarm	No effect

Table 3

Failure Modes and Effects Analysis

MSL Leakage Detection System

Description or Failure	First Sump Level Detection System (LDS) (Existing)	Second Sump LDS (Redundant)	Containment Sump Flow Monitor
PPC			
System failure	No monitoring available – instant indication in control room via continuous output monitors. An equivalent monitoring and alarming device can be used to replace PPC.	MAS LDS alarm still functional. Loss of data quality alarming and operator monitoring capability. Raw level and flow data available in cable spreading room on CSPC. An equivalent data quality monitoring device can be used to replace PPC.	No effect
Logic error/hangup	No change in indication, no alarm. Can be eventually identified by comparison to second sump LDS.	MAS LDS alarm still functional. Loss of data quality alarming and operator monitoring capability. Raw level and flow data available in cable spreading room on CSPC. Moderate history of level is retained in the CSPC and can be accessed at the CSPC.	No effect

The two containment sump level detection systems are considered redundant and capable of detecting a 0.2-gpm steam leak. The containment sump flow monitor system provides a diverse method to detect a 0.2-gpm steam leak. Only one of the two containment sump level detection systems or the containment sump flow monitor system is necessary to detect a 0.2-gpm steam leak inside containment.

New TS 3.7.19 requires two containment sump level detection systems to be operable during Modes 1 through 4 when SGs are locked by expansion joints. This provides two redundant systems that can detect a steam line leak rate of 0.2 gpm. In addition, TS 3.7.19 requires one containment sump flow monitor system to be operable. New TS 3.7.19 is structured to ensure three means of detecting a 0.2-gpm leak will be used at all times. Unit shutdown is required in the event that none of the three means can be provided. Actions are provided for one containment sump level detection system inoperable, two containment sump level detection systems inoperable, the containment sump flow monitor inoperable, and all MSL leakage detection systems inoperable. If one containment sump level detection system is inoperable, Action A.1 requires verification of proper operation of the operable containment sump level detection system by performing a containment sumps inventory calculation once per 4 hours. Action A.2 requires restoration of the containment sump level detection system to operable status within 14 days. The 14-day Completion Time is acceptable considering the frequency and adequacy of the containment sumps inventory calculation to ensure the remaining containment sump level detection system is operable and the availability of the containment sump flow monitor to determine sump level. If two containment sump level detection systems are inoperable, to provide a diverse method to identify MSL leakage Action B.1 requires a visual inspection of the steam lines inside containment once per 24 hours. Action B.2 requires restoration of one containment sump level detection system to operable status within 72 hours, which is acceptable considering the visual inspection of the steam lines inside containment once per 24 hours and the diverse method to detect MSL leakage provided by the containment sump flow monitor. If the containment sump flow monitor is inoperable, Action C.1 requires restoration of the containment sump flow monitor to operable status within 30 days. The 30-day Completion Time is acceptable considering the diverse method to detect MSL leakage from the two containment sump level detection systems. If the required action and associated completion time are not met, the plant must be in Mode 3 in 6 hours and Mode 5 in 36 hours. If all MSL leakage detection systems are inoperable, Action E.1 requires limiting condition for operation 3.0.3 to be entered immediately.

TS 3.7.19 surveillance requirements (SR) 3.7.19.1 and 3.7.19.2 requires a channel calibration of the containment sump level detection systems and containment sump flow monitors every 24 months. The frequency of 24 months is consistent with the refueling cycle and considers channel reliability. Operating experience has proven the frequency is acceptable.

TS 3.7.20 for MSL Leakage

TS 3.7.20 provides a new TS for MSL Leakage. TS LCO 3.7.20 requires that MSL leakage through the pipe walls inside containment shall be less than 0.2 gpm. MSL leakage is defined as leakage inside containment from any portion of the four MSL pipe walls. Fluid loss from components in or connected to the MSL is not MSL leakage. Less than 0.2 gpm of leakage is allowable because it is less than one-tenth (0.1) of the calculated leakage from the LBB analysis leakage crack and poses negligible risk to MSL integrity. The NUREG-1061, Volume 3, guideline specifies a factor of 10 between the leakage detection capability and the leakage from the LBB analysis leakage crack. Violation of this LCO constitutes an unacceptable reduction in safety margin.

The LCO is applicable during Modes 1, 2, 3, and 4 when the SGs are locked by expansion joints. The MSL leakage limit is only required to support application of LBB to the MSL piping for a unit which has SGs locked by expansion joints as described in proposed TS 5.5.9.b.4. The MSL leakage limit inside containment is required to support the MSL LBB analysis assumed as part of the TS 5.5.9.d.1.j(i) SG 4-volt lower voltage repair limit. The SGs are required to be operable as part of an operable reactor coolant system loop in Modes 1 and 2 per TS 3.4.4, Mode 3 per TS 3.4.5, and Mode 4 per TS 3.4.6. In Mode 5, the SGs cannot produce steam.

TS 3.7.20 Action A requires that with the MSL leakage not within the LCO limit, the reactor must be brought to a Mode in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner without challenging plant systems.

TS SR 3.7.20.1 requires verification that MSL leakage is within the LCO limit and assures the integrity of those lines inside containment is maintained. Information from the Containment Sumps' Inventory and Discharge Evaluation performed per surveillance test procedure STP I-1A is used to verify the MSL leakage is less than 0.2 gpm. When the total change in sump inventory is greater than 0.2 gpm, MSL leakage must be confirmed to be less than 0.2 gpm by use of other containment leak detection methods. Information from the Containment Sumps' Inventory and Discharge Evaluation, the RCS water inventory balance performed per SR 3.4.13.1, and the RCS leakage detection instrumentation required by TS 3.4.15, is used to determine whether the MSL is a potential source of leakage inside containment. An early warning of MSL leakage is provided by the two containment sumps used to collect containment leakage, which are instrumented to provide an alarm in the control room for increases of greater than or equal to 0.2 gpm in the normal leakage inside containment. The alarm could be due to leakage from any system or component which can leak into containment, and leakage due to the MSL is most positively identified by inspection.

For the RCS water inventory balance performed per SR 3.4.13.1, the reactor must be at steady state operating conditions (stable temperature, power level, pressurizer level, makeup and letdown, and reactor coolant pump seal injection flows). Therefore, consistent with SR 3.4.13.1, a Note is added allowing that this SR is not required to be performed until 12 hours after establishing steady state operation. The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established. Steady state operation is required to perform a proper RCS inventory balance since calculations during power level changes are not useful.

The frequency of 72 hours is a reasonable interval to trend leakage and recognizes the importance of early leakage detection to support the MSL LBB analysis assumed as part of the TS 5.5.9.d.1.j(i) SG 4-volt lower voltage repair limit.

The proposed TS 3.7.19 MSL Leakage Detection Instrumentation has been based in part on the MSL leakage detection instrumentation required for the Westinghouse AP1000 advance plant design TS 3.4.9 and TS 3.3.3. Also, the proposed DCPP MSL TS 3.7.20 MSL Leakage Limit has been based on the MSL leakage limit for the AP1000 TS 3.7.8. The Westinghouse AP1000 plant and associated TS received final design approval from the NRC in a letter to Westinghouse Electric Company dated September 13, 2004. A table comparing the DCPP and AP1000 TS related to MSL leakage detection instrumentation and MSL leakage is contained in Table 4.

Table 4
Comparison of DCPP and AP1000 TS Related to MSL Leakage Detection Instrumentation and MSL Leakage

AP1000	**DCPP Leakage Detection System**	**Comparison**
Primary (Redundant)		
TS 3.4.9	TS 3.7.19	-
LCO 2 containment sump level channels operable (provides redundancy)	LCO 2 containment sump level detection systems operable (provides redundancy)	Number of indicators per sump: Equivalent Type of indicators per sump: Not equivalent: AP1000 uses two of same type, DCPP uses two different types that use a different level measurement process
Actions	Actions	-
A. 1 containment sump level channel inoperable	A. 1 containment sump level detection system inoperable	-
Verify volume input per day to sump does not change more than 10 gallons or 33 percent of volume input (whichever is greater) every 24 hours (verifies proper operation of remaining sump level sensor)	Verify proper operation of OPERABLE containment sump level detection system by performing a containment sumps inventory calculation every 4 hours	Equivalent: both actions observe sump volume changes to verify proper operation of remaining sump level sensor
AND	AND	-
Restore two containment sump channels to operable in 14 days	Restore containment sump level detection system to OPERABLE status in 14 days	Equivalent
B. 2 containment sump channels inoperable	B. 2 containment sump level detection system inoperable	-
Perform RCS inventory balance every 24 hours (note, does not detect steam leakage, but there is a 3rd sump channel available)	Perform a visual inspection of the steam lines inside containment once per 24 hours	Not Equivalent: DCPP visual inspection of steam lines every 24 hours will identify steam leak within 24 hours, RCS inventory balance for AP1000 does not identify main steam leakage however there is a third sump level channel available to provide indication of steam leakage although it is not required to be operable
AND	AND	-
Restore one containment sump channel to operable in 72 hours	Restore one containment sump level detection system to OPERABLE status in 72 hours	Equivalent
D. Required Action and associated Completion Time not met	D. Required Action and associated Completion Time not met	Equivalent

Table 4 Comparison of DCPP and AP1000 TS Related to MSL Leakage Detection Instrumentation and MSL Leakage		
AP1000	**DCPP Leakage Detection System**	**Comparison**
Be in Mode 3 in 6 hours and Mode 5 in 36 hours	Be in Mode 3 in 6 hours and Mode 5 in 36 hours	Equivalent
E. All required monitors inoperable	E. All leakage detection systems inoperable	Equivalent
Enter LCO 3.0.3 immediately	Enter LCO 3.0.3 immediately	Equivalent
SR	SR	-
3.4.9.3. Perform a channel calibration of the required containment sump monitor	3.7.19.1. Perform a channel calibration of the containment sump level detection systems	Equivalent
Backup (Diverse System)		
TS 3.3.3	TS 3.7.19	-
LCO 2 containment water level sensors	LCO Containment sump flow monitor system (one flow totalizer for each sump, same as system required by TS 3.4.15.a)	Not equivalent, DCPP has only one integrated flow indicator per sump; however, integrated sump pump flow can also be determined by indicated flow and pumping time
Action	Action	-
A. One channel inoperable	C. Containment sump flow monitor inoperable	Not equivalent, DCPP has only one integrated flow indicator per sump
Restore to operable in 30 days	Restore containment sump flow monitor to operable status in 30 days	Equivalent - AP1000 has 30 days because there is another post accident monitoring channel available. For DCPP, there is at least one containment sump level detection system available to provide MSL leakage detection.
C. Two channels inoperable	N/A	-
Restore one channel in 7 days	N/A	-
SR	SR	-
3.3.3.1. Perform channel check every 31 days	-	Not equivalent - however AP1000 instrument is a post accident monitoring channel credited for MSL leakage detection
3.3.3.2. Perform channel calibration every 24 months	3.7.19.2. Perform channel calibration of containment sump flow monitors every 24 months	Equivalent

ENCLOSURE 2
MARKED-UP TECHNICAL SPECIFICATION PAGES

There are no changes to this page. Included for information only.

3.7 PLANT SYSTEMS

3.7.18 Secondary Specific Activity

LCO 3.7.18 The specific activity of the secondary coolant shall be ≤ 0.10 μCi/gm DOSE EQUIVALENT I-131.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Specific activity not within limit.	A.1 Be in MODE 3.	6 hours
	AND	
	A.2 Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.18.1	Verify the specific activity of the secondary coolant is ≤ 0.10 μCi/gm DOSE EQUIVALENT I-131.	31 days

Insert new TS 3.7.19 "Main Steam Line (MSL) Leakage Detection Instrumentation" and new TS 3.7.20 "Main Steam Line (MSL) Leakage" after this page.

3.7 PLANT SYSTEMS

3.7.19 Main Steam Line (MSL) Leakage Detection Instrumentation

LCO 3.7.19 The following MSL leakage detection instrumentation shall be OPERABLE:

a. Two containment sump level detection systems and,

b. One containment sump flow monitor system.

APPLICABILITY: MODES 1, 2, 3, and 4 when SGs are locked by expansion joints.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One containment sump level detection system inoperable.	A.1	Verify proper operation of OPERABLE containment sump level detection system by performing a containment sumps inventory calculation.	Once per 4 hours
	AND		
	A.2	Restore containment sump level detection system to OPERABLE status.	14 days
B. Two containment sump level detection systems inoperable.	B.1	Perform a visual inspection of the steam lines inside containment.	Once per 24 hours
	AND		
	B.2	Restore one containment sump level detection system to OPERABLE status.	72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. Containment sump flow monitor inoperable.	C.1	Restore containment sump flow monitor to OPERABLE status.	30 days
D. Required Action and associated Completion Time not met.	D.1	Be in MODE 3.	6 hours
	AND		
	D.2	Be in MODE 5.	36 hours
E. All MSL leakage detection systems inoperable.	E.1	Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.19.1	Perform CHANNEL CALIBRATION of the containment sump level detection systems.	24 months
SR 3.7.19.2	Perform CHANNEL CALIBRATION of the containment sump flow monitors.	24 months

3.7 PLANT SYSTEMS

3.7.20 Main Steam Line (MSL) Leakage

LCO 3.7.20 MSL leakage through the pipe walls inside containment shall be < 0.2 gpm.

APPLICABILITY: MODES 1, 2, 3, and 4 when SGs are locked by expansion joints.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. MSL leakage not within limit.	A.1 Be in MODE 3. AND A.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.20.1	----------NOTE---------- Not required to be performed until 12 hours after establishment of steady state operation. ------------------------------ Verify MSL leakage into the containment sumps < 0.2 gpm.	72 hours

ENCLOSURE 3
RETYPED TECHNICAL SPECIFICATION PAGES

3.7 PLANT SYSTEMS

3.7.19 Main Steam Line (MSL) Leakage Detection Instrumentation

LCO 3.7.19 The following MSL leakage detection instrumentation shall be OPERABLE:

a. Two containment sump level detection systems and,

b. One containment sump flow monitor system.

APPLICABILITY: MODES 1, 2, 3, and 4 when SGs are locked by expansion joints.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One containment sump level detection system inoperable.	A.1	Verify proper operation of OPERABLE containment sump level detection system by performing a containment sumps inventory calculation.	Once per 4 hours
	<u>AND</u>		
	A.2	Restore containment sump level detection system to OPERABLE status.	14 days
B. Two containment sump level detection systems inoperable.	B.1	Perform a visual inspection of the steam lines inside containment.	Once per 24 hours
	<u>AND</u>		
	B.2	Restore one containment sump level detection system to OPERABLE status.	72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. Containment sump flow monitor inoperable.	C.1	Restore containment sump flow monitor to OPERABLE status.	30 days
D. Required Action and associated Completion Time not met.	D.1	Be in MODE 3.	6 hours
	AND		
	D.2	Be in MODE 5.	36 hours
E. All MSL leakage detection systems inoperable.	E.1	Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.19.1	Perform CHANNEL CALIBRATION of the containment sump level detection systems.	24 months
SR 3.7.19.2	Perform CHANNEL CALIBRATION of the containment sump flow monitors.	24 months

3.7 PLANT SYSTEMS

3.7.20 Main Steam Line (MSL) Leakage

LCO 3.7.20 MSL leakage through the pipe walls inside containment shall be < 0.2 gpm.

APPLICABILITY: MODES 1, 2, 3, and 4 when SGs are locked by expansion joints.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. MSL leakage not within limit.	A.1 Be in MODE 3. AND A.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.20.1	------------------------NOTE-------------------------------- Not required to be performed until 12 hours after establishment of steady state operation. --- Verify MSL leakage into the containment sumps < 0.2 gpm.	72 hours

ENCLOSURE 4
MARKED-UP TECHNICAL SPECIFICATION BASES PAGES
(for information only)

B 3.7.19 Main Steam Line (MSL) Leakage Detection Instrumentation

BASES

BACKGROUND

Leakage detection instrumentation to detect MSL leakage inside containment is required to detect the presence of main steam piping leakage. Detection of main steam piping leakage is required to support the MSL Leak-Before-Break (LBB) analysis discussed in Updated Final Safety Analysis report section 5.5.2.5.4 (Reference 1) which was assumed as part of the TS 5.5.9.d.1.j(i) steam generator (SG) 4-volt lower voltage repair limit. 10 CFR 50 Appendix A General Design Criteria 4 (Reference 2) allows the use of advanced technology to exclude from structural design consideration the dynamic effects of pipe ruptures in nuclear plants, provided it is demonstrated that the probability of pipe rupture is extremely low under conditions consistent with the design bases for the piping. The demonstration of low probability of pipe rupture utilizes a deterministic fracture mechanics analysis that evaluates the stability of postulated, small, through-wall flaws in piping and the ability to detect leakage through the flaw long before the flaw could grow to unstable sizes and rupture the pipe. The concept underlying these analyses is referred to as LBB. The limitations and acceptance criteria for LBB are discussed in NUREG-1061, Volume 3 (Reference 3). The NUREG-1061, Volume 3, guidelines specify that there is the capability to detect leakage from piping in which LBB has been applied and that there is a factor of 10 between the leakage detection capability and the leakage which would result from the LBB analysis leakage crack when the pipe is subjected to normal operational loads.

The MSL leakage detection instrumentation system must have the capability to detect significant main steam piping degradation as soon after occurrence as practical to minimize the potential for propagation to a gross failure. To meet the NUREG-1061, Volume 3, guideline of a factor of 10 between the leakage detection capability and the leakage from the LBB analysis leakage crack, the MSL leakage detection instrumentation system must be capable of detecting 0.2 gpm.

Each of the two containment sumps used to collect containment leakage are instrumented with two different types of level detectors. Each of the level detectors provide an alarm in the control room for increases of greater than or equal to 0.2 gpm in the normal leakage inside containment. Since there is no other TS required method to quantify steam piping leakage inside containment in a short time frame, two containment sump level detection systems are required to be OPERABLE to provide redundancy.

(continued)

BACKGROUND (continued)

The containment sump level indicators and plant process computer are highly reliable and are capable of detecting main steam line leakage. During times when the plant process computer or equivalent is unavailable, the containment sump flow monitor system and visual inspection of the steam lines inside containment can be used to detect main steam line leakage. The sensitivity of the containment sump level detection systems is sufficient to detect the level change associated with a 0.2 gpm leak, accounting for all possible fan cooler alignments.

The leakage detection systems that detect MSL leakage inside containment are only required while LBB is applied to the MSL piping to support the TS 5.5.9.d.1.j(i) SG 4-volt lower voltage repair limit.

APPLICABLE SAFETY ANALYSES

The TS 5.5.9.d.1.j(i) SG 4-volt lower voltage repair limit is based on limited SG tube support plate displacement following a MSL break downstream of the flow restrictor in the MSL (small MSL break). The flow restrictor is located in the main steam line downstream of the SG nozzle. The area of the MSL pipe on either side of the flow restrictor is the same, however if a MSL break occurs downstream of the flow restrictor the dynamic effects of the break are limited since the break size is limited to the area of the flow restrictor. A MSL break upstream of the flow restrictor (large MSL break) is not impacted by the flow restrictor and the MSL break size is the area of the MSL pipe. Large MSL breaks were not considered due to application of LBB to the MSL piping.

The SG alternate repair criteria based on limited tube support plate displacement is described in Westinghouse Report WCAP-16170-P, Revision 0 (Reference 4). The limited tube support displacement is based on SG tube expansion joints that are applied at the tube support plate locations. The SG tube expansion joints mechanically lock the tube support plates in place. SGs which have tube expansion joints mechanically locking the tube support plates in place are referred to as locked SGs. The number of SG tube expansion joints which are required to limit the tube support plate displacement following a MSL break depends on the fluid loads on the tube support plate following the break, which in turn depends on the size of the break. The analyses in WCAP-16170-P, Revision 0, are based on a small MSL break downstream of the flow restrictor in the MSL. Large MSL breaks upstream of the flow restrictor were precluded by application of LBB to the MSL piping.

MSL leakage detection instrumentation satisfies the requirements of Criterion 2 of 10 CFR 50.36(c)(2)(ii) since it is required as part of the analysis basis for the TS 5.5.9.d.1.j(i) steam generator (SG) 4-volt lower voltage repair limit, in which large MSL breaks upstream of the flow restrictor were precluded by application of LBB to the MSL piping.

(continued)

LCO

To protect against a main steam pipe flaw growing to an unstable size resulting in rupture of the pipe, MSL leakage detection instrumentation is required. This LCO requires two containment sump level detection systems and a containment sump flow monitor system to be OPERABLE to provide a high degree of confidence that small MSL leaks are detected in time to allow action to place the plant in a safe condition when MSL leakage exists.

There are two required OPERABLE containment sump level detection systems. Each OPERABLE containment sump level detection system consists of two containment sumps which are shared between the two containment sump level detection systems. Each of the two sumps must have an operating CFCU aligned to the sump and a level indicator (transmitter) in the sump. Each OPERABLE containment sump level detection system must also have a level monitoring computer that monitors the level in each of the two sumps and provides a control room alarm. The table below identifies the required equipment for each OPERABLE containment sump level detection system.

Detection System	1		2	
Sump	1	2	1	2
Operating CFCU	1, 2, or 3	4 or 5	1, 2, or 3	4 or 5
Level Indicator	level indictor LI-60	level indictor LI-61	level indicator LI-xx	level indicator LI-xx
Level monitoring computer with control room alarm capability	plant process computer or equivalent		control system process computer or equivalent	

Number to be assigned when new instrument installed

The containment sump flow monitor system consists of an integrated flow measurement device (totalizer) on each containment sump and, is the same as the flow monitor system required by TS 3.4.15.a. The containment sump flow monitor system provides a diverse backup method to the containment sump level detection systems and can detect a 0.2 gpm leak within 3 days through the containment sumps inventory calculation performed every 12 hours.

(continued)

APPLICABILITY

In MODES 1, 2, 3, and 4 when the SGs are locked by expansion joints, the MSL leakage detection instrumentation is required to be OPERABLE in the event that a small MSL pipe flaw occurs. The MSL leakage detection instrumentation is only required to support application of LBB to the MSL piping for a unit which has SGs locked by expansion joints as described in TS 5.5.9.b.4. Leakage detection instrumentation to detect MSL leakage inside containment is required to support the MSL Leak-Before-Break (LBB) analysis assumed as part of the TS 5.5.9.d.1.j(i) steam generator (SG) 4-volt lower voltage repair limit. The SGs are required to be OPERABLE as part of an OPERABLE RCS loop in MODES 1 and 2 per TS 3.4.4, MODE 3 per TS 3.4.5, and MODE 4 per TS 3.4.6. In MODE 5, the SGs cannot produce steam.

ACTIONS

A.1 and A.2

With one of the two required containment sump level detection systems inoperable, the one remaining OPERABLE containment sump level detection system is sufficient for MSL leakage detection. A failed level indicator, loss of level indicator power supply, loss of level indicator control air, loss of the plant process computer and equivalent, or loss of the control system process computer and equivalent are examples of situations that result in one inoperable containment sump level detection system. In order to verify the proper operation of the OPERABLE containment sump level detection system, ACTION A.1 requires a containment sumps inventory calculation to be performed once per 4 hours. The containment sumps inventory calculation is performed by performing the Containment Sumps' Inventory and Discharge Evaluation contained of surveillance test procedure STP I-1A (Reference 5). In the event the containment sump flow totalizer is not operable, the sump integrated flow can also be determined by sump pump indicated flow and pumping time. The information obtained from the containment sumps inventory calculation will allow verification of proper operation of the remaining OPERABLE containment sump level detection system. Four hours provides time to perform the containment sump inventory calculation and is an acceptable frequency to ensure at least one containment sump level detection system is OPERABLE.

Restoration of the containment sump level detection system to OPERABLE status is required to regain the function in a Completion Time of 14 days. This time is acceptable, considering the frequency and adequacy of the containment sumps inventory calculation performed once per 4 hours to ensure a redundant containment sump level detection system is OPERABLE to quantify MSL leakage.

(continued)

ACTIONS (continued)

B.1 and B.2

With two of the two required containment sump level detection systems inoperable, the redundant capability of the containment sump level detection system is lost. A failed indicator in each level detection system, a sump with no operating CFCU aligned to the sump, or simultaneous loss of the plant process computer (and equivalent) and the control system process computer (and equivalent) are examples of situations that result in two inoperable containment sump level detection systems. To provide a diverse method to identify MSL leakage, ACTION B.1 requires a visual inspection of the steam lines inside containment once per 24 hours.

Visual inspection of the steam lines inside containment once per 24 hours provides adequate assurance that MSL leakage will be detected. The visual inspection is performed on the MSL piping inside containment between the SG outlet nozzle and the containment penetration. Visual inspection requires an ASME-qualified VT-2 inspector to inspect the main steam lines with the insulation installed. Line-of-site view is acceptable.

Restoration of one containment sump level detection system to OPERABLE status is required in a Completion Time of 72 hours. This time is acceptable, considering the visual inspection of the steam lines inside containment performed once per 24 hours required by ACTION B.1 and the diverse method to detect MSL leakage provided by the containment sump flow monitor.

C.1

With the containment sump flow monitor inoperable, ACTION C.1 requires the containment sump flow monitor to be restored to OPERABLE status in 30 days.

The 30 day Completion Time is acceptable considering the diverse method to detect MSL leakage from the two containment sump level detection systems.

D.1 and D.2

If a REQUIRED ACTION of CONDITION A, B, or C cannot be met within the required Completion Time, the reactor must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner without challenging plant systems.

(continued)

ACTIONS (continued)

E.1

With all MSL leakage detection systems inoperable, there is no ability to remotely detect MSL leakage in a timely manner to minimize the potential for propagation to a gross failure. Therefore, ACTION E.1 requires LCO 3.0.3 to be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.7.19.1

Performing a CHANNEL CALIBRATION of the two containment sump level detection system channels verifies the accuracy of the instrument string, including the instruments located inside containment. The Frequency of 24 months is consistent with the refueling cycle and considers channel reliability. Operating experience has proven that this Frequency is acceptable.

SR 3.7.19.2

Performing a CHANNEL CALIBRATION of the containment sump flow monitors verifies the accuracy of the integrated flow measurement device. The Frequency of 24 months is consistent with the refueling cycle and considers channel reliability. Operating experience has proven that this Frequency is acceptable.

REFERENCES

1. FSAR, Section 5.5.2.5.4, Voltage-based Alternate Repair Criteria.
2. 10 CFR 50 Appendix A General Design Criterion 4, 52 FR 41288; October 27, 1987.
3. NUREG-1061, Volume 3, "Evaluation of Potential for Pipe Breaks, Report of the U.S. Nuclear Regulatory Commission Piping Review Committee," dated November 1984.
4. WCAP-16170-P, Revision 0, "Diablo Canyon SG Alternate Repair Criteria Based On Limited Tube Support Plate Displacement," dated November 2003.
5. Surveillance Test Procedure STP I-1A, "Routine Shift Checks Required by Licenses".

BASES

BACKGROUND

A limit on leakage from the main steam line (MSL) inside containment is required to limit system operation in the presence of excessive leakage. Leakage is limited to an amount which would not compromise safety consistent with the MSL Leak-Before-Break (LBB) analysis discussed in Updated Final Safety Analysis report section 5.5.2.5.4 (Reference 1) which was assumed as part of the TS 5.5.9.d.1.j(i) steam generator (SG) 4-volt lower voltage repair limit. This leakage limit ensures appropriate action can be taken before the integrity of the lines is impaired.

10 CFR 50 Appendix A General Design Criteria 4 (Reference 2) allows the use of advanced technology to exclude from structural design consideration the dynamic effects of pipe ruptures in nuclear plants, provided it is demonstrated that the probability of pipe rupture is extremely low under conditions consistent with the design bases for the piping. The demonstration of low probability of pipe rupture utilizes a deterministic fracture mechanics analysis that evaluates the stability of postulated, small, through-wall flaws in piping and the ability to detect leakage through the flaw long before the flaw could grow to unstable sizes and rupture the pipe. The concept underlying these analyses is referred to as LBB. The limitations and acceptance criteria for LBB are discussed in NUREG-1061, Volume 3 (Reference 3). The NUREG-1061, Volume 3, guidelines specify that there is the capability to detect leakage from piping in which LBB has been applied and that there is a factor of 10 between the leakage detection capability and the leakage which would result from the LBB analysis leakage crack when the pipe is subjected to normal operational loads.

LBB has been applied to the MSL pipes inside containment as part of the analysis basis for the TS 5.5.9.d.1.j(i) steam generator (SG) 4-volt lower voltage repair limit. The potential safety significance of large MSL breaks inside containment require detection and monitoring of leakage inside containment. This LCO protects the MSLs inside containment against degradation, and helps assure that large MSL breaks inside containment will not develop. The consequences of violating this LCO include the possibility of further degradation of the main steam lines, which may lead to a large MSL break, and invalidation of the analysis basis for the TS 5.5.9.d.1.j(i) steam generator (SG) 4-volt lower voltage repair limit.

(continued)

APPLICABLE SAFETY ANALYSES

The safety significance of plant leakage inside containment varies depending on its source, rate, and duration. Therefore, detection and monitoring of plant leakage inside containment are necessary. This is accomplished by instrumentation required by TS LCO 3.4.15, "RCS Leakage Detection Instrumentation," for the reactor coolant system (RCS) and TS 3.7.19, "Main Steam Line (MSL) Leakage Detection Instrumentation," for the MSLs. The two containment sumps used to collect containment leakage, are instrumented to provide an alarm in the control room for increases of greater than or equal to 0.2 gpm in the normal leakage inside containment. Use of the RCS Leakage detection instrumentation information, and any other available information, provides qualitative information to the operators regarding possible main steam line leakage. This allows the operators to take corrective action should leakage occur which is detrimental to the safety of the facility and/or the public.

The TS 5.5.9.d.1.j(i) SG 4-volt lower voltage repair limit is based on limited SG tube support plate displacement following a MSL break downstream of the flow restrictor in the MSL (small MSL break). The flow restrictor is located in the main steam line downstream of the SG nozzle. The area of the MSL pipe on either side of the flow restrictor is the same, however if a MSL break occurs downstream of the flow restrictor the dynamic effects of the break are limited since the break size is limited to the area of the flow restrictor. A MSL break upstream of the flow restrictor (large MSL break) is not impacted by the flow restrictor and the MSL break size is the area of the MSL pipe. Large MSL breaks were not considered due to application of LBB to the MSL piping.

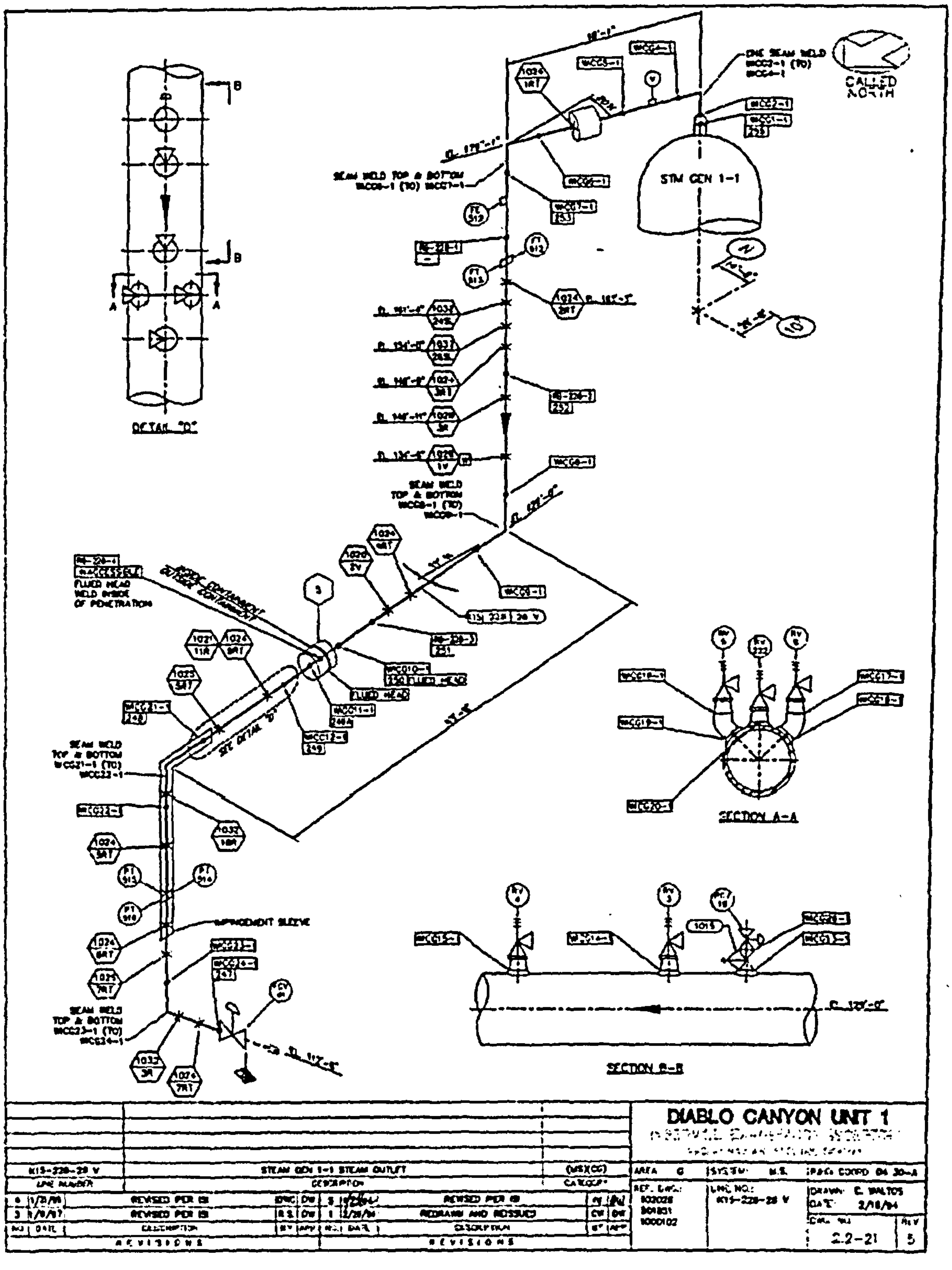
The SG *alternate repair criteria based on limited tube support plate* displacement is described in Westinghouse Report WCAP-16170-P, Revision 0 (Reference 4). The limited tube support displacement is based on SG tube expansion joints that are applied at the tube support plate locations. The SG tube expansion joints mechanically lock the tube support plates in place. SGs which have tube expansion joints *mechanically locking the tube support plates in place are referred to as* locked SGs. The number of SG tube expansion joints which are required to limit the tube support plate displacement following a MSL break depends on the fluid loads on the tube support plate following the break, which in turn depends on the size of the break. The analyses in WCAP-16170-P, Revision 0, are based on a small MSL break downstream of the flow restrictor in the MSL. Large MSL breaks upstream of the flow restrictor were precluded by application of LBB to the MSL piping.

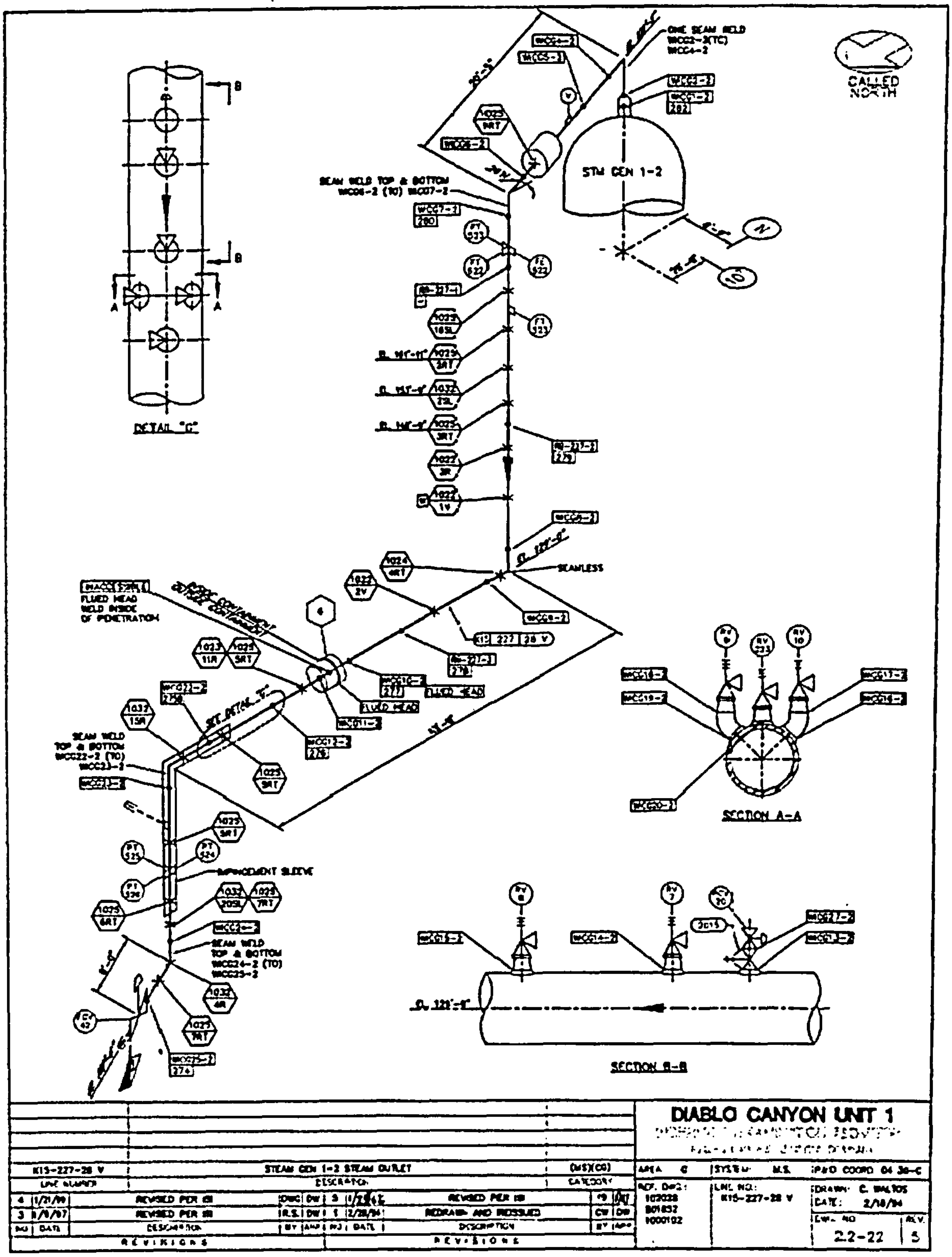
(continued)

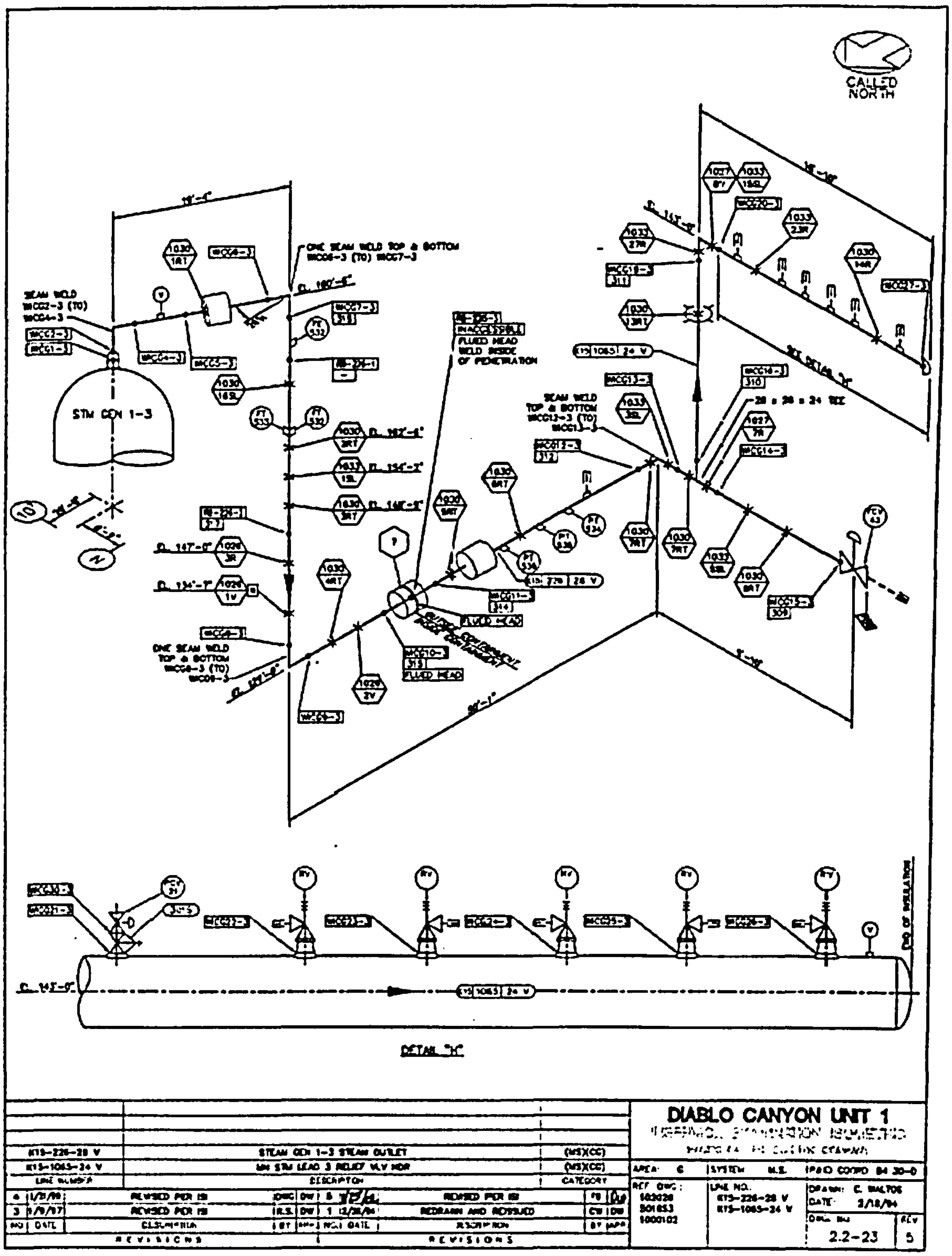
APPLICABLE SAFETY ANALYSES (continued)	The MSL leakage limit satisfies the requirements of Criterion 2 of 10 CFR 50.36(c)(2)(ii) since it is required as part of the analysis basis for the TS 5.5.9.d.1.j(i) steam generator (SG) 4-volt lower voltage repair limit, in which large MSL breaks upstream of the flow restrictor were precluded by application of LBB to the MSL piping.
LCO	Main steam line leakage is defined as leakage inside containment from any portion of the four main steam line pipe walls. Fluid loss from components in or connected to the main steam line is not main steam line leakage. Less than 0.2 gpm of leakage is allowable because it is less than one tenth (0.1) of the calculated leakage from the LBB analysis leakage crack. The NUREG-1061, Volume 3, guideline specifies a factor of 10 between the leakage detection capability and the leakage from the LBB analysis leakage crack. Violation of this LCO constitutes an unacceptable reduction in safety margin.
APPLICABILITY	In MODES 1, 2, 3, and 4 when the SGs are locked by expansion joints, the MSL leakage limit is APPLICABLE. The MSL leakage limit is only required to support application of LBB to the MSL piping for a unit which has SGs locked by expansion joints as described in TS 5.5.9.b.4. The MSL leakage limit inside containment is required to support the MSL Leak-Before-Break (LBB) analysis assumed as part of the TS 5.5.9.d.1.j(i) steam generator (SG) 4-volt lower voltage repair limit. The SGs are required to be OPERABLE as part of an OPERABLE RCS loop in MODES 1 and 2 per TS 3.4.4, MODE 3 per TS 3.4.5, and MODE 4 per TS 3.4.6. In MODE 5, the SGs cannot produce steam.
ACTIONS	<u>A.1 and A.2</u> With the MSL leakage in excess of the LCO limit, the reactor must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner without challenging plant systems.
SURVEILLANCE REQUIREMENTS	<u>SR 3.7.20.1</u> Verifying that MSL leakage is within the LCO limit assures the integrity of those lines inside containment is maintained. Information from the Containment Sumps' Inventory and Discharge Evaluation performed per surveillance test procedure STP I-1A (Reference 5) is used to

SURVEILLANCE REQUIREMENTS (continued)	verify the MSL leakage is less than 0.2 gpm. When the total change in sump inventory is greater than 0.2 gpm, MSL leakage must be confirmed to be less than 0.2 gpm by use of other containment leak detection methods. Information from the Containment Sumps' Inventory and Discharge Evaluation, the RCS water inventory balance performed per SR 3.4.13.1, and the RCS leakage detection instrumentation required by TS 3.4.15, is used to determine whether the main steam line is a potential source of leakage inside containment. An early warning of main steam line leakage is provided by the two containment sumps used to collect containment leakage, which are instrumented to provide an alarm in the control room for increases of greater than or equal to 0.2 gpm in the normal leakage inside containment. The alarm could be due to leakage from any system or component which can leak into containment, and leakage due to the MSL is most likely positively identified by inspection. For the RCS water inventory balance performed per SR 3.4.13.1, the reactor must be at steady state operating conditions (stable temperature, power level, pressurizer level, makeup and letdown, and reactor coolant pump seal injection flows). Therefore, consistent with SR 3.4.13.1, a Note is added allowing that this SR is not required to be performed until 12 hours after establishing steady state operation. The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established. Steady state operation is required to perform a proper RCS inventory balance since calculations during maneuvering are not useful. The Frequency of 72 hours is a reasonable interval to trend leakage and recognizes the importance of early leakage detection to support the MSL LBB analysis assumed as part of the TS 5.5.9.d.1.j(i) steam generator (SG) 4-volt lower voltage repair limit.
REFERENCES	1. FSAR, Section 5.5.2.5.4, Voltage-based Alternate Repair Criteria. 2. 10 CFR 50 Appendix A General Design Criterion 4, 52 FR 41288; October 27, 1987. 3. NUREG-1061, Volume 3, "Evaluation of Potential for Pipe Breaks, Report of the U.S. Nuclear Regulatory Commission Piping Review Committee," dated November 1984. 4. WCAP-16170-P, Revision 0, "Diablo Canyon SG Alternate Repair Criteria Based On Limited Tube Support Plate Displacement," dated November 2003. 5. Surveillance Test Procedure STP I-1A, "Routine Shift Checks Required by Licenses".

ENCLOSURE 5
MAIN STEAM LINE WELD MAPS
DCPP UNIT 1 MAIN STEAM LINE 1-1, 1-2, 1-3, 1-4
DCPP UNIT 2 MAIN STEAM LINE 2-1, 2-2, 2-3, 2-4


DETAIL "D"
SECTION A-A
SECTION B-B
STM GEN 1-1
CALLED NORTH
IMPINGEMENT SLEEVE
FLUED HEAD
DIABLO CANYON UNIT 1
K15-228-28 V
STEAM GEN 1-1 STEAM OUTLET
REVISED PER ISI
REDRAWN AND REISSUED
DRAWN: E. WALTOS
DATE: 2/18/94
2.2-21
5


STM GEN 1-2
CALLED NORTH
DETAIL "C"
SECTION A-A
SECTION B-B
SEAMLESS
IMPINGEMENT SLEEVE
FLUED HEAD
DIABLO CANYON UNIT 1
K15-227-28 V
STEAM GEN 1-2 STEAM OUTLET
REVISED PER ISI
REDRAWN AND REISSUED
DRAWN: C. WALTOS
DATE: 2/18/94
22-22
5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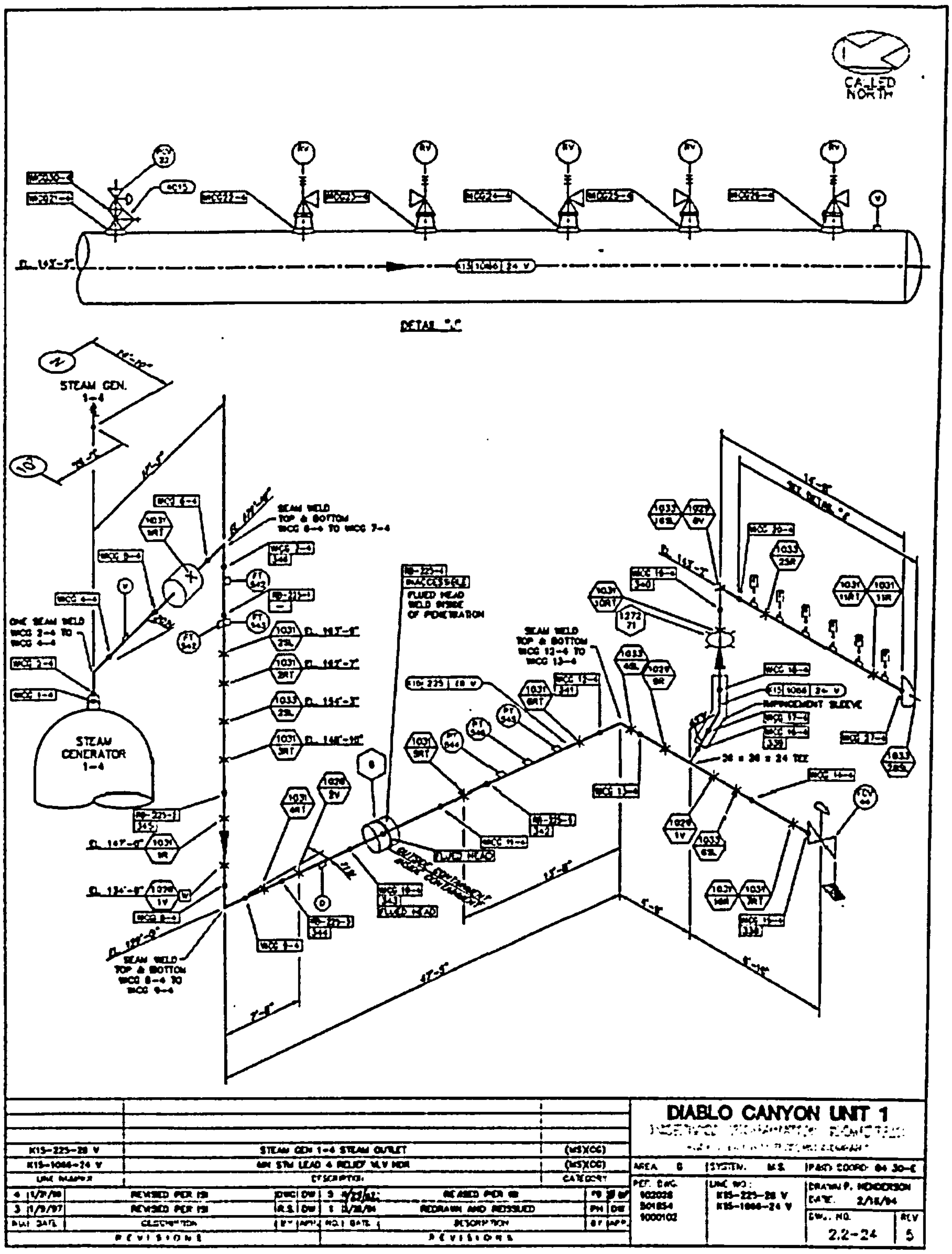
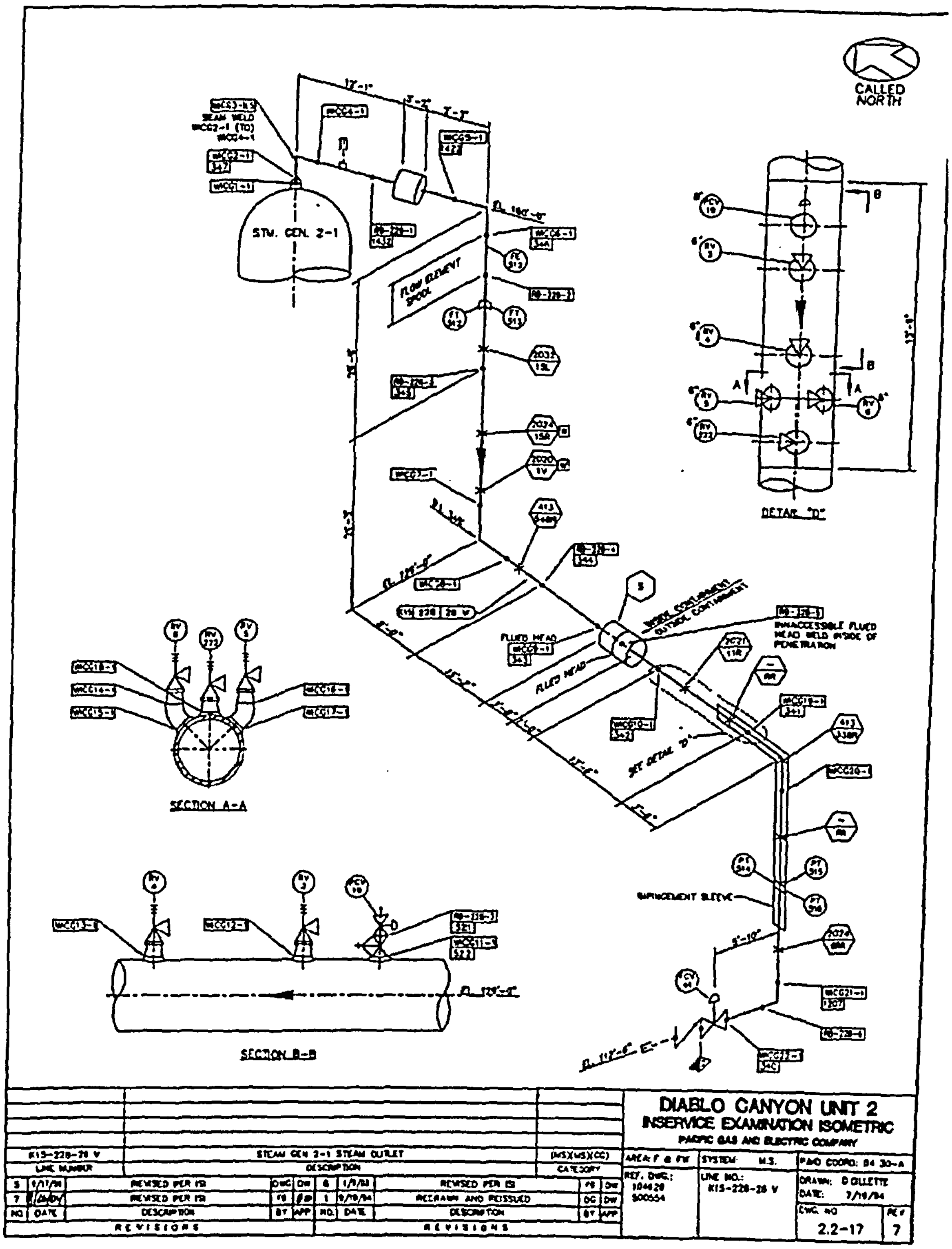
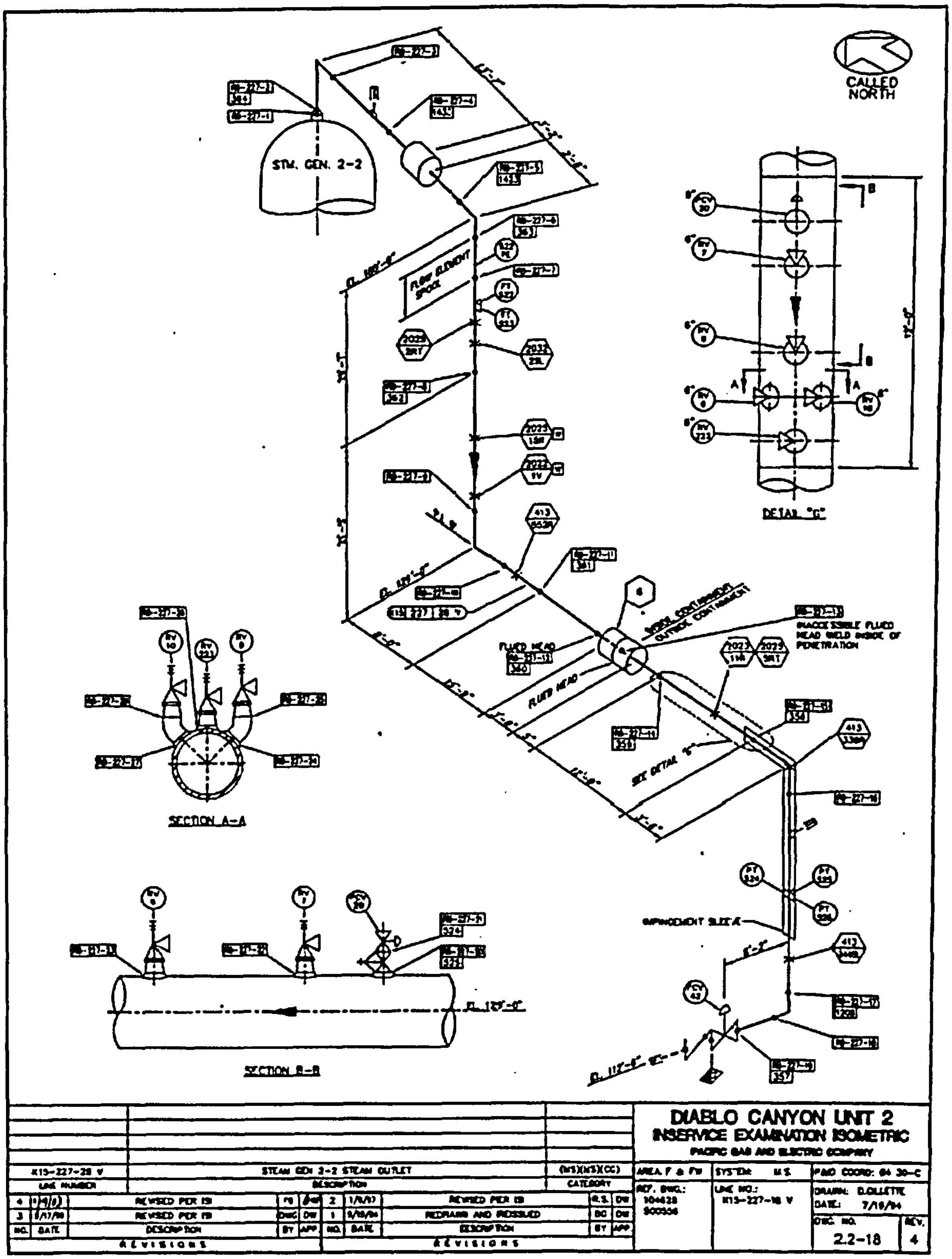
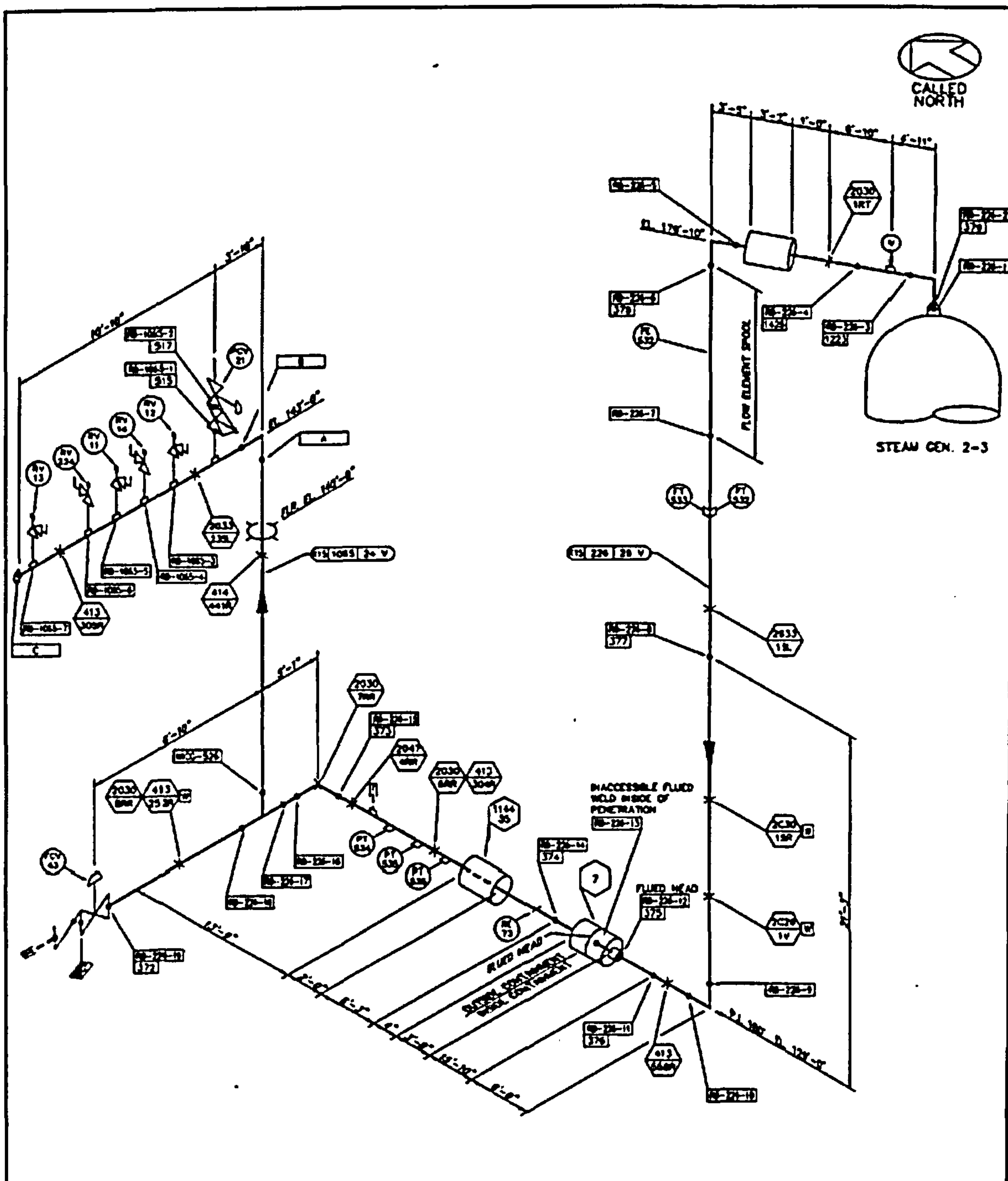
DETAIL "H"
DIABLO CANYON UNIT 1
2.2-23


CALLED NORTH
DETAIL "C"
STEAM GEN. 1-4
STEAM GENERATOR 1-4
SEAM WELD TOP & BOTTOM
IMPINGEMENT SLEEVE
FLUED HEAD
36 x 36 x 24 TEE
DIABLO CANYON UNIT 1
K15-225-28 V
STEAM GEN 1-4 STEAM OUTLET
(MSXCC)
K15-1066-24 V
(MSXCC)
LINE NUMBER
DESCRIPTION
CATEGORY
4
REVISED PER ISI
3
1/3/97
REVISED PER ISI
REVISED PER ISI
REDRAWN AND REISSUED
DESCRIPTION
REVISIONS
REVISIONS
AREA
SYSTEM
M.S.
REF. DWG.
102028
501854
1000102
LINE NO.:
K15-225-28 V
K15-1066-24 V
DATE
DWG. NO.
2.2-24
REV
5


CALLED NORTH
STM. GEN. 2-1
FLOW ELEMENT SPOOL
FLUED HEAD
INACCESSIBLE FLUED HEAD WELD INSIDE OF PENETRATION
SEE DETAIL "D"
IMPINGEMENT SLEEVE
DETAIL "D"
SECTION A-A
SECTION B-B
DIABLO CANYON UNIT 2
INSERVICE EXAMINATION ISOMETRIC
PACIFIC GAS AND ELECTRIC COMPANY
K15-228-28 V
LINE NUMBER
STEAM GEN 2-1 STEAM OUTLET
DESCRIPTION
(MS)(MS)(CC)
CATEGORY
AREA: F & FW
SYSTEM: M.S.
REF. DWG.: 104428 500554
LINE NO.: K15-228-28 V
DRAWN: D OLLETTE
DATE: 7/19/84
DWG. NO 2.2-17
REV 7
REVISED PER ISI
REDRAWN AND REISSUED
REVISIONS


CALLED NORTH
STM. GEN. 2-2
FLOW ELEMENT SPOOL
DETAIL "C"
SECTION A-A
SECTION B-B
FLUED HEAD
SEE DETAIL "C"
IMPINGEMENT SLEEVE
INSIDE CONTAINMENT
OUTSIDE CONTAINMENT
DIABLO CANYON UNIT 2
INSERVICE EXAMINATION ISOMETRIC
PACIFIC GAS AND ELECTRIC COMPANY
K15-227-28 V
STEAM GEN 2-2 STEAM OUTLET
LINE NUMBER
DESCRIPTION
CATEGORY
REVISED PER ISI
REDRAWN AND REISSUED
REVISIONS
AREA F & FW
SYSTEM M.S.
LINE NO.: K15-227-18 V
DRAWN: D.OLLETTE
DATE: 7/18/94
DWG. NO. 2.2-18
REV. 4



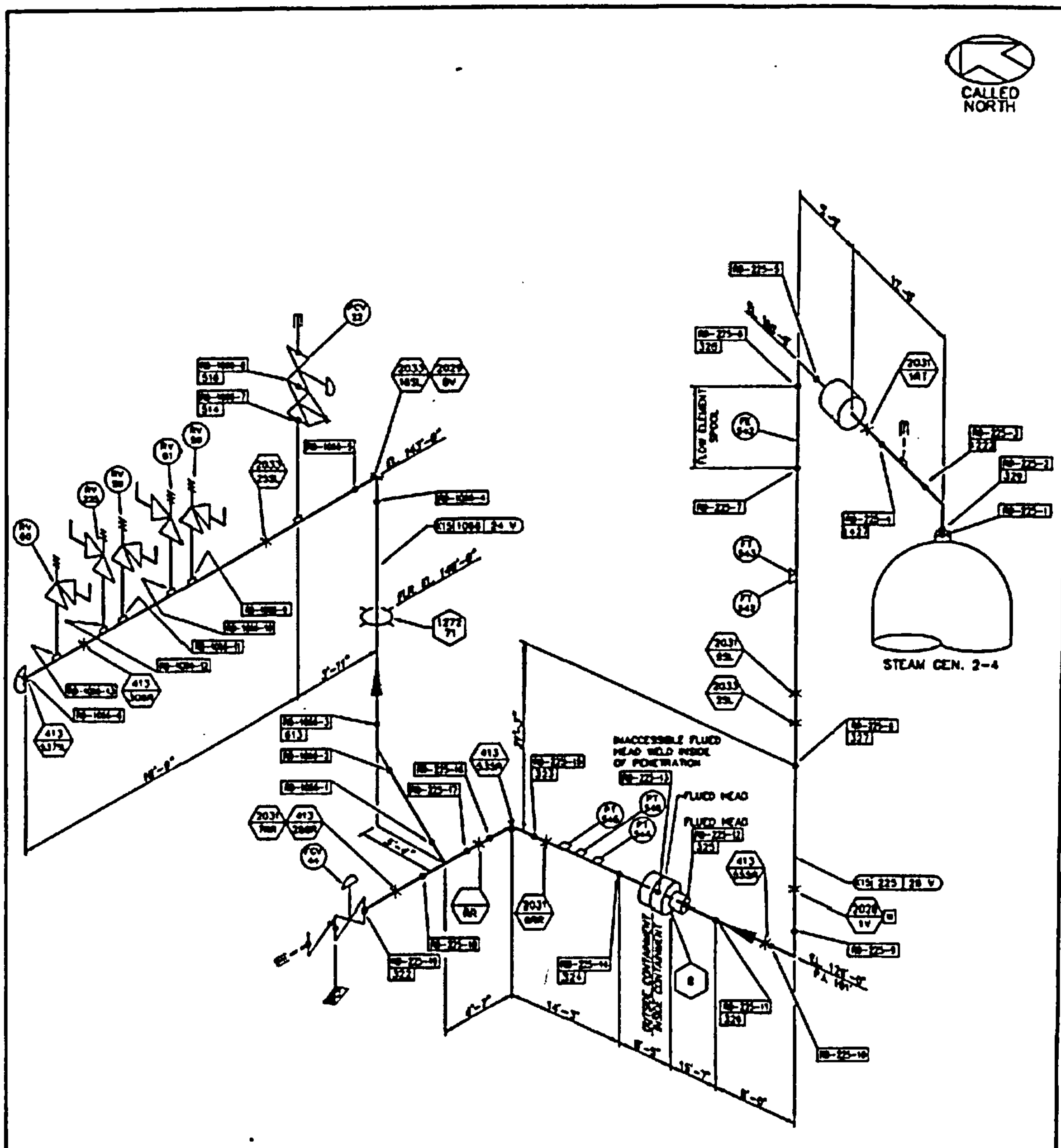
DIABLO CANYON UNIT 2
INSERVICE EXAMINATION ISOMETRIC
PACIFIC GAS AND ELECTRIC COMPANY

LINE NUMBER	DESCRIPTION	CATEGORY
K15-226-28 V	STEAM GEN 2-3 STEAM OUTLET	(MS)(MS)(CC)
K15-1065-24 V	MN STM LEAD 3 RELIEF VLV HDR	(MS)(MS)(CC)

NO.	DATE	DESCRIPTION	BY	APP.	NO.	DATE	DESCRIPTION	BY	APP.
4	[illegible]	REVISED PER ISI	[illegible]	[illegible]	2	1/8/97	REVISED PER ISI	R.S.	DW
3	9/17/98	REVISED PER ISI	DWC	DW	1	8/11/94	REDRAWN AND REISSUED	R.S.	DW

REVISIONS

AREA G & GW — SYSTEM: M.S. — P&ID COORD: 04 30-D
REF. DWG.: 104628, 228656, 500560
LINE NO.: K15-226-28 V, K15-1065-24 V
DRAWN: R. SALDIVAR
DATE: 7/19/94
DWG. NO 2.2-19 — REV. 4



K15-225-28 V	STEAM GEN 2-4 STEAM OUTLET	(MS)(MS)(CC)
K15-1066-24 V	MN STM LEAD & RELIEF VLV HDR	(MS)(MS)(CC)
LINE NUMBER	DESCRIPTION	CATEGORY

NO.	DATE	DESCRIPTION	BY	APP	NO.	DATE	DESCRIPTION	BY	APP
4	[illegible]	REVISED PER [illegible]	[illegible]	[illegible]	2	[illegible]	REVISED PER [illegible]	R.S.	DW
3	[illegible]	REVISED PER [illegible]	DWG	DW	1	[illegible]	REDRAWN AND REISSUED	[illegible]	DW

REVISIONS — REVISIONS

DIABLO CANYON UNIT 2
INSERVICE EXAMINATION ISOMETRIC
PACIFIC GAS AND ELECTRIC COMPANY

AREA: G & GW	SYSTEM: M.S.	P&ID COORD: 04 3I-C
REF. DWG.: 104628 500098	LINE NO.: K15-225-28 V K15-1066-24 V	DRAWN: P. HOSGOOD... DATE: 7/19/94
		DWG. NO. 2.2-20 — REV. 4

LAR/RAI
COMMITMENT TRACKING MEMO
(Remove prior to NRC submittal)

Document:	PG&E Letter DCL-04-141
Subject:	Response to September 8, 2004, Request for Additional Information Regarding License Amendment Request 03-18, "Revision to Technical Specifications 5.5.9, 'Steam Generator (SG) Tube Surveillance Program,' and 5.6.10, 'Steam Generator (SG) Tube Inspection Report,' for 4-volt Alternate Repair Criteria for Steam Generator Tube Repair"
File Location:	S:\RS\TAS\GRP_WORK\LARS\2003-LAR\03-18 (SG ARC for locked TSP)\PG&E Correspondence\DCL04141.doc

FSAR Update Review
Utilizing the guidance in XI3.ID2, does the FSAR Update need to be revised? Yes ☐ No ☒
If "Yes", submit an FSAR Update Change Request in accordance with XI3.ID2 (or if this is an LAR, process in accordance with WG-9)

Commitment # 1
The design change to install the second containment sump level detection system will be performed on a schedule to support locking of the SG tube support plates and prior to crediting the requested 4-volt alternate repair criteria. The design change is required to provide a control room alarm in the event of a 0.2-gpm leak using the second containment sump level detection system.

Clarification: None

When will commitment be implemented?	*BEFORE OR AFTER LICENSE AMENDMENT RECEIPT* After	
Tracking Document:	*AR or NCR* AR A0593570	*AE or ACT* **Create New AE**
Assigned To:	*NAME* TRB1	*ORGANIZATION CODE* PTEL
Commitment Code:	*FIRM OR TARGET* T	*DUE DATE:* 09/01/2006
Outage Commitment?	*YES OR NO* No	*IF YES, WHICH? (E.G., 2R9, 1R10, ETC.)*
PCD Commitment?	*YES OR NO* No	*IF YES, LIST THE IMPLEMENTING DOCUMENTS (IF KNOWN)*
Old PCD Commitment being changed?	*YES OR NO* No	*1. IF YES, LIST PCD NUMBER, AND 2. CLARIFY TO CLERICAL HOW COMMITMENT TO BE REVISED*

Commitment # 2
The proposed weld inspection plan was previously provided to the NRC in PG&E Letter DCL-04-089 dated July 30, 2004. The previously submitted inspection schedule has been revised due to deferring the Unit 2 SG Tube Support Plate (TSP) locking until Unit 2 Refueling Outage 13 (2R13). The inspections previously planned for Unit 2 Refueling Outage 12 will be performed in 2R13. The inspection plans start with the outage when the SG TSP locking is performed. Thus, deferral of SG locking will result in the deferral of any planned inspections to the outage in which the SG TSP locking is performed. Inspections planned for outages after locking will be performed as planned, although inspections will not be performed if SG TSP locking has not been not performed. The modified inspection plan is provided below.

The 15 circumferential welds to be inspected are:

MSL 1-1: Welds WICG10-1/250, RB-228-1, WICG2-1, RB-228-3/251
MSL 1-2: Welds WICG10-2/277, RB-227-3/278
MSL 1-3: Weld WICG10-3/315
MSL 1-4: Welds WICG10-4/343, RB-225-3/344
MSL 2-1: Weld WICG9-1/343
MSL 2-2: Welds RB-227-12/360, RB-227-10
MSL 2-3: Weld RB-226-12/375
MSL 2-4: Welds RB-225-8/327, RB-225-12/325

The nine Unit 1 circumferential welds will be inspected according to the schedule contained in the following table:

MSL for Unit 1	MSL Weld Inspection Schedule			
	Outage # 1R13	Outage # 1R14	Outage # 1R15	Outage # 1R16
1-1	WICG10-1/250	WICG2-1 **	RB-228-1*	RB-228-3/251*
1-2	WICG10-2/277	-	RB-227-3/278*	-
1-3	WICG10-3/315	-	-	-
1-4	WICG10-4/343	RB-225-3/344	-	-

* This weld will not be inspected if the Steam Generators are replaced prior to or during the outage.
** This will include the adjacent pipe to nozzle weld (WICG1-1).

The six Unit 2 circumferential welds will be inspected according to the schedule contained in the following table:

MSL for Unit 2	MSL Weld Inspection Schedule	
	Outage # 2R13	Outage # 2R14
2-1	WICG9-1/343	-
2-2	RB-227-10, RB-227-12/360	-
2-3	RB-226-12/375	-
2-4	RB-225-12/325	RB-225-8/327*

* ***This weld will not be inspected if the Steam Generators are replaced during the outage.***

Clarification: None

When will commitment be implemented?	*BEFORE OR AFTER LICENSE AMENDMENT RECEIPT* After	
Tracking Document:	*AR or NCR* AR A0593570	*AE or ACT* **Create New AE**
Assigned To:	*NAME* DAG1	*ORGANIZATION CODE* PTPI
Commitment Code:	*FIRM OR TARGET* T	*DUE DATE:* 09/01/2005
Outage Commitment?	*YES OR NO* No	*IF YES, WHICH? (E.G., 2R9, 1R10, ETC.)*
PCD Commitment?	*YES OR NO* No	*IF YES, LIST THE IMPLEMENTING DOCUMENTS (IF KNOWN)*
Old PCD Commitment being changed?	*YES OR NO* No	*3. IF YES, LIST PCD NUMBER, AND 4. CLARIFY TO CLERICAL HOW COMMITMENT TO BE REVISED*

Commitment # 3

The evaluation was performed for the first containment sump level detection system and bounds the second containment sump level detection system since the level detectors which will be used in the new second containment sump level detection system will be required to be as accurate or more accurate than those used in the current first containment sump level detection system.

Clarification: None

When will commitment be implemented?	*BEFORE OR AFTER LICENSE AMENDMENT RECEIPT* After	
Tracking Document:	*AR or NCR* AR A0593570	*AE or ACT* **Create New AE**
Assigned To:	*NAME* TRB1	*ORGANIZATION CODE* PTEL
Commitment Code:	*FIRM OR TARGET* T	*DUE DATE:* 09/01/2006
Outage Commitment?	*YES OR NO* No	*IF YES, WHICH? (E.G., 2R9, 1R10, ETC.)*
PCD Commitment?	*YES OR NO* No	*IF YES, LIST THE IMPLEMENTING DOCUMENTS (IF KNOWN)*
Old PCD Commitment being changed?	*YES OR NO* No	*5. IF YES, LIST PCD NUMBER, AND* *6. CLARIFY TO CLERICAL HOW COMMITMENT TO BE REVISED*

LAR/RAI
COMMITMENT TRACKING MEMO
(Remove prior to NRC submittal)

Document: PG&E Letter DCL-04-141
Subject: Response to September 8, 2004, Request for Additional Information Regarding License Amendment Request 03-18, "Revision to Technical Specifications 5.5.9, 'Steam Generator (SG) Tube Surveillance Program,' and 5.6.10, 'Steam Generator (SG) Tube Inspection Report,' for 4-volt Alternate Repair Criteria for Steam Generator Tube Repair"

File Location: S:\RS\TAS\GRP_WORK\LARS\2003-LAR\03-18 (SG ARC for locked TSP)\PG&E Correspondence\DCL04141.doc

FSAR Update Review
Utilizing the guidance in XI3.ID2, does the FSAR Update need to be revised? Yes ☐ No ☒
If "Yes", submit an FSAR Update Change Request in accordance with XI3.ID2 (or if this is an LAR, process in accordance with WG-9)

Commitment # 1
The design change to install the second containment sump level detection system will be performed on a schedule to support locking of the SG tube support plates and prior to crediting the requested 4-volt alternate repair criteria. The design change is required to provide a control room alarm in the event of a 0.2-gpm leak using the second containment sump level detection system.

Clarification: None

When will commitment be implemented?	BEFORE OR AFTER LICENSE AMENDMENT RECEIPT After	
Tracking Document:	AR or NCR AR A0593570	AE or ACT **Create New AE**
Assigned To:	NAME TRB1	ORGANIZATION CODE PTEL
Commitment Code:	FIRM OR TARGET T	DUE DATE: 09/01/2006
Outage Commitment?	YES OR NO No	IF YES, WHICH? (E.G., 2R9, 1R10, ETC.)
PCD Commitment?	YES OR NO No	IF YES, LIST THE IMPLEMENTING DOCUMENTS (IF KNOWN)
Old PCD Commitment being changed?	YES OR NO No	1. IF YES, LIST PCD NUMBER, AND 2. CLARIFY TO CLERICAL HOW COMMITMENT TO BE REVISED

Commitment # 2
The proposed weld inspection plan was previously provided to the NRC in PG&E Letter DCL-04-089 dated July 30, 2004. The previously submitted inspection schedule has been revised due to deferring the Unit 2 SG Tube Support Plate (TSP) locking until Unit 2 Refueling Outage 13 (2R13). The inspections previously planned for Unit 2 Refueling Outage 12 will be performed in 2R13. The inspection plans start with the outage when the SG TSP locking is performed. Thus, deferral of SG locking will result in the deferral of any planned inspections to the outage in which the SG TSP locking is performed. Inspections planned for outages after locking will be performed as planned, although inspections will not be performed if SG TSP locking has not been not performed. The modified inspection plan is provided below.

The 15 circumferential welds to be inspected are:

MSL 1-1: Welds WICG10-1/250, RB-228-1, WICG2-1, RB-228-3/251
MSL 1-2: Welds WICG10-2/277, RB-227-3/278
MSL 1-3: Weld WICG10-3/315
MSL 1-4: Welds WICG10-4/343, RB-225-3/344
MSL 2-1: Weld WICG9-1/343
MSL 2-2: Welds RB-227-12/360, RB-227-10
MSL 2-3: Weld RB-226-12/375
MSL 2-4: Welds RB-225-8/327, RB-225-12/325

The nine Unit 1 circumferential welds will be inspected according to the schedule contained in the following table:

MSL for Unit 1	MSL Weld Inspection Schedule			
	Outage # 1R13	Outage # 1R14	Outage # 1R15	Outage # 1R16
1-1	WICG10-1/250	WICG2-1 **	RB-228-1*	RB-228-3/251*
1-2	WICG10-2/277	-	RB-227-3/278*	-
1-3	WICG10-3/315	-	-	-
1-4	WICG10-4/343	RB-225-3/344	-	-

* This weld will not be inspected if the Steam Generators are replaced prior to or during the outage.

** This will include the adjacent pipe to nozzle weld (WICG1-1).

The six Unit 2 circumferential welds will be inspected according to the schedule contained in the following table:

MSL for Unit 2	MSL Weld Inspection Schedule	
	Outage # 2R13	Outage # 2R14
2-1	WICG9-1/343	-
2-2	RB-227-10, RB-227-12/360	-
2-3	RB-226-12/375	-
2-4	RB-225-12/325	RB-225-8/327*

* ***This weld will not be inspected if the Steam Generators are replaced during the outage.***

Clarification: None

When will commitment be implemented?	BEFORE OR AFTER LICENSE AMENDMENT RECEIPT After	
Tracking Document:	AR or NCR AR A0593570	AE or ACT **Create New AE**
Assigned To:	NAME DAG1	ORGANIZATION CODE PTPI
Commitment Code:	FIRM OR TARGET T	DUE DATE: 09/01/2005
Outage Commitment?	YES OR NO No	IF YES, WHICH? (E.G., 2R9, 1R10, ETC.)
PCD Commitment?	YES OR NO No	IF YES, LIST THE IMPLEMENTING DOCUMENTS (IF KNOWN)
Old PCD Commitment being changed?	YES OR NO No	3. IF YES, LIST PCD NUMBER, AND 4. CLARIFY TO CLERICAL HOW COMMITMENT TO BE REVISED

Commitment # 3

The evaluation was performed for the first containment sump level detection system and bounds the second containment sump level detection system since the level detectors which will be used in the new second containment sump level detection system will be required to be as accurate or more accurate than those used in the current first containment sump level detection system.

Clarification: None

When will commitment be implemented?	BEFORE OR AFTER LICENSE AMENDMENT RECEIPT After	
Tracking Document:	AR or NCR AR A0593570	AE or ACT **Create New AE**
Assigned To:	NAME TRB1	ORGANIZATION CODE PTEL
Commitment Code:	FIRM OR TARGET T	DUE DATE: 09/01/2006
Outage Commitment?	YES OR NO No	IF YES, WHICH? (E.G., 2R9, 1R10, ETC.)
PCD Commitment?	YES OR NO No	IF YES, LIST THE IMPLEMENTING DOCUMENTS (IF KNOWN)
Old PCD Commitment being changed?	YES OR NO No	5. IF YES, LIST PCD NUMBER, AND 6. CLARIFY TO CLERICAL HOW COMMITMENT TO BE REVISED