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CRANE,P.A.	Pacific Gas & Electric Co.
RECIP.NAME	**RECIPIENT AFFILIATION**
DENTON,H.R.	Office of Nuclear Reactor Regulation

SUBJECT: Forwards response to NUREG-0578:short-term Lessons Learned requirements.Rept supercedes 790827 & 1231 responses.
See Rpts

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	AD PLANT SYS	1	0	AD REAC SAFETY	1	0
	AD SITE ANLYSIS	1	0	DIRECTOR NRR	1	0
	HYDRO-METEOR BR	2	2	MPA	1	0
	OELD	1	0			
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	30 ACRS	10	10			

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PACIFIC GAS AND ELECTRIC COMPANY

PGandE 77 BEALE STREET, 31ST FLOOR • SAN FRANCISCO, CALIFORNIA 94106 • (415) 781-4211

February 29, 1980

Mr. Harold R. Denton, Director
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Phillips Building
7920 Norfolk Avenue
Bethesda, Maryland 20014

BY COURIER

Re: Docket No. 50-275
Docket No. 50-323

Dear Mr. Denton:

Enclosed are 20 copies of a report entitled "Pacific Gas and Electric Company Response to NUREG-0578 Requirements."

This report supersedes the previous PGandE reports entitled "Status Report to the Nuclear Regulatory Commission from PGandE Company Responding to NUREG-0578: TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendation" and Clarifications issued August 27 and December 31, 1979. Additionally, this report includes our addenda to these submittals, dated October 26, 1979 and January 25, 1980.

Twenty additional copies will be forwarded to you by regular mail and copies for the service list will be mailed not later than March 3, 1980.

Kindly acknowledge receipt of the above enclosures on the copy of this letter and return it to me in the enclosed envelope.

Very truly yours,

Philip A. Crane Jr.

8003260592

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PACIFIC GAS AND ELECTRIC COMPANY

RESPONSE TO

NUREG-0578: SHORT TERM LESSONS LEARNED REQUIREMENTS

April 21, 1980

Revision 5
4/21/80

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Introduction and Summary

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Purpose

This report to the Nuclear Regulatory Commission provides the total response to and status of implementing the commitments made by PG&E as a result of the lessons learned from the accident at Three Mile Island, Unit 2.

Background

Following the issuance on July 19, 1979 of NUREG-0578, PG&E issued a "Report to the Nuclear Regulatory Commission from the Pacific Gas and Electric Company Responding to NUREG-0578: 'TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations'", dated August 27, 1979.

During the subsequent reviews of NUREG-0578 by the NRC and the ACRS, the NRC issued letters on September 13 and 27, 1979, on the subject of Follow-up Actions Resulting from the NRC Staff Reviews Regarding the Three Mile Island Unit 2 Accident. The additional recommendations of these letters were addressed in PG&E's Addendum dated October 26, 1979, to the August 27, 1979 report.

On November 9, 1979 the NRC issued clarifications to some of the recommendations of NUREG-0578 resulting in modifications to some of the implementation commitments. To incorporate changes in PG&E's responses due to the clarifications and to apprise the NRC of PG&E's progress toward implementation of the commitments and recommendations, PG&E issued a "Status Report to the Nuclear Regulatory Commission from Pacific Gas and Electric Company Responding to NUREG-0578: 'TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations' and Clarifications", dated December 31, 1979.

As a result of questions from the NRC on certain responses and development of new material by PG&E, PG&E issued an Addendum dated January 25, 1980, to the December 31, 1979 status report.

Scope

This report sets forth the current comprehensive response to and status of PG&E's efforts in implementing PG&E commitments and recommendations as stated and clarified or modified in the above documents. This report stands alone as PG&E's response to NUREG-0578 and is intended to replace the previously issued documents referenced in "Background" above. This report follows the sectional numbering of NUREG-0578 and provides the Task Force's position and NRC clarifications to facilitate review.

Summary

This status report is a comprehensive compilation of PG&E's actions to implement the short-term recommendations of the Lessons Learned Task Force and the comments raised by the ACRS. This effort further demonstrates PG&E's commitment to comply with the recommendations.

Response to

NUREG-0578

and Clarifications

Section 2.1.1 - Emergency Power Supply Requirements for the Pressurizer Heaters, Power-Operated Relief Valves and Block Valves, and Pressurizer Level Indicators in PWR's

A. Task Force Position (TFP) on Pressurizer Heater Power Supply

Task Force Position 1

The pressurizer heater power supply design shall provide the capability to supply, from either the offsite power source or the emergency power source (when offsite power is not available), a predetermined number of pressurizer heaters and associated controls necessary to establish and maintain natural circulation at hot standby conditions. The required heaters and their controls shall be connected to the emergency buses in a manner that will provide redundant power supply capability. (Category A: Implementation shall be completed prior to OL, or January 1, 1980, whichever is later.)

Task Force Position 2

Procedures and training shall be established to make the operator aware of when and how the required pressurizer heaters shall be connected to the emergency buses. If required, the procedures shall identify under what conditions selected emergency loads can be shed from the emergency power source to provide sufficient capability for the connection of the pressurizer heaters. (Category A: Implementation shall be completed prior to OL, or January 1, 1980, whichever is later.)

Section 2.1.1. (Continued)

Task Force Position 3

The time required to accomplish the connection of the preselected pressurizer heater to the emergency buses shall be consistent with the timely initiation and maintenance of natural circulation conditions. (Category A: Implementation shall be completed prior to OL, or January 1, 1980, whichever is later.)

Task Force Position 4

Pressurizer heater motive and control power interfaces with the emergency buses shall be accomplished through devices that have been qualified in accordance with safety-grade requirements. (Category A: Implementation shall be completed prior to OL, or January 1, 1980, whichever is later.)

Clarification

1. In order not to compromise independence between the sources of emergency power and still provide redundant capability to provide emergency power to the pressurizer heaters, each redundant heater or group of heaters should have access to only one Class 1E division power supply.

Section 2.1.1 (Continued)

2. The number of heaters required to have access to each emergency power source is that number required to maintain natural circulation in the hot standby condition.

3. The power sources need not necessarily have the capacity to provide power to the heater concurrent with the loads required for LOCA.

4. Any change-over of the heaters from normal offsite power to emergency onsite power is to be accomplished manually in the control room.

5. In establishing procedures to manually reload the pressurizer heaters onto the emergency power sources, careful consideration must be given to:

    a. Which ESF loads may be appropriately shed for a given situation.

    b. Reset of the Safety Injection Actuation Signal to permit the operation of the heaters.

    c. Instrumentation and criteria for operator use to prevent overloading a diesel generator.

Section 2.1.1 (Continued)

6. The Class IE interfaces for main power and control power are to be protected by safety-grade circuit breakers. (See also Regulatory Guide 1.75.)

7. Being non-Class IE loads, the pressurizer heaters must be automatically shed from the emergency power sources upon the occurrence of a safety injection actuation signal. (See Item 5.b. above.)

<u>PG&E Response and Status for TFP 1</u>

All of the four pressurizer heater groups can be supplied with power from the offsite power sources when they are available. In addition, provisions will be made to provide power to two out of four heater groups from the emergency power source through the Engineered Safety Features (ESF) buses when offsite power is not available (see Figure 2.1.1-2). Sufficient power is available from the ESF buses to energize enough heaters to establish and maintain natural circulation at hot standby conditions. Redundancy is provided by supplying each of the two groups of heaters from a different ESF bus.

The minimum capacity and time requirements of the emergency power supply for the pressurizer heaters have been specified. These requirements are well within current design. It is recommended that one bank of backup

heaters be available to each emergency power train within 60 minutes after a blackout. A review of several pressurizer heat loss calculations has resulted in the minimum heater requirements without offsite power of 150 Kw. These capacities will conservatively cover heat losses from the pressurizer at or below normal operating pressure with no allowance for continuous spray. With continuous spray, loss of subcooling would occur between five and six hours. Heater input at any time of 150 Kw as specified above would more than offset the heat loss and allow system pressure to be stabilized at any desired value. Ability to supply emergency power to the heaters within four hours will prevent loss of subcooling in the primary following a loss of offsite power.

All of the equipment associated with pressurizer heater power supply described in this response will be seismically qualified for the Hosgri event except for those devices specifically noted as non-safety grade.

Circuit breakers 52-1G-72 and 52-1H-74 will be added to 480 volt ESF buses 1G and 1H, respectively (see Figure 2.1.1-1). These breakers will be seismically qualified and installed to meet safety-grade requirements. The seismic qualification is based on PG&E's vast testing experience which has previously demonstrated that electromechanical equipment can withstand numerous seismic tests simulating high seismic events without damage and that the equipment will be available to perform its safety function when called upon after the seismic event.

Section 2.1.1 (Continued)

Emergency power is generated by the onsite emergency diesel generators and supplied directly to the 4.16 kV ESF buses. Power is then fed through a step-down transformer to the 480 volt ESF buses.

The heater banks will be automatically tripped off of the ESF buses upon occurrence of a safety injection (SI) actuation signal. This feature satisfies Clarification 7.

PG&E Response and Status for TFP 2

PG&E will develop the required procedures and implement the proper training of the operators. Procedures and training will be completed to make the operator aware of when and how the required pressurizer heaters should be connected to the emergency buses. Loading of each ESF bus can be accomplished from the main control board (see TFP3 below). Procedures will identify under what conditions and which selected loads can be shed from the ESF bus to prevent overloading when the pressurizer heaters are connected. The procedures will include provisions to ensure that the heaters are transferred to the ESF power source as described in TFP3 below. The time required to transfer the power supplies will be less than 10 minutes and will expose the operator to no more than 10 mRem.

The procedures will be written and approved, and the operators trained, by May 1, 1980.

Section 2.1.1 (Continued)

PG&E Response and Status for TFP 3

The proposed design modifications will provide for simple and rapid transfer of the heater groups to the ESF power source. Within 2 minutes after loss of offsite power, the onsite emergency diesel generators will have started and been connected to any required ESF loads.

When it is determined that the pressurizer heaters are required, the Shift Foreman needs only to dispatch an operator to the 100 foot elevation in the Auxiliary Building, which is just three floors directly below the main control room (two separate stairwells are available). Once in the area, the operator simply verifies that the source breakers (52-1H-74, 52-13D-6, 52-13E-2, 52-1G-72) are open, white "Power on" lights indicate if either source is energized, and manually throws the deenergized transfer switches. This action in itself will not connect the pressurizer heaters onto the ESF buses. Only when the Shift Foreman is informed that the transfers have been made, will the heaters again be controlled using the normal control devices provided on the main control console (see Figure 2.1.1-2). This control room function is intended to meet the requirements of Clarification 4. Even with manual transfer, there is no problem in meeting the Westinghouse estimated time requirement of providing pressurizer heaters on emergency power within one hour after the accident. PG&E will provide control room indication of actual wattage being supplied to each heater group that has been transferred to the emergency power sources. Diesel generator loading parameters are also displayed in the control room.

Section 2.1.1 (Continued)

Should the operator inadvertently transfer power while energized, neither the transfer switch nor the diesel generator would be adversely affected. The operating and emergency procedures will be changed to reflect these requirements and changes by May 1, 1980.

PG&E Response and Status for TFP 4

The seismic qualification mentioned in PG&E status for position 1 above will qualify to safety grade requirements the interface between the pressurizer heater motive power and the emergency bus.

B. Task Force Position on Power Supply for Pressurizer Relief and Block Valves and Pressurizer Level Indicators

Task Force Position 1

Motive and control components of the power-operated relief valves (PORV's) shall be capable of being supplied from either the offsite power source or the emergency power source when the offsite power is not available. (Category A: Implementation shall be completed prior to OL, or January 1, 1980, whichever is later.)

Task Force Position 2

Motive and control components associated with the PORV block valves shall be capable of being supplied from either the offsite power source or the emergency power source when the offsite power is not available. (Category A: Implementation shall be completed prior to OL, or January 1, 1980, whichever is later.)

Task Force Position 3

Motive and control power connections to the emergency buses for the PORV's and their associated block valves shall be through devices that have been qualified in accordance with safety-grade requirements. (Category A: Implementation shall be completed prior to OL, or January 1, 1980, whichever is later.)

Task Force Position 4

The pressurizer level indication instrument channels shall be powered from the vital instrument buses. These buses shall have the capability of being supplied from either the offsite power source or the emergency power source when offsite power is not available. (Category A: Implementation shall be completed prior to OL, or January 1, 1980, whichever is later.)

Section 2.1.1 (Continued)

Clarification

1. While the prevalent consideration from TMI Lessons Learned is being able to close the PORV/block valves, the design should retain, to the extent practical, the capability to open these valves.

2. The motive and control power for the block valve should be supplied from an emergency power bus different from that which supplies the PORV.

3. Any changeover of the PORV and block valve motive and control power from the normal offsite power to the emergency onsite power is to be accomplished manually in the control room. .

4. For those designs where instrument air is needed for operation, the electrical power supply requirement should be capable of being manually connected to the emergency power sources.

PG&E Response and Status for TFP 1

FSAR Figure 3.2-07 shows the arrangement of the power-operated relief valves (PORV's). These valves are air-to-open, fail-closed valves. They are normally supplied by the plant air compressors with 80 psi air as

shown in Figure 2.1.1-5. Two of the three valves have a backup supply from the nitrogen system to function on loss of air, and Class I high pressure accumulators which have sufficient capability to operate each valve 120 times after the loss of both air and nitrogen.

The third PORV is not supplied with a backup motive power supply. Its only function is to preclude the possibility of turbine-generator trip, ASME Code safety valve actuation, and reactor trip following the postulated loss of 100% of net plant electrical load.* Furthermore, this function is only required during those periods of early core life characterized by low inherent transient capability. Since the normal supply of valve motive power (i.e., a shared plant air system redundantly supplied by compressors powered from both units) would continue to be available unless both generators tripped, and since the combined probability of the initiating event occurring during the fraction of core life during which the valve is needed is low, the addition of a back-up air system for this valve will not significantly reduce the probability of ASME Code safety valve actuation and is, therefore, not considered necessary.

*Net plant electrical load is that portion of the generator output which does not power "house loads" such as the reactor coolant pumps, instrument air compressors, and other equipment necessary for continued plant operation.

Each PORV is opened by a solenoid valve which is energized-to-open, spring-to-close. The circuits to the solenoid valves are supplied with redundant interlocks which prevent energization below normal operating pressures. These control circuits are powered from the emergency station batteries (see Figures 2.1.1-6 and 2.1.1-7).

PG&E Response and Status for TFP 2

The PORV block valves are shown schematically in FSAR Figure 3.2-07. As shown in Figures 2.1.1-3, 2.1.1-4 and 2.1.1-6, these valves are powered from ESF buses which are served by either offsite power or the emergency diesel generators. Each of the three valves is powered from a separate 480 volt ESF bus (Bus Sections 1F, 1G and 1H).

PG&E Response and Status for TFP 3

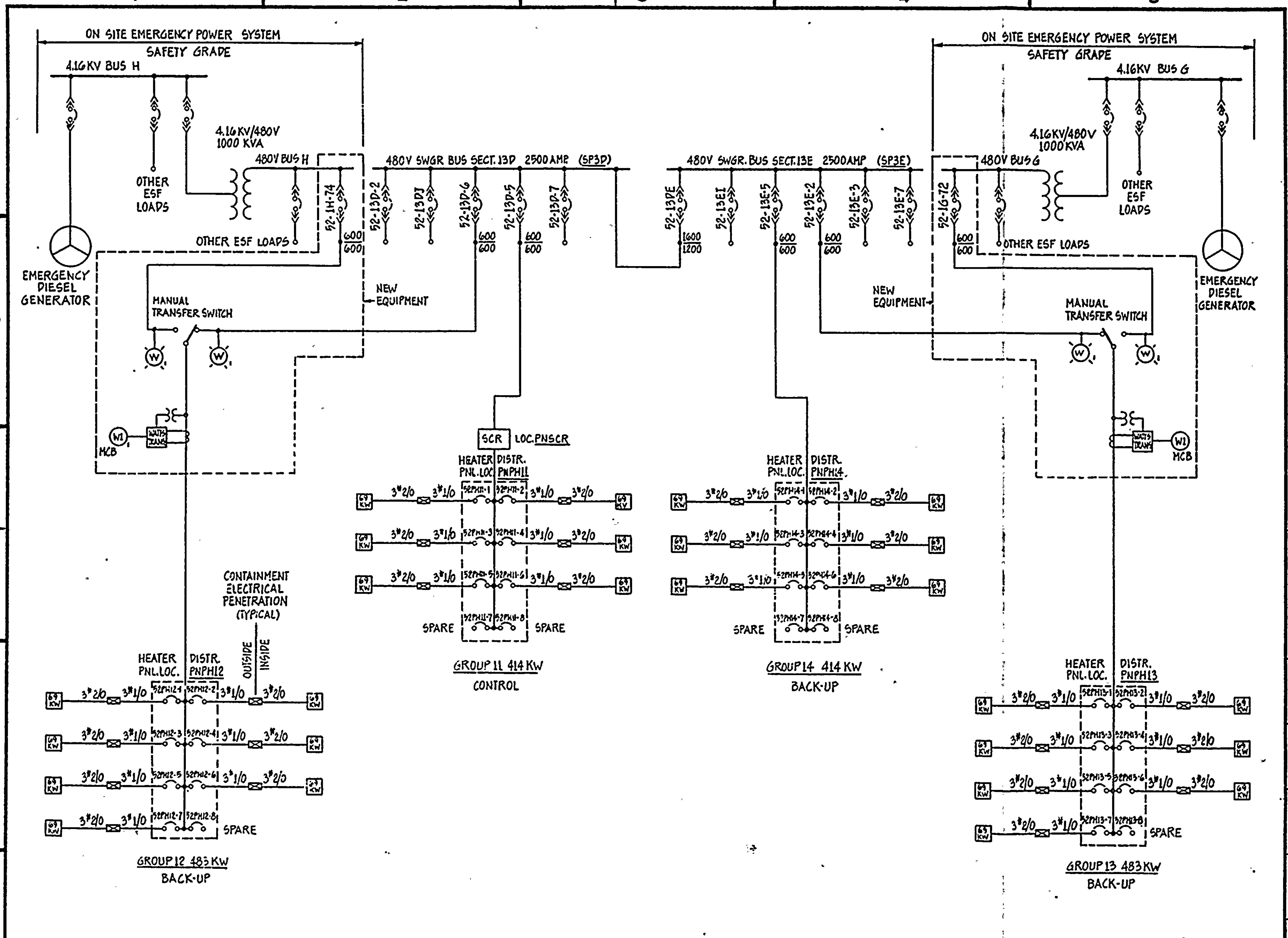
The motive and control power connections for the PORV block valves are made with equipment qualified to safety-grade requirements. The motive power for the PORV's is air or nitrogen (see 1 above). The piping, accumulators, control power connections, and the solenoid valves are qualified in accordance with safety-grade requirements.

A description of the qualifications is given in the attached pages (3.11-9 through 3.11-11) of the Diablo Canyon FSAR Section 3.11.

The PORV's are powered from the safety grade station batteries of which there are three. Each battery bus is aligned with a 480 volt ESF bus and while not physically connected, except through the battery charger, is treated as the same circuit category for separation purposes. Due to the redundancy requirements for low temperature overpressurization protection, it is necessary to supply both the PORV's and the block valves with power from the same circuit category. This is in disagreement with Clarification 2 but conforms with the intent of Clarification 1.

PG&E Response and Status for TFP 4

The pressurizer level indication circuits are safety-grade and post-accident qualified. AC power for all Class IE instrument channels is supplied from inverters which are supplied from the ESF buses with automatic backup from the emergency batteries (see Figures 2.1.1-4, 2.1.1-8 to 2.1.1-10).



NO.	DATE	DESCRIPTION	GM/SPEC	DWN.	CHKD.	SUPV.	APVD. BY

REVISIONS

APPROVED BY: GM, SUPV., DSGN., DWN., CHKD., O.K., DATE, SCALES

PRESSURIZER HEATERS
SINGLE LINE DIAGRAM
FIG. 2.1.1-1
III - B - 14

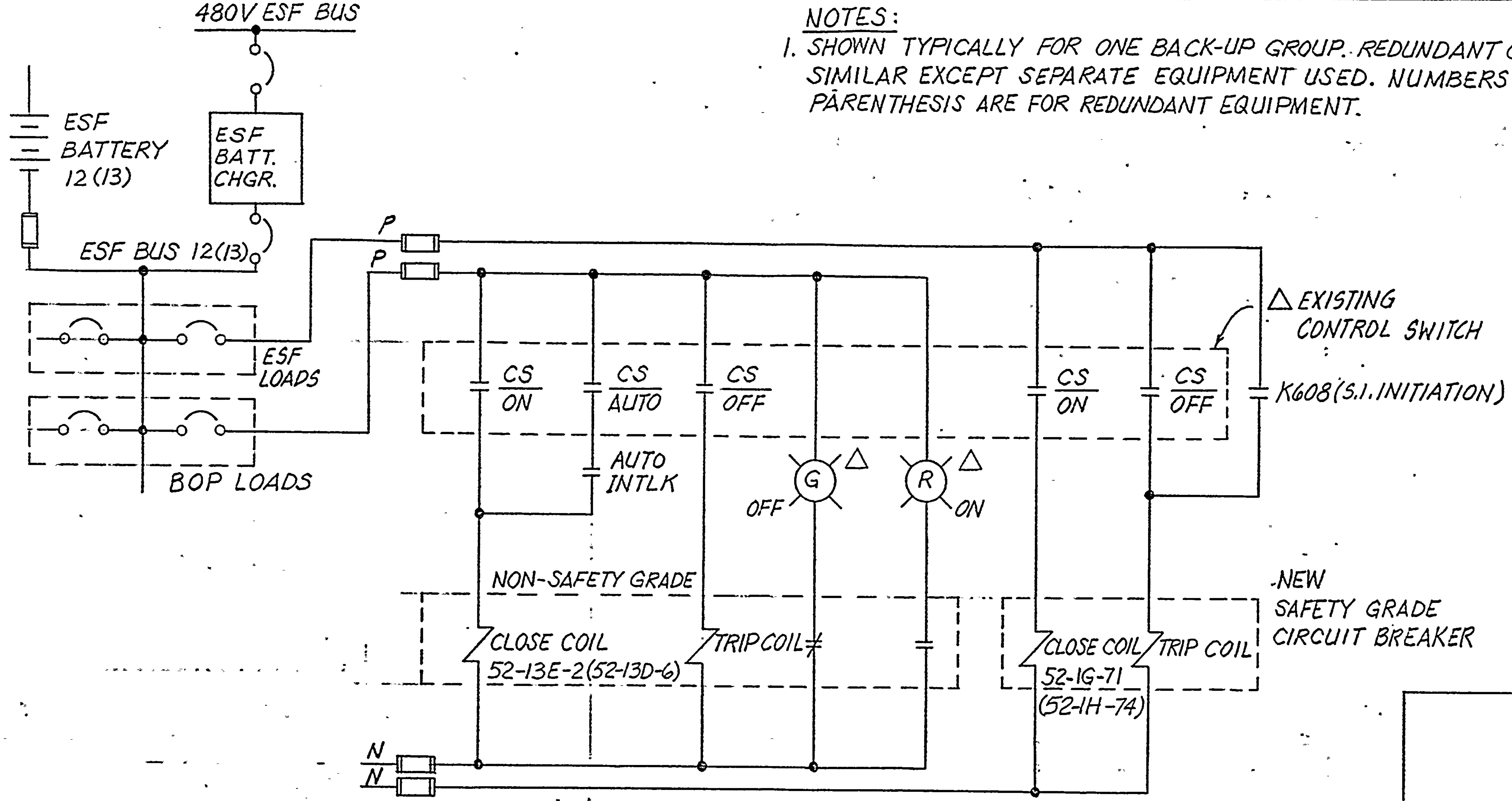
PACIFIC GAS AND ELECTRIC COMPANY
SAN FRANCISCO, CALIFORNIA

BILL OF MATL
DWG LIST
SUPSDS
SUPSD BY
SHEET NO. SHEETS
REV.

Revision 2
3/31/80

NOTES:

1. SHOWN TYPICALLY FOR ONE BACK-UP GROUP. REDUNDANT GROUP SIMILAR EXCEPT SEPARATE EQUIPMENT USED. NUMBERS IN PARENTHESIS ARE FOR REDUNDANT EQUIPMENT.



△ ON OPERATOR CONTROL CONSOLE IN MAIN CONTROL ROOM.

NO.	DATE	DESCRIPTION	GM	DWN.	CHKD.	SUPV.	APVD.

REVISIONS

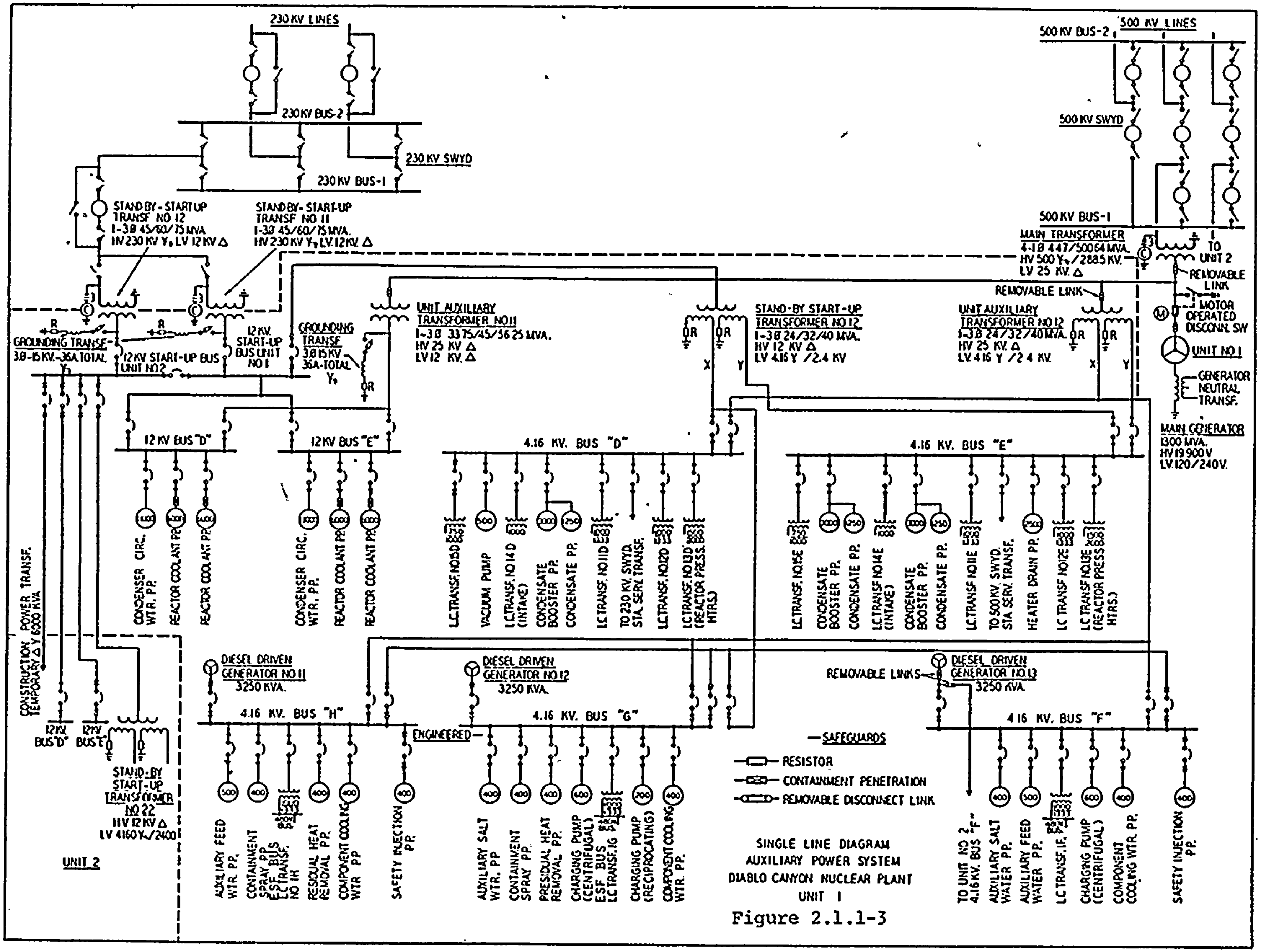
APPROVED BY: GM / SUPV. / DSGN. / DWN. / CHKD. / O.K. / DATE / SCALES

PRESSURIZER HEATERS
SIMPLIFIED CONTROL DIAGRAM
FIG. 2.1.1 - 2

Revision 0
2/29/80

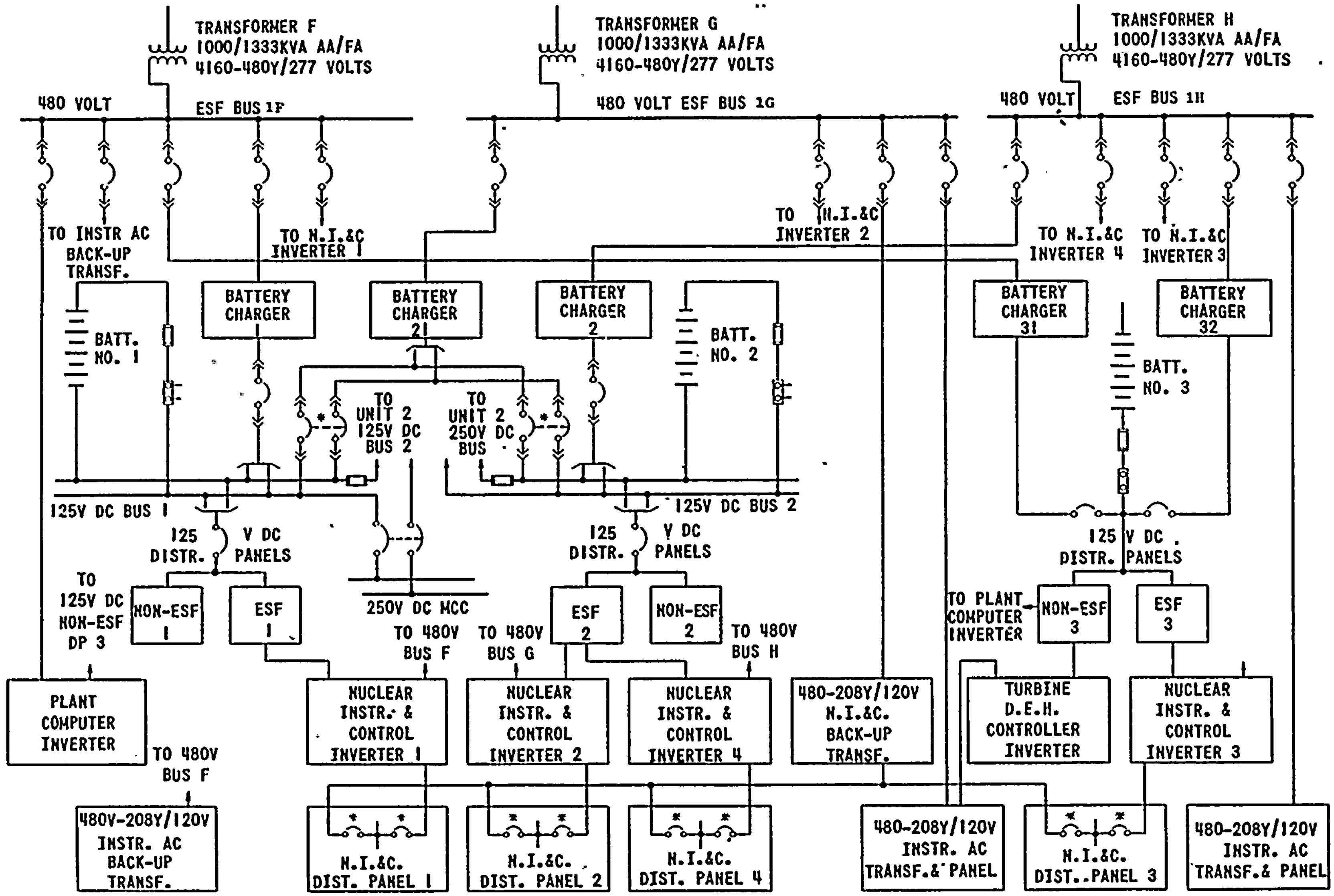
PACIFIC GAS AND ELECTRIC COMPANY
SAN FRANCISCO, CALIFORNIA

MICROFILM
BILL OF MATERIAL
DRAWING LIST
SUPERSEDES
SUPERSEDED BY
SHEET NO. III - B - 15
SHEETS
REV. 1



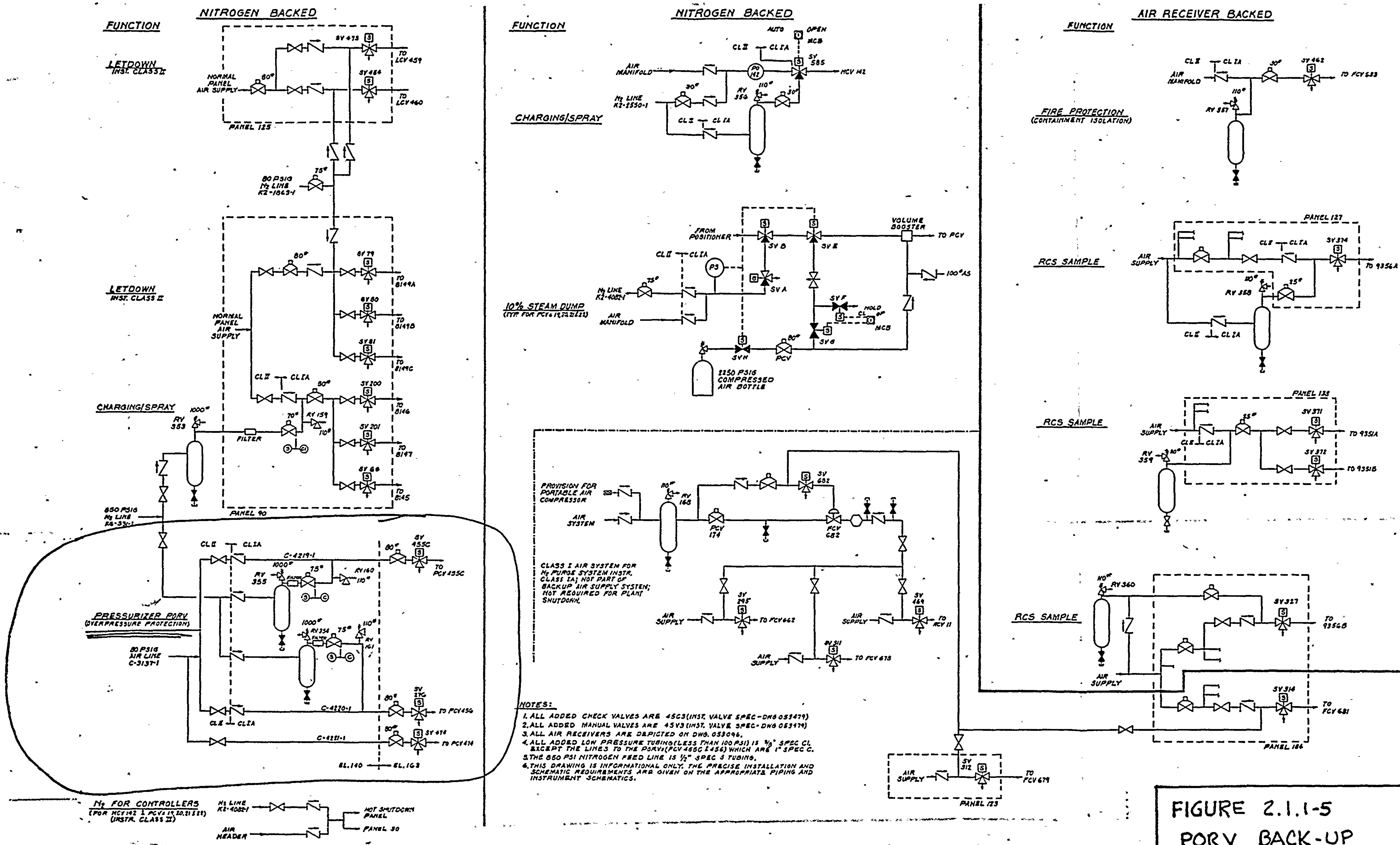
SINGLE LINE DIAGRAM
AUXILIARY POWER SYSTEM
DIABLO CANYON NUCLEAR PLANT
UNIT 1

Figure 2.1.1-3



* BREAKERS MECHANICALLY INTERLOCKED

DIABLO CANYON SITE, UNIT 1
SINGLE LINE DIAGRAM
480V ESF & 250/125 DC
Figure 2.1.1-4

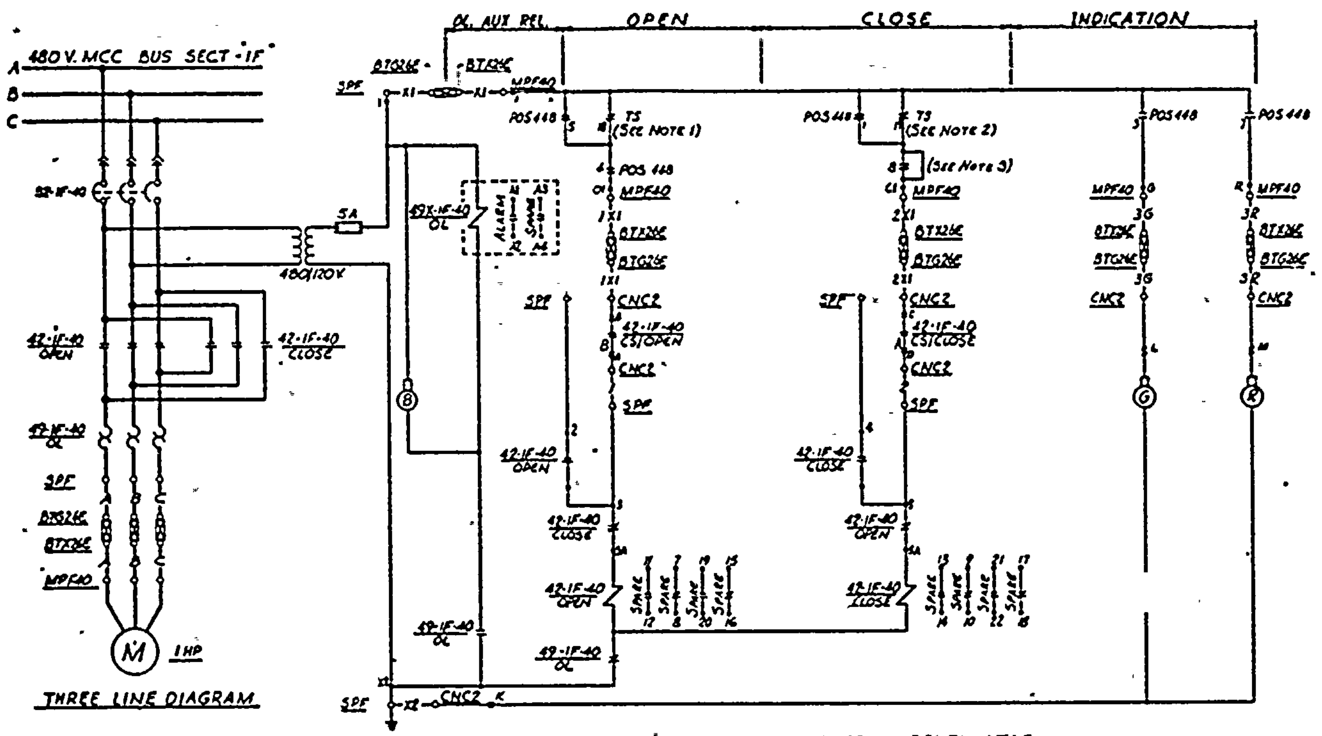


NOTES:

1. ALL ADDED CHECK VALVES ARE 45C3 (INST. VALVE SPEC-DWG 053479)
2. ALL ADDED MANUAL VALVES ARE 45V3 (INST. VALVE SPEC-DWG 053479)
3. ALL AIR RECEIVERS ARE DEPICTED ON DWG. 053096.
4. ALL ADDED LOW PRESSURE TUBING (LESS THAN 100 PSI) IS 3/8" SPEC C1. EXCEPT THE LINES TO THE PORVs (FCV 456C & 456) WHICH ARE 1" SPEC C.
5. THE 850 PSI NITROGEN FEED LINE IS 1/2" SPEC S TUBING.
6. THIS DRAWING IS INFORMATIONAL ONLY. THE PRECISE INSTALLATION AND SCHEMATIC REQUIREMENTS ARE GIVEN ON THE APPROPRIATE PIPING AND INSTRUMENT SCHEMATICS.

FIGURE 2.1.1-5
PORV BACK-UP AIR SUPPLY

Revision 0
2/29/80



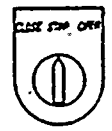
THREE LINE DIAGRAM

120V AC CONTROL SCHEMATIC

8000A PRESSURIZER POWER RELIEF STOP VALVE II - CKT Nº F40P00

PRESSURIZER RELIEF VALVES SIMILAR EXCEPT AS SHOWN IN TABLE

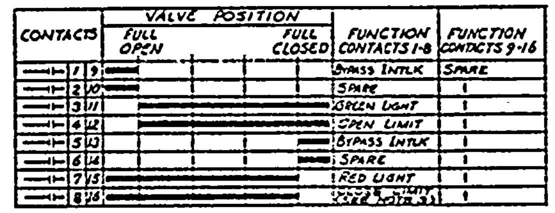
VALVE No.	DESCRIPTION	CIRCUIT BKR No	CIRCUIT No.	BUS SECT	NORMAL POSITION	ENGINEER SAFETY VITAL FUNCTION	VALVE POSITION SWITCH-(POS) POS No.	ALARM CKT Nº OVER-CURRENT	PENETR Nº	MOTOR Nº
8000A	Pressurizer Pwr Relief Stop Vv II	52-1F-40	F40P00	1F	Open	———	448	A1440BDF	26E	MPF40
8000B	〃 12	52-1G-46	G46P001	1G	〃	———	455	A1430BDG	19E	MPG46
8000C	〃 13	52-1H-33	H33P001	1H	〃	———	462	A1420BDH	12E	MPH33



CONTACTS	POSITION CLOSE	STOP	OPEN	REMARKS
A	X			This Dwg
B			X	This Dwg

CONTROL SWITCH $\frac{42\text{-}1F\text{-}40}{CS}$, $\frac{42\text{-}1G\text{-}46}{CS}$, $\frac{42\text{-}1H\text{-}33}{CS}$

USED AT LOCATION CNC2
NO SPRING RETURN



TYPICAL VALVE POSITION SWITCH CONTACT DEVELOPMENT

CONTACTS	POSITION CLOSE	AUTO	OPEN	REMARKS
A		X	X	This Dwg
B			X	This Dwg

CONTROL SWITCH $\frac{PCV456}{CS}$, $\frac{PCV474}{CS}$, $\frac{PCV455C}{CS}$

USED AT LOCATION CNC2
NO SPRING RETURN

TABLE OF DEVICES

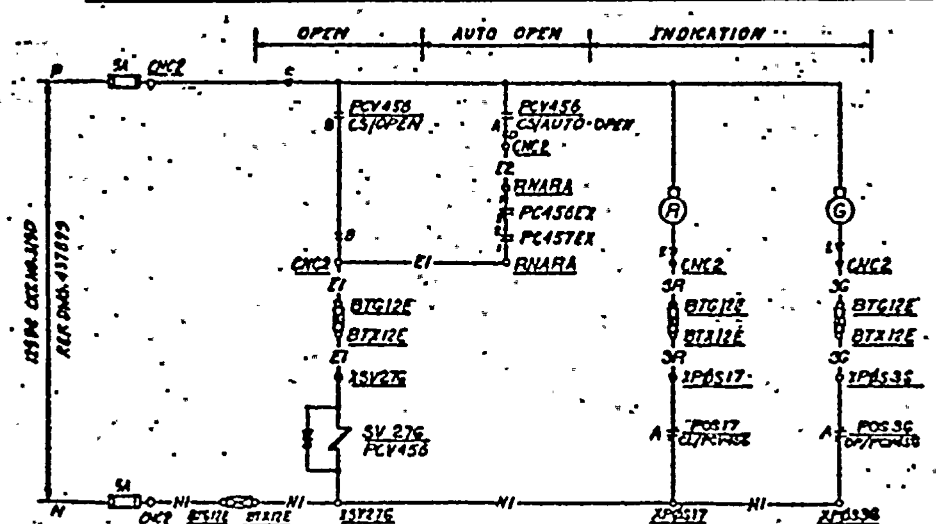
DEVICE No	FUNCTION	RATING	MFR.	TYPE	CAT/DWG.#	REMARKS
42-1F-40, 1G-46, 1H-33	480V AC MOTOR STARTER REVERSIBLE, SIZE 1	—	W.E.Corp	—	Ref Dwg #1,2	
49-1F-40, 1G-46, 1H-33	MOTOR OVERLOAD RELAY	—	W.E.Corp	—	—	PART OF MOTOR STARTER
49X-1F-40, 1G-46, 1H-33	MOTOR OVERLOAD AUXILIARY RELAY	—	W.E.Corp	—	—	PART OF MOTOR STARTER
52-1F-40, 1G-46, 1H-33	480V AC Air Circuit Breaker	—	W.E.Corp	—	Ref Dwg #1,2	
FCV	FLOW CONTROL VALVE	—	—	—	—	SEE TABLE FOR VALVE NOS
PC456EX Etc	PRESSURE CONTROLLER AUX. REL.					
POS	FCV POSITION SWITCH	—	—	—	—	SEE TABLE FOR SW NOS
SV...	SOLENOID VALVE					
TS	TORQUE SWITCH					

EQUIPMENT LOCATION NUMBERS

SPF - 480V Motor Control Center Bus Section 1F
MPF40 - Motor Operated Valve 8000A
CNC2 - Control Board, Reactor Coolant
BTG26C - Terminal Box, Area G, No 26C
RNARA - Rack Nuclear Aux. Relay Cubicle A

NOTES:

1. Switch Opens On Mechanical Torque During Opening Cycle
2. Switch Opens On Mechanical Torque During Closing Cycle Or Fully Closed Valve (17)
3. Field To Install Jumper If Torque Seating Is Required



NOTE: DC CIRCUIT ASSOCIATED AS FOLLOWS:

119D WITH BUS 1F
217D WITH BUS 1G
315D WITH BUS 1H

CONTACTS	VALVE POSITION CLOSE	OPEN & INTERM.	REMARKS
A		X	RED LT.
B	X		SPARE
C		X	SPARE
D	X		SPARE

VALVE CLOSE POSITION SWITCH
POS 16, 17, & 18

CONTACTS	VALVE POSITION CLOSE & INTERM.	OPEN	REMARKS
A	X		GREEN LT.
B		X	SPARE
C	X		SPARE
D		X	SPARE

VALVE OPEN POSITION SWITCH
POS 35, 36, & 37

125V DC CONTROL SCHEMATIC

PCV456 PRESSURIZER POWER RELIEF VALVE - CKT. Nº RP087

PRESSURIZER POWER RELIEF VALVES SIMILAR EXCEPT AS SHOWN IN TABLE

VALVE No.	DESCRIPTION	D.C. CKT. No.	CIRCUIT No.	VALVE LOC.	SOL. VLV No.	SOL. VLV LOC	NORMAL POSITION	ENGINEER SAFETY VITAL FUNCTION	VALVE POSITION SWITCH (POS) CLOSE	OPEN	PRESSURE CONTROL AUX REL. DEVICE	CONTACT	DEVICE	CONTACT	PENN. No.
PCV456	Pressurizer Power Relief Valve	315D	RP087	1PCV456	276	1SV276	Closed	———	17	36	PC456EX	1-2	PC457EX	2-1	12E
PCV474	〃	119D	RP094	1PCV474	474	1SV474	〃	———	18	37	PC457EX	3-4	PC456EX	4-3	26E
PCV455C	〃	217D	RP101	1PCV455C	455C	1SV455C	〃	———	16	35	PC455EX	1-2	PC418BX	2-1	19E

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FIGURE 2.1.1-6 PRESSURIZER PORVs & BLOCK VALVES

III - B - 19

R1

NOTES:

1- PRESSURIZER PC CONTACTS ARE IN SERIES THROUGH AUX. RELAY RACK.
2- SEE INSTRUMENT AIR PIPING REQUIREMENTS (SPECIAL AIR REQ'T)

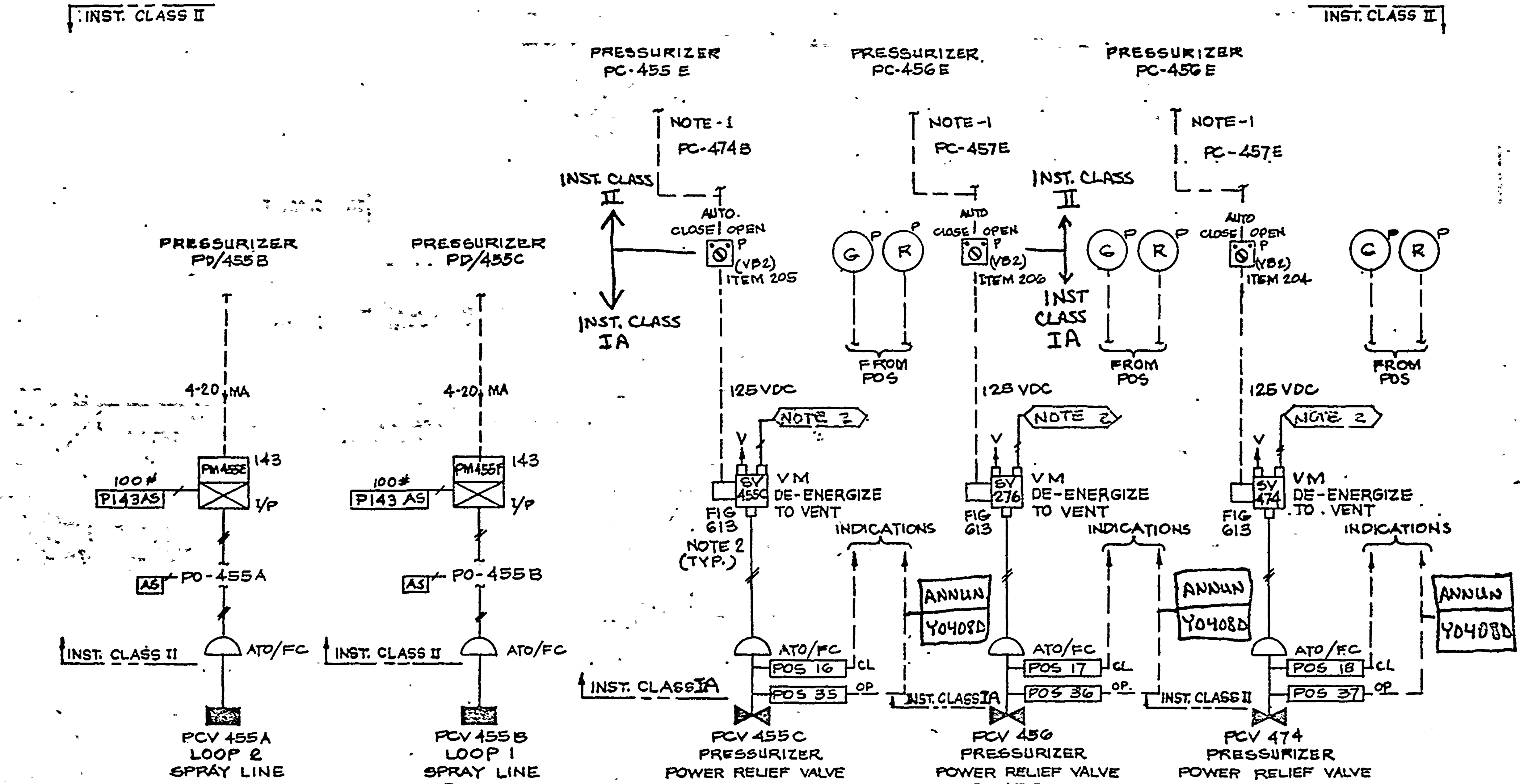

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FIGURE 2.1.1-7
PRESSURIZER
PORV DIAGRAM

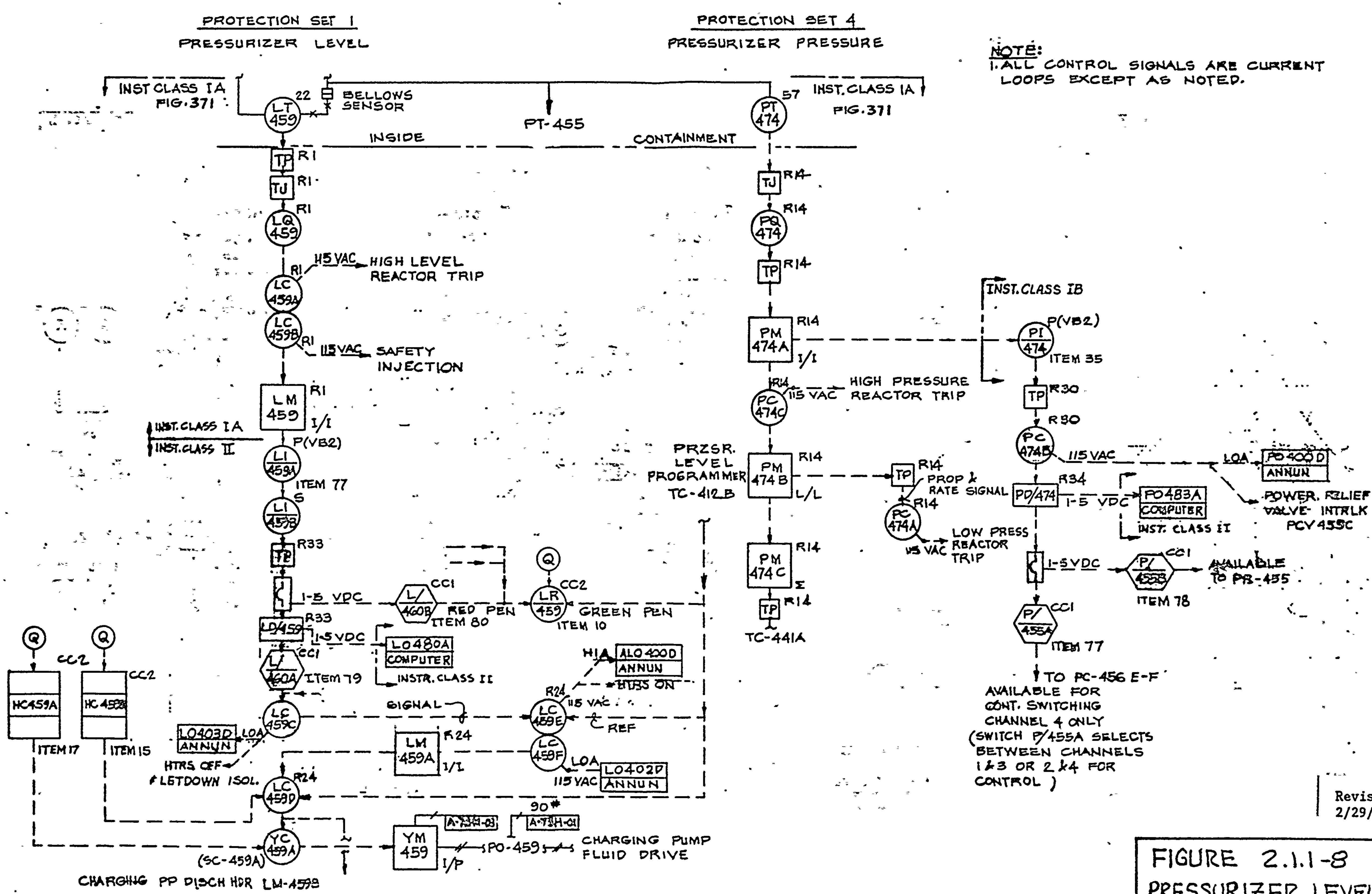

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FIGURE 2.1.1-8
PRESSURIZER LEVEL, #1
& PRESSURE SET #4
III - B - 21

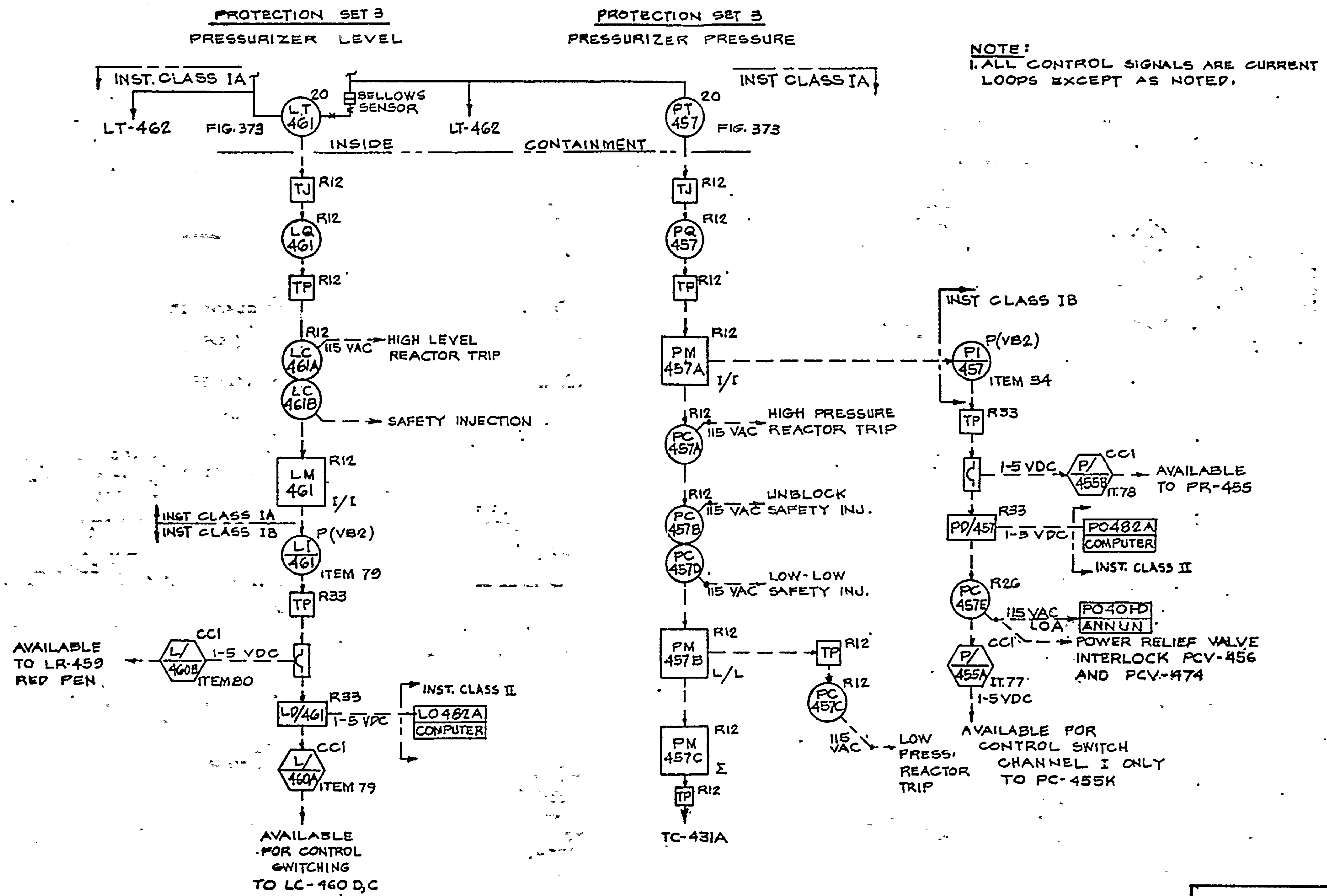

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FIGURE 2.1.1-9
PRESSURIZER LEVEL
AND PRESSURE, SET 3

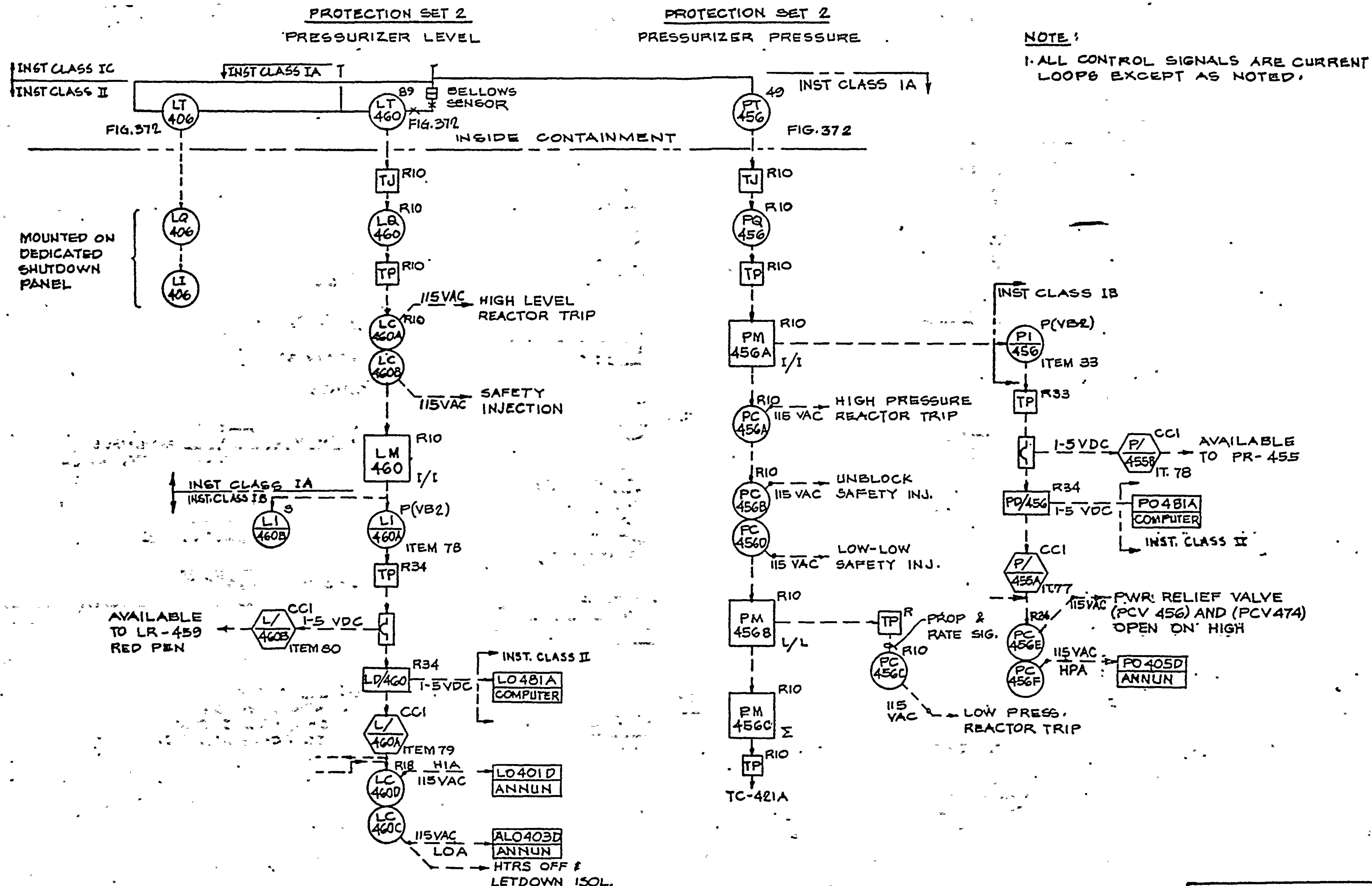

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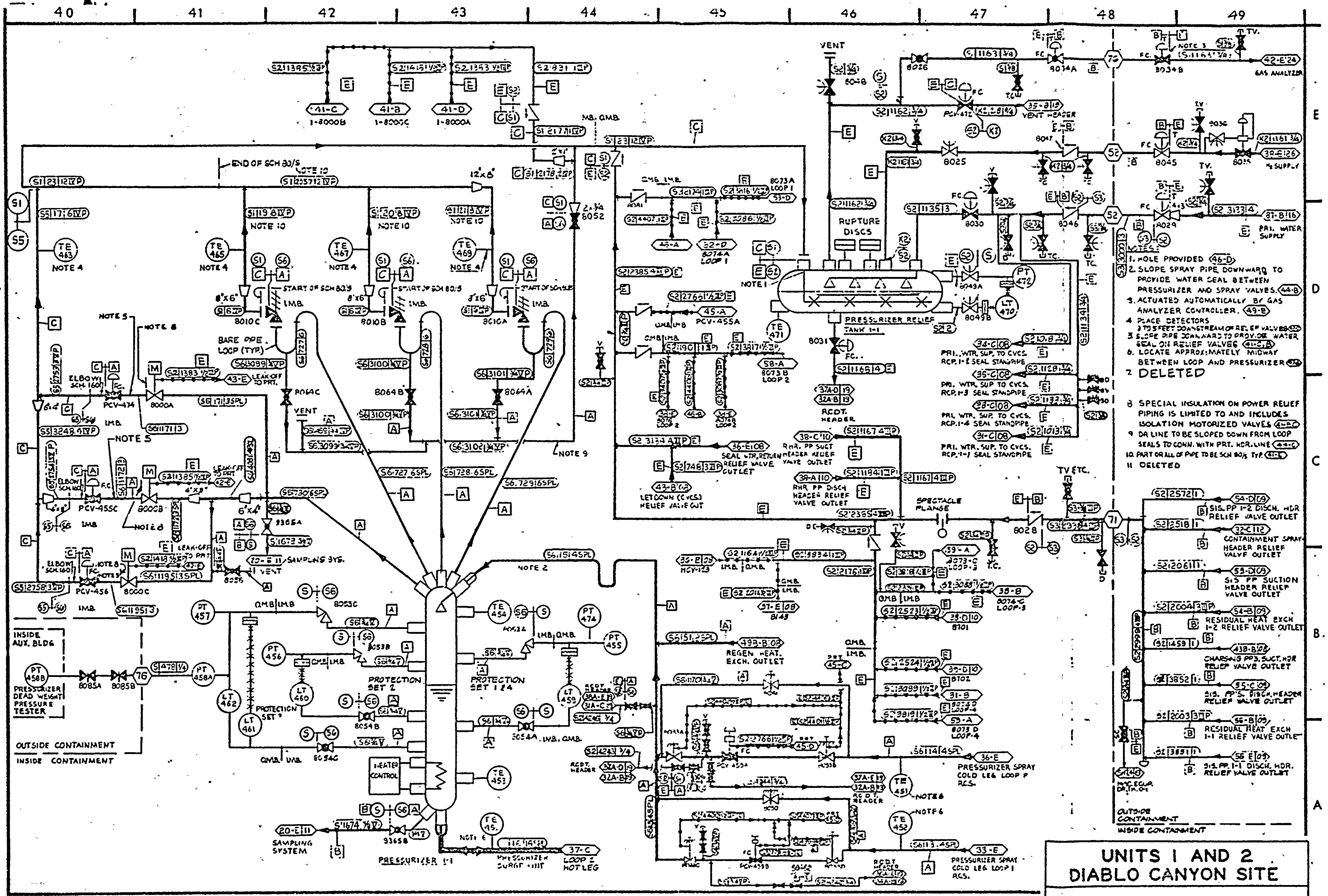
FIGURE 2.1.1-10
PRESSURIZER LEVEL AND PRESSURE SET 2



UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.2-07 (Sheet 2 of 4)
PIPING SCHEMATIC
REACTOR COOLANT SYSTEM

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3. Valve Operators - All Westinghouse-supplied safety-related electric motor valve operators which are required to operate in the post-accident containment environment (regardless of specified length of operation time) have class H insulation. These safety related valves are identified in Westinghouse Submittal NS-CE-847 dated November 24, 1975 (Eicheldinger to Vassallo)[6]. Westinghouse conducted environmental tests on a class H - insulated valve motor operator similar to those being used in the Diablo Canyon plant. The results of these tests demonstrate that the equipment will perform its required function in the post-LOCA environment[1]. As part of the Westinghouse Supplemental Program[4], Westinghouse provided additional information regarding the qualification of class H insulated valve motor operators in Reference 4. The operability, under severe accident conditions, of Westinghouse supplied solenoid valves is demonstrated by a Failure Modes and Effects Analysis and is documented in NS-CE-755[7]. 55

Electric valve operators for the balance of plant are qualified to withstand the same environment as that for which the Westinghouse-supplied operators are qualified.

4. Wire and Cable - Vital wire and cable of the type that is installed in the containment has undergone tests simulating conditions during a LOCA.

Low voltage power and control wire and cable, except for power cable to the containment fan cooler motors, have had the following tests made by the cable manufacturer:

Time of Cycle	Pressure, psig	Temp., Degrees F	Minimum Insulation Resistance, ohm-ft	Test Voltage
Initial	0	65	2.7×10^{11}	2200 v a-c
End of First Hour	90	333	5.4×10^{8}	"
End of Third Hour	60	290	2.04×10^{8}	"
End of 24 Hours	20	260	1.13×10^{8}	"
End of Fifth Day	7	230	1.26×10^{8}	"

The above test was performed after a total radiation dose of 5.5×10^{7} R. No failures were encountered.

Cable for containment fan cooler motors was tested by Pacific Gas and Electric Company at its Emeryville Laboratory under conditions of high humidity, pressure and temperature. Temperatures up to 302°F at a steam pressure of 50 psig for a period of approximately 2 hours, followed by a temperature of 263°F at a pressure of 20 psig for 20 hours were applied. The insulation resistance was measured every half hour and was above 1×10^{7} ohm-ft each time. This cable was not exposed to radiation before being subjected to the steam environmental test. Since this cable has the same Hypalon jacket as that used for the low voltage power and control cable, and since the insulation is Kapton with a gamma radiation resistance of 10^{9} R, a special radiation test for this cable makeup is not needed. Vital instrumentation and thermocouple extension wire was supplied by three different manufacturers, utilizing three different types of insulation. All were type tested and passed simulated LOCA tests.

5. Electrical Connections - All splices and terminal connections made in the containment for safety related electrical circuits are low voltage and were made using a polyolefin heat shrinkable material, which has been type tested for loss of coolant accident conditions before and after exposure to nuclear radiation. The test sequence for assembled low voltage splices consisted of:

a. Heat aging at 121°C for 168 hours in a forced air oven.

b. Irradiation of splices with cobalt 60 gamma radiation at 0.27 Mrads per hour to total doses of 100 and 200 Mrads.

c. Subjecting irradiated assemblies maintained at maximum rated voltage to LOCA tests in a pressurized autoclave according to the following schedule:

(1) 5 hours at 360°F, 70 psig steam
(2) 6 hours at 320°F, 70 psig steam
(3) 24 hours at 250°F, 21 psig steam, 0.2% boric acid spray, buffered to pH of 10.
(4) 12 days at 221°F, 2.5 psig steam

Tests results show that when properly assembled, the splices have successfully withstood DBE and LOCA tests and will remain functional during a LOCA accident.

6. <u>Electrical Penetrations</u> - Low voltage power and control, medium voltage power, and shielded signal electrical penetrations were all successfully prototype tested by the manufacturer at a temperature of 281°F, 63 psig, and a relative humidity of 90 to 100 percent for a duration of 240 hours. Leakage rates were all less than 1×10^{-6} cc/sec.

7. <u>Instrumentation</u> - The instruments which are inside the containment and are required for action during and after the LOCA (pressurizer pressure, pressurizer level, and containment sump level) were environmentally qualified by test (testing described in Reference 1) to assure performance of their protective function. Supplemental testing, at conditions more severe than reported in Reference 1, did not confirm the long term survival capability of the instruments in a hostile environment. As a result, the company will replace those instruments required for long term survival in these severe environments (pressurizer level, wide range reactor coolant system pressure, narrow range steam generator level, and containment sump level) with instruments which have passed the supplemental testing (Ref. 8). This will occur during the first planned outage of one week or more after they become available. 55

Section 2.1.2 - Performance Testing for BWR and PWR Relief and Safety Valves

Task Force Position

Pressurized water reactor and boiling water reactor licensees and applicants shall conduct testing to qualify the reactor coolant system relief and safety valves under expected operating conditions for design basis transients and accidents. The licensees and applicants shall determine the expected valve operating conditions through the use of analyses of accidents and anticipated operational occurrences referenced in Regulatory Guide 1.70, Revision 2. The single failures applied to these analyses shall be chosen so that the dynamic forces on the safety and relief valves are maximized. Test pressures shall be the highest predicted by conventional safety analysis procedures. Reactor coolant system relief and safety valve qualification shall include qualification of associated control circuitry, piping, and supports as well as the valves themselves. (Category A: Submit the program description and schedule prior to OL, or January 1, 1980, whichever is later, and complete the test program by July 1981).

Clarification

1. Expected operating conditions can be determined through the use of analysis of accidents and anticipated operational occurrences referenced in Regulatory Guide 1.70.

Section 2.1.2 (Continued)

2. This testing is intended to demonstrate valve operability under various flow conditions, that is, the ability of the valve to open and shut under the various flow conditions should be demonstrated.

3. Not all valves on all plants are required to be tested. The valve testing may be conducted on a prototypical basis.

4. The effect of piping on valve operability should be included in the test conditions. Not every piping configuration is required to be tested, but the configurations that are tested should produce the appropriate feedback effects as seen by the relief or safety valve.

5. Test data should include data that would permit an evaluation of discharge piping and supports if those components are not tested directly.

6. A description of the test program and the schedule for testing should be submitted by January 1, 1980.

7. Testing shall be complete by July 1, 1981.

Section 2.1.2 (Continued)

PG&E Response and Status

PG&E is participating in an ongoing EPRI safety and relief valve test program. This program will assure that safety and relief valves can perform to prevent over-pressurization of the reactor coolant system pressure boundary. The hydraulic and structural performance of the valves and the associated discharge piping will be verified by testing. This testing will demonstrate: (1) that the valves open and close correctly; (2) that the flow capacity is sufficient; and (3) that piping integrity is maintained. The valves to be used at Diablo Canyon are included in this program. The desired capability to test valves at full pressure and full flow does not currently exist in the industry. Multiple test facilities are being modified or developed to allow for this testing capability. Initial testing with small safety valves and piping is scheduled to begin in April, 1980. This part of the test program (incorporating steam, water, and two phase flow) will be completed by July, 1981. The full capacity test facility is scheduled to be available by July, 1981, and will explore over-pressure protection system phenomena. It will be possible to test both a safety valve and a power-operated relief valve simultaneously, as well as flow phase transitions.

The entire EPRI safety and relief valve test program is anticipated to take four years and to be completed in 1983.

Section 2.1.2 (Continued)

In addition to the valve qualification program, power operated relief valve control circuitry will be upgraded as described in Section 2.1.1. The analysis of relief and safety valve discharge piping and supports will be reviewed and, if necessary, modified to accommodate the loadings expected for accidents that result in two-phase slug flow and subcooled liquid flow. Completion of this and any field modification work is necessarily dependent upon completion of the qualification program.

Section 2.1.3.a - Direct Indication of Power-Operated Relief Valve and Safety Valve Position for PWR's and BWR's

Task Force Position

Reactor system relief and safety valves shall be provided with a positive indication in the control room derived from a reliable valve position detection device or a reliable indication of flow in the discharge pipe. (Category A: Implementation complete prior to OL or January 1, 1980, whichever is later.)

Clarification

1. The basic requirement is to provide the operator with unambiguous indication of valve position (open or closed) so that appropriate operator actions can be taken.

2. The valve position should be indicated in the control room. An alarm should be provided in conjunction with this indication.

3. The valve position indication may be safety grade. If the position indication is not safety grade, a reliable single channel direct indication powered from a vital instrument bus may be provided if backup methods of determining valve position are available and are discussed in the emergency procedures as an aid to operator diagnosis and action.

Section 2.1.3.a (Continued)

4. The valve position indication should be seismically qualified consistent with the component or system to which it is attached. If the seismic qualification requirements cannot be met feasibly by January 1, 1980, a justification should be provided for less than seismic qualification and a schedule should be submitted for upgrade to the required seismic qualification.

5. The position indication should be qualified for its appropriate environment (any transient or accident which would cause the relief or safety valve to lift). If the environmental qualification program for this position indication will not be completed by January 1, 1980, a proposed schedule for completion of the environmental qualification program should be provided.

PG&E Response and Status

There are 3 PORVs and 3 safety valves on the pressurizer. The pressurizer PORV's presently have both open and close limit switches which control indicating lights mounted at their respective control switches on the main control board. The limit switches are snap acting, positive throw switches mounted on the valve yokes. They are operated by the actual valve stem motion. The indication circuits are powered from the station batteries. All devices have been seismically qualified to meet the postulated Hosgri Earthquake, and environmentally qualified for the design basis event.

Section 2.1.3.a (Continued)

The pressurizer PORV's have a position indicating system that complies with the Task Force Position and all clarifications except clarification 2. To comply with clarification 2, an alarm will be provided, and will be operative by May 1, 1980.

The position of the pressurizer safety valves will be measured with acoustic monitors manufactured by Technology for Energy Corporation (TEC). Readouts will be provided on the control board which give analog indications which will be correlated to valve positions. Precalibrated setpoints will be used to provide alarm of open valves.

The Safety Valve acoustic monitors will be calibrated using experimental data developed by the manufacturer. (EPRI Report NP1313, January 1980, Valve Position Indication Through Acoustic Monitoring of Steam Flow, by W. F. Hartman). The gain of the unit is set by the calculation:

$$G = 2.0 * F/(S*R)$$

Where G is the gain setting to use.
F is an engineering safety factor (2.0 per Diablo).
S is the tested sensitivity of the monitor components.
R is the RMS noise level for the particular valve (approximately 30 for Diablo).

It should be understood that this calibration will detect any significant leakage and an order of magnitude indication of valve opening. Since the manufacturer's data is not based on the same valve (Crosby 6" x 10" tested, Crosby 6" x 6" at Diablo), exact calibration for accurate flow measurements is not presently available.

Section 2.1.3.a (Continued)

Accelerometers, acting as acoustical sensors, are to be located on the discharge piping within six inches of the valve for sensing valve flow signals. High frequency (30 KHz) signals to which the accelerometers are sensitive are rapidly attenuated in the roughly 30 feet minimum of heavy piping and supports between each valve and the common header which is twice the diameter of the discharge piping. Due to the isolation which is provided by this arrangement, crosstalk has been shown in other plants, to generally be reduced by a factor of at least 100 so that the indication of an open valve would be readily distinguished from any noise introduced by an adjacent valve. Monitor gains are adjusted so that normal background noise levels do not influence position indications. Thus the effects of any feedback are minimized.

The monitors will be safety grade. Backup indication is provided by valve discharge temperature indicators on the main control board. Devices will be environmentally and seismically qualified to IEEE Standards No. 323-1974 and No. 344-1975. The manufacturers qualification program is scheduled to be completed in late 1980.

Installation is expected to be completed by June 1, 1980.

Backup indication is provided by discharge pipe temperature monitors for each safety valve and for the PORV header. Indicators are mounted on the main control board and high alarms are provided on the main annunciators.

Additionally the pressurizer relief tank is provided with pressure, level and temperature indication on the main control board, with high alarms on the main annunciator for each parameter.

The emergency operating procedures OP-0, OP-1, and OP-3, which are appended to Section 2.1.9 of this response, require that the operator verify valve position by using discharge pipe temperatures.

Section 2.1.3.b - Instrumentation for Detection of Inadequate Core Cooling in PWR's

A. Task Force Position on Subcooling Meter

Licensees shall develop procedures to be used by the operator to recognize inadequate core cooling with currently available instrumentation. The licensee shall provide a description of the existing instrumentation for the operators to use to recognize these conditions. A detailed description of the analyses needed to form the basis for operator training and procedure development shall be provided pursuant to another short-term requirement, "Analysis of Off-Normal Conditions, Including Natural Circulation". (See Section 2.1.9 of this appendix.)

In addition, each PWR shall install a primary coolant saturation meter to provide on-line indication of coolant saturation condition. Operator instruction as to use of this meter shall include consideration that is not to be used exclusive of other related plant parameters. (Category A: Implementation complete prior to OL or January 1, 1980, whichever is later.)

Clarification

1. The analysis and procedures addressed in Paragraph 1 above should be submitted to the NRC for review.

Section 2.1.3.b (Continued)

2. The purpose of the subcooling meter is to provide a continuous indication of margin to saturated conditions. This is an important diagnostic tool for the reactor operators.

3. Redundant safety grade temperature input from each hot leg (or use of multiple core exit in T/C's) are required.

4. Redundant safety grade system pressure measures should be provided.

5. Continuous display of the primary coolant saturation conditions should be provided.

6. Each PWR should have: (A.) Safety grade calculational devices and display (minimum of two meters) or (B.) a highly reliable single channel environmentally qualified, and testable system plus a backup procedure for use of steam tables. If the plant computer is to be used, its availability must be documented.

7. In the long term, the instrumentation qualifications must be required to be upgraded to meet the requirements of Regulatory Guide 1.97 (Instrumentation for Light Water Cooled Nuclear Plants to Assess Plant Conditions During and Following an Accident) which is under development.

Section 2.1.3.b (Continued)

8. In all cases appropriate steps (electrical, isolation, etc.) must be taken to assure that the addition of the subcooling meter does not adversely impact the reactor protection or engineered safety features systems.

9. The attachment provides a definition of information required on the subcooling meter.

Section 2.1.3.b (Continued)

ATTACHMENT
INFORMATION REQUIRED ON THE SUBCOOLING METER

Display

Information Displayed (T-Tsat, Tsat, Press, etc.) ________
Display Type (Analog, Digital, CRT) ________
Continuous or on Demand ________
Single or Redundant Display ________
Location of Display ________
Alarms (include setpoints) ________
Overall uncertainty (°F, PSI) ________
Range of Display ________
Qualifications (seismic, environmental, IEEE323) ________

Calculator

Type (process computer, dedicated digital or analog calc.) ________
If process computer is used specify availability. (% of time) ________
Single or redundant calculators ________
Selection Logic (highest T., lowest press) ________
Qualifications (seismic, environmental, IEEE323) ________
Calculational Technique (Steam Tables, Functional Fit, ranges) ________

Input

Temperature (RTD's or T/C's) ________
Temperature (number of sensors and locations) ________
Range of temperature sensors ________
Uncertainty* of temperature sensors (°F at 1) ________
Qualifications (seismic, environmental, IEEE323) ________

*Uncertainties must address conditions of forced flow and natural circulation.

Section 2.1.3.b (Continued)

Pressure (specify instrument used) __________
Pressure (number of sensors and locations) __________
Range of Pressure sensors __________
Uncertainty* of pressure sensors (PSI at 1) __________
Qualifications (seismic, environmental, IEEE323) __________

Backup Capability

Availability of Temp & Press __________
Availability of Steam Tables etc. __________
Training of operators __________
Procedures __________

PG&E Response and Status

Procedures and Description of Existing Instrumentation

The Westinghouse Owners' Group, of which PG&E is a member, has performed analyses as required by Item 2.1.9 to study the effects of inadequate core cooling. These analyses were provided to the NRC "Bulletins and Orders Task Force" for review on October 31, 1979. As part of the submittal made by the Owners' Group, an "Instruction to Restore Core Cooling during a small LOCA" was included. This instruction provides the basis for procedure changes and operator training required to recognize the existence of inadequate core cooling and restore core cooling based on existing instrumentation. PG&E will incorporate the key considerations of this instruction into the LOCA procedures, and provide training to the operators in this area.

*Uncertainties must address conditions of forced flow and natural circulation.

Section 2.1.3.b (Continued)

Subcooling Meter

PG&E is installing a Combustion Engineering PWR subcooled margin monitor. The equipment is on order and delivery is expected by May 1, 1980 and installation will be completed by June 1, 1980. Details of the display, calculator and inputs are as follows:

Display

The display indicates either the temperature or pressure margin continuously on a digital type display and on an analog recorder. The analog recorder provides a redundant display. The digital display is located on the main control board in the control room. There is a low alarm at 30°F subcooling and a low-low alarm at 20°F subcooling. The uncertainty in the monitor is 0.5 percent. The overall uncertainty is estimated to be ±10°F. The range of the display is -40 to +200°F subcooling. The display is qualified to meet the seismic requirements of IEEE 344. The analog recorder will be on the post accident monitoring panel with other recorders to assess core cooling conditions.

Calculator

The calculator module is a dedicated digital type. The plant process computer is not used. The calculator module is not redundant. The

Section 2.1.3.b (Continued)

selection logic uses the highest temperature and the lowest pressure. The module is qualified to meet the seismic requirements of IEEE 344.

Inputs

1. Temperature

The subcooled meter has 10 temperature inputs. Four temperature signals come from each of the four hot leg wide range RTD's and six temperatures are taken from core exit thermocouples. All temperature signals have a range of 0 to 700°F. The uncertainty is estimated to be ±5°F with no data available to evaluate the difference between forced flow and natural circulation conditions. At the present time, none of the temperature inputs are safety grade, however, PG&E is upgrading these inputs to meet safety grade requirements.

2. Pressure

Pressure is sensed by two safety grade reactor coolant loop pressure transmitters. Both pressure transmitters are located on the hot leg of loop 4. The pressure range is 0 to 3000 psi with an uncertainty of ±15 psi. These transmitters are seismically qualified to the requirements of IEEE 344 and environmentally qualified to the requirements of IEEE 323.

Section 2.1.3.b (Continued)

INFORMATION REQUIRED ON THE SUBCOOLING METER

Display

Information Displayed (T-Tsat, Tsat, Press, etc.)	TSAT - T, P - PSAT
Display Type (Analog, Digital, CRT)	Digital and Analog
Continuous or on Demand	Continuous
Single or Redundant Display	Redundant
Location of Display	Control Board, PAM Board
Alarms (include setpoints)	30°F, 20°F
Overall uncertainty (°F, PSI)	±10°F
Range of Display	-40 to +200°F
Qualifications (seismic, environmental, IEEE 323)	Seismic

Calculator

Type (process computer, dedicated digital or analog calc.)	Dedicated Digital
If process computer is used specify availability. (% of time)	N/A
Single or redundant calculators	Single
Selection Logic (highest T., lowest press.)	High T - low P
Qualifications (seismic, environmental, IEEE 323)	Seismic

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Section 2.1.3.b (Continued)

Calculational Technique (Steam Tables, Functional Fit, ranges)	Steam Tables
	0 to 3200 psi
	0 to 999°F

<u>Input</u>

Temperature (RTD's or T/C's)	4 RTD's, 6 T/C's
Temperature (number of sensors and locations)	Note 1
Range of temperature sensors	0.0 to 999°F
Uncertainty* of temperature sensors (°F at 1)	±5°
Qualifications (seismic, environmental, IEEE 323)	Note 1
Pressure (specify instrument used)	Barton Model 763
Pressure (number of sensors and locations)	2 on Loop 4 Hot Leg
Range of pressure sensors	0 to 3000 psi
Uncertainty* of pressure sensors (PSI at 1)	±15 psi
Qualifications (seismic, environmental, IEEE 323)	Seismic, environmental

Note 1: See Inputs, above.

*Uncertainties must address conditions of forced flow and natural circulation.

Section 2.1.3.b (Continued)

Backup Capability

Availability of Temp. & Press.	Yes
Availability of Steam Tables, etc.	Yes
Training of operators	See below
Procedures	See below

Procedures to recognize inadequate core cooling are presently being written. The procedures will be approved and the operators trained by May 1, 1980. Backup temperature and pressure readouts are provided on the main control board. Steam tables will be available in the control room and emergency procedures will be provided. Additionally, the plant process computer has been programmed to provide margin to saturation information. This is not considered to be the backup of record.

[illegible]

Section 2.1.3.b (Continued)

B. <u>Task Force Position on Additional Instrumentation</u>

Licensees shall provide a description of any additional instrumentation or controls (primary or backup) proposed for the plant to supplement those devices cited in the preceding section giving an unambiguous, easy-to-interpret indication of inadequate core cooling. A description of the functional design requirements for the system shall also be included. A description of the procedures to be used with the proposed equipment, the analysis used in developing these procedures, and a schedule for installing the equipment shall be provided. (Category B: Implementation will be completed in January 1, 1981.)

<u>Clarification</u>

1. Design of new instrumentation should provide an unambiguous indication of inadequate core cooling. This may require new measurements to or a synthesis of existing measurements which meet safety-grade criteria.

2. The evaluation is to include reactor water level indication.

3. A commitment to provide the necessary analysis and to study advantages of various instruments to monitor water level and core cooling is required in the response to the September 13, 1979 letter.

Section 2.1.3.b (Continued)

4. The indication of inadequate core cooling must be unambiguous, in that, it should have the following properties:

   a. It must indicate the existence of inadequate core cooling caused by various phenomena (i.e., high void fraction pumped flow as well as stagnant boil off).

   b. It must not erroneously indicate inadequate core cooling because of the presence of an unrelated phenomenon.

5. The indication must give advanced warning of the approach of inadequate core cooling.

6. The indication must cover the full range from normal operation to complete core uncovering. For example, if water level is chosen as the unambiguous indication, then the range of the instrument (or instruments) must cover the full range from normal water level to the bottom of the core.

Section 2.1.3.b (Continued)

PG&E Response and Status

Additional Instrumentation to Indicate Inadequate Core Cooling

The submittal referenced in A above described the capabilities of the core exit thermocouples in determining the existence of inadequate core cooling conditions and their superiority in some instances to the loop RTD's for measuring true core conditions. Other means of determining the approach to or existence of inadequate core cooling could be:

1. Reactor vessel water level
2. Incore detectors
3. Excore detectors
4. Reactor coolant pump motor currents
5. Steam generator pressure

The use of incore movable detectors to determine the existence of inadequate core cooling conditions appears doubtful. The detectors could be driven in to the tops of the incore thimbles, which are located at the top of the core, following an accident in which concern for inadequate core cooling exists. The problem comes in the lack of sensitivity of the detectors to very low neutron levels and changes that would occur due to core uncovery. Gamma detectors could perhaps be employed, but they suffer from similar sensitivity problems, and the fact that gamma levels in the fuel region change

Section 2.1.3.b (Continued)

insignificantly between the covered and uncovered condition. As a result, it does not appear worthwhile to pursue incore movable detectors as a means of determining inadequate core cooling conditions.

The use of excore detectors has been mentioned as a possibility in responding to core uncovery. The only detectors which would have the required sensitivity are the source range monitors.. Since the intermediate and power range monitors are not sensitive enough to the low level changes resulting from vessel voiding. The use of the source range monitors will be investigated further as part of the more indepth study of inadequate core cooling being performed by the Westinghouse Owners' Group. However, their use is probably limited to those instances when significant voiding exists in the downcomer region, since normally water in the downcomer wuld effectively shield the detectors from the core region whether voids existed or not.

Reactor coolant pump motor current, which could be indicative of core voiding, is inappropriate for a reliable means of determining inadequate core cooling, since a loss of offsite power or pump trip due to a LOCA blowdown would shut down the pumps.

Steam generator pressure, which already exists, is useful in the case where heat transfer from primary to secondary is interrupted due to loss of natural circulation. This, however, does not satisfy requirements to indicate the approach to inadequate core cooling, nor does it indicate the true condition of the core.

Reactor vessel water level determination is the most promising of the items discussed to provide additional capability of determining the approach to and the existence of inadequate core cooling. Several systems for determining water level are under review by the Westinghouse Owners' Group. A conceptual design of one system is given below:

Vessel Level System Description

After examining many different methods and principles for determining the water level in the reactor vessel, a basic differential pressure measurement from the bottom of the vessel to the top of the vessel appears to provide the most meaningful and reliable information to the operator. One of the reasons for choosing this system is that the sources of potential errors are better known for this system than for any other new or untested system.

The attached figure shows a simplified sketch of the proposed vessel level instrumentation system. The bottom tap of the instrument would use a thimble of the incore movable detector system either at the seal table or in the thimble below the vessel. Use of the thimble as part of the incore flux monitoring would not be lost. The flux thimble guide tube would be tapped below the vessel and an instrument line connection made. The instrument line would have an isolation valve and slope down to a hydraulic coupler connected to a sealed reference leg. The sealed reference leg would go to the

Section 2.1.3.b (Continued)

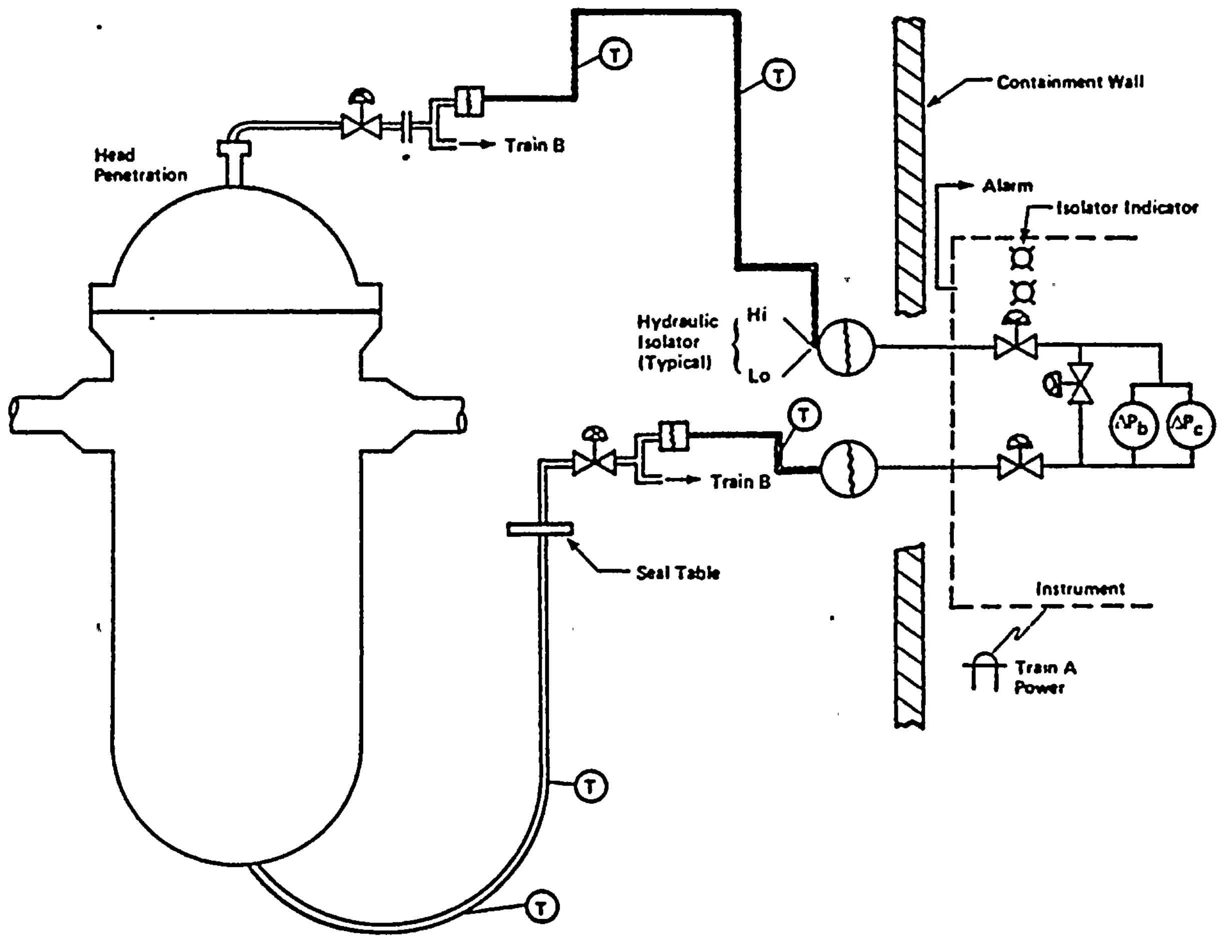
differential pressure transmitter located outside of containment. A similar sealed leg would go to the top of the vessel and penetrate the head using the vent line or a special connection on a spare RCC mechanism penetration. Two trains of vessel level instrumentation would be provided.

The behavior of the signal generated by this level instrument under normal and accident conditions is being evaluated. The usefulness of this instrument to provide an unambiguous indication of inadequate core cooling is being evaluated as part of Item 2.1.9. The potential errors and accuracy of a final system configuration are being evaluated to assess its usefulness to provide information to the operator for proper operation of a vessel venting system and for normal water level control during periods when the primary system is open and a water level may exist in the vessel. The connection of the level system to the vessel head will be designed to be compatible with the head vent system. Operation of the vent system should not upset all indications of vessel level. This can easily be avoided by using a separate instrument tap or by using more than one location.

Section 2.1.3.b (Continued)

Detailed analyses and system descriptions will be provided when available from Westinghouse. Delivery is not scheduled at this time.

PG&E is presently evaluating technical proposals from Westinghouse for a reactor vessel level indication system. PG&E and other near-term license applicants have met with the NRC to discuss the requirements given in the draft Regulatory Guide 1.97, Revision 2. These requirements in final form may well include additional instrumentation requirements. PG&E will comply with any new requirements.



PROCESS CONNECTION SCHEMATIC (TRAIN A)

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Section 2.1.4 - <u>Containment Isolation Provisions for PWR's and BWR's</u>

<u>Task Force Position 1</u>

All containment isolation system designs shall comply with the recommendations of SRP 6.2.4; i.e., that there be diversity in the parameters sensed for the initiation of containment isolation. (Category A: Implementation shall be completed prior to OL, or January 1, 1980, whichever is later.)

<u>Task Force Position 2</u>

All plants shall give careful reconsideration to the definition of essential and nonessential systems, shall identify each system determined to be essential, shall identify each system determined to be nonessential, shall describe the basis for selection of each essential system, shall modify their containment isolation designs accordingly, and shall report the results of the reevaluation to the NRC. (Category A: Implementation shall be completed prior to OL, or January 1, 1980, whichever is later.)

<u>Task Force Position 3</u>

All nonessential systems shall be automatically isolated by the containment isolation signal. (Category A: Implementation shall be completed prior to OL, or January 1, 1980, whichever is later.)

Section 2.1.4 (Continued)

Task Force Position 4

The design of control systems for automatic containment isolation valves shall be such that resetting the isolation signal will not result in the automatic reopening of containment isolation valves. Reopening of containment isolation valves shall require deliberate operator action. (Category A: Implementation shall be completed prior to OL, or January 1, 1980, whichever is later.)

Clarification

1. Provide diverse containment isolation signals that satisfy safety-grade requirements.

2. Identify essential and non-essential systems and provide results to NRC.

3. Non-essential system should be automatically isolated by containment isolation signals.

4. Resetting of containment isolation signals shall not result in the automatic loss of containment isolation.

Section 2.1.4 (Continued)

PG&E Response and Status for TFP 1

There are two phases of containment isolation at Diablo Canyon. Phase A isolates all nonessential process lines but does not affect safety injection, containment spray, component cooling water supplied to the reactor coolant pumps and containment fan coolers, and steam and auxiliary feedwater lines. Phase B isolates all process lines except safety injection, containment spray, auxiliary feedwater, and the containment fan coolers component cooling water system.

Phase A isolation is initiated by high containment pressure, high differential pressure between steam lines, low pressurizer pressure, high steam flow with low steam pressure or Low-Low Tave, or manual initiation. Phase B isolation is initiated by high-high containment pressure or manual initiation.

This system fully complies with Section II.6 of the SRP 6.2.4. Compliance with all remaining sections of SRP 6.2.4 is documented in Section 6.2.4 of the Diablo Canyon FSAR.

Section 2.1.4 (Continued)

PG&E Response and Status for TFP 2

PG&E has three levels of containment process penetrations. These are defined as:

1. "Nonessential" process lines are defined as those who do not increase the potential for damage for in-containment equipment when isolated. These are isolated on Phase A isolation.

2. "Essential" process lines are those providing cooling water and seal water flow through the reactor coolant pumps. These services should not be interrupted while the reactor coolant pumps are operating unless absolutely necessary. These are isolated on Phase B isolation.

3. Safety system process lines are those required to perform the function of the Engineered Safety Features System.

The attached Table 2.1.4-1 provides the identification of nonessential, essential, and safety systems penetrating containment.

Section 2.1.4 (Continued)

PG&E Response and Status for TFP 3

All nonessential systems use either manually sealed closed valves or else the valves are automatically isolated on a Phase A containment isolation signal. Additionally, all essential systems (defined in response 2 above) are automatically isolated on a Phase B containment isolation signal.

PG&E Response and Status for TFP 4

The Diablo Canyon design complies with the position. There are two basic actuator methods, one for motor operated valves and one for air operated valves. For a motor operated valve (MOV), the trip signal operates the close coil until the valve closes. If the trip signal is removed, the valve will not operate unless the open coil is energized by an explicit operator action. The attached FSAR Figure 7.3-35 shows a typical MOV circuit.

For an air operated valve (AOV), the control switch must be held in the open position to open the valve. Once it is opened, a stem mounted position switch on the valve closes thus closing a latch-in circuit which holds the valve open when the control switch spring-returns to neutral. The isolation signal contacts are in this latch-in circuit. When an isolation signal is generated, the circuit opens and the valve is de-energized and closes. As soon as the valve begins to close, the position switch opens so that the circuit will remain open and the valve will remain closed even after the isolation signal is reset. The attached FSAR Figure 7.3-43 shows a typical AOV circuit.

Section 2.1.4 (Continued)

Control of Liquid Radwaste Isolation Valves is somewhat different than described above. Each valve does not receive an individual isolation signal. Instead four (4) valves inside the containment are closed by one signal from Train A and 5 valves outside of containment are closed by one signal from Train B.

The control of these valves can be seen on the attached simplified schematic diagram, Figure 2.1.4-2.

The valves inside the containment are controlled as a group by control switch CSA and in case of containment isolation from Train A of the nuclear safeguard solid state protection system.

The valves outside the containment are controlled by their control switch SV/CS to open or close any valve individually during normal plant operation. The reactor coolant drain tank to gas analyser valve has an automatic feature in parallel to its SV/CS control switch which has no impact on the safety operation of the valves and is therefore not shown on the simplified schematic.

Again the outside valves can be operated as a group by their common control switch CSB with the limitation that all valves will close on switch CSB operation and only those valves can be opened which have been switched to open by their individual control switch.

Section 2.1.4 (Continued)

During normal plant operation the valves inside the containment are open by means of relay R1 which when energized seals in through CSA, CI-SIS, and R1 contact. The control power for the valves outside the containment is established in the same manner by means of relay R2.

A containment isolation signal will open contacts CI-SIS of Train A and Train B which will cause the de-energization of relays R1 and R2 and in turn de-energize all solenoid valves controlling the inside and outside containment isolation valves. De-energization of the solenoid valves causes the isolation valves to close.

Reset of the containment isolation signals will not cause any of the valves to open since relays R1 and R2 cannot be energized by this action. When it is necessary to open a given flow path the operator will place all of the individual control switches in the close position, reset isolation relays R1 and R2 by operating both CSA and CSB, respectively, and then open the required valve. This scheme meets the requirement that no flow path shall be established by resetting the isolation signal without subsequent operator action.

TABLE 2.1.4-1
CONTAINMENT PENETRATIONS

Penetration Numbers	System	Priority	Safety Function (For Essential and Safety Systems)
1. 2. 3. 4	Feedwater	Nonessential/ Safety	Feedwater is nonessential. Auxiliary feedwater is necessary for safe shutdown. (See Figure 6.2-14, Sheet 1 of 23.)
5, 8	Main steam	Nonessential/ Safety	Main steam is nonessential. 10% steam dump is required for safe shutdown. (See Figure 6.2-14, Sheet 1 of 23.)
6, 7	Main steam	Nonessential/ Safety	Main steam is nonessential. 10% steam dump and auxiliary feedwater steam turbine are required for safe shutdown.
9-13	Component cooling water to fan coolers	Safety	Fan coolers are required for post-accident containment cooling.
14-18	Component cooling water from fan coolers.	Safety	Fan coolers are required for post-accident containment cooling.
19	Component cooling water to reactor coolant pumps	Essential	Reactor coolant pumps may be necessary for certain post-accident activities.
20	Component cooling water from reactor coolant pumps	Essential	Reactor coolant pumps may be necessary for certain post-accident activities.
21	Component cooling water from reactor coolant pumps	Essential	Reactor coolant pumps may be necessary for certain post-accident activities.
22	Component cooling water to excess letdown heat exchanger	Nonessential	
23	Component cooling water to excess letdown heater exchanger	Nonessential	
24	Residual Heat Removal 1 Injection	Safety	Residual Heat Removal is required for cold shutdown.
25	Residual Heat Removal 2 Injection	Safety	Residual Heat Removal is required for cold shutdown.
26	Residual Heat Removal Hot Leg Injections	Safety	Residual Heat Removal is required for cold shutdown.

TABLE 2.1.4-1 (Cont'd)
CONTAINMENT PENETRATIONS

Penetration Numbers	System	Priority	Safety Function (For Essential and Safety Systems)
27	Reactor Coolant System Loop 4 Recirculation	Safety	Residual Heat Removal is required for cold shutdown.
28	Containment Sump Recirculation	Safety	Sump Recirculation is required for post-accident operation.
29	Containment Sump Recirculation	Safety	Sump Recirculation is required for post-accident operation.
30	Containment Spray System	Safety	Containment Spray is a safety function.
31	Containment Spray System	Safety	Containment Spray is a safety function.
32	Spare		
33	Safety Injection System	Safety	Safety Injection is a safety function.
34	Safety Injection System	Safety	Safety Injection is a safety function.
35	Regenerative heat exchanger to let-down heat exchanger	Nonessential	
36	Regenerative heat exchanger	Nonessential	
37, 38, 39, 40	Steam generator blowdown	Nonessential	
41, 42, 43, 44	Reactor coolant pump seal water supply	Essential	The Reactor Coolant Pumps may be necessary in certain post-accident activities.
45	Reactor coolant pump seal water return	Essential	The Reactor Coolant Pumps may be necessary in certain post-accident activities.
46	Refueling canal recirculation	Nonessential	
47	Refueling canal recirculation	Nonessential	
48	Spare		

TABLE 2.1.4-1 (Cont'd)
CONTAINMENT PENETRATIONS

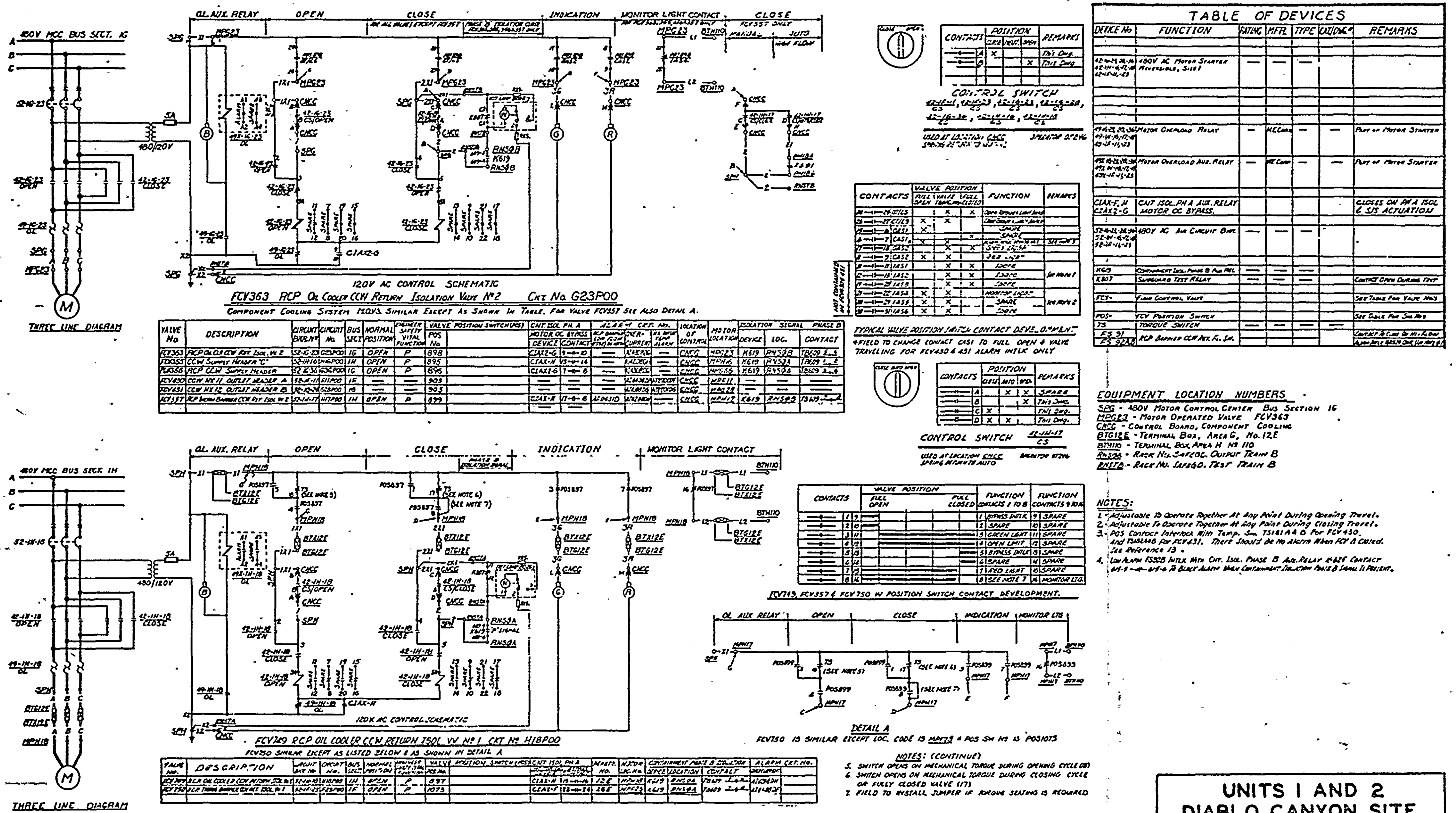
Penetration Numbers	System	Priority	Safety Function (For Essential and Safety Systems)
49	Containment sump discharge to radwaste	Nonessential	
50	Reactor coolant drain tank discharge	Nonessential	
51	Reactor coolant drain tank vent	Nonessential	
51	Reactor coolant drain tank to gas analyzer	Nonessential	
51	Safety injection system test line	Nonessential	
51	Nitrogen supply header to accumulators	Nonessential	
52	Pressurizer relief tank nitrogen supply	Nonessential	
52	Pressurizer relief tank makeup	Nonessential	
52	Reactor coolant drain tank nitrogen supply	Nonessential	
52	Steam generators nitrogen supply	Nonessential	
52, 53, 59, 76	Containment pressures	Safety	Containment pressure signal is required for certain safeguards actuation and post-accident monitoring.
53 (4 Lines)	Steam generator blowdown sample	Nonessential	
54	Instrument air header	Nonessential	
55	Spare		
56	Service air header	Nonessential	

TABLE 2.1.4-1 (Cont'd)
CONTAINMENT PENETRATIONS

Penetration Numbers	System	Priority	Safety Function (For Essential and Safety Systems)
58	Not used		
59	Pressurizer liquid sample	Nonessential	
59	Hot leg sample	Nonessential	Although this is nonessential, motive power is available to operate the valves and samples can be taken by a continuous manual override until the sampling is complete.
59	Accumulator sample	Nonessential	
59	Spare		
60	Not used		
61	Containment purge supply	Nonessential	
62	Containment purge exhaust	Nonessential	
63	Containment pressure and vacuum relief	Nonessential	
64	Fuel transfer	Nonessential	
65	Personnel hatch	Nonessential	
66	Emergency personnel hatch	Nonessential	
67	Equipment hatch	Nonessential	
68	Containment air sample	Nonessential	
69	Containment air sample	Nonessential	
70	Auxiliary steam supply	Nonessential	
71	Various relief valve outlets to PRT	Nonessential	
72, 73, 74	Spare		

TABLE 2.1.4-1 (Cont'd)
CONTAINMENT PENETRATIONS

Penetration Numbers	System	Priority	Safety Function (For Essential and Safety Systems)
75	Safety injection system pump 2 discharge	Safety	Safety injection is a safety function.
76	Pressurizer relief tank gas analyzer	Nonessential	
76	Pressurizer steam sample	Nonessential	
76	Deadweight	Nonessential	
77	Safety injection system pump 1 discharge	Safety	Safety injection is a safety function.
78	Spare		
79	Firewater	Nonessential	
80	Class I air system	Nonessential	This is required for long-term hydrogen control, but can be opened by the operator to effect post-accident hydrogen control.
81	Spare		
82	Chilled water supply	Nonessential	
83	Chilled water return	Nonessential	
83	Hydrogen purge supply	Nonessential	This is required for long-term hydrogen control, but can be opened by the operator to effect post-accident hydrogen control.
84	Spare		



UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 7.3-35
SCHEMATIC DIAGRAM
COMPONENT COOLANT WATER SYSTEM
MOTOR OPERATED VALVES

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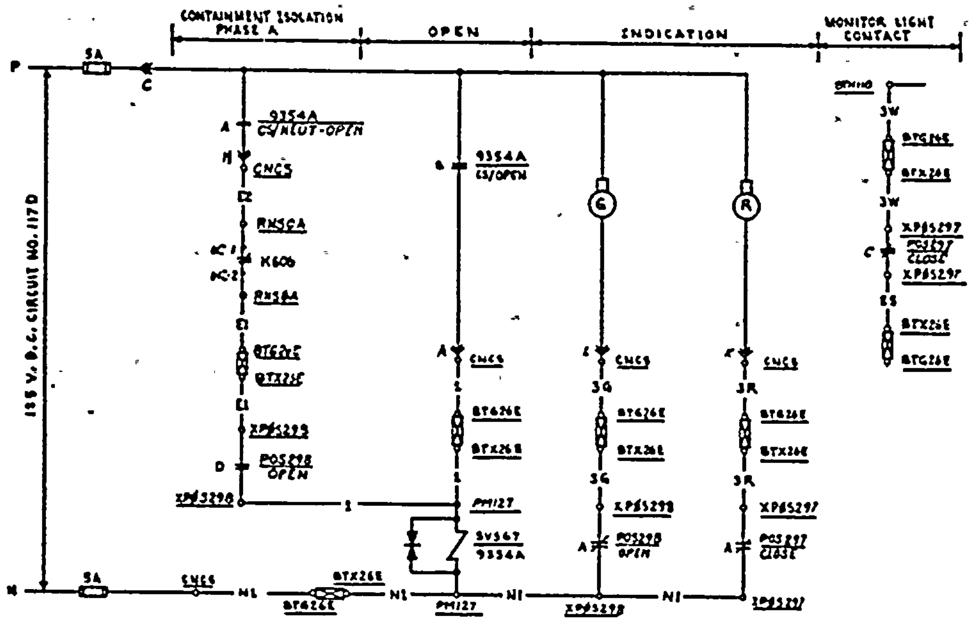
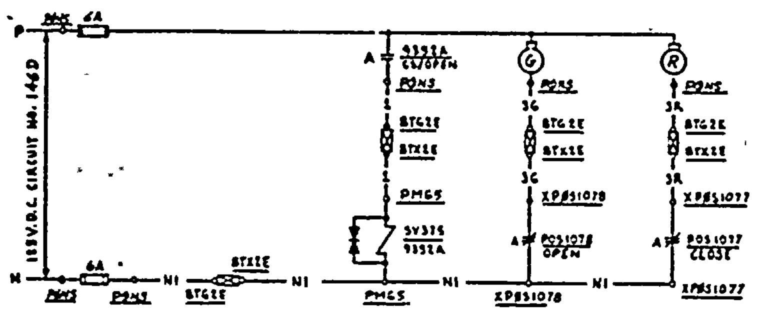


9354A PRESSURIZER STEAM SAMPLE ISOL. VALVE CIRCUIT NO. RSS043

OTHER SAMPLE SYSTEM VALVES SIMILAR EXCEPT AS SHOWN IN TABLE. CONTROL SWITCH FOR THESE VALVES — DETAIL B. CIRCUITS LISTED ON DRAWING 103072.

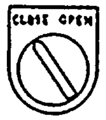
VALVE NO.	DESCRIPTION	D.C. CKT. NO.	VALVE LOC. NO.	SOLENOID VALVE NO.	SOL. VALVE LOC. NO.	ENG. SFGD. FUNCTION	VALVE POSITION SW. (POS) CLOSED	OPEN			PENN NO.	CIRCUIT NO.	LOC. OF CONTROL	CONTAINMENT ISOL. PHASE A DEVICE	LOC.	CONTACT	NORMAL POSITION
9354A	PRZR. STM. SAMPLE ISOL. IN CNT.	117D	X9354A	367	PM127	T	297	298			26E	RSS043	CNCS	K606	RNSBA		OPEN
9355A	PRZR. LIQ SAMPLE ISOL. IN CNT	117D	X9355A	370	PM127		303	1044			26E	RSS049		K606	RNSBA		OPEN
9356A	RCS SAMPLE ISOL. IN CNT	117D	X9356A	374	PM127		1075	1046			26E	RSS055		K606	RNSBA		OPEN
9357A	ACCUM. SAMPLE ISOL. IN CNT	117D	X9357A	380	PM127		1087	1048			26E	RSS061		K606	RNSBA		OPEN
9354B	PRZR. STM. SAMPLE ISOL. OUT CNT.	215D	X9354B	325	PM186		1312	1068			—	RSS008		K606	RNSBB		OPEN
9355B	PRZR. LIQ SAMPLE ISOL. OUT CNT.	215D	X9355B	326	PM186		1313	1070			—	RSS022		K606	RNSBB		OPEN
9356B	RCS SAMPLE ISOL. OUT CNT.	215D	X9356B	327	PM186		1314	1088			—	RSS029		K606	RNSBB		OPEN
9357B	ACCUM. SAMPLE ISOL. OUT CNT.	215D	X9357B	328	PM186		1319	1318			—	RSS036		K606	RNSBB		OPEN



9352A ACCUMULATOR 1 SAMPLE VALVE CIRCUIT NO. RSS079

OTHER SAMPLE SYSTEM SOLENOID VALVES SIMILAR EXCEPT AS SHOWN IN TABLE BELOW. CONTROL SWITCH FOR THESE VALVES — DETAIL A

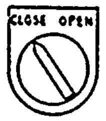
VALVE NO.	DESCRIPTION	D.C. CKT. NO.	VALVE LOC. NO.	SOL. VALVE NO.	SOL. VALVE LOC. NO.	VLV. POS. SW. (POS) CLOSED	OPEN	PENN. NO.	CIRCUIT NO.	CONTROL LOC. NO.
9350A	PRZR. STM. SPACE IN CNT.	146D	X9350A	365	PM125	293	294	2E	RSS067	PONS
9350B	PRZR. LIQ. SPACE IN CNT.	146D	X9350B	368	PM125	299	296	2E	RSS070	PONS
9351A	RCS HOT LEG LOOP 1	146D	X9351A	371	PM138	1069	1041	2E	RSS073	PONS
9351B	RCS HOT LEG LOOP 4	146D	X9351B	372	PM138	1071	1043	2E	RSS076	PONS
9352A	ACCUM. 1 SAMPLE	146D	X9352A	375	PM65	1077	1078	2E	RSS079	PONS
9352B	2	146D	X9352B	376	PM67	1079	1080	2E	RSS082	PONS
9352C	3	146D	X9352C	377	PM68	1081	1082	2E	RSS085	PONS
9352D	4	146D	X9352D	378	PM71	1083	1084	2E	RSS088	PONS
9353A	RHR LOOPS 1 & 2	146D	X9353A	381	XSV381	1089	1090	—	RSS091	PONS
9353B	RHR LOOPS 3 & 4	146D	X9353B	382	XSV382	1091	328	—	RSS094	PONS



CONTACT		POSITIONS CLOSE	OPEN	REMARKS
	A		X	THIS DWG.
	B	X		SPARE

CONTROL SWITCH $\frac{9352A}{CS}$ --- DETAIL A

USED AT LOCATION PONS
NO SPRING RETURN.



CONTACT		POSITIONS CLOSE	NEUT.	OPEN	REMARKS
	A		X	X	THIS DWG.
	B			X	THIS DWG.

CONTROL SWITCH $\frac{9354A}{CS}$ --- DETAIL B

USED AT LOCATION CNCS.
SPRING RETURN TO NEUTRAL FROM OPEN.

CONTACT		POSITION CLOSE	OPEN	REMARKS
	A		X	RED LIGHT
	B	X		SPARE
	C		X	MONITOR LT
	D	X		SPARE

VALVE CLOSE POSITION SWITCH

CONTACT		POSITION CLOSE	OPEN	REMARKS
	A	X		GREEN LT.
	B		X	SPARE
	C	X		SPARE
	D		X	SEAL IN

VALVE OPEN POSITION SWITCH

TABLE OF DEVICES

DEVICE NO.	FUNCTION	RATING	MFR.	TYPE	CAT/DWG. NO.	REMARKS
SV367, 370,374 390,365 368,371 372,325 326,327 328,375 376,377 378,381 382	SOLENOID VALVE	—	—	—		
935__	FLOW CONTROL VALVE	—	—	—		SEE TABLE FOR VALVE NOS
POS___	VALVE POSITION SWITCHES	—	—	—		SEE TABLE FOR SWITCH NOS
K606	CONTAINMENT ISOLATION PHASE A AUX. RELAY	—	—	—		

EQUIPMENT LOCATION NUMBERS

CNCS — CONTROL BOARD CONTAINMENT SPRAY
RNSBA — NUCLEAR SAFEGUARD OUTPUT RACK A
X9354A — AIR OPERATED VALVE 9354A
XSV381 — INSTRUMENT SV381 (LOCAL MOUNTED)
BTG26E — TERMINAL BOX, AREA G NO. 26E
PM127 — MECH. PANEL № 127, SAMPLE ISOL. VVS.
BTH110 — TERMINAL BOX AREA H № 110
PONS — CONTROL PANEL NUCLEAR SAMPLE

VALVE NOS.: 9350A, 9350B, 9351A, 9351B, 9352A, 9352B, 9352C, 9352D, 9353A, 9353B, 9354A, 9354B, 9355A, 9355B, 9356A, 9356B, 9357A, 9357B

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UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 7.3-43
SCHEMATIC DIAGRAM
SAMPLING SYSTEM SOLENOID VALVES

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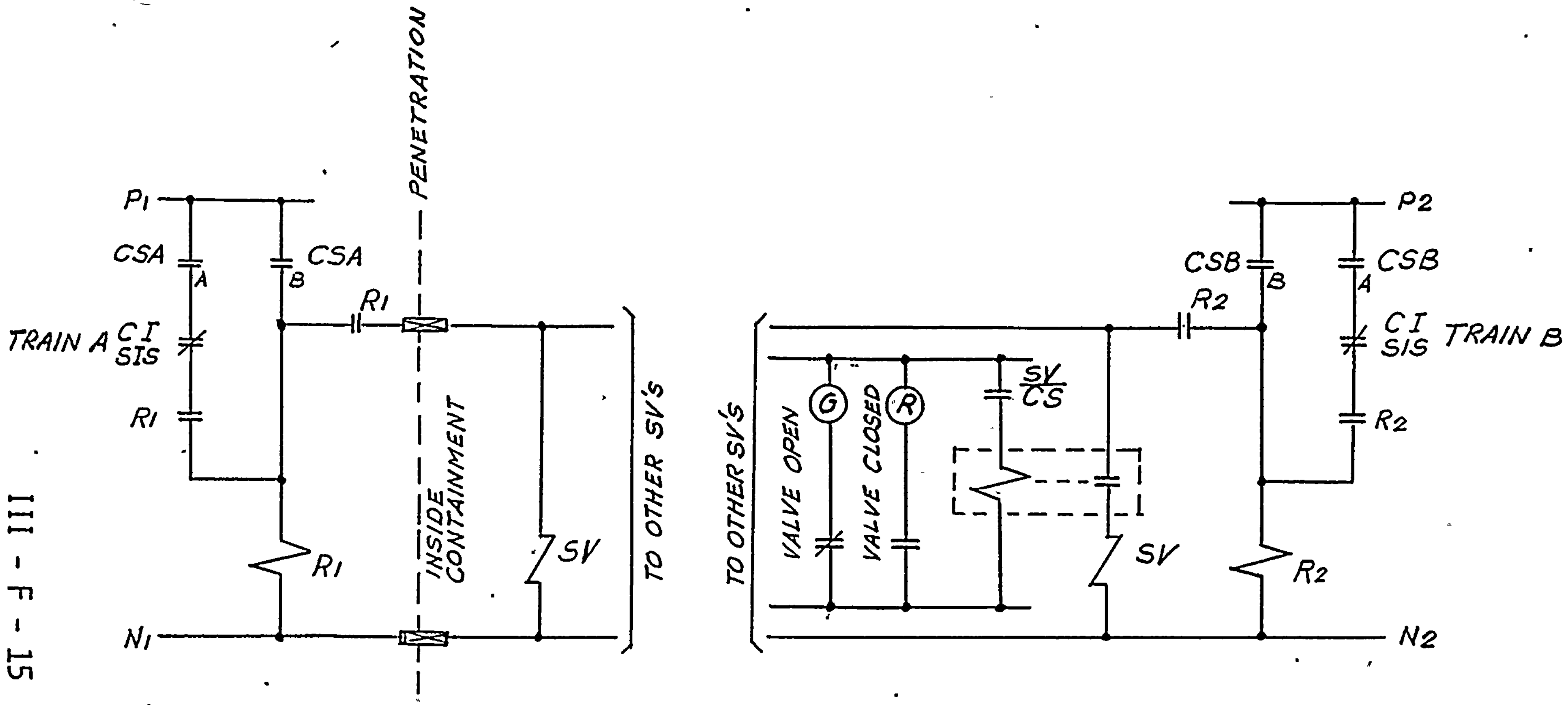


SYMPLIFIED SCHEMATIC FOR LIQUID
RADWASTE SOLENOID VALVES
(CONTAINMENT ISOL. VALVES TO OPEN WHEN SV's ENERGIZED)

CONTACTS		POSITION		
		CLOSE	NEUT.	RESET
—||—	A		X	X
—||—	B			X

ISOLATING VALVES
CONTROL SWITCH (SPRING RETURN TO NEUT.)

CSA FOR VALVES INSIDE
CONTAINMENT TRAIN A

CSB FOR VALVES OUTSIDE
CONTAINMENT TRAIN B

FIGURE 2.1.4-2

Section 2.1.5.a - Dedicated Penetrations for External Recombiner or Post-Accident External Purge System

Task Force Position

Plants using external recombiners or purge systems for post-accident combustible gas control of the containment atmosphere should provide containment isolation systems for external recombiner or purge systems that are dedicated to service only, that meet the redundancy and single failure requirements of General Design Criteria 54 and 56 of Appendix A to 10 CFR Part 50, and that are sized to satisfy the flow requirements of the recombiner or purge system. (Description and implementation schedule is Category A: Implementation shall be completed prior to OL, or January 1, 1980, whichever is later. Category B: Implementation shall be completed by January 1, 1981.)

Clarification

1. This requirement is only applicable to those plants whose licensing basis includes requirements for external recombiners or purge systems for post-accident combustible gas control of the containment atmosphere.

2. An acceptable alternative to the dedicated penetration is a combined design that is single-failure proof for containment isolation purposes and single-failure proof for operation of the recombiner or purge system.

Section 2.1.5.a (Continued)

3. The dedicated penetration or the combined single-failure proof alternative should be sized such that the flow requirements for the use of the recombiner or purge system are satisfied.

4. Components necessitated by this requirement should be safety grade.

5. A description of required design changes and a schedule for accomplishing these changes should be provided by January 1, 1980. Design changes should be completed by January 1, 1981.

PG&E Response and Status

Although recombiners located inside the containment are being provided for Diablo Canyon, PG&E has chosen to comply with the Task Force Position and clarifications concerning dedicated penetrations for external recombiner or post-accident purge system.

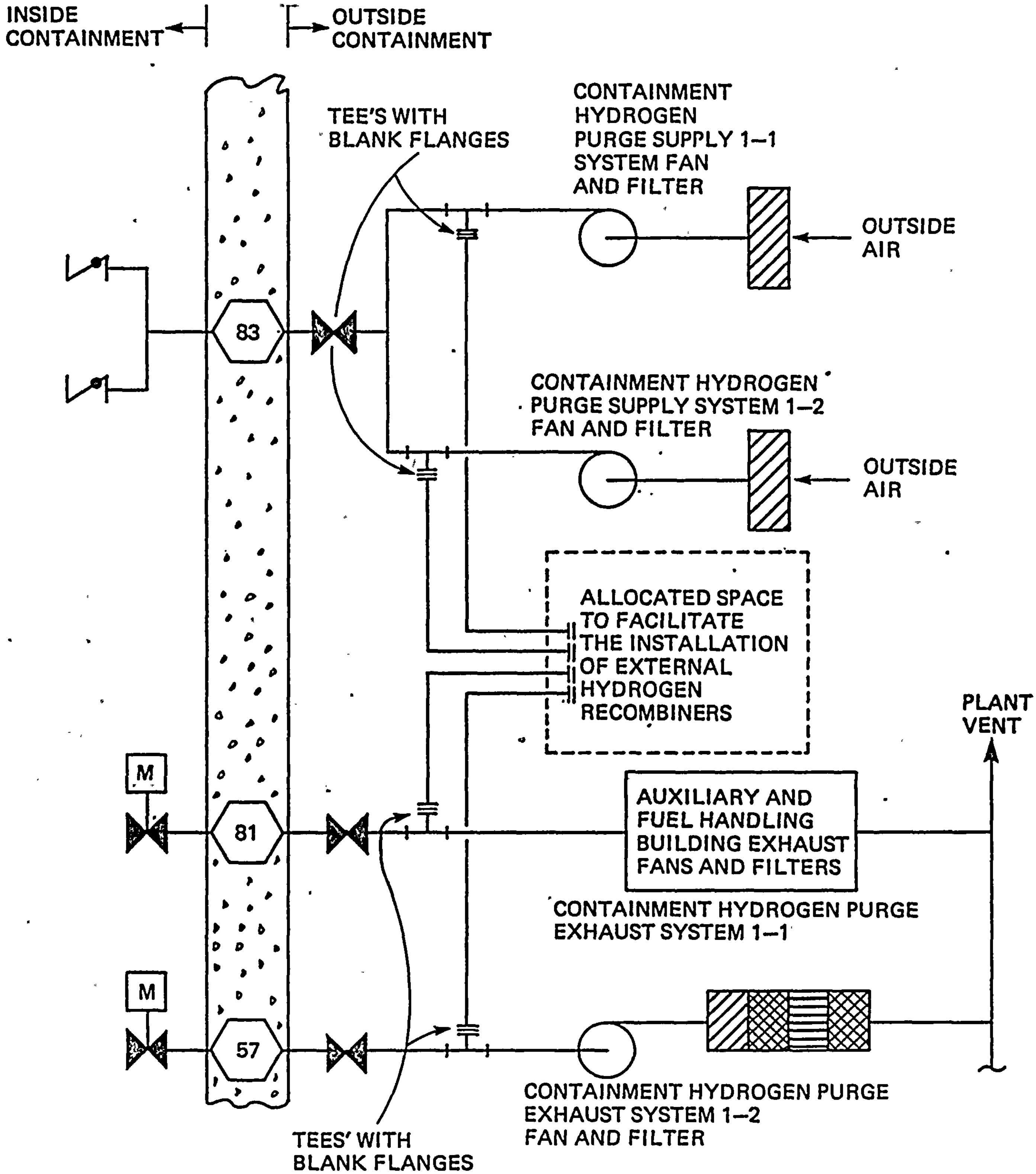
Design changes have been made to provide dedicated penetrations and isolation systems for the hydrogen recombiner and hydrogen purge systems. It is anticipated, depending upon equipment availability, these modifications will be completed by July 1, 1980.

The supply lines for the existing Containment Hydrogen Purge Systems use containment penetrations which are solely dedicated for that purpose. The exhaust lines previously were teed-off from the 48-inch containment purge lines. In response to NUREG-0578, PG&E has selected different containment penetrations (previously designated as spares) which will be solely dedicated to post-LOCA hydrogen control. New lines will be from those penetrations to the existing iodine filters and blowers of the Containment Hydrogen Purge exhaust lines.

The capability of adding external post-LOCA hydrogen recombiners will be facilitated by placing piping tees and blank flanges in the post-LOCA hydrogen purge lines at a place where it would be convenient to install external recombiners.

The areas selected for the control panels for the external recombiners and for the piping tee connections will be analyzed to evaluate the possible personnel exposures in connecting and operating the recombiners during the accident conditions. This analysis will be completed prior to March 15, 1980.

A schematic diagram is included which shows the dedicated penetrations for the post-LOCA purge system and the provisions for external recombiners.



SCHEMATIC DIAGRAM
CONTAINMENT HYDROGEN PURGE SYSTEM
AND
PROVISIONS TO FACILITATE INSTALLATION OF EXTERNAL RECOMBINERS
DIABLO CANYON

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Section 2.1.5.b - Inerting BWR Containments

Task Force Position

It shall be required that the Vermont Yankee and Hatch 2 Mark I BWR containments be inerted in a manner similar to other operating BWR plants. Inerting shall also be required for near-term OL licensing of Mark I and Mark II BWR's.

PG&E Status

No action is required. Both Diablo Canyon Units 1 and 2 are Westinghouse PWR's.

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Section 2.1.5.c - Capability to Install Hydrogen Recombiners at Each Light Water Nuclear Power Plant

Task Force Position (Minority View)

1. All licensees of light water reactor plants shall have the capability to obtain and install recombiners in their plants within a few days following an accident if containment access is impaired and if such a system is needed for long-term post-accident combustible gas control. Implementation schedules will be established by the Commission in the course of the immediately effective rulemaking. The Task Force recommends that the rulemaking process be initiated promptly.

2. The procedures and bases upon which the recombiners would be used on all plants should be the subject of a review by the licensees in considering shielding requirements and personnel exposure limitations as demonstrated to be necessary in the case of TMI-2. (Category A: Implementation complete by January 1, 1980, or prior to OL, whichever is later.)

Clarification

1. This requirement applies only to those plants that included Hydrogen Recombiners as a design basis for licensing.

2. The shielding and associated personnel exposure limitations associated with recombiner use should be evaluated as part of licensee response to requirement 2.1.6.b, "Design review for Plant Shielding".

Section 2.1.5.c (Continued)

3. Each licensee should review and upgrade, as necessary, those criteria and procedures dealing with recombiner use. Action taken on this requirement should be submitted by January 1, 1980.

PG&E Response and Status

Hydrogen recombiners were not included as a design basis for licensing Diablo Canyon Units 1 and 2, however, PG&E has chosen to install hydrogen recombiners inside containment at Diablo Canyon. Westinghouse hydrogen recombiners and associated equipment have been purchased and are presently at the site. Installation of the recombiners will be completed by May 1, 1980.

The recombiners will be housed inside the containment and therefore will not present any shielding problems during operation of the recombiners. Procedures for operation of the installed hydrogen recombiners will be written and the operators trained prior to May 1, 1980.

Section 2.1.6.a - Integrity of Systems Outside Containment Likely to Contain Radioactive Materials (Engineered Safety Systems & Auxiliary Systems)

Task Force Position

Applicants and licensees shall immediately implement a program to reduce leakage from systems outside containment that would or could contain highly radioactive fluids during a serious transient or accident to as-low-as practical levels. This program shall include the following:

1. Immediate Leak Reduction

   a. Implement all practical leak reduction measures for all systems that could carry radioactive fluid outside of containment.

   b. Measure actual leakage rates with system in operation and report them to the NRC.

2. Continuing Leak Reduction

   Establish and implement a program of preventive maintenance to reduce leakage to as-low-as practical levels. This program shall include periodic integrated leak tests at a frequency not to exceed refueling cycle intervals. (Category A: Implementation shall be completed prior to OL, or January 1, 1980, whichever is later.)

Section 2.1.6.a (Continued)

Clarification

Licensees shall, by January 1, 1980, provide a summary description of their program to reduce leakage from systems outside containment that would or could contain highly radioactive fluids during a serious transient or accident. Examples of such systems are given on page A-26 of NUREG-0578. Other examples include the Reactor Core Isolation Cooling and Reactor Water Cleanup (letdown function) Systems for BWRs. Include a list of systems which are excluded from this program. Testing of gaseous systems should include helium leak detection or equivalent testing methods. Consider in your program to reduce leakage potential release paths due to design and operator deficiencies as discussed in our letter to you regarding North Anna and Related Incidents dated October 17, 1979.

PG&E Response and Status

At intervals not exceeding 18 months, operating pressure leak tests will be performed on appropriate portions of SIS, RHR, NSS Sampling, LRW and GRW Systems. Pressurized systems will be visually inspected for leakage into the building environment. Any observed leakage will be eliminated. An attempt

Section 2.1.6.a (Continued)

will be made during the initial testing to measure system makeup during the period of pressurization, where the system configuration permits. System makeup rate provides some indication of system leakage, but may not be conclusive because of valve seat leakage. Initial testing will be conducted prior to fuel loading.

Where feasible, liquid containing systems will be pressurized with a hydro pump and makeup determined by measuring level changes in a graduated tank, or by normal operating pressure sources. During pressurization each system will be walked down and visually inspected for leaks. Visual inspection or other appropriate means will be used to differentiate system boundary leakage from test boundary leakage to determine actual leakage outside the system. There are portions of systems that will be pressurized with a system pump, and since makeup rate cannot be measured, any leaks discovered during the walkdown will be evaluated to determine the approximate leakage from that system. Baseline leakage rates will be recorded after appropriate measures to eliminate undesirable leakage paths have been taken.

For the Gaseous Radwaste System the immediate leak reduction plan will consist of a preoperational measurement, followed by an operational monitoring program.

Section 2.1.6.a (Continued)

With the waste gas compressors running on recirc to maintain impeller seals the system will be maintained at pressure using a regulated nitrogen source. The vent header and gas analyser including source lines outside of containment will be leak tested with nitrogen. The gas decay tanks including relief valves will be pressurized and leak tested. The system makeup rate will be determined with a gas flow-meter at the nitrogen regulator. All non-welded connections in the system will be checked with a soap and water solution to locate leaks and appropriate means taken to eliminate them. This is the preoperational measurement. Thereafter (during operation), a routine radiation monitoring program will be implemented to detect minute changes in activity of air in the areas occupied by the system. If leakage is indicated by an increase in airborne activity, appropriate means, such as explosive gas detectors or soap, will be used to localize the leak.

Portions of the charging system which are in service during normal operation (makeup and letdown) are monitored with the rest of the reactor coolant system by the reactor coolant system water inventory balance. Excessive leakage into controlled areas will be indicated by abnormally high airborne radioactivity levels.

Some portions of the CVCS are used for boron recycling during normal operation. The boron recycling system will not be used under post-accident circumstances, and is not included in this program.

Section 2.1.6.a (Continued)

Containment spray recirc piping and valves outside containment are leak rate tested with precision volumetrics equipment at a 24 month interval as part of a containment isolation valve surveillance test.

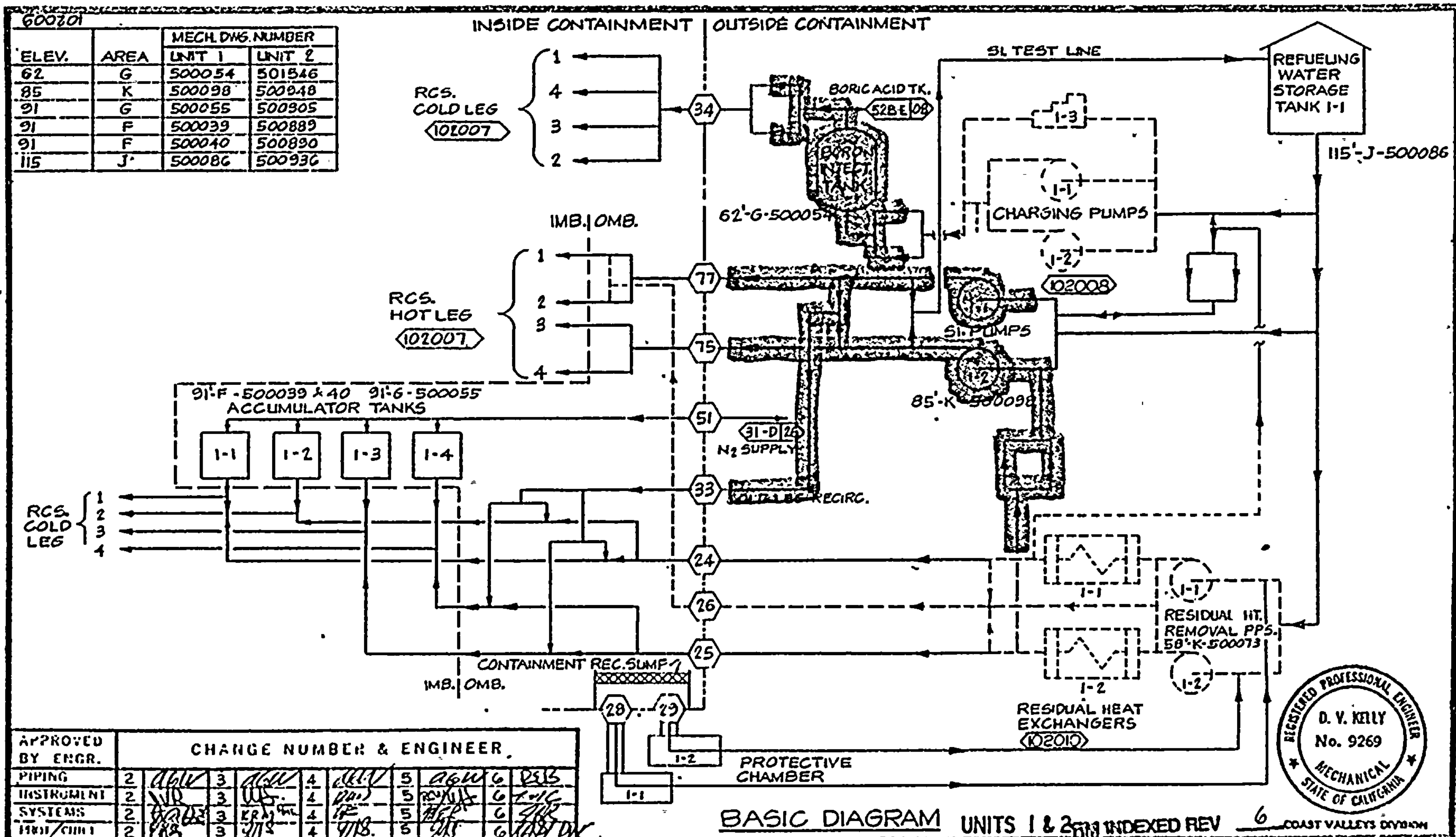
Individual surveillance test procedures (STP) will be written for each system or each half system in the case of SIS and RHR. Each STP will list system boundary valves and specify test pressures. Each test will be performed prior to fuel loading, and at refueling outage intervals thereafter.

The portions of systems that will be monitored for leakage in this program are indicated on the attached piping schematics.

The initial leak test of the Gaseous Radwaste System has been completed. Test results are available for inspection at the Diablo Canyon site. Test procedures for the RHR and SIS tests have been written. Testing of the SIS has started, but is being temporarily delayed because of water supply problems. The test procedure for the NSSS Sampling system is currently being written. Overall, testing is about 60% complete. Testing is currently anticipated to be fully completed by May 1980.

600201

ELEV.	AREA	MECH. DWG. NUMBER UNIT 1	UNIT 2
62	G	500054	501546
85	K	500098	500948
91	G	500055	500905
91	F	500039	500889
91	F	500040	500890
115	J	500086	500936



APPROVED BY ENGR.	CHANGE NUMBER & ENGINEER									
PIPING	2	AGW	3	AGW	4	[illegible]	5	AGW	6	RSB
INSTRUMENT	2	WB	3	WS	4	[illegible]	5	[illegible]	6	[illegible]
SYSTEMS	2	[illegible]	3	[illegible]	4	[illegible]	5	[illegible]	6	[illegible]
HOT/CHILL	2	[illegible]	3	[illegible]	4	[illegible]	5	[illegible]	6	DK

BASIC DIAGRAM UNITS 1 & 2 INDEXED REV 6 COAST VALLEYS DIVISION

NO.	DATE	DESCRIPTION	GM	BY	CH.	APRD. LEAD ENGR.
6	5-3-78	SEE DESCRIPTION OF CHANGES SH 2B	[illegible]	DOM	LM	[illegible]
5	7-20-76	SEE DESCRIPTION OF CHANGES SH. 2B	167027	RK	L.M.	[illegible]
4	11-12-74	SEE DESCRIPTION OF CHANGES SH 2A, 2B	167027	J.M.	L.M.	[illegible]
3	4-8-74	SEE DESCRIPTION OF CHANGES SH. 2A	67027	J.M.	L.M.	[illegible]
2	11-8-72	CHANGED SHEET 2 → 5 PER DETAILS SHEET 2A	167027	L.P.B.	PS	[illegible]
1	5-6-71	APPROVED FOR CONSTRUCTION	167027	L.P.B.	PS	[illegible]

TABLE OF CHANGES

APPROVED BY

GM 67027
SUPT. BY W. Dodson
DSGN. C. Kirk
DR. E. HORVATH
CH. L. MANALAC
O.K. RHS
DATE 4-3-68
SCALES None

PIPING SCHEMATIC SAFETY INJECTION SYSTEM

DIABLO CANYON

DEPARTMENT OF ENGINEERING
PACIFIC GAS AND ELECTRIC COMPANY
SAN FRANCISCO, CALIFORNIA

BILL OF MATERIAL
DRAWING LIST
SUPERSEDES
SUPERSEDED BY
SHEET NO. 1 of 9 SHEETS

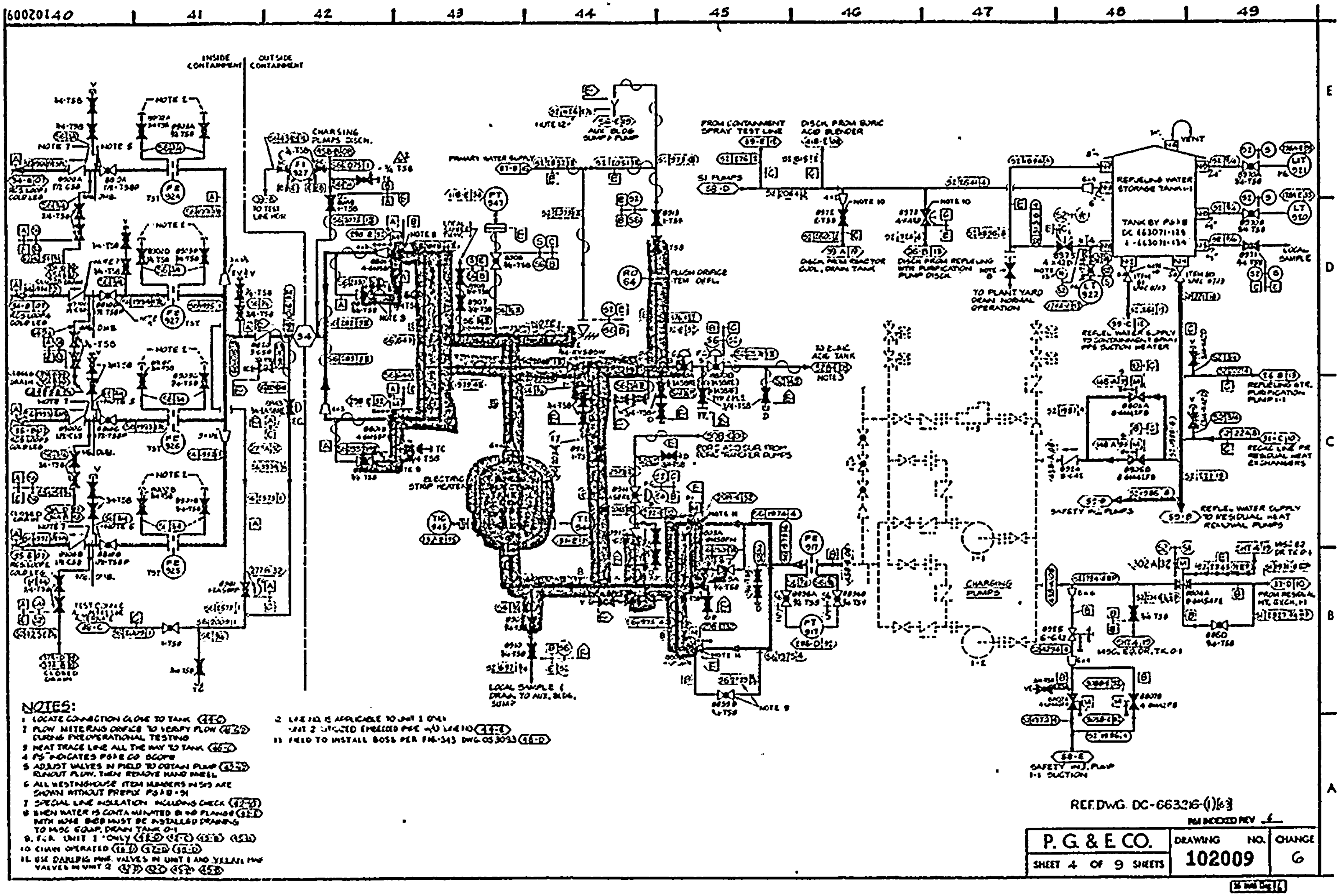
DRAWING NUMBER 102009 CHANGE 6

REGISTERED PROFESSIONAL ENGINEER D. V. KELLY No. 9269 MECHANICAL STATE OF CALIFORNIA

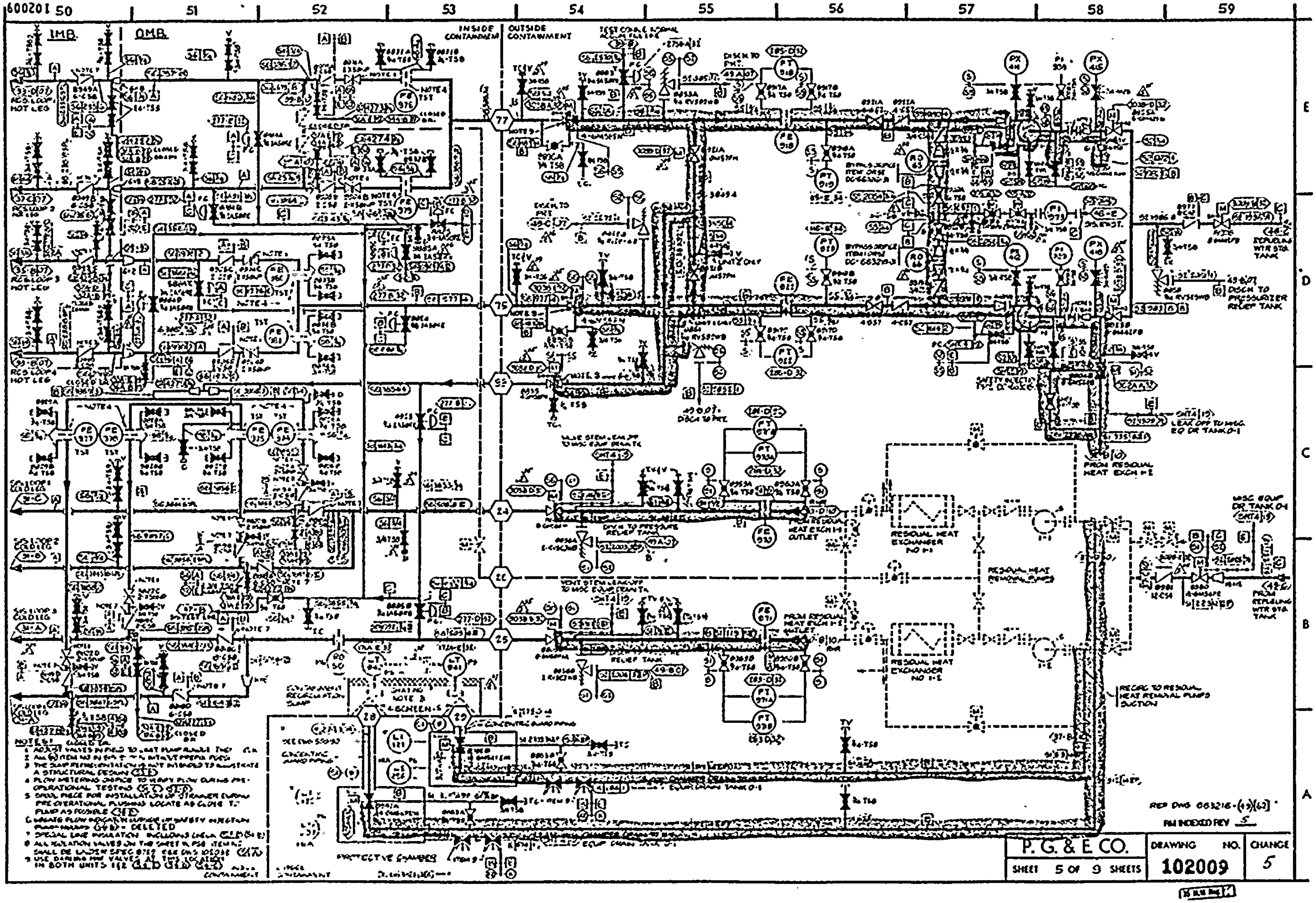
INSTR. CHECK: emv LINE VALVE CHECK SYSTEM CHECK

III-J-6

Revision 0
2/29/80



Revision 0
2/29/80



600201
50
51
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56
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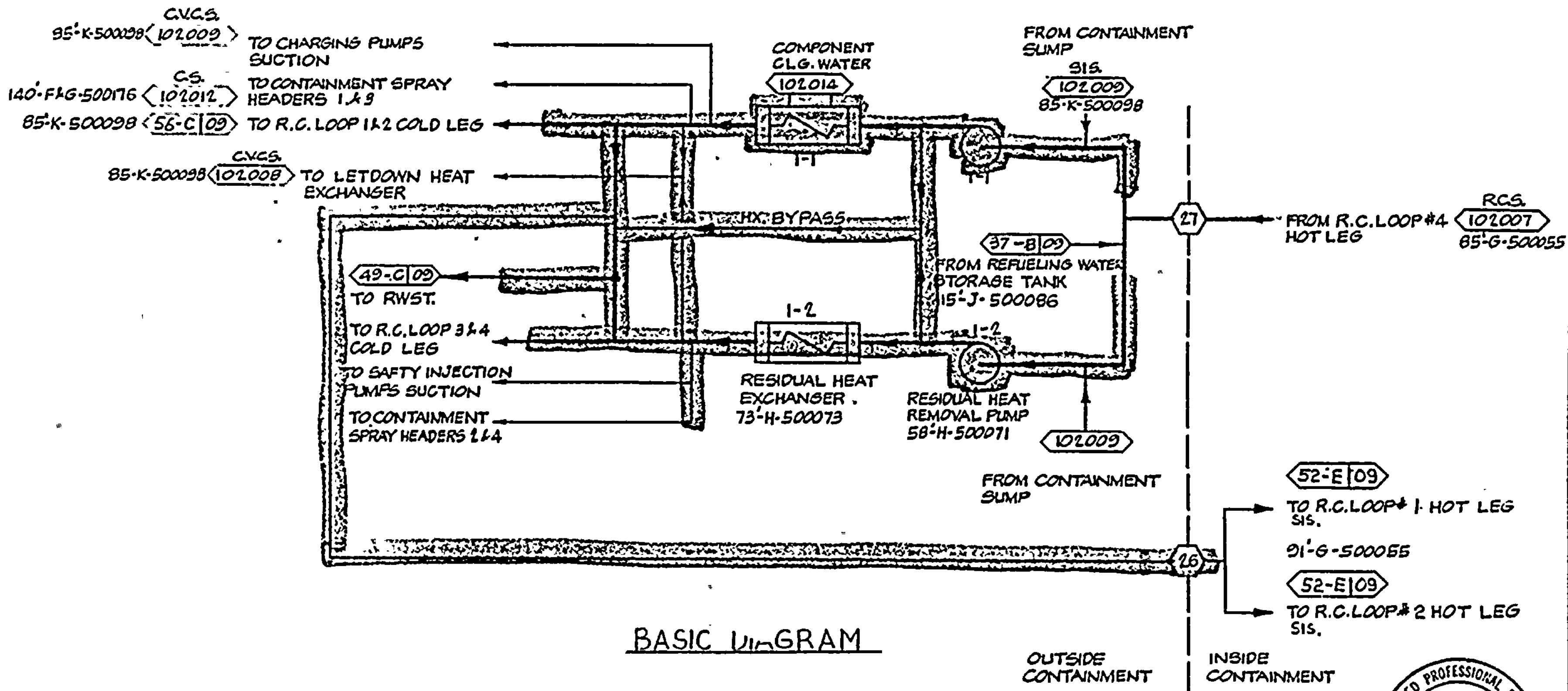
58
59
IMB.
OMB.
INSIDE CONTAINMENT
OUTSIDE CONTAINMENT
RESIDUAL HEAT EXCHANGER NO 1-1
RESIDUAL HEAT REMOVAL PUMPS
RESIDUAL HEAT EXCHANGER NO 1-2
FROM RESIDUAL HEAT EXCH 1-2
PROTECTIVE CHAMBER
NOTES:
P. G. & E. CO.
DRAWING NO.
102009
CHANGE
5
SHEET 5 OF 9 SHEETS
A
B
C
D
E

010201



BASIC DIAGRAM

ELEV.	AREA	MECH. DWG. NO. UNIT 1	UNIT 2
58	H	500071	500921
85-91	G	500055	500905
73	H	500073	500923
95	K	500098	500948
115	J	500086	500936
140	F & G	500176	501520

APPROVED BY ENGR.	CHANGE NUMBER & ENGINEER							
PIPING	2	[illegible]	3	[illegible]	4	[illegible]	5	[illegible]
INSTRUMENT	2	[illegible]	3	[illegible]	4	[illegible]	5	[illegible]
SYSTEMS	2	[illegible]	3	[illegible]	4	[illegible]	5	[illegible]
PROJ./CHIEF	2	[illegible]	3	[illegible]	4	[illegible]	5	[illegible]

D. V. KELLY
No. 9250
REGISTERED PROFESSIONAL ENGINEER
MECHANICAL
STATE OF CALIFORNIA

UNITS 1 & 2 RM INDEXED REV 5 COAST VALLEYS DIVISION

NO	DATE	DESCRIPTION	GM	BY	CH.	APPD
5	5-3-78	SEE DESCRIPTION OF CHANGES SH. 2A	169972	R.C.	CV	[illegible]
4	6-22-76	SEE DESCRIPTION OF CHANGES SH. 2	169972	RSK	CV/LM	[illegible]
3	2-6-75	SEE DESCRIPTION OF CHANGES SH. 2	169972	J.M.	L.M.	NJL
2	5-22-74	SEE DESCRIPTION OF CHANGES SHT. 2	169972	J.M.	L.M.	[illegible]
1	5-17-72	APPROVED FOR CONSTRUCTION	169972	LPB	HGG	[illegible]

TABLE OF CHANGES

APPROVED BY | LEAD ENGR.

GM 167052 169972
SUPV. ENGR. W. Dodson
DSGN. C. Kwok
DR. E. HORVATH
CH. L. MANALAC
O.K.
DATE 4-3-68
SCALES None

PIPING SCHEMATIC RESIDUAL HEAT REMOVAL SYSTEM

DIABLO CANYON

DEPARTMENT OF ENGINEERING
PACIFIC GAS AND ELECTRIC COMPANY
SAN FRANCISCO, CALIFORNIA

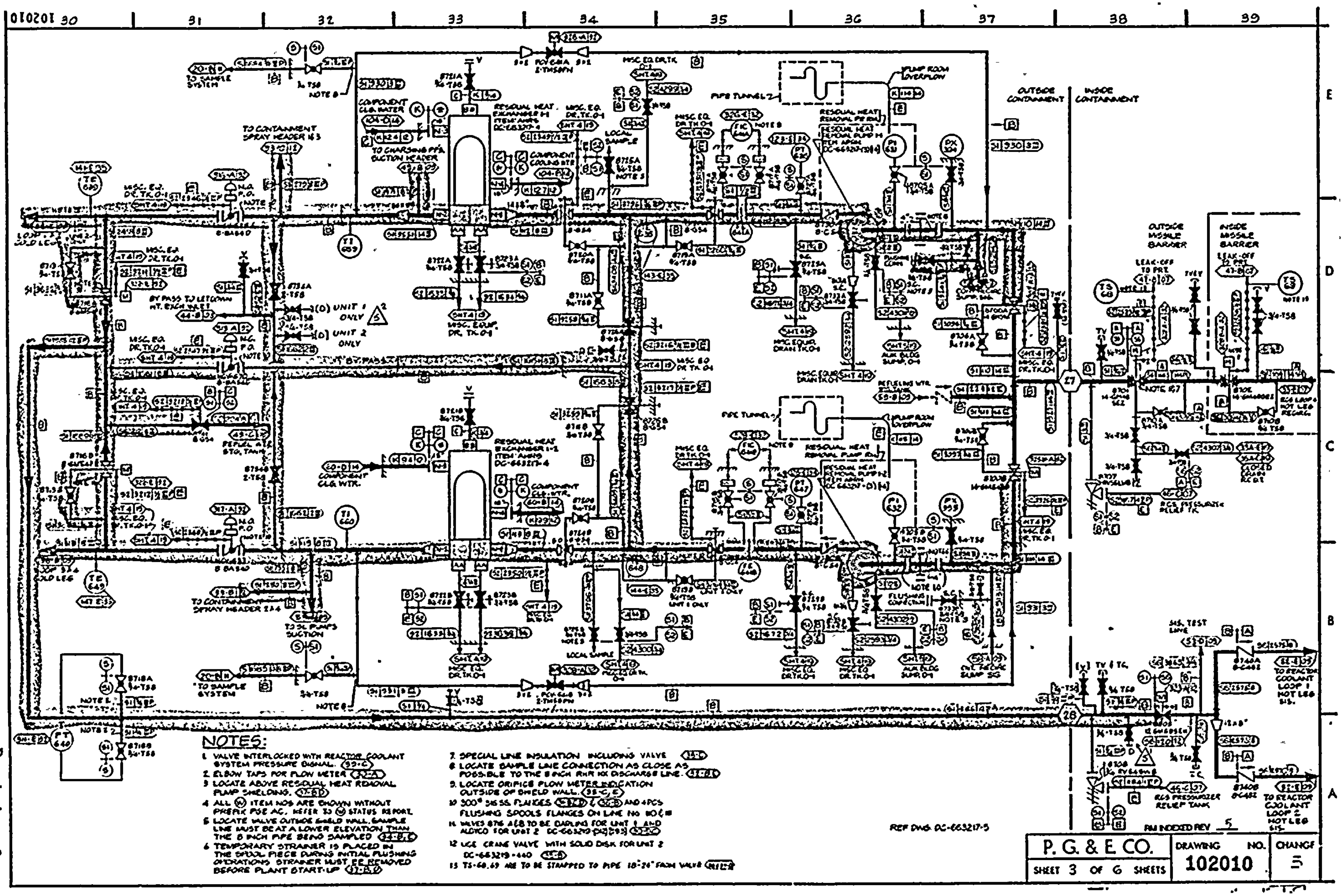
BILL OF MATERIAL
DRAWING LIST
SUPERSEDES
SUPERSEDED BY
SHEET NO. 1 OF 6 SHEETS
DRAWING NUMBER 102010
CHANGE 5

INSTR. CHECK em.valeriano [illegible] CHECK RS KERSTEN 4/6/76 VALVE CHECK [illegible]

III-J-9

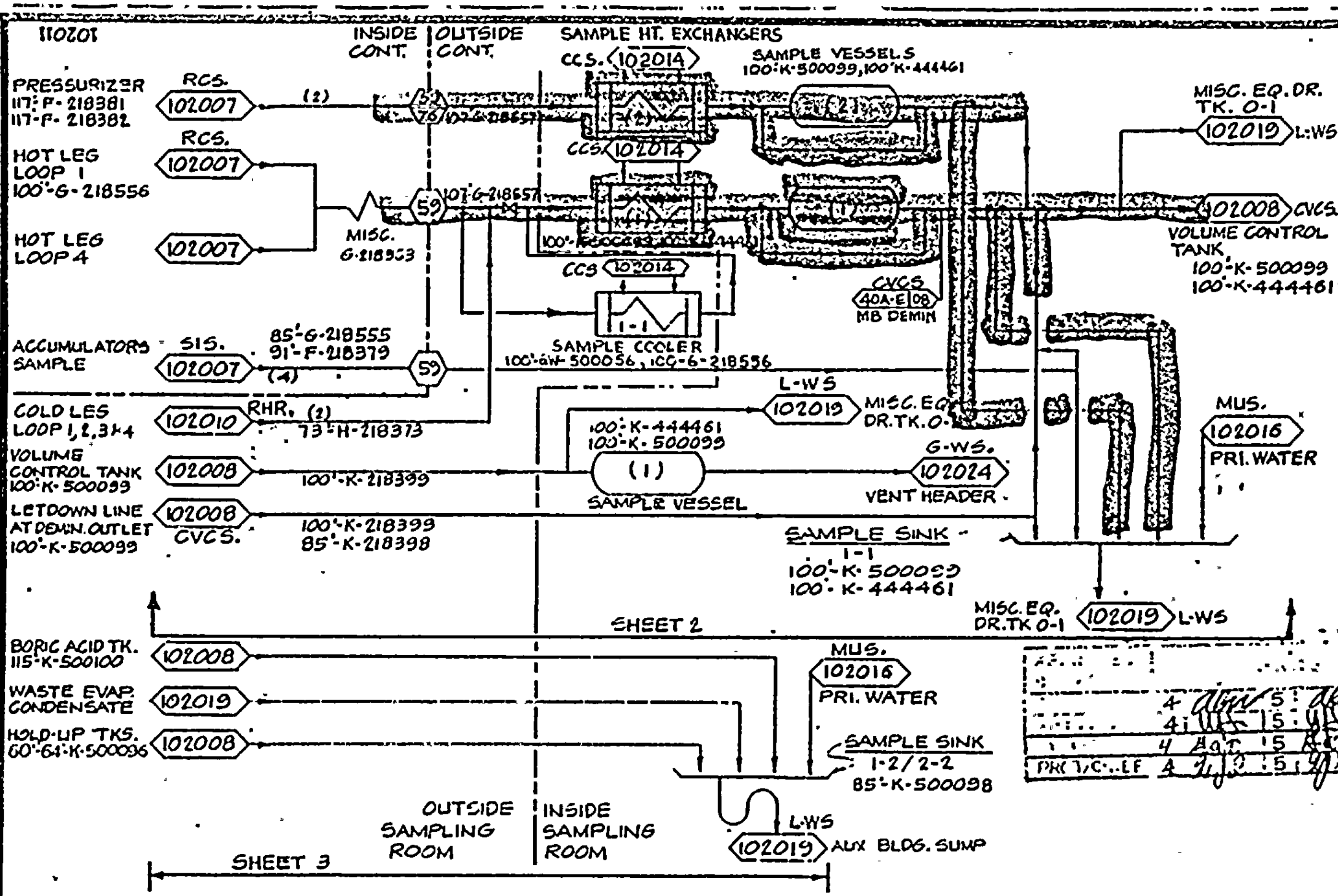
35 MAY [illegible]

Revision 0
2/29/80



Revision 0
2/29/80

110201



ELEV.	AREA	TUBING RUN DWG. NO. UNIT 1	UNIT 2
73'	H	218373	219173
85'	G	218555	219155
85'	K	218398	219198
91'	F	218379	219139
100'	G	218556	219156
100'	F	218380	219140
100'	K	218399	219199
100'	K	444461	
107	F	218381	219141
107	G	218557	219157
117	F	218382	219142
MISC.	G	218963	219163

ELEV.	AREA	MECH. DWG NO. UNIT 1	UNIT 2
60-64	K	500096	500946
100	K	500099	500949
115	K	500100	500950
85	K	500098	500948
100	GW	500056	500906

[illegible] & ENGINEER

PROJ. CHIEF 4 5 6 7

FOR DISTRIBUTION SEE SHT. 1A

D. V. KELLY No. 9269 REGISTERED PROFESSIONAL ENGINEER MECHANICAL STATE OF CALIFORNIA

CHANGES APPROVED BY PROJECT MECH. ENGINEER

CHANGES APPROVED BY SYSTEMS ENGINEER

CHANGE 3 — INSTR. ENGR. / PIPING ENGR.

BASIC DIAGRAM

RM INDEXED REV. 7 UNITS 1 & 2

35 M/M Neg. 7

COAST VALLEYS DIVISION

NO	DATE	DESCRIPTION	GM	BY	CH.	APPD
6	3-3-76	SEE DESCRIPTION OF CHANGES SH 2A		DOM	LM	
5	11-14-74	SEE DESCRIPTION OF CHANGES SH 2A	167027	J.M.	L.M.	
4	4-10-74	SEE DESCRIPTION OF CHANGES SHT. 2 A	167027	J.M.	L.M.	
3	10-31-72	CHANGED SHEETS 1A→3, PER DETAILS SHEET 4	167027	LPB	M66	
2	4-24-72	SEE TABLE OF CHANGES 1A	167027	LPB	M66	
7	4-24-78	SEE DESCRIPTION OF CHANGES	167027	RC		

TABLE OF CHANGES

APPROVED BY — PROJ. LEAD ENGR.

GM 167027 169972
SUPV. ENG. W. Dodson
DSGN. G. GHALRANG
DR. E. HORVATH
CH. L. MANALAC
O.K. RHS
DATE 2-2-69
SCALES None

PIPING SCHEMATIC
NUCLEAR STEAM SUPPLY SAMPLING SYSTEM

DIABLO CANYON

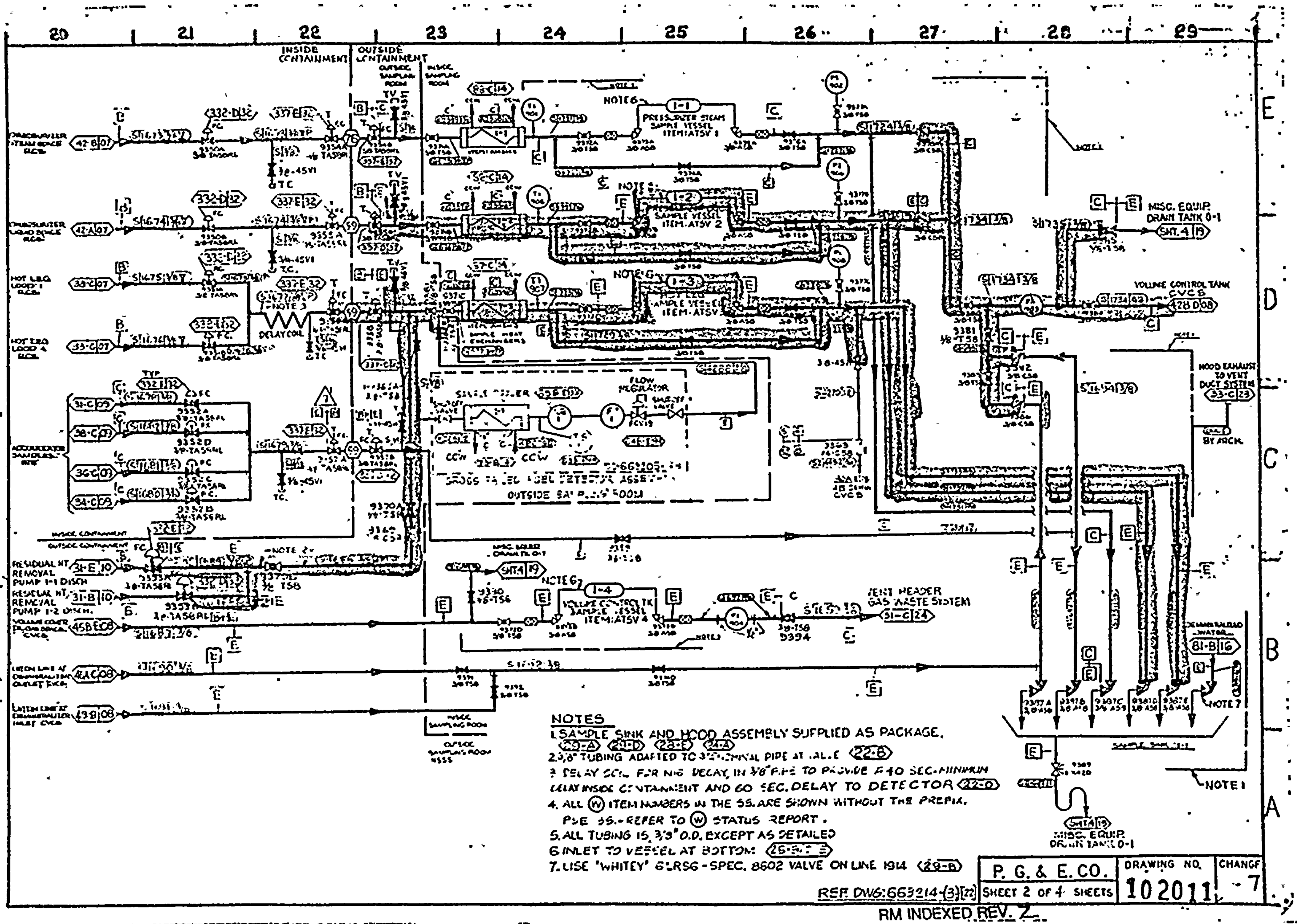
DEPARTMENT OF ENGINEERING
PACIFIC GAS AND ELECTRIC COMPANY
SAN FRANCISCO, CALIFORNIA

BILL OF MATERIAL
DRAWING LIST
SUPERSEDES
SUPERSEDED BY
SHEET NO. 1 OF 4 SHEETS
DRAWING NUMBER 102011 CHANGE 7

INSTR. CHECK G.M. Valeriano | LINE CHECK | VALVE CHECK

III-J-11

Revision 0
2/29/80

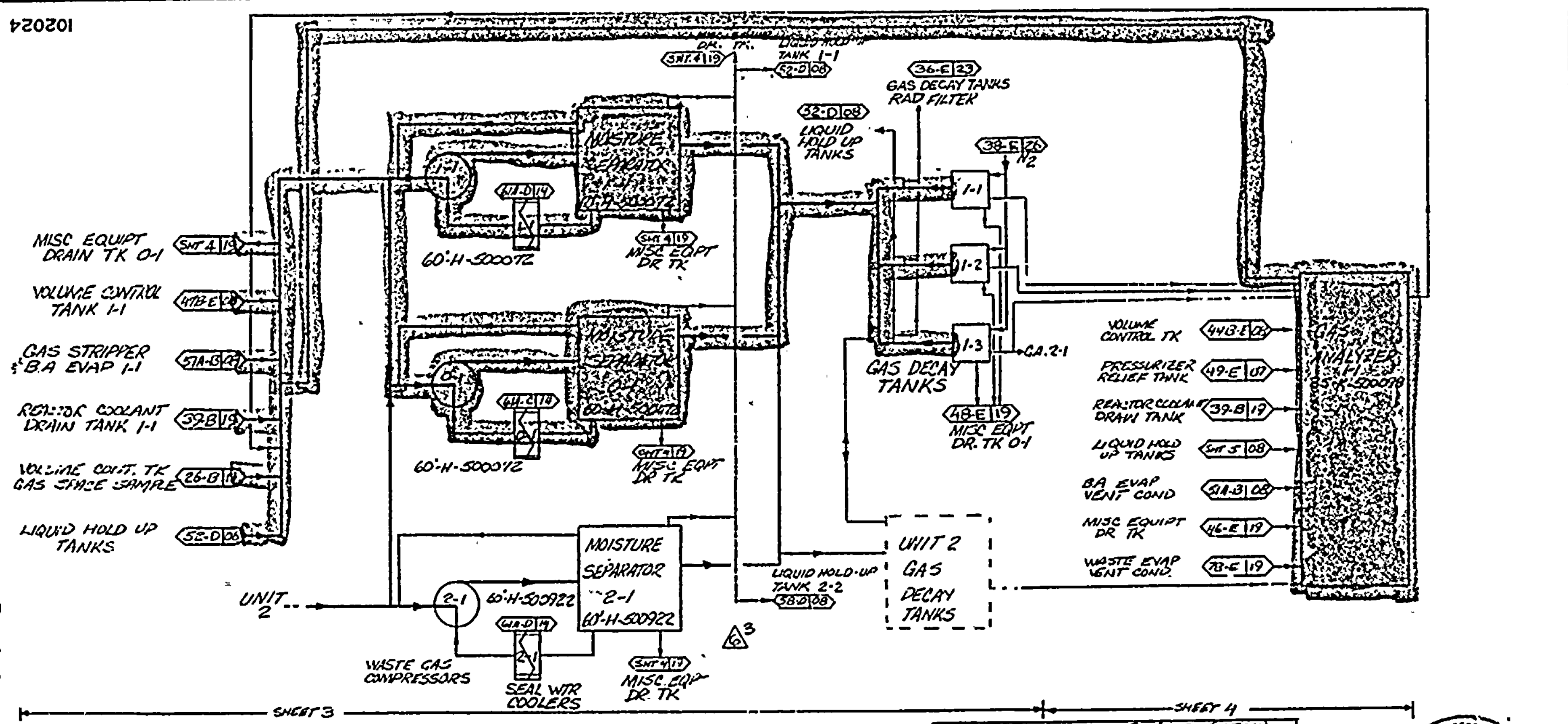


III-J-12

Revision 0
2/29/80

III-J-13 Revision 0 2/29/80

102024



BASIC DIAGRAM

ELEV	AREA	DWG NO (MECH) UNIT 1	UNIT 2
54	H	500071	500922
60	H	500072	500923
85	K	500098	

REGISTERED PROFESSIONAL ENGINEER
D. V. KELLY
No. 9269
MECHANICAL
STATE OF CALIFORNIA

APPROVED BY ENGR.	CHANGE NUMBER & ENGINEER									
PIPING	2	[illegible]	3	[illegible]	4	[illegible]	5	[illegible]	6	[illegible]
INSTRUMENT	2	[illegible]	3	[illegible]	4	[illegible]	5	[illegible]	6	[illegible]
SYSTEMS	2	[illegible]	3	[illegible]	4	[illegible]	5	[illegible]	6	[illegible]
PROJ/CHIEF	2	[illegible]	3	[illegible]	4	[illegible]	5	[illegible]	6	[illegible]

RM INDEXED REV. 6 UNITS 1 & 2

COAST VALLEYS DIVISION

NO	DATE	DESCRIPTION	GM	BY	CH.	APRD
6	5-18-78	SEE DESCRIPTION OF CHANGES SH. 2A	167027	COM	CMV	JBG
5	4-23-76	SEE DESCRIPTION OF CHANGES SH. 2A	167027	OOM	CV/LM	[illegible]
4	10-3-74	CHANGED SHTS. 2A,3,&4 PER SHEET 2A	167027	AS	LM	[illegible]
3	3-26-74	CHANGED SHTS. 2→4 PER DETAILS SHT. 2	167027	RSP	LVM	JBG
2	1-22-73	REVISED SHTS 2-4 PER SHEET 2	167027	TAC	LPB	[illegible]
1	6-23-72	APPROVED FOR CONSTRUCTION	167027	PI	E.P.	[illegible]

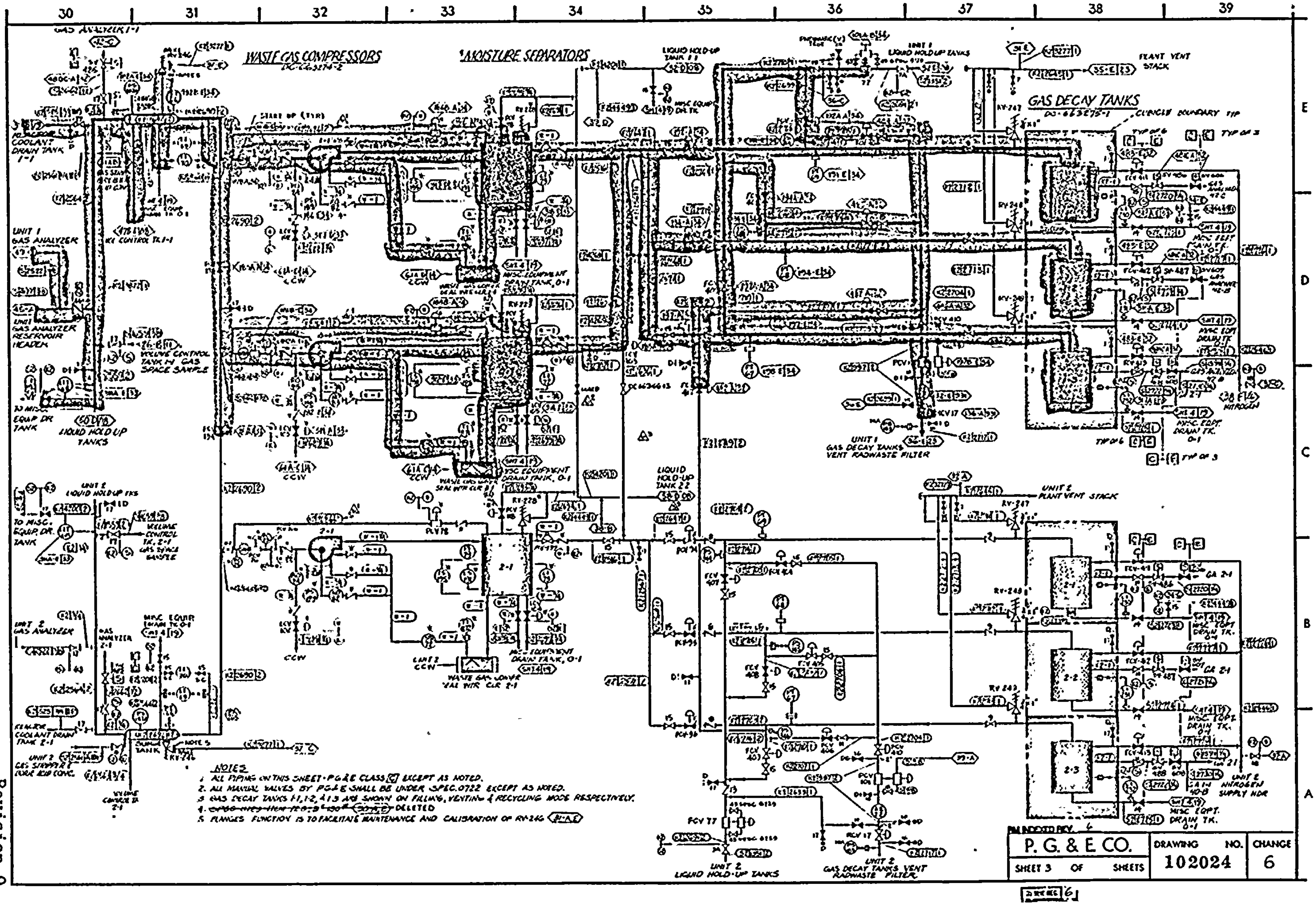
TABLE OF CHANGES

APPROVED BY / LEAD ENGR

GM 167027 169972
SUPV. BY W. Dodson
DSGN J. MADARANG
DR. R.S.P.
CH. L. MANALAC
O.K. [illegible]
DATE 4-13-66
SCALES None

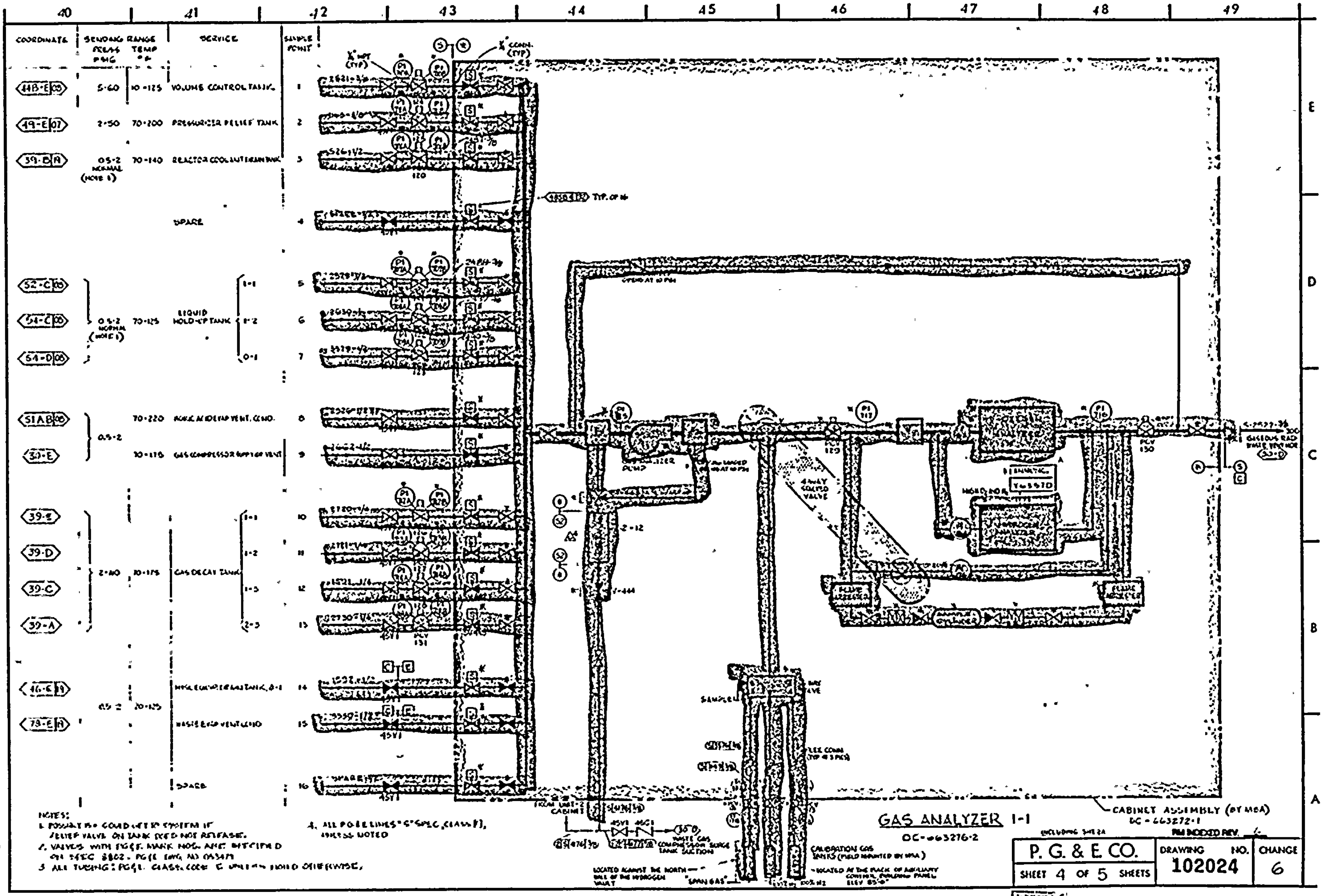
PIPING SCHEMATIC
GASEOUS RADWASTE SYSTEM
DIABLO CANYON
DEPARTMENT OF ENGINEERING
PACIFIC GAS AND ELECTRIC COMPANY
SAN FRANCISCO, CALIFORNIA

BILL OF MATERIAL	-
DRAWING LIST	-
SUPERSEDES	-
SUPERSEDED BY	-
SHEET NO. 1 OF 5 SHEETS	
DRAWING NUMBER 102024	CHANGE 6



III-J-14

Revision 0
2/29/80.



III-J-15

Revision 0
2/29/80

Section 2.1.6.b - Design Review of Plant Shielding and Environmental Qualification of Equipment for Spaces/Systems Which May Be Used in Post-Accident Operations

Task Force Position

With the assumption of a post-accident release of radioactivity equivalent to that described in Regulatory Guides 1.3 and 1.4 (i.e., the equivalent of 50% of the core radioiodine and 100% of the core noble gas inventory are contained in the primary coolant), each licensee shall perform a radiation and shielding design review of the spaces around systems that may, as a result of an accident, contain highly radioactive materials. The design review should identify the location of vital areas and equipment, such as the control room, radwaste control stations, emergency power supplies, motor control centers, and instrument areas, in which personnel occupancy may be unduly limited or safety equipment may be unduly degraded by the radiation fields during post-accident operations of these systems.

Each licensee shall provide for adequate access to vital areas and protection of safety equipment by design changes, increased permanent or temporary shielding, or post-accident procedural controls. The design review shall determine which types of corrective actions are needed for vital areas throughout the facility. (Category A: Complete the design review prior to OL, or January 1, 1980, whichever is later. Category B: Complete plant modifications by January 1, 1981.)

Section 2.1.6.b (Continued)

Clarification

Any area which will or may require occupancy to permit an operator to aid in the mitigation of or recovery from an accident is designated as a vital area. In order to assure that personnel can perform necessary post-accident operations in the vital areas, we are providing the following guidance to be used by licensees to evaluate the adequacy of radiation protection to the operators:

1. Source Term

The minimum radioactive source term should be equivalent to the source terms recommended, in Regulatory Guides 1.3, 1.4, 1.7 and Standard Review Plant 15.6.5. with appropriate decay times based on plant design.

a. Liquid Containing Systems: 100% of the core equilibrium noble gas inventory, 50% of the core equilibrium halogen inventory and 1% of all others are assumed to be mixed in the reactor coolant and liquids injected by HPCI and LPCI.

b. Gas Containing Systems: 100% of the core equilibrium noble gas inventory and 25% of the core equilibrium halogen activity are assumed to be mixed in the containment atmosphere. For gas containing lines connected to the primary system (e.g., BWR steam lines) the concentration of radioactivity shall be determined assuming the activity is contained in the gas space in the primary coolant system.

2. Dose Rate Criteria

The dose rate for personnel in a vital area should be such that the guidelines of GDC 19 should not be exceeded during the course of the accident. GDC 19 limits the dose to an operator to 5 Rem whole body or its equivalent to any part of the body. When determining the dose to an operator, care must be taken to determine the necessary occupancy time in a specific area. For example, areas requiring continuous occupancy will require much lower dose rates than areas where minimal occupancy is required. Therefore, allowable dose rates will be based upon expected occupancy, as well as the radioactive source terms and shielding. However, in order to provide a general design objective, we are providing the following dose rate criteria with alternatives to be documented on a case-by-case basis. The recommended dose rates are average rates in the

area. Local hot spots may exceed the dose rate guidelines provided occupancy is not required at the location of the hot spot. These doses are design objectives and are <u>not</u> to be used to limit access in the event of an accident.

a. <u>Areas Requiring Continuous Occupancy</u>: <u>F</u>15mr/hr. These areas will require full time occupancy during the course of the accident. The Control Room and onsite technical support center are areas where continuous occupancy will be required. The dose rate for these areas is based on the control room occupancy factors contained in SRP 6.4.

b. <u>Areas Requiring Infrequent Access</u>: GDC 19. These areas may require access on a regular basis, but not continuous occupancy. Shielding should be provided to allow access at a frequency and duration estimated by the licensee. The plant Radiochemical/Chemical Analysis Laboratory, radwaste panel, motor control center, instrumentation locations, and reactor coolant and containment gas sample stations are examples where occupancy may be needed often but not continuously.

Section 2.1.6.b (Continued)

PG&E Response and Status

A comprehensive site inspection and evaluation was conducted to identify those portions of the systems exposed to high activity reactor coolant both during the short-term post-accident cooldown mode and the long-term post-accident cleanup mode. Plant piping drawings and equipment arrangement drawings were reviewed and the systems and components were identified and labeled to locate all source terms during realistic accident scenarios. Personnel access pathways, equipment requiring access, and constantly or frequently manned areas of the plant during accident conditions were identified for dose rate calculations.

Initial area calculations have been made for the Control Room, Onsite Technical Support Center, Reactor Coolant Sampling Area and the penetration area between the Containment and the Auxiliary Building.

A computer model of the Auxiliary Building sources and calculations areas was developed. The initial calculations will be further refined using this computer model. Dose rates in those areas of the auxiliary and turbine buildings requiring personnel access will be calculated. Calculations will be performed to evaluate exposure to equipment needed after the accident to insure adequate environmental equipment qualification. Evaluation of the new sampling equipment (see Section 2.1.8.a) for post-accident sampling will be conducted to insure personnel protection. Shielding analysis and environmental qualification studies are currently in progress and will be

Section 2.1.6.b (Continued)

completed by April 1, 1980. When the shielding studies have been completed (prior to July 1, 1980), a formal design review report of the results will be delivered to the NRC. If modifications or procedural changes are required as a result of the findings, details of the necessary changes will be provided to the NRC.

Redesign and addition of necessary shielding, if any, and changes in operating and administrative procedures will begin following completion of the evaluation effort.

Section 2.1.7.a - Automatic Initiation of the Auxiliary Feedwater System

Task Force Position

Consistent with satisfying the requirements of General Design Criterion 20 of Appendix A to 10 CFR 50 with respect to the timely initiation of the auxiliary feedwater system, the following requirements shall be implemented in the short term:

1. The design shall provide for the automatic initiation of the auxiliary feedwater system.

2. The automatic initiation signals and circuits shall be designed so that a single failure will not result in the loss of auxiliary feedwater system function.

3. Testability of the initiating signals and circuits shall be a feature of the design.

4. The initiating signals and circuits shall be powered from the emergency buses.

5. Manual capability to initiate the auxiliary feedwater system from the control room shall be retained and shall be implemented so that a single failure in the manual circuits will not result in the loss of system function.

Section 2.1.7.a (Continued)

6. The ac motor-driven pumps and valves in the auxiliary feedwater system shall be included in the automatic actuation (simultaneous and/or sequential) of the loads to the emergency buses.

7. The automatic initiating signals and circuits shall be designed so that their failure will not result in the loss of manual capability to initiate the AFWS from the control room.

In the long term, the automatic initiation signals and circuits shall be upgraded in accordance with safety-grade requirements. (Category A: Implementation shall be completed prior to OL, or January 1, 1980, whichever is later.)

Clarification

Control Grade (Short-Term)

1. Provide automatic/manual initiation of AFWS.

2. Testability of the initiating signals and circuits is required.

3. Initiating signals and circuits shall be powered from the emergency buses.

Section 2.1.7.a (Continued)

4. Necessary pumps and valves shall be included in the automatic sequence of the loads to the emergency buses. Verify that the addition of these loads does not comprimise the emergency diesel generating capacity.

5. Failure in the automatic circuits shall not result in the loss of manual capability to initiate the AFWS from the control room.

6. Other Considerations

   a. For those designs where instrument air is needed for operation, the electric power supply requirement should be capable of being manually connected to emergency power sources.

PG&E Response and Status

The auxiliary feedwater system is shown in FSAR Figure 3.2.-03, Sheet 2 of 4. The pumps are automatically started by low-low steam generator level, feedwater pump trip, safety injection, or loss of offsite power. See FSAR Figures 7.3-8, 7.3-17 and 7.3-18.

As shown on FSAR Figures 7.3-8 and 7.3-17, the motor-driven auxiliary feedwater pumps are started by closure of the Solid State Protection System (SSPS) output relay K633, timer 2HH8(2HF9) or timer 2HH8A(2HF9A). Relay K633 is actuated by safety injection initiation or low-low level in any steam generator. The timers

provide automatic starting sequences after bus transfer either with or without safety injection. Each pump is started by a separate relay or timer from redundant SSPS trains A and B. The motor-driven pumps are also automatically started by trip of both main feedwater pumps.

The turbine driven auxiliary feedwater pump is started by opening steam supply valve FCV-95. As shown on FSAR Figure 7.3-18, this valve is opened by SSPS output relay K632 or K634. Relay K632 initiates for starting on loss of offsite power and relay K634 initiates starting on low-low level in any steam generator. Loss of offsite power is determined by low voltage on the 12kV reactor coolant pump buses. An automatic starting signal is provided by redundant SSPS trains A and B.

The system valves are normally open and require no actions for system operation. The auxiliary feedwater initiation circuitry is part of the Engineered Safety Features (ESF) system, and as such, is installed in accordance with IEEE Standard 279. This standard is referenced in 10 CFR 50.55a(h).

The auxiliary feedwater initiation signals and circuitry are testable. Such testability is included in the surveillance test procedures for the plant as delineated in the Plant Technical Specifications.

Section 2.1.7.a (Continued)

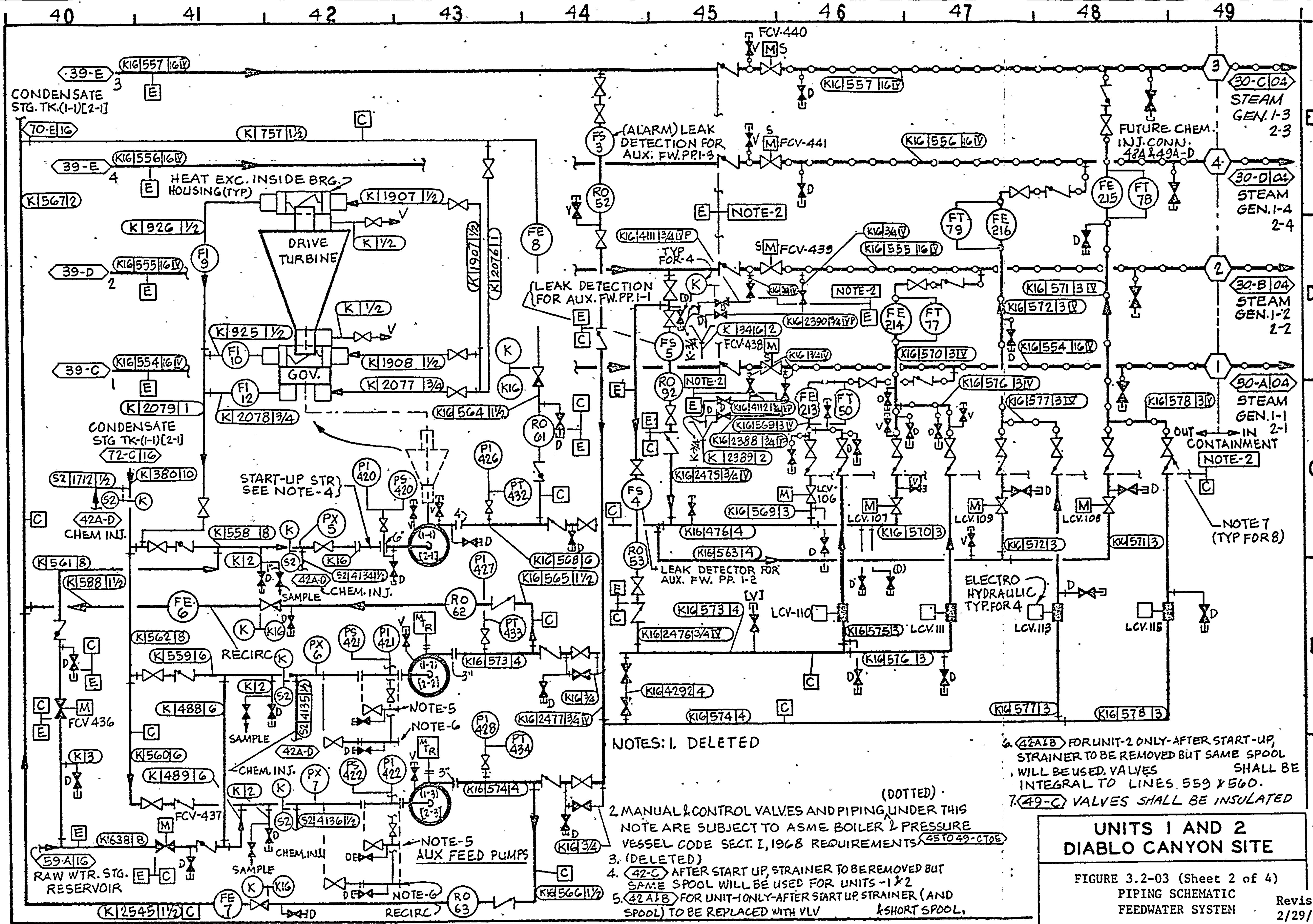
The initiating sensors such as steam generator low-low level are powered from separate and redundant nuclear instrumentation and control panels, each of which is supplied by either on-site emergency generators or station emergency batteries. Each of the two redundant SSPS trains is supplied by a separate safety grade power source. Initiation and flow paths will be available upon loss of offsite power.

Manual initiation for each train exists in the control room. The manual initiation system is installed in the same manner as the automatic initiation system. No single failure in the manual initiation portion of the circuit can result in the loss of auxiliary feedwater system function. See FSAR Figures 7.3-17 and 7.3-18 for the circuitry.

As with all ESF equipment, the AC motor-driven pumps and all valves in the system are automatically transferred to, and sequentially loaded on, the emergency buses on loss of offsite power. The sequence is shown in FSAR Table 8.3-2, attached.

All automatic initiating signals and circuits are installed in accordance with regulatory requirements and are safety grade and redundant. No single failure in the automatic portion of the system will result in loss of the capability to manually initiate the AFWS from the control room.

As described, the automatic initiating signals presently meet all safety grade requirements. No upgrading is required.



NOTES: 1. DELETED

2. MANUAL & CONTROL VALVES AND PIPING (DOTTED) UNDER THIS NOTE ARE SUBJECT TO ASME BOILER & PRESSURE VESSEL CODE SECT. I, 1968 REQUIREMENTS (45 TO 49-C TO E)

3. (DELETED)

4. (42-C) AFTER START UP, STRAINER TO BE REMOVED BUT SAME SPOOL WILL BE USED FOR UNITS -1 & 2

5. (42 A & B) FOR UNIT-1 ONLY-AFTER START UP, STRAINER (AND SPOOL) TO BE REPLACED WITH VLV & SHORT SPOOL.

6. (42 A & B) FOR UNIT-2 ONLY-AFTER START-UP, STRAINER TO BE REMOVED BUT SAME SPOOL WILL BE USED, VALVES SHALL BE INTEGRAL TO LINES 559 & 560.

7. (49-C) VALVES SHALL BE INSULATED

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.2-03 (Sheet 2 of 4)
PIPING SCHEMATIC
FEEDWATER SYSTEM

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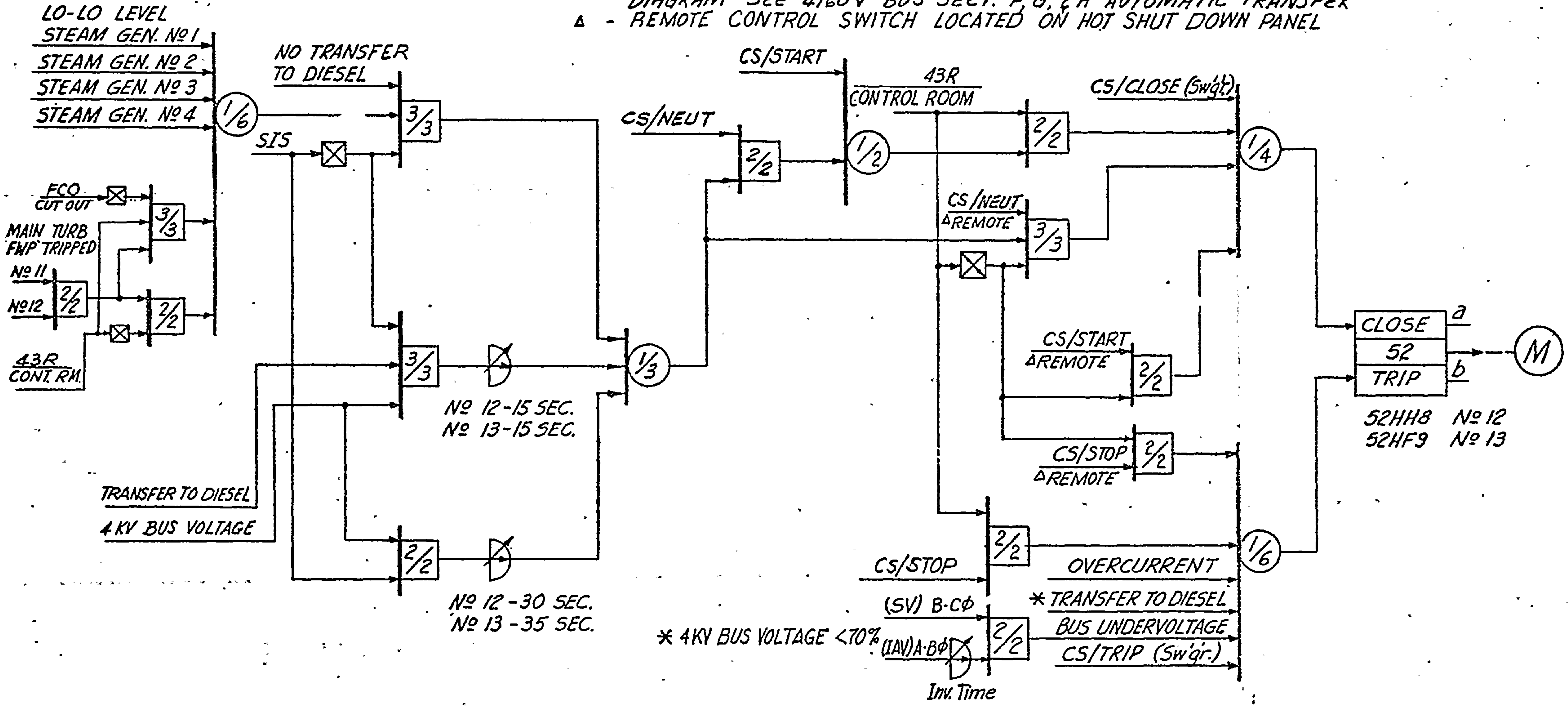
NOTES

43R - TRANSFERS CONTROL FROM MAIN CONTROL BOARD TO HOT SHUT DOWN PANEL.
* - FOR COMPLETE TRANSFER TO DIESEL & 4KV BUS UNDERVOLTAGE LOGIC DIAGRAM - SEE 4160V BUS SECT. F, G, & H AUTOMATIC TRANSFER
Δ - REMOTE CONTROL SWITCH LOCATED ON HOT SHUT DOWN PANEL



UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 7.3-8
LOGIC DIAGRAM
AUXILIARY FEEDWATER PUMPS

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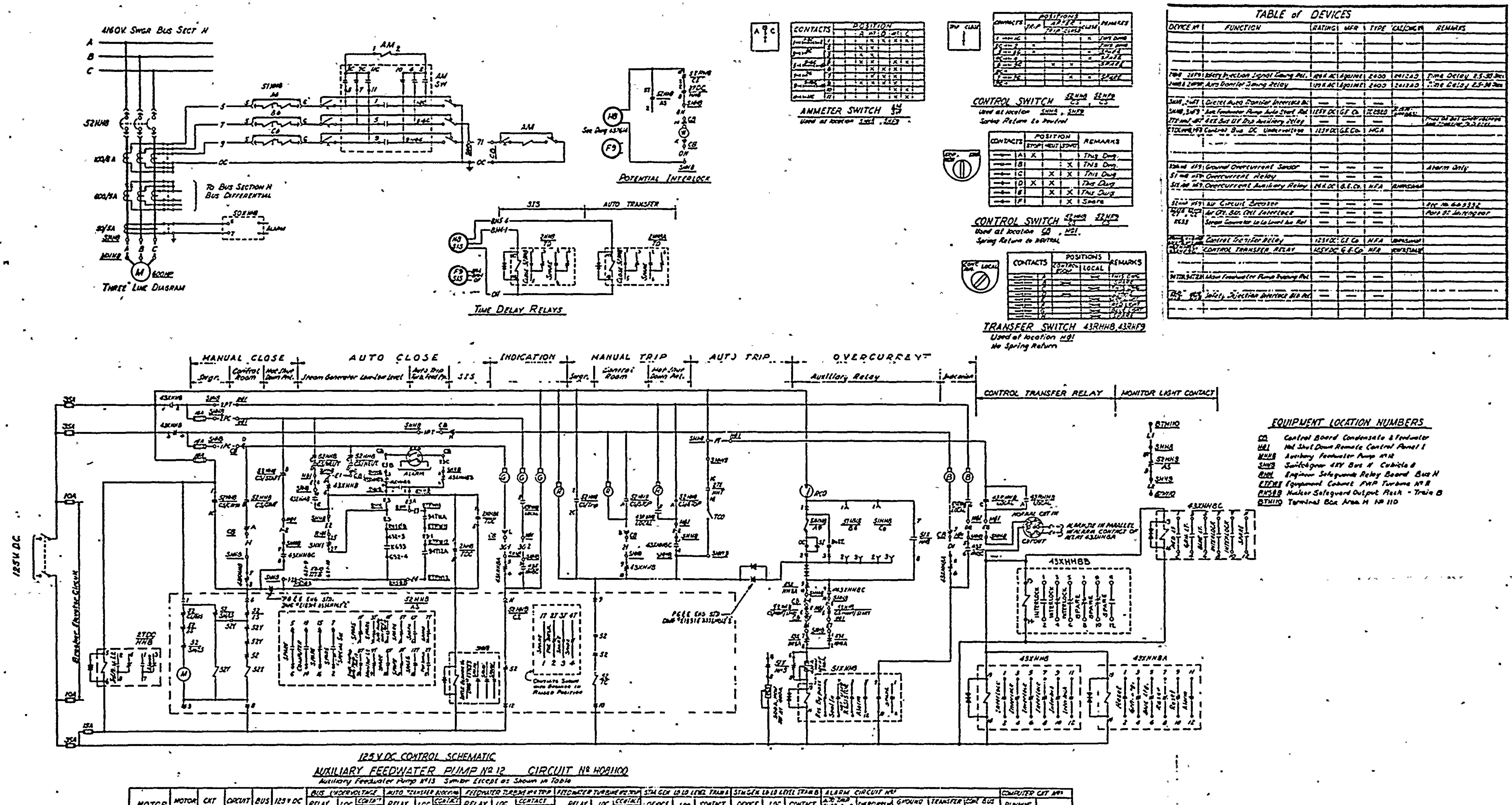

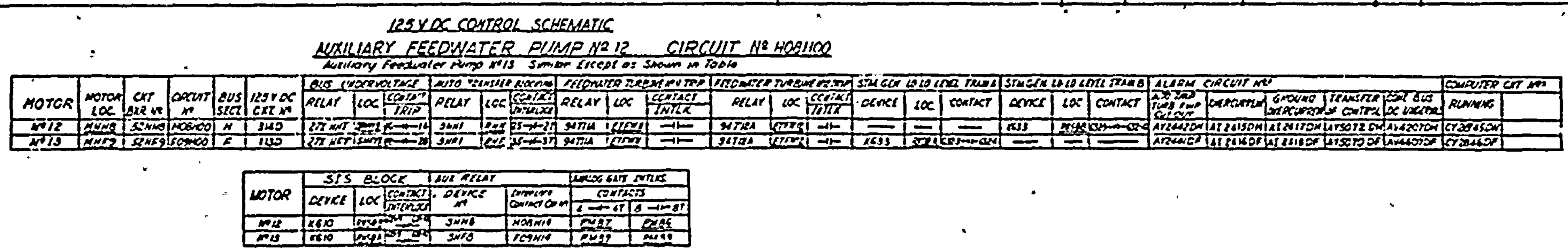

UNITS 1 AND 2 DIABLO CANYON SITE

FIGURE 7.3-17
SCHEMATIC DIAGRAM
AUXILIARY FEEDWATER PUMPS

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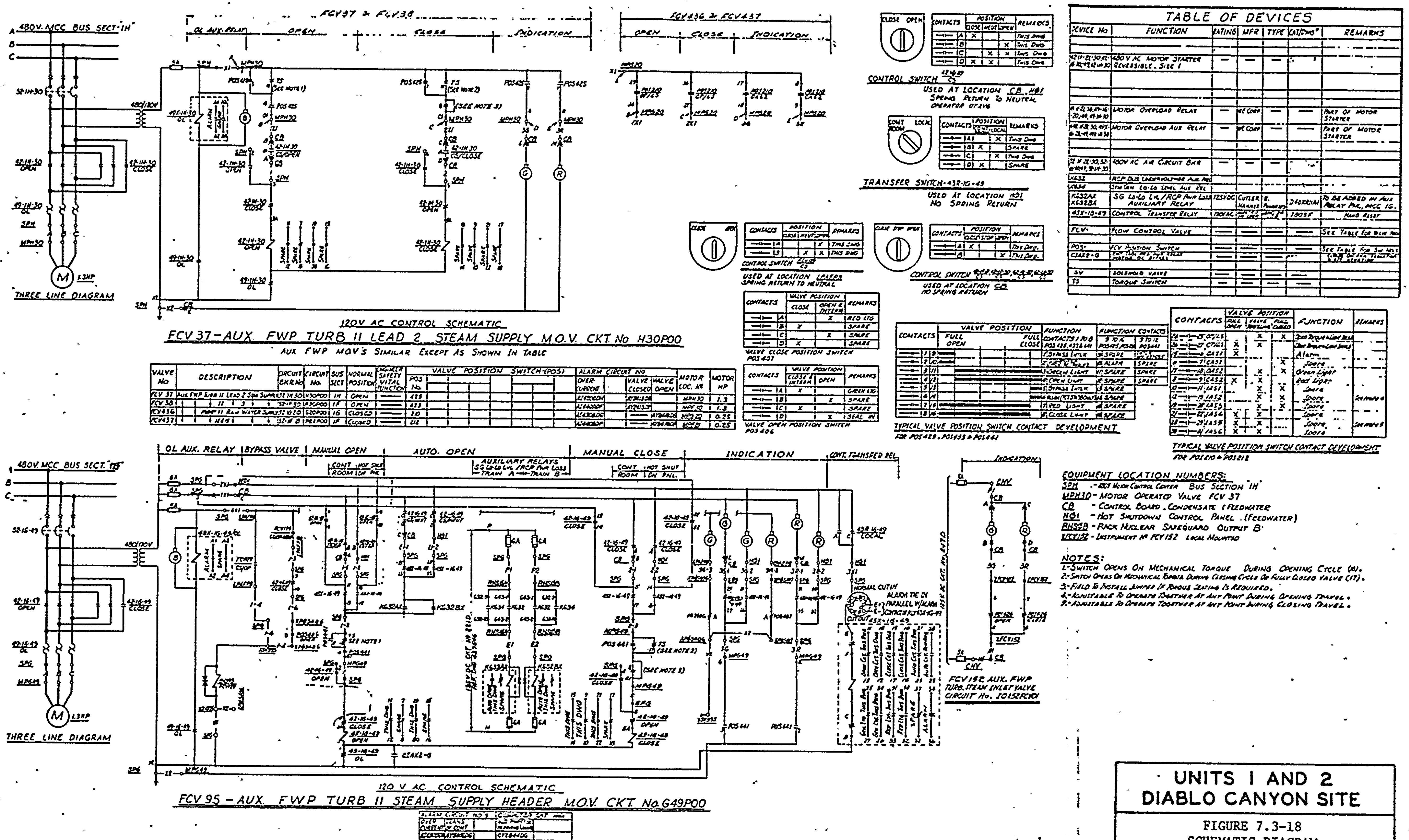

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 7.3-18
SCHEMATIC DIAGRAM
AUXILIARY FEEDWATER PUMP
TURBINE CONTROL

Amendment 78

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TABLE 8.3-2

TIMING SEQUENCE AND INTERVALS - SAFETY INJECTION SIGNAL

Load	Starting Delay (Seconds) After Power is Restored to the Vital Buses (6)			Minimum Number Required
	Bus F	Bus C	Bus H	
Small Loads (480 and 120 Volt) on Vital 480 Volt Load Centers	0	0	0	2
Centrifugal Charging Pumps	5	5	-	1
Safety Injection Pumps	10	-	5	1
Containment Spray Pumps	-	10	10	1
Residual Heat Removal Pumps	-	15	15	1
Containment Fan Coolers	15, 20	20, 25	20	3
Component Cooling Water Pumps	25	30	25	2
Auxiliary Saltwater Pumps	30	35	-	1
Auxiliary Feedwater Pumps	35	-	30	1

Section 2.1.7.b - Auxiliary Feedwater Flow Indication to Steam Generators for PWR's

Task Force Position

Consistent with satisfying the requirements set forth in GDC 13 to provide the capability in the control room to ascertain the actual performance of the AFWS when it is called to perform its intended function, the following requirements shall be implemented:

1. Safety-grade indication of auxiliary feedwater flow to each steam generator shall be provided in the control room.

2. The auxiliary feedwater flow instrument channels shall be powered from the emergency buses consistent with satisfying the emergency power diversity requirements of the auxiliary feedwater system set forth in Auxiliary Systems Branch Technical Position 10-1 of the Standard Review Plan, Section 10.4.9. (Category A: Implementation shall be completed prior to OL, or January 1, 1980, whichever is later.)

Clarification

A. Control Grade (Short-Term)

1. Auxiliary feedwater flow indication to each steam generator shall satisfy the single failure criterion.

Section 2.1.7.b (Continued)

2. Testability of the auxiliary feedwater flow indication channels shall be a feature of the design.

3. Auxiliary feedwater flow instrument channels shall be powered from the vital instrument buses.

B. Safety-Grade (Long-Term)

1. Auxiliary feedwater flow indication to each steam generator shall satisfy safety-grade requirements.

C. Other

1. For the Short-Term the flow indication channels should by themselves satisfy the single failure criterion for each steam generator. As a fall-back position, one auxiliary feed water flow channel may be backed up by a steam generator level channel.

2. Each auxiliary feed water channel should provide an indication of feed flow with an accuracy on the order of ± 10%.

Section 2.1.7.b (Continued)

PG&E Response and Status for TFP 1

The Diablo Canyon design has one auxiliary feedwater flow indicator for each of four steam generators. The indicators are safety grade. Indication is provided at the main control board and the hot shutdown panel. Accuracy is ±7.5% or better.

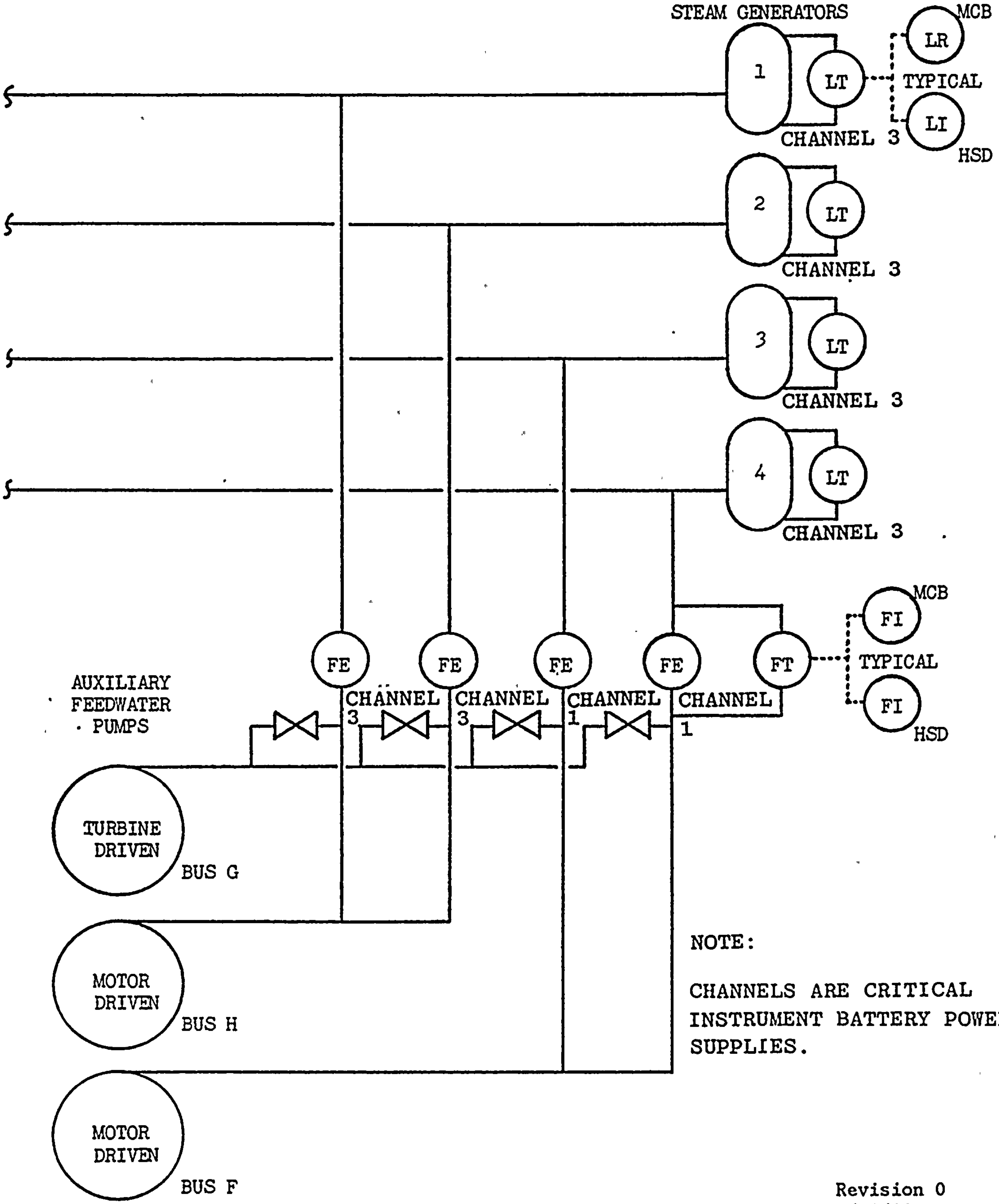
PG&E Response and Status for TFP 2

Two separate critical instrument power buses are used for the four flow indicators, with two flow indicators on each bus.

The flow from the turbine-driven auxiliary feedwater pump is monitored by the same indicators which monitor the motor-driven auxiliary feedwater pump flow.

An additional indication of auxiliary feedwater flow is provided by the safety grade steam generator wide range level indication. This provides recording on the main control board and indication on the hot shutdown panel. It is powered from the same bus as powers two of the flow indicators. See attached Figure 2.1.7.b.1.

[illegible]



NOTE:

CHANNELS ARE CRITICAL INSTRUMENT BATTERY POWER SUPPLIES.

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FIGURE 2.1.7.B.1

Section 2.1.8.a - Improved Post-Accident Sampling Capability

Task Force Position

A design and operational review of the reactor coolant containment atmosphere sampling systems shall be performed to determine the capability of personnel to promptly obtain (less than 1 hour) a sample under accident conditions without incurring a radiation exposure to any individual in excess of 3 and 18 3/4 Rems to the whole body or extremities, respectively. Accident conditions should assume a Regulatory Guide 1.3 or 1.4 release of fission products. If the review indicates that personnel could not promptly and safely obtain the samples, additional design features or shielding should be provided to meet the criteria.

A design and operational review of the radiological spectrum analysis facilities shall be performed to determine the capability to promptly quantify (less than 2 hours) certain radioisotopes that are indicators of the degree of core damage. Such radionuclides are noble gases (which indicate cladding failure), iodines and cesiums (which indicate high fuel temperatures), and non-volatile isotopes (which indicate fuel melting). The initial reactor coolant spectrum should correspond to a Regulatory Guide 1.3 or 1.4 release. The review should also consider the effects of direct radiation from piping and components in the auxiliary building and possible contamination and direct radiation from airborne effluents. If the review indicates that the analyses required cannot be performed in a prompt manner with existing equipment, then design modifications or equipment procurement shall be undertaken to meet the criteria.

Section 2.1.8.a (Continued)

In addition to the radiological analyses, certain chemical analyses are necessary for monitoring reactor conditions. Procedures shall be provided to perform boron and chloride chemical analyses assuming a highly radioactive initial sample (Regulatory Guide 1.3 or 1.4 source term). Both analyses shall be capable of being completed promptly; i.e., the boron sample analysis within an hour and the chloride sample analysis within a shift. (Category A: Implementation of design reviews and description of proposed modifications will be completed by January 1, 1980. Category B: Implementation of plant modifications and preparation of revised procedures will be completed by June 1, 1980.)

<u>Clarification</u>

The licensee shall have the capability to promptly obtain (in less than 1 hour) pressurized and unpressurized reactor coolant samples and a containment atmosphere (air) sample.

The licensee shall establish a plan for an onsite radiological and chemical analysis facility with the capability to provide, within 1 hour of obtaining the sample, quantification of the following:

1. Certain isotopes that are indicators of the degree of core damage (i.e., noble gases, iodines and cesiums and non-volatile isotopes),

2. Hydrogen levels in the containment atmosphere in the range 0 to 10 volume percent,

Section 2.1.8.a (Continued)

3. Dissolved gases, (i.e., H_2, O_2) and boron concentration of liquids,

or have in-line monitoring capabilities to perform the above analysis. Plant procedures for the handling and analysis of samples, minor plant modifications for taking samples and a design review and procedural modifications (if necessary) shall be completed by January 1, 1980. Major plant modifications shall be completed by January 1, 1981.

During the review of the post accident sampling capability consideration should be given to the following items:

1. Provisions shall be made to permit containment atmosphere sampling under both positive and negative containment pressure.

2. The licensee shall consider provisions for purging sample lines, for reducing plateout in sample lines, for minimizing sample loss or distortion, for preventing blockage of sample lines by loose material in the RCS or containment, for appropriate disposal of the samples, and for passive flow restrictions to limit reactor coolant loss or containment air leak from a rupture of the sample line.

Section 2.1.8.a (Continued)

3. If changes or modifications to the existing sampling system are required, the seismic design and quality group classification or sampling lines and components shall conform to the classification of the system to which each sampling line is connected. Components and piping downstream of the second isolation valve can be designed to quality Group D and nonseismic Category I requirements.

The licensee's radiological sample analysis capability should include provisions to:

a. Identify and quantify the isotopes of the nuclide categories discussed above to levels corresponding to the source terms given in Lessons Learned Item 2.1.6.b. Where necessary, ability to dilute samples to provide capability for measurement and reduction of personnel exposure should be provided. Sensitivity of onsite analysis capability should be such as to permit measurement of nuclide concentration in the range from approximately 1 mCi/gm to the upper levels indicated here.

b. Restrict background levels of radiation in the radiological and chemical analysis facility from sources such that the sample analysis will provide results with an acceptably small error (approximately a factor of 2). This can be accomplished through the use of sufficient shielding around samples and outside sources, and by the use of ventilation system design which will control the presence of airborne radioactivity.

Section 2.1.8.a (Continued)

c. Maintain plant procedures which identify the analysis required, measurement techniques and provisions for reducing background levels.

The licensees chemical analysis capability shall consider the presence of the radiological source term indicated for the radiological analysis.

In performing the review of sampling and analysis capability, consideration shall be given to personnel occupational exposure. Procedural changes and/or plant modifications must assure that it shall be possible to obtain and analyze a sample while incurring a radiation dose to any individual that is as low as reasonably achievable and not in excess of GDC 19. In assuring that these limits are met, the following criteria will be used by the staff.

1. For shielding calculations, source terms shall be as given in Lessons Learned Item 2.1.6.b.

2. Access to the sample station and the radiological and chemical analysis facilities shall be through areas which are accessible in post accident situations and which are provided with sufficient shielding to assure that the radiation dose criteria are met.

Section 2.1.8.a (Continued)

3. Operations in the sample station, handling of highly radioactive samples from the sample station to the analysis facilities, and handling while working with the samples in the analysis facilities shall be such that the radiation dose criteria are met. This may involve sufficient shielding of personnel from the samples and/or the dilution of samples for analysis. If the existing facilities do not satisfy these criteria, then additional design features, e.g., additional shielding, remote handling, etc., shall be provided. The radioactive sample lines in the sample station, the samples themselves in the analysis facilities, and other radioactive lines of the vicinity of the sampling station and analysis facilities shall be included in the evaluation.

4. High range portable survey instruments and personnel dosimeters should be provided to permit rapid assessment of high exposure rates and accumulated personnel exposure.

The licensee shall demonstrate their capability to obtain and analyze a sample containing the isotopes discussed above according to the criteria given in this section.

Section 2.1.8.a (Continued)

PG&E Response and Status

SUMMARY

A review of existing reactor coolant and containment atmosphere sampling facilities has been conducted for Diablo Canyon Units 1 and 2. The purpose of this review was to evaluate the stations capability to obtain samples during accident and post-accident situations. NUREG-0578 Section 2.1.8.a, "Improved Post-Accident Sampling Station Capability" requirements were used as the basis for this evaluation.

This review and evaluation has resulted in a conceptual design providing a tentative Remote Sampling Facility which is projected to be located at the 115 foot elevation on each unit. Shielded sample lines will be provided for both reactor coolant sampling and containment atmosphere sampling. A control panel will be provided where controls and indication may be located for the Remote Sampling System components.

The described Remote Sample Station meets the requirements of NUREG-0578. Personnel radiation exposures have been minimized by shielding the sample lines and minimizing sample quantity to as low as practical limits. The final Sample Station design will allow Diablo Canyon Units 1 and 2 personnel to obtain RCS and Containment Atmosphere samples during post-accident conditions with a minimum of effort while also limiting personnel exposure.

Section 2.1.8.a (Continued)

Plant procedures for the handling and analysis of samples, plant modifications for taking samples and a design review and procedural modifications (if necessary) shall be completed by October 1, 1980.

Plant modifications and plant procedures shall be completed by January 1, 1981 to permit on-line monitoring of reactor coolant pH, dissolved oxygen and chloride and an automated collection system for analysis of containment atmosphere for gas composition and radioactivity. The conceptual design of the system shall be completed by May 1, 1980.

INTRODUCTION

This report summarizes the conceptual design of the system that will permit the collection of reactor coolant and containment atmosphere samples.

REMOTE SAMPLE STATION LOCATION

Consideration was given to a number of locations where a remote sample station could be installed. A location was chosen on the 115 foot elevation because of low potential radiation considerations, spaciousness, and access to and from grade level.

Section 2.1.8.a (Continued)

The remote station will be installed at the 115 foot elevation adjacent to the steam generator blowdown demineralizers. Shielded sample tubing for both containment air and reactor coolant sampling will be routed from the reactor coolant system (RCS) sample room (100 foot elevation).

Radiation sources in the area result from the Chemical Volume Control System (CVCS) piping, the Volume Control Tank (VCT), and containment spray piping. These potential sources will be discussed in Section 3.0.

A ventilation hood will be installed at the remote sample station above the sample points to remove any potential airborn activity and will be sized to provide a high flow rate. A blower will also be installed in the hood as opposed to simply branching into an auxiliary building return duct. This will insure quick removal and dilution of any airborn contamination.

A control panel containing switches for operating valves, status indication and direct telephone communications with the control room, will be provided at the remote sample station location.

POTENTIAL BACKGROUND SOURCES

The remote sample station sampling tubing, CVCS piping, VCT, and containment spray piping contribute to personnel exposure during remote sampling.

The volume control tank, located beneath the S.G. blowdown demineralizers, will become an important radiation source if a feed and bleed operation occurs using the assumed TID source terms.

The containment spray piping is located in the penetration area adjacent to the auxiliary building wall at the proposed sampling location. This piping will be a significant radiation source in post-accident operations.

A preliminary evaluation consisting of determining the radiation levels during and after the accident situation has been performed to determine shielding requirements for the area. A further, more specific evaluation will be conducted to determine the shielding designs.

RCS LIQUID SAMPLING SYSTEM

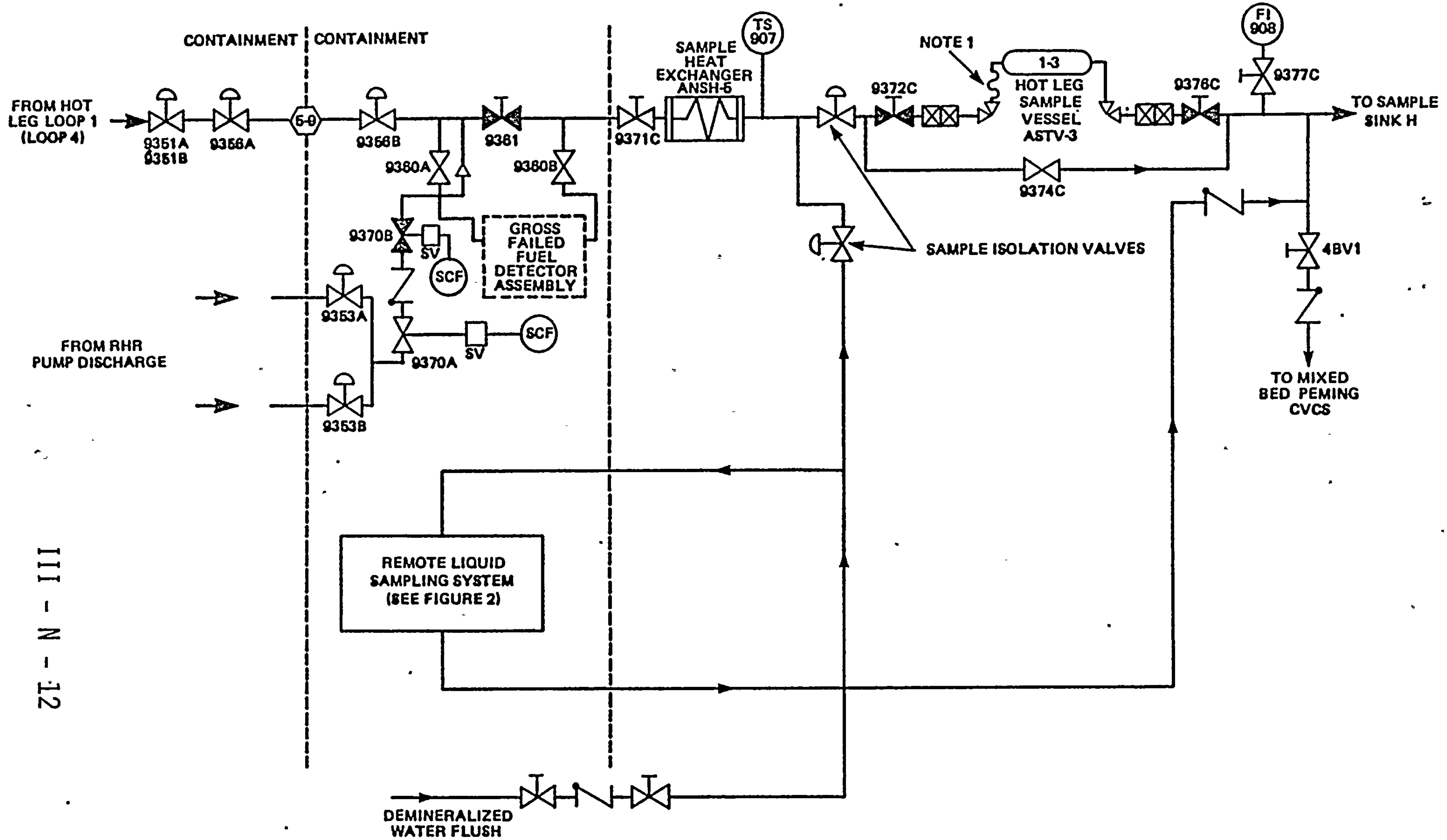
Under normal operation, reactor coolant is continuously let down from either the hot leg of loop 1 or 4 to the Gross Failed Fuel Detector and to the hot leg sample vessel, ATSV3. Flow passing through the Gross Failed Fuel Detector returns to the sample heat exchangers. The flow continues through the sample line upstream of its connection to the CVCS Mixed Bed Demineralizers or the sample sink; depending on valve line-up. The remote sampling system utilizes this existing system and adds the capability for remote sampling.

Section 2.1.8.a (Continued)

1. Remote RCS Liquid Sampling System

The Remote Sample System, shown in Figure 1, will utilize new isolation sample valves downstream of the sample heat exchanger to divert flow to a shielded, removable sample vessel for obtaining a reactor coolant sample. The shielded sample vessel may be used to obtain coolant samples from either the RHR pump discharge or hot leg 1 or 4 depending on valve line up. Capability to control valves 9370A and B must be provided on the remote sample system panel, due to the fact that the radiation level of the lines those lines are mounted on would preclude personnel access. The reactor coolant returns to the CVCS mixed bed demineralizers to allow the sample to flow to the liquid radwaste system. This minimizes potential gas releases from the sample sink to the auxiliary building atmosphere.

The Remote Sampling System allows for the collection of liquid samples of the following types: 1) a 30 ml removable pressurized, undiluted liquid sample container, 2) a 15 ml unpressurized, undiluted sample vial, 3) a one liter, diluted (up to 1000 to 1) unpressurized, liquid sample. A sample of gases stripped from the liquid, diluted with argon, can be withdrawn with a syringe.



NOTES:
1. FLEXIBLE METAL HOSE CONNECTOR SHOULD BE USED (SWAGELOK OR EQUIVALENT)
2. SCP- REMOTE SAMPLE CONTROL PANEL SWITCH
3. VALVES NOT NUMBERED ARE NEW

FIGURE 1
CONCEPTUAL DESIGN FLOW DIAGRAM FOR LIQUID SAMPLING SYSTEM

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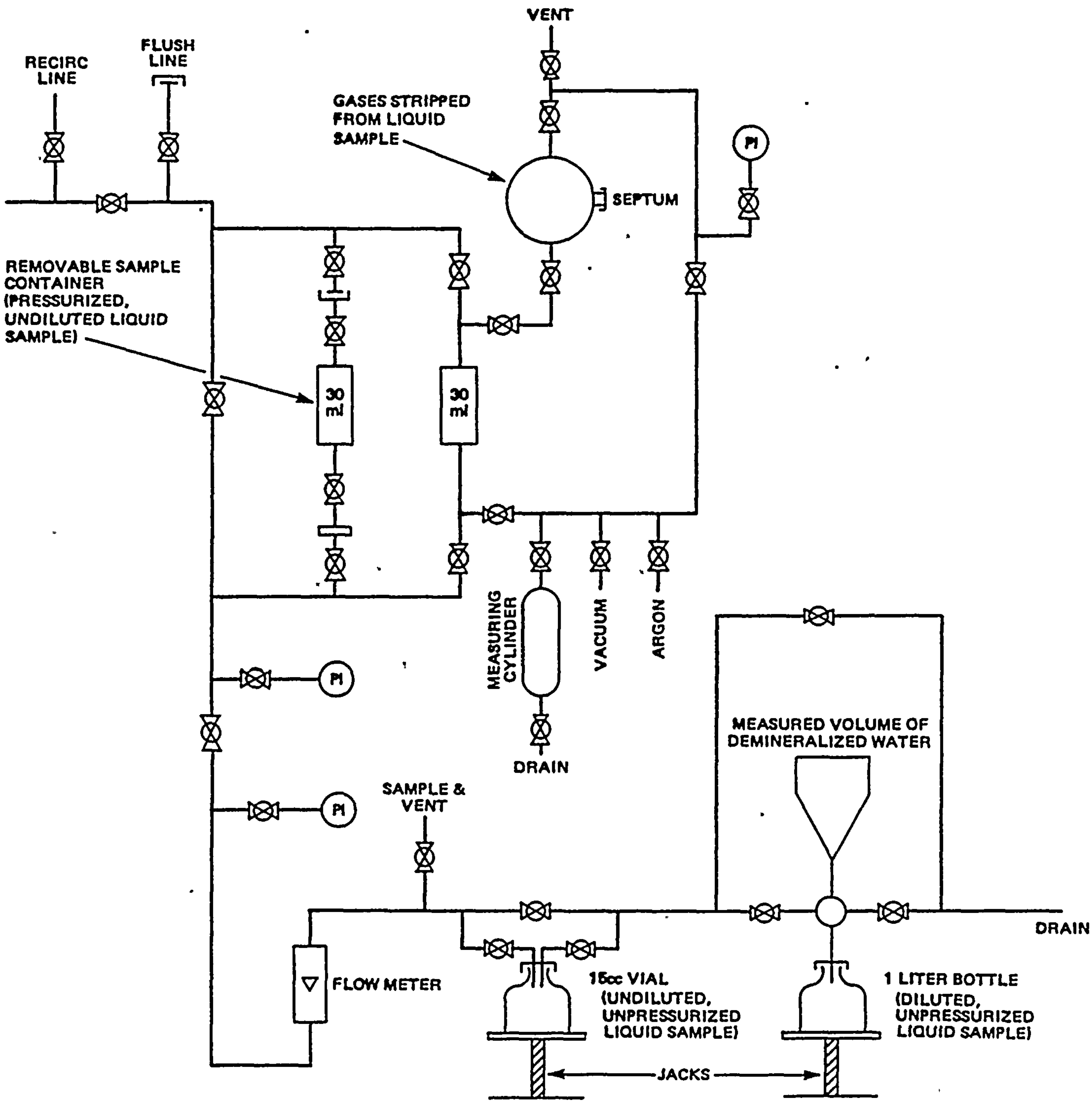


FIGURE 2
REMOTE LIQUID SAMPLING SYSTEM CONCEPTUAL FLOW DIAGRAM

Section 2.1.8.a (Continued)

CONTAINMENT ATMOSPHERE SAMPLING SYSTEM, NORMAL OPERATING CONDITIONS

Containment atmosphere sampling is normally accomplished by connecting a sample vessel with a flexible line upstream of the particulate air monitor (RE 11 and 12). The existing particulate monitor is normally used to determine radiation levels by passing the containment atmosphere through filter paper and reading levels of particulates which do not pass through. The existing monitor also measures radiation levels of any noble gases in the containment atmosphere. For the worst case, post-accident situation, noble gases, particulates, halogens and hydrogen may exist along with a sizable quantity of wet steam. Modifications must be made to the existing monitor as it cannot withstand this environment. In addition, the existing system, since it is not capable of withstanding high pressures, isolates on high containment pressure.

AUTOMATIC GRAB SAMPLING SYSTEM, ACCIDENT CONDITIONS

Automatic grab sampling is initiated and sample time is automatically recorded upon a containment isolation signal. Sampling may also be initiated from the remote sample station. Sampling cycles start at preset times after the alarm (e.g., at 0, 20 and 120 minutes after the alarm). Each cycle begins with a line purge to clean the line prior to sampling. To enhance system reliability, suction for drawing samples is provided by flow of nitrogen gas through an eductor.

Section 2.1.8.a (Continued)

Samples are collected in removable Marinelli flasks designed for counting on Ge(Li) detectors. To count high level samples, it is necessary to employ special handling and counting techniques including dilution of samples. After initial counting, a sample may be kept for additional analysis after decay (an analytical technique not possible with on-line monitoring) or for confirmatory reanalysis by a regulatory agency. Additionally, a sample flask may be reused; any contamination may be measured prior to reuse.

Samples will also be collected in sample containers suitable for transportation to a laboratory gas chromatograph for hydrogen and oxygen analysis.

Section 2.1.8.b - Increased Range of Radiation Monitors

Task Force Position

The requirements associated with this recommendation should be considered as advanced implementation of certain requirements to be included in a revision to Regulatory Guide 1.97, "Instrumentation to Follow the Course of an Accident", which has already been initiated, and in other Regulatory Guides, which will be promulgated in the near-term.

1. Noble gas effluent monitors shall be installed with an extended range designed to function during accident conditions as well as during normal operating conditions; multiple monitors are considered to be necessary to cover the ranges of interest.

   a. Noble gas effluent monitors with an upper range capacity of 10^5 μCi/cc (Xe-133) are considered to be practical and should be installed in all operating plants.

   b. Noble gas effluent monitoring shall be provided for the total range of concentrations extending from normal condition (ALARA) concentration to a maximum of 10^5 μCi/cc (Xe-133). Multiple monitors are considered to be necessary to cover the ranges of interest. The range capacity of individual monitors should overlap by a factor of ten.

Section 2.1.8.b (Continued)

2. Since iodine gaseous effluent monitors for the accident condition are not considered to be practical at this time, capability for effluent monitoring of radioiodines for the accident condition shall be provided with sampling conducted by adsorption on charcoal or other media, followed by onsite laboratory analysis.

3. In-containment radiation level monitors with a maximum range of 10^8 rad/hr shall be installed. A minimum of two such monitors that are physically separated shall be provided. Monitors shall be designed and qualified to function in an accident environment. (Category B: Implementation complete by January 1, 1981.)

Clarification

1. Radiological Noble Gas Effluent Monitors

   a. January 1, 1980 Requirements

      Until final implementation in January 1, 1981, all operating reactors must provide, by January 1, 1980, an interim method for quantifying high level releases which meets the requirements of Table 2.1.8.b.1. This method is to serve only as a provisional fix with the more detailed, exact methods to follow. Methods are to be developed to quantify release rates of up to 10,000 Ci/sec for noble

gases from all potential release points, (e.g., auxiliary building, radwaste building, fuel handling building, reactor building, waste gas decay tank releases, main condenser air ejector, BWR main condenser vacuum pump exhaust, PWR steam safety valves and atmosphere steam dump valves and BWR turbine buildings) and any other areas that communicate directly with systems which may contain primary coolant or containment gases, (e.g., letdown and emergency core cooling systems and external recombiners). Measurements/ analysis capabilities of the effluents at the final release point (e.g., stack) should be such that measurements of individual sources which contribute to a common release point may not be necessary. For assessing radioiodine and particulate releases, special procedures must be developed for the removal and analysis of the radioiodine/particulate sampling media (i.e., charcoal canister/ filter paper). Existing, sampling locations are expected to be adequate; however, special procedures for retrieval and analysis of the sampling media under accident conditions (e.g., high air and surface contamination and direct radiation levels) are needed.

Section 2.1.8.b (Continued)

It is intended that the monitoring capabilities called for in the interim can be accomplished with existing instrumentation or readily available instrumentation. For noble gases, modifications to existing monitoring systems, such as the use of portable high range survey instruments, set in shielded collimators so that they "see" small sections of sampling lines is an acceptable method for meeting the intent of this requirement. Conversion of the measured dose rate (mR/hr) into concentration (μCi/cc) can be performed using standard volume source calculations. A method must be developed with sufficient accuracy to quantify the iodine releases in the presence of high background radiation from noble gases collected on charcoal filters. Seismically qualified equipment and equipment meeting IEEE-279 is not required.

The licensee shall provide the following information on his methods to quantify gaseous releases of radioactivity from the plant during an accident.

(1) Noble Gas Effluents

a) System/Method description including:

i) Instrumentation to be used including range or sensitivity, energy dependence, and calibration frequency and technique,

ii) Monitoring/sampling locations, including methods to assure representative measurements and background radiation correction,

iii) A description of method to be employed to facilitate access to radiation readings. For January 1, 1980, Control room read-out is perferred: however, if impractical, in-situ readings by an individual with verbal communication with the Control Room is acceptable based on (iv) below.

iv) Capability to obtain radiation readings at least every 15 minutes during an accident.

v) Source of power to be used. If normal AC power is used, an alternate back-up power supply should be provided. If DC power is used, the source should be capable of providing continuous readout for 7 consecutive days.

b) Procedures for conducting all aspects of the measurement/ analysis including:

i) Procedures for minimizing occupational exposures.

Section 2.1.8.b (Continued)

ii) Calculational methods for converting instrument readings to release rates based on exhaust air flow and taking into consideration radionuclide spectrum distribution as function of time after shutdown.

iii) Procedures for dissemination of information.

iv) Procedures for calibration.

b. January 1, 1981 Requirements

By January 1, 1981, the licensee shall provide high range noble gas effluent monitors for each release path. The noble gas effluent monitor should meet the requirements of Table 2.1.8.b.2. The licensee shall also provide the information given in Sections 1.A.1.a.i, 1.A.1.a.ii, 1.A.1.b.ii, 1.A.1.b.iii, and 1.A.1.b.iv above for the noble gas effluent monitors.

2. Radioiodine and Particulate Effluents

a. For January 1, 1980 the licensee should provide the following:

Section 2.1.8.b (Continued)

(1) System/Method description including:

a) Instrumentation to be used for analysis of the sampling media with discussion on methods used to correct for potentially interfering background levels of radioactivity.

b) Monitoring/sampling location.

c) Method to be used for retrieval and handling of sampling media to minimize occupational exposure.

d) Method to be used for data analysis of individual radionuclides in the presence of high levels of radioactive noble gases.

e) If normal AC power is used for sample collection and analysis equipment, an alternate back-up power supply should be provided. If DC power is used, the source should be capable of providing continuous read-out for 7 consecutive days.

Section 2.1.8.b (Continued)

(2) Procedures for conducting all aspects of the measurement analysis including:

a) Minimizing occupational exposure.

b) Calculational methods for determining release rates.

c) Procedures for dissemination of information.

d) Calibration frequency and technique.

b. For January 1, 1981, the licensee should have the capability to continuously sample and provide onsite analysis of the sampling media. The licensee should also provide the information required in 2.a above.

Section 2.1.8.b (Continued)

3. Containment Radiation Monitors

Provide by January 1, 1981, two radiation monitor systems in containment which are documented to meet the requirements of Table 2.1.8.b.2. It is possible that future regulatory requirements for emergency planning interfaces may necessitate identification of different types of radionuclides in the containment air, e.g., noble gases (indication of core damage) and non-volatiles (indication of core melt). Consequently, consideration should be given to the possible installation or future conversion of these monitors to perform this function.

TABLE 2.1.8.b.1

INTERIM PROCEDURES FOR QUANTIFYING HIGH LEVEL

ACCIDENTAL RADIOACTIVITY RELEASES

- Licensees are to implement procedures for estimating noble gas and radioiodine release rates if the existing effluent instrumentation goes off scale.

- Examples of major elements of a highly radioactive effluent release special procedures (noble gas).

  - Preselected location to measure radiation from the exhaust air, e.g., exhaust duct or sample line.

  - Provide shielding to minimize background interference.

  - Use of an installed monitor (preferable) or dedicated portable monitor (acceptable) to measure the radiation.

  - Predetermined calculational method to convert the radiation level to radioactive effluent release rate.

TABLE 2.1.8.b.2

HIGH RANGE EFFLUENT MONITOR

- NOBLE GASES ONLY
- RANGE: (Overlap with Normal Effluent Instrument Range)

- UNDILUTED CONTAINMENT EXHAUST	10^{+5}	μCi/CC
- DILUTED (@10: 1) CONTAINMENT EXHAUST	10^{+4}	μCi/CC
- MARK I BWR REACTOR BUILDING EXHAUST	10^{+4}	μCi/CC
- PWR SECONDARY CONTAINMENT EXHAUST	10^{+4}	μCi/CC
- BUILDINGS WITH SYSTEMS CONTAINING PRIMARY COOLANT OR GASES	10^{+3}	μCi/CC
- OTHER BUILDINGS (E.G., RADWASTE)	10^{+2}	μCi/CC

- NOT REDUNDANT - 1 PER NORMAL RELEASE POINT
- SEISMIC - NO
- POWER - VITAL INSTRUMENT BUS
- SPECIFICATIONS - PER R.G. 1.97 AND ANSI N320-1979
- DISPLAY*: CONTINUOUS AND RECORDING WITH READOUTS IN THE TECHNICAL SUPPORT CENTER (TSC) AND EMERGENCY OPERATIONS CENTER (EOC)
- QUALIFICATIONS - NO

*Although not a present requirement, it is likely that this information may have to be transmitted to the NRC. Consequently, consideration should be given to this possible future requirement when designing the display interfaces.

TABLE 2.1.8.b.3

HIGH RANGE CONTAINMENT RADIATION MONITOR

- RADIATION: TOTAL RADIATION (ALTERNATE: PHOTON ONLY)
- RANGE:
  - UP TO 10^8 RAD/HR (TOTAL RADIATION)
  - ALTERNATE: 10^7 R/HR (PHOTON RADIATION ONLY)
  - SENSITIVE DOWN TO 60 KEV PHOTONS*
- REDUNDANT: TWO PHYSICALLY SEPARATED UNITS
- SEISMIC: PER R. G. 1.97
- POWER: VITAL INSTRUMENT BUS
- SPECIFICATIONS: PER R. G. 1.97 REV. 2 and ANSI N320-1978
- DISPLAY: CONTINUOUS AND RECORDING
- CALIBRATION: LABORATORY CALIBRATION ACCEPTABLE

*Monitors must not provide misleading information to the operators assuming delayed core damage when the 80 KEV photon Xe-133 is the major noble gas present.

Section 2.1.8.b (Continued)

HIGH RANGE CONTAINMENT MONITOR (HRCM):

Two mutually redundant HRCMs are provided at Diablo Canyon. Each monitor consists of a detector mounted inside containment about five feet above the operating deck at elevation 140, a readout module, and a strip chart recorder in the control room. The detectors are about 135 degrees apart on the containment liner to mitigate the effects of local "hot spots." The monitor units are powered from separate instrument power channels.

Each detector is a hermetically sealed stacked parallel plate, 3 terminal, guarded ionization chamber, operated in the saturated mode. The detector and its special cable are environmentally qualified to IEEE 323-1974.

Each readout has a range of 1 to 10^7 R/hr. and has high alarm, failure alarm, logarithmic scale, recorder output, and electronic system and detector checks.

The system is depicted in Figure 2.1.8.b-1.

PLANT VENT MONITORING SYSTEM:

All major, potentially radioactive, gaseous effluents from the plant pass through the plant vent. These include all ventilation exhausts (except control room and technical support center), containment purge, steam jet air

Section 2.1.8.b (Continued)

ejector, gland steam condenser exhaust, gaseous radwaste vent, gas decay tank vent, and waste evaporator vent. The only exceptions are the 10% steam dump exhausts and the blowdown tank. These are discussed at the end of this section.

Due to the varying levels of background and ability to discriminate at different dose rates, several ranges of plant vent monitors are provided.

The normal plant vent monitors detect noble gases to 10^{-4}uCi/cc, air particulates to 10^{-6}uCi/cc, and iodine to 10^{-7}uCi/cc. They are described in Section 11.4 of the Diablo Canyon FSAR.

The accident monitors are broken down into midrange and high level monitors.

The midrange monitor consists of an air particulate prefilter/grab sampler, an iodine monitor, and a noble gas monitor. The iodine monitor uses an iodine filter (either charcoal or silver zeolite) and a gamma scintillator with a single channel analyzer to monitor in the range of 10^{-8}uCi/cc to 10^{-1}uCi/cc. The noble gas monitor uses a beta scintillator to monitor in the range of 10^{-5}uCi/cc to 1uCi/cc. Both monitors have readouts in the control room which have indication, recorder output, high alarm, failure alarm, and check source operation. The unit has purge and bypass capability which can be operated either locally or from the control room. The system is depicted in Figure 2.1.8.b-2.

Section 2.1.8.b (Continued)

When the radiation level exceeds the trip limit of the midrange system, the system is automatically isolated (to minimize contamination) and the high range system is utilized. The high range system consists of a gross gamma monitor and an iodine sampler.

The gross gamma monitor consists of a shielded ion chamber mounted directly on the plant vent, a local readout at the access door to the vent ladder, and a control room readout. The readout has a range of 10^{-3}uCi/cc to 10^{+5}uCi/cc, and consists of an indicator, high alarm, failure alarm, recorder output, and electronic system and detector checks. The system is depicted in Figure 2.1.8.b-3.

Should the radiation level rise to the range covered by this monitor, it would be impossible to detect iodine presence against the noble gas background. It would also be impossible to enter the monitor area to obtain a grab sample due to the high radiation shine from the vent itself. Therefore a separate iodine grab sampler is mounted in a remote location, shielded from the plant vent and containment. The system has particulate prefilters at the isokinetic probes in the plant vent, and sample lines which run to the sampler. The sampler consists on an iodine collection cannister holder and an air moving system. A lead transfer carriage is used to remove contaminated cartridges and transport them to the laboratory for analysis. The sampler has the capability to purge the iodine cannister and the sample line, as well as the capability to purge one prefilter while the other is in operation. These purges can either

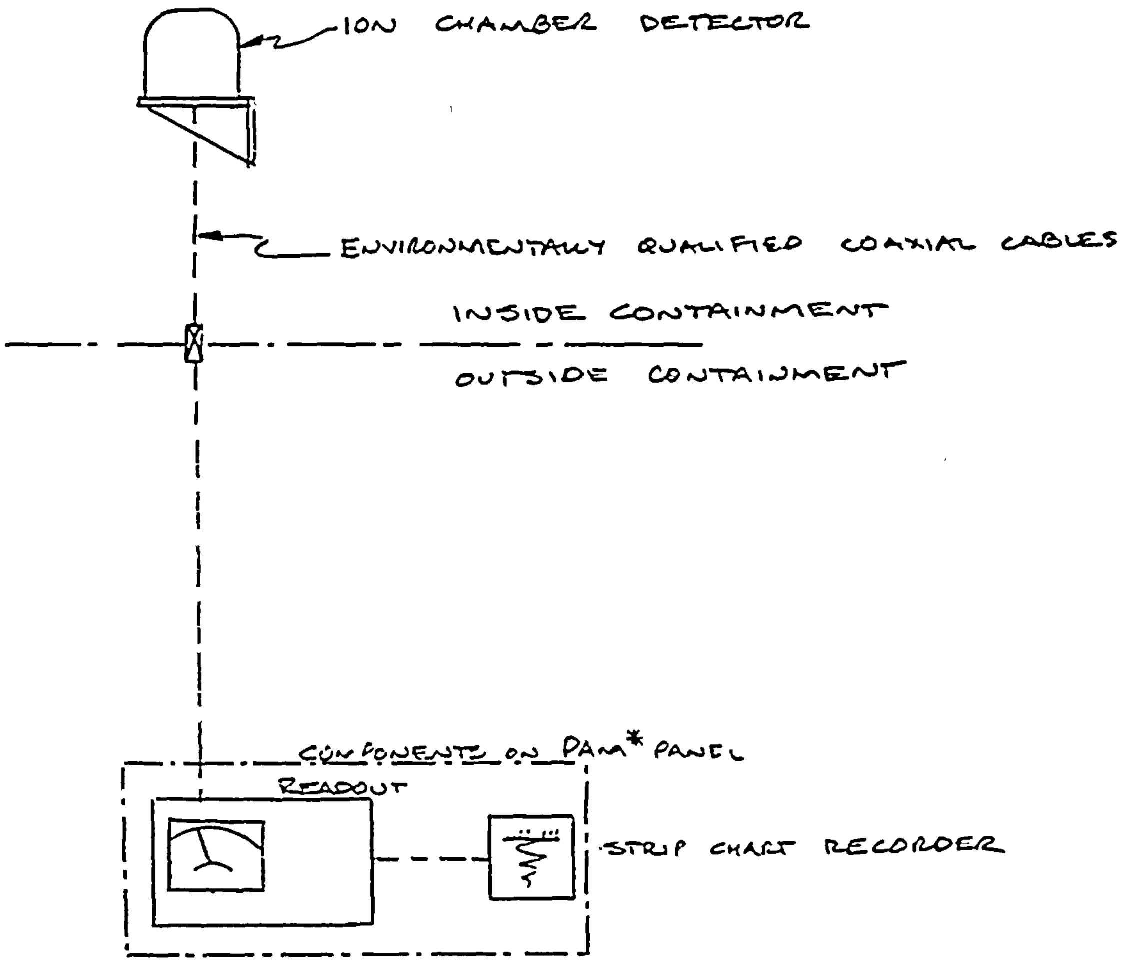
Section 2.1.8.b (Continued)

be controlled locally or from the control room. Although the system is capable of operating continuously, it is envisioned for use as a timed, grab sampler only. It is depicted in Figure 2.1.8.b-4.

ALARA monitors are provided for all sample locations. They are depicted in Figure 2.1.8.b-5.

If PG&E's supplier meets current delivery date commitments, installation is expected to be completed by September 1, 1980, except for the iodine grab sampler which will be installed by November 1, 1980. For operation prior to September 1, 1980, PG&E will provide the necessary instrumentation and methods as required by the clarifications.

The only two potential release paths not using the plant vent are the 10% atmospheric steam dumps and the steam generator blowdown tank vent. There is a radiation monitor on the blowdown tank vent, but it has never worked properly. Several design changes have been made without resolution. Work is continuing on this problem. When a solution is found, the monitoring system will be implemented on the 10% steam dumps.



READOUT HAS HIGH ALARM
AND FAILURE ALARM

*Post Accident Monitoring

ONE MONITOR IS SHOWN. THE REDUNDANT UNIT IS IDENTICAL.

Figure 2.1.8.b-1

CONTAINMENT HIGH RANGE
GROSS GAMMA MONITOR

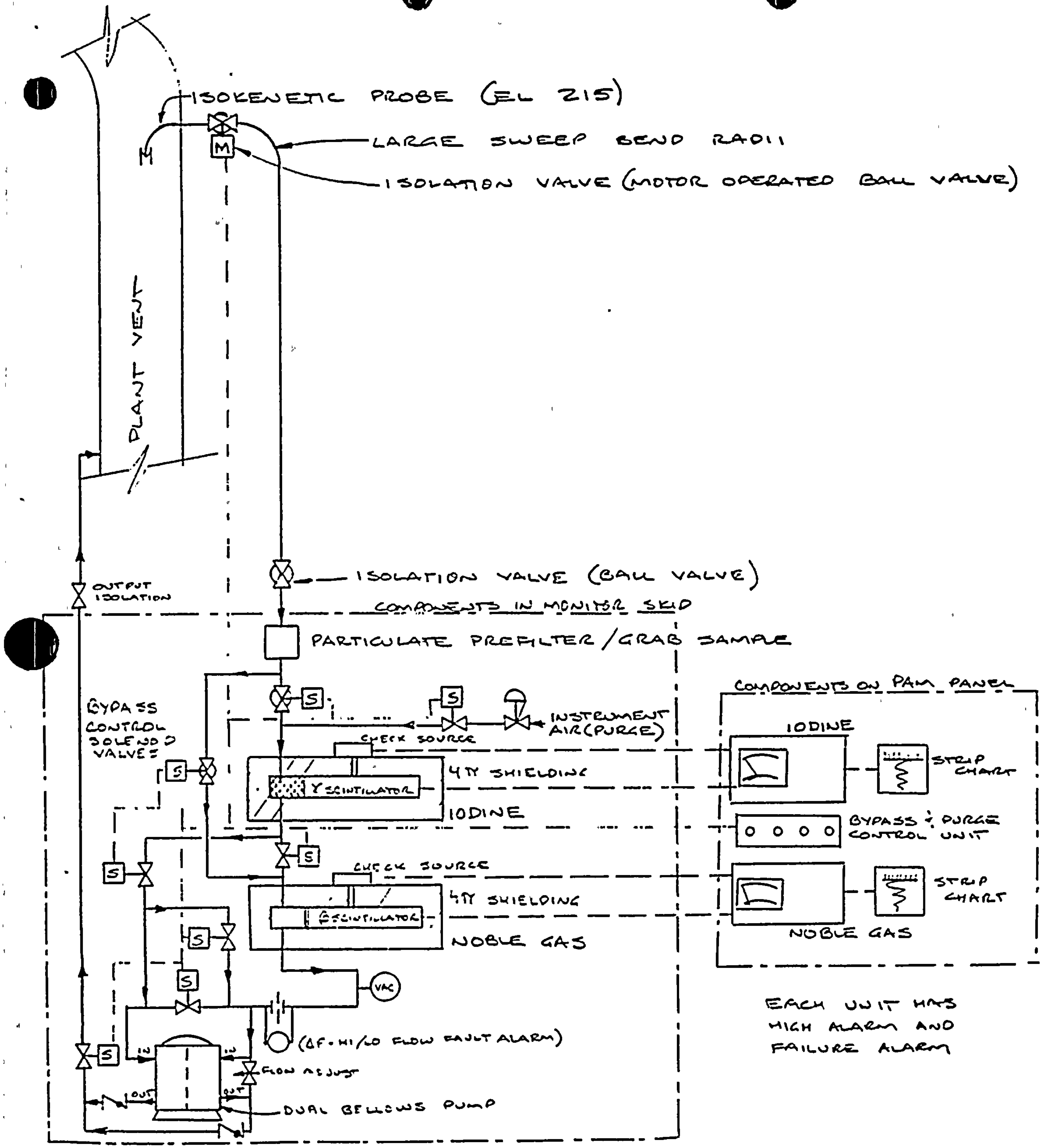


Figure 2.1.8.b-2
MID-RANGE IODINE AND NOBLE GAS PLANT VENT MONITORING SYSTEM

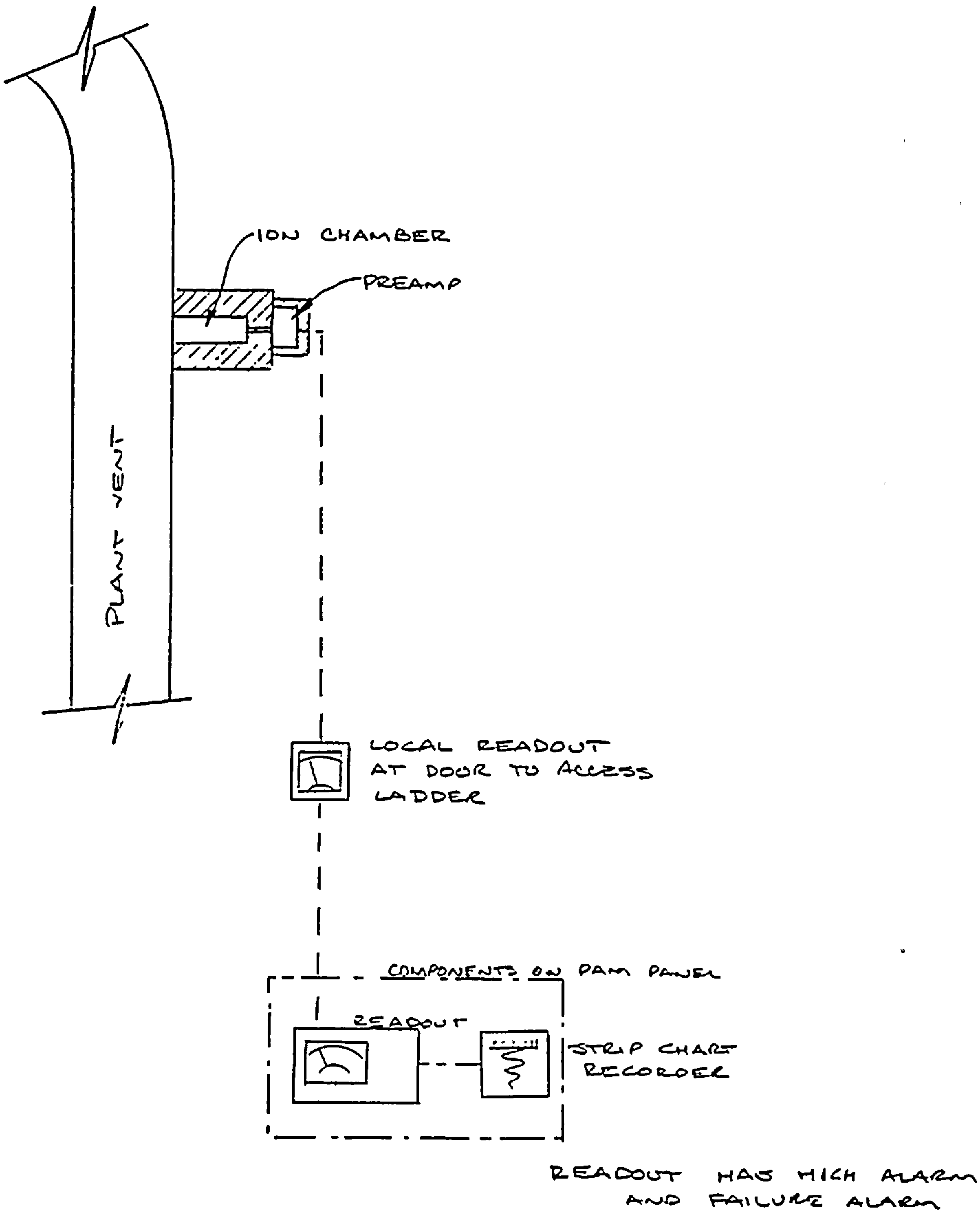


Figure 2.1.8.b-3

PLANT VENT HIGH RANGE
GROSS GAMMA MONITOR

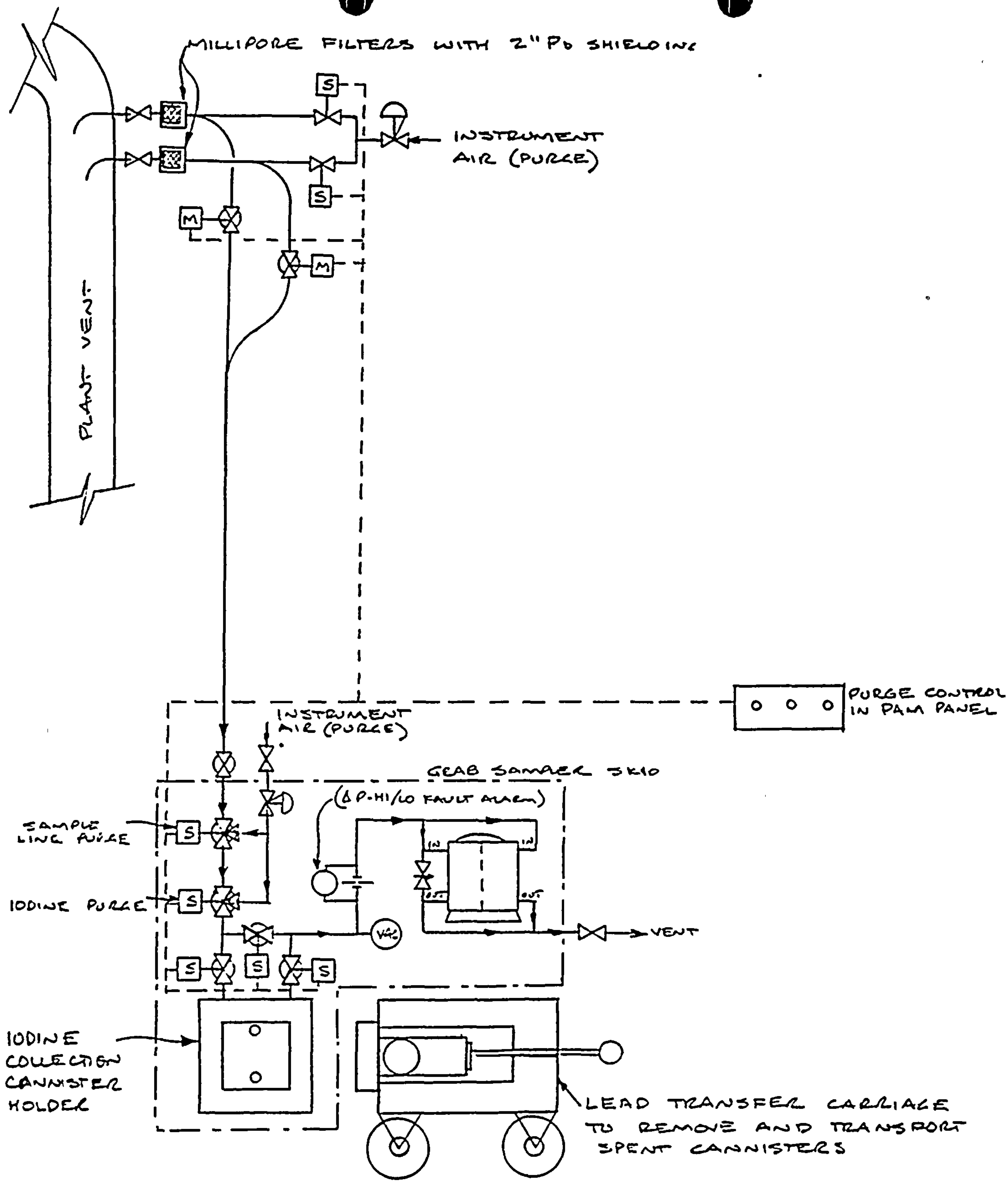
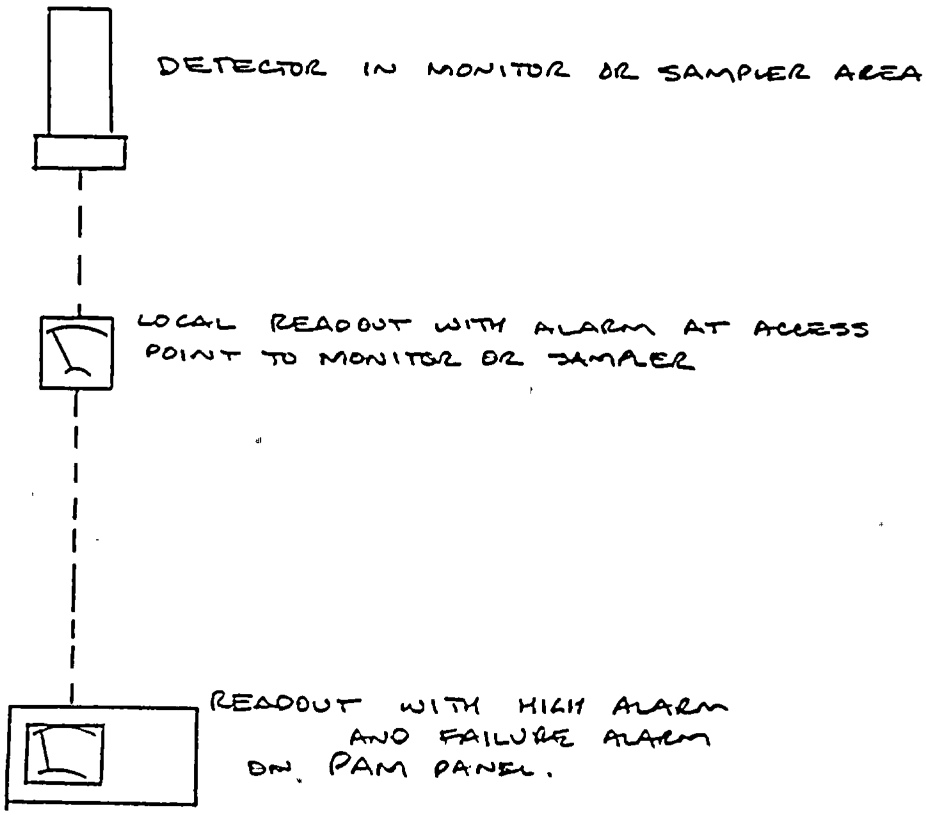


Figure 2.1.8.b-4
IODINE GRAB SAMPLER



ONE ALARA MONITOR IS USED FOR THE PLANT VENT MONITOR AREA, AND ONE IS USED FOR THE SAMPLER AREA.

THE LOCAL READOUT FOR THE PLANT VENT GROSS GAMMA MONITOR SERVES AS ALARA MONITOR FOR THAT ACCESS.

Figure 2.1.8.b-5

ALARA MONITORS FOR POST-ACCIDENT MONITOR ACCESS

Section 2.1.8.c - Improved In-Plant Iodine Instrumentation Under Accident Conditions

Task Force Position

Each licensee shall provide equipment and associated training and procedures for accurately determining the airborne iodine concentration in areas within the facility where plant personnel may be present during an accident. (Category A: Implementation shall be completed prior to OL, or January 1, 1980, whichever is later.)

CLARIFICATION

1. Use of Portable versus Stationary Monitoring Equipment

   Effective monitoring of increasing iodine levels in the buildings under accident conditions must include the use of portable instruments for the following reasons:

   a. The physical size of the auxiliary/fuel handling building precludes locating stationary monitoring instrumentation at all areas where airborne iodine concentration data might be required.

   b. Unanticipated isolated "hot spots" may occur in locations where no stationary monitoring instrumentation is located.

Section 2.1.8.c (Continued)

c. Unexpectedly high background radiation levels near stationary monitoring instrumentation after an accident may interfere with filter radiation readings.

d. The time required to retrieve samples after an accident may result in high personnel exposures if these filters are located in high dose rate areas.

2. Iodine Filters and Measurement Techniques

a. The following are short-term recommendations and shall be implemented by the licensee by January 1, 1980. The licensee shall have the capability to accurately detect the presence of iodine in the region of interest following an accident. This can be accomplished by using a portable or cart-mounted iodine sampler with attached single channel analyzer (SCA). The SCA window should be calibrated to the 365 keV of ^{131}I. A representative air sample shall be taken and then counted for ^{131}I using the SCA. This will give an initial conservative estimate of presence of iodine and can be used to determine if respiratory protection is required. Care must be taken to assure that the counting system is not saturated as a result of too much activity collected on the sampling cartridge.

Section 2.1.8.c (Continued)

b. By January 1, 1981: The licensee shall have the capability to remove the sampling cartridge to a low background, low contamination area for further analysis. This area should be ventilated with clean air containing no airborne radionuclides which may contribute to inaccuracies in analyzing the sample. Here, the sample should first be purged of any entrapped noble gases using nitrogen gas or clean air free of noble gases. The licensee shall have the capability to measure accurately the iodine concentrations present on these samples and effluent charcoal samples under accident conditions.

PG&E Response and Status

PG&E will meet the requirements of the Task Force Position and clarifications by locating an additional multichannel analyzer in a low background, low contamination area near the Technical Support Center. PG&E has 500 silver zeolite cartridges in stock for use with the analyzer to provide accurate iodine sampling. This addition to the system will also give plant personnel the capability to accomplish the iodine analysis in the event that the normal chemistry lab becomes contaminated. This additional capability will be provided by May 1, 1980. In addition, PG&E will provide, if necessary, the installation of additional area monitors with remote read out to be in compliance with forthcoming requirements.

Section 2.1.9 - Analysis of Design and Off-Normal Transients and Accidents

Task Force Position

Analyses, procedures, and training addressing the following are required:

1. Small break loss-of-coolant accidents;

2. Inadequate core cooling; and

3. Transients and accidents.

Some analysis requirements for small breaks have already been specified by the Bulletins and Orders Task Force. These should be completed. In addition, pretest calculations of some of the Loss of Fluid Test (LOFT) small break tests (schedules to start in September 1979) shall be performed as means to verify the analyses performed in support of the small break emergency procedures and in support of an eventual long-term verification of compliance with Appendix K of 10 CFR Part 50.

In the analysis of inadequate core cooling, the following conditions shall be analyzed using realistic (best-estimate) methods:

1. Low reactor coolant system inventory (two examples will be required - LOCA with forced flow, LOCA without forced flow).

Section 2.1.9 (Continued)

2. Loss of natural circulation (due to loss of heat sink).

These calculations shall include the period of time during which inadequate core cooling is approached as well as the period of time during which inadequate core cooling exists. The calculations shall be carried out in real time far enough that all important phenomena and instrument indications are included. Each case should then be repeated taking credit for correct operation action. These additional cases will provide the basis for developing appropriate emergency procedures. These calculations should also provide the analytical basis for the design of any additional instrumentation needed to provide operators with an unambiguous indication of vessel water level and core cooling adequacy (see Section 2.1.3.b in this Appendix).

The analyses of transients and accidents shall include the design basis events specified in Section 15 of each FSAR. The analyses shall include a single active failure for each system called upon to function for a particular event. Consequential failures shall also be considered. Failures of the operators to perform required control manipulations shall be given consideration for permutations of the analyses. Operator actions that could cause the complete loss of function of a safety system shall also be considered. At present, these analyses need not address passive failures or multiple system failures in the short term. In the recent analysis of small break LOCAs, complete loss of auxiliary feedwater was considered. The complete loss of auxiliary

feedwater may be added to the failures being considered in the analysis of transients and accidents if it is concluded that more is needed in operator training beyond the short-term actions to upgrade auxiliary feedwater system reliability. Similarly, the long-term, multiple failures and passive failures may be considered depending in part on staff review of the results of the short-term analyses.

The transient and accident analyses shall include event tree analyses, which are supplemented by computer calculations for those cases in which the system response to operator actions is unclear or these calculations could be used to provide important quantitative information not available from an event tree. For example, failure to initiate high-pressure injection could lead to core uncovery for some transients, and a computer calculation could provide information on the amount of time available for corrective action. Reactor simulators may provide some information in defining the event trees and would be useful in studying the information available to the operators. The transient and accident analyses are to be performed for the purpose of identifying appropriate and inappropriate operator actions relating to important safety considerations such as natural circulation, prevention of core uncovery, and prevention of more serious accidents.

Section 2.1.9 (Continued)

The information derived from the preceding analyses shall be included in the plant emergency procedures and operator training. It is expected that analyses performed by the NSSS vendors will be put in the form of emergency procedure guidelines and that the changes in the procedures will be implemented by each licensee or applicant.

In addition to the analyses performed by the reactor vendors, analyses of selected transients should be performed by the NRC Office of Research, using the best available computer codes, to provide the basis for comparisons with the analytical methods being used by the reactor vendors. These comparisons together with comparisons to data, including LOFT small break test data, will constitute the short-term verification effort to assure the adequacy of the analytical methods being used to generate emergency procedures.

(Analyses, Procedural changes, and operating training shall be provided by all operating plant licensees and applicants for operating licenses following the schedule in Table B-2 of NUREG-0578.)

PG&E Response and Status

Analyses of small break loss-of-coolant accidents, symptoms of inadequate core cooling and required actions to restore core cooling, and analysis of transient and accident scenarios including operator actions not previously analyzed are being performed on a generic basis by the Westinghouse Owners' Group, of which

PG&E is a member. The small break analyses have been completed and were reported in WCAP-9600, which was submitted to the Bulletins and Orders Task Force by the Owners' Group on June 29,1979. Incorporated in that report were guidelines that were developed as a result of small break analyses. These guidelines have been reviewed and approved by the B&O Task Force and have been presented to the Owners' Group utility representatives in a seminar held on October 16-19, 1979. Following this seminar, each utility has developed plant specific procedures and trained their personnel on the new procedures.

The work required to address the other two areas--inadequate core cooling and other transient and accident scenarios--has been performed in conjunction with schedules and requirements established by the Bulletins and Orders Task Force. Analysis related to the definition of inadequate core cooling and guidelines for recognizing the symptoms of inadequate core cooling based on existing plant instrumentation and for restoring core cooling following a small break LOCA were submitted on October 31, 1979. This analysis is a less detailed analysis than was originally proposed, and will be followed up with a more extensive and detailed analysis which will be available during the first quarter of 1980.

With respect to other transient accidents contained in Chapter 15 of the Diablo Canyon FSAR, the Westinghouse Owners' Group has performed an evaluation of the actions which occur during an event by constructing sequence of event trees for each of the non-LOCA and LOCA transients. From these event trees a

list of decision points for operator action has been prepared, along with a list of information available to the operator at each decision point. Following this, criteria have been set for credible misoperation, and time available for operator decisions have been qualitatively assessed. The information developed was then used to test Abnormal and Emergency Operating Procedures against the event sequences and determine if inadequacies exist in the AOPs and EOPs. The results of this study will be provided to the Bulletins and Orders Task Force on March 31, 1980, as required.

The Owners' Group has also provided test predictions analysis of the LOFT L3-1 nuclear small break experiment. This analysis was provided on December 15, 1979, in accordance with the schedule established mutually with the Bulletins and Orders Task Force.

Procedures identified by these analyses are presently being written. The procedures and operator training will be completed by May 1, 1980.

ACRS Comment No. 1

Containment Pressure Indication

Task Force Position

A continuous indication of containment pressure should be provided in the control room. Measurement and indication capability shall include three times the design pressure of the containment for concrete, four times the design pressure for steel, and minus five psig for all containments.

Clarification

1. The containment pressure indication shall meet the design provisions of Regulatory Guide 1.97 including qualification, redundancy, and testability.

2. The containment pressure monitor shall be installed by January 1, 1981.

PG&E Response and Status

The Diablo Canyon containment is a steel lined, reinforced concrete structure designed for a maximum pressure of 54 psig concurrent with a safe shutdown earthquake, or 70 psig without an earthquake. PG&E is in the process of adding containment pressure transmitters with a range of 0 to 200 psig connected to control room recorders in accordance with Regulatory Guide 1.97. This

ACRS Comment No. 1 (Continued)

instrumentation will compliment the existing post-accident containment pressure indicators which have a range from -5 to +55 psig and meet the requirements of Regulatory Guide 1.97, although they do not have recording capabilities.

High level containment pressure transmitters are on order and will be delivered by March 15, 1980. The instrumentation will be installed by May 1, 1980, along with appropriate control board readouts.

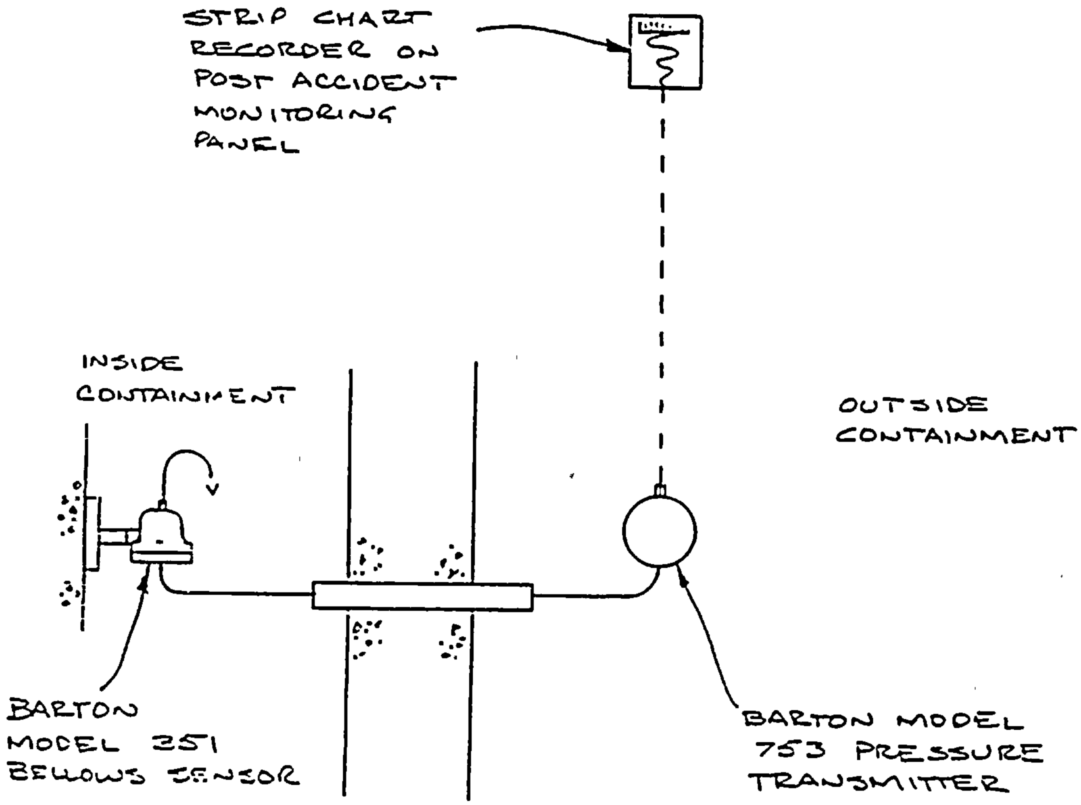


Figure ACRS.1-1

CONTAINMENT HIGH RANGE
PRESSURE INDICIATION (1 SHOWN, TYPICAL OF 2)

ACRS Comment No. 2

Containment Water Level Indication

Task Force Position

A continuous indication of containment water level shall be provided in the control room for all plants. A narrow range instrument shall be provided for PWRs and cover the range from the bottom to the top of the containment sump. A wide range instrument shall also be provided for PWRs and shall cover the range from the bottom of the containment to the elevation equivalent to a 600,000 gallon capacity. For BWRs, a wide range instrument shall be provided and cover the range from the bottom to 5 feet above the normal water level of the suppression pool.

Clarification

1. The narrow range sump level instrument shall monitor the normal containment sump level vice the containment emergency sump level.

2. The wide range containment water level instruments shall meet the requirements of the proposed revision to Regulatory Guide 1.97 (Instrumentation for Light-Water Cooled Nuclear Power Plant to Assess Plant Conditions During and Following a Accident).

ACRS Comment No. 2 (Continued)

3. The narrow range containment water level instruments shall meet the requirements of Regulatory Guide 1.89 (Qualification of Class 1E Equipment of Nuclear Power Plants).

4. The equivalent capacity of the wide range PWR level instrument has been changed from 500,000 gallons to 600,000 gallons to ensure consistency with the proposed revision to Regulatory Guide 1.97. It should be noted that this measurement capability is based on recent plant designs. For older plants with smaller water capacities, licensees may propose deviations from this requirement based on the available water supply capability at their plant.

5. The containment water level indication shall be installed by January 1, 1981.

PG&E Response and Status

Existing containment sump level instrumentation at Diablo Canyon is post-accident qualified. The monitor range is from sump bottom (elevation 88') to seven feet above the top of the three foot deep sump (elevation 98'). This level is approximately two feet above the worst calculated accident flooding (elevation 96' 1") which accounts for 535,000 gallons of water as described in FSAR Section 15.4.1. The accuracy of the loop is ±2.5%, or ±3 inches. The bottom of the reactor cavity sump is at elevation 60' 4". Therefore, a

ACRS Comment No. 2 (Continued)

wide-range indicator as required would cover from 60' 4" to something less than 96' 1". Wide-range monitors with a 37' 8" span from the sump bottom to the top of the existing narrow-range monitors will be added as will recorders in the control room. The equipment will comply with Regulatory Guide 1.97.

Figure ACRS.2-1 describes the containment water level indication system. Mutually redundant loops are provided which are wired and separated in accordance with IEEE Class IE requirements. Each loop utilizes a Barton Model 764 differential pressure transmitter which, although qualified for submergence, is mounted above maximum flood level. A sealed capillary sensing leg connects each transmitter to a Barton Model 351 bellows sensor mounted in the reactor cavity sump - the lowest point in containment (wide range) or the containment recirculate sump (narrow range). The other leg of each transmitter is vented.

The wide range recorders are mounted on the Post Accident Monitoring Panel, and the narrow range indicators are mounted on the Main Control Board. The narrow range indicators are used when operating pumps for recirculation and are located above the respective recirculation control switches.

The existing sump level instrumentation meets the requirements for narrow range, except that the level range is from the bottom of the recirculation sump to the highest level used for the recirculation mode. Since the operator is using this instrumentation for recirculation control, it is not advisable to reduce the range. A wide range sump level instrument will be purchased by May 1, 1980. The instrumentation will be installed by January 1, 1981.

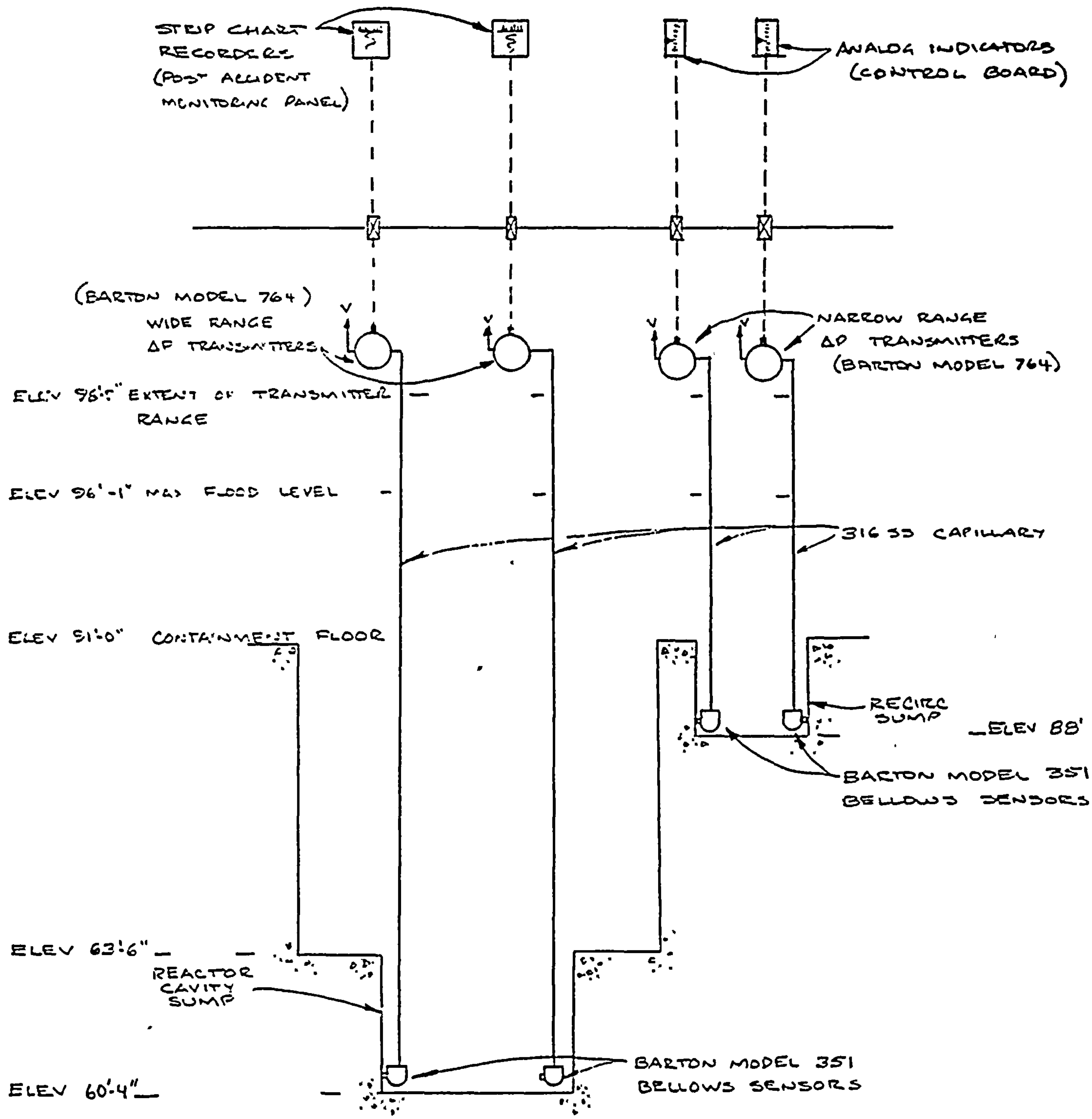


Figure ACRS.2-1

CONTAINMENT WATER LEVEL INDICATION
(DIAGRAMMATIC PRESENTATION - NOT AN ACTUAL LAYOUT)

ACRS Comment No. 3

Containment Hydrogen Indication

Task Force Position

A continuous indication of hydrogen concentration in the containment atmosphere shall be provided in the control room. Measurement capability shall be provided over the range of 0 to 10% hydrogen concentration under both positive and negative ambient pressure.

Clarification

1. The containment hydrogen indication shall meet the design provisions of Regulatory Guide 1.97 including qualification, redundancy, and testability.

2. The containment hydrogen indication shall be installed by January 1, 1981.

ACRS Comment No. 3 (Continued)

PG&E Response and Status

The ability to monitor containment hydrogen presently exists. These devices are not redundant, are not seismically nor environmentally qualified, and do not readout in the control room and therefore do not meet the requirements of Regulatory Guide 1.97. Instrumentation required to meet the requirements will be ordered by March 15, 1980. The monitors will be installed by January 1, 1981, along with appropriate control board readouts.

ACRS Comment No. 4

Reactor Coolant System Venting

Task Force Position

Each applicant and licensee shall install reactor coolant system and reactor vessel head high point vents remotely operated from the control room. Since these vents form a part of the reactor coolant pressure boundary, the design of the vents shall conform to the requirements of Appendix A to 10 CFR Part 50 General Design Criteria. In particular, these vents shall be safety grade, and shall satisfy the single failure criterion and the requirements of IEEE-279 in order to ensure a low probability of inadvertent actuation.

Each applicant and licensee shall provide the following information concerning the design and operation of these high point vents:

1. A description of the construction, location, size, and power supply for the vents along with results of analyses of loss-of-coolant accidents initiated by a break in the vent pipe. The results of the analyses should be demonstrated to be acceptable in accordance with the acceptance criteria of 10 CFR 50.46.

ACRS Comment No. 4 (Continued)

2. Analyses demonstrating that the direct venting of noncondensable gases with perhaps high hydrogen concentrations does not result in violation of combustible gas concentration limits in containment as described in 10 CFR Part 50.44, Regulatory Guide 1.7 (Rev. 1), and Standard Review Plan Section 6.2.5.

3. Procedural guidelines for the operators' use of the vents. The information available to the operator for initiating or terminating vent usage shall be discussed.

Clarification

A. General

1. The two important safety functions enhanced by this venting capability are core cooling and containment integrity. For events within the present design basis for nuclear power plants, the capability to vent non-condensible gases will provide additional assurance of meeting the requirements of 10 CFR 50.46 (LOCA criteria) and 10 CFR 50.44 (containment criteria for hydrogen generation). For events beyond the present design basis, this venting capability will substantially increase the plant's ability to deal with large quantities of non-condensible gas without the loss of core cooling or containment integrity.

ACRS Comment No. 4 (Continued)

2. Procedures addressing the use of the RCS vents are required by January 1, 1981. The procedures should define the conditions under which the vents should be used as well as the conditions under which the vents should not be used. The procedures should be based on the following criteria: (1) assurance that the plant can meet the requirements of 10 CFR 50.46 and 10 CFR 50.44 for Design Basis Accidents; and (2) a substantial increase in the plants ability to maintain core cooling and containment integrity for events beyond the Design Basis.

B. BWR Design Considerations

1. Since the BWR owners group has suggested that the present BWR designs inherent capability of venting, this question relates to the capability of existing systems. The ability of these systems to vent the RCS of non-condensible gas must be demonstrated. In addition the ability of these systems to meet the same requirements as the PWR vent systems must be documented. Since there are important differences among BWR's, each licensee should address the specific design features of his plant.

2. In addition to reactor coolant system venting, each BWR licensee should address the ability to vent other systems such as the isolation condenser, which may be required to maintain adequate core cooling. If the production of a large amount of non-condensible gas would cause the loss of function of such a system, remote venting of that system is required. The qualifications of such a venting system should be the same as that required for PWR venting systems.

C. PWR Vent Design Considerations

1. The location for PWR Vents are as follows:

   a. Each PWR licensee should provide the capability to vent the reactor vessel head.

   b. The reactor vessel head vent should be capable of venting non-condensible gas from the reactor vessel hot legs (to the elevation of the top of the outlet nozzle) and cold legs (through head jets and other leakage paths). Additional venting capability is required for those portions of each hot leg which can not be vented through the reactor vessel head vent. The NRC recognizes that it is impractical to vent each of the many thousands of tubes in a U-tube steam generator. However, we believe that a

ACRS Comment No. 4 (Continued)

procedure can be developed which assures that sufficient liquid or steam can enter the U-tube region so that decay heat can be effectively removed from the reactor coolant system. Such a procedure is required by January 1981.

c. Venting of the pressurizer is required to assure its availability for system pressure and volume control. These are important considerations especially during natural circulation.

2. The size of the reactor coolant vents is not a critical issue. The desired venting capability can be achieved with vents in a fairly large range of sizes. The criteria for sizing a vent can be developed in several ways. One approach, which we consider reasonable, is to specify a volume of non-condensible gas to be vented and a venting time i.e, a vent capable of venting a gas volume of 1/2 the RCS in one hour. Other criteria and engineering approaches should be considered if desired.

3. Where practical, the RCS vents should be kept smaller than the size corresponding to the definition of a LOCA (10 CFR 50 Appendix A). This will minimize the challenges to the ECCS since the inadvertent opening of a vent smaller than the LOCA definition would not require ECCS actuation although it may result in leakage beyond Technical

ACRS Comment No. 4 (Continued)

Specification Limits. On PWRs the use of new or existing valves which are larger than the LOCA definition will require the addition of a block valve which can be closed remotely to terminate the LOCA resulting from the inadvertent opening of the vent.

4. An indication of valve position should be provided in the control room.

5. Each vent should be remotely operable from the control room.

6. Each vent should be seismically qualified.

7. The requirements for a safety grade system is the same as the safety grade requirement on other Short Term Lessons Learned items, that is, it should have the same qualifications as were accepted for the reactor protection system when the plant was licensed. The exception to this requirement is that we do not require redundant valves at each venting location. Each vent must have its power supplied from an emergency bus. A degree of redundancy should be provided by powering different vents from different emergency buses.

8. For systems where a block valve is required, the block valve should have the same qualifications as the vent.

ACRS Comment No. 4 (Continued)

9. Since the RCS vent system will be part of the reactor coolant systems boundary, efforts should be made to minimize the probability of an inadvertent actuation of the system. Removing power from the vents is one step in the direction. Other steps are also encouraged.

10. Since the generation of large quantities of non-condensible gas could be associated with substantial core damage, venting to atmosphere is unacceptable because of the associated released radioactivity. Venting into containment is the only presently available alternative. Within containment those areas which provide good mixing with containment air are preferred. In addition, areas which provide for maximum cooling of the vented gas are preferred. Therefore the selection of a location for venting should take advantage of existing ventilation and heat removal systems.

11. The inadvertent opening of an RCS vent must be addressed. For vents smaller than the LOCA definition, leakage detection must be sufficient to identify the leakage. For vents larger than the LOCA definition, an analysis is required to demonstrate compliance with 10 CFR 50.46.

ACRS Comment No. 4 (Continued)

PG&E Response and Status

A head vent system meeting the requirements of this comment will be installed at Diablo Canyon. The system design is being purchased from the nuclear steam supply system manufacturer, Westinghouse. The remotely operated valves, which are the item controlling the schedule, have been on order for several months and will be delivered in September, 1980.

The head vent system will use the existing manual vent connection to the reactor head, which is three-quarter inch diameter. Four one-inch electrically operated valves meeting the requirements of IEEE-323-74 and IEEE-344-75 will be installed in a series-parallel arrangement satisfying the single failure criterion. These valves will be operated from and have position indicated in the control room. They will fail closed. A flow diagram showing the arrangement schematically is attached. A three-eights inch diameter orifice will be installed in each of the parallel vent lines between the existing manual valve and the new electrically operated valves. The new valves, orifices, and connecting piping will be supported from the head lifting structure and will be qualified seismically for this location. Instrumentation and control will meet the requirements of IEEE-279.

The orifices in the vent lines would restrict the flow thru a postulated break in the new vent system to that which normal makeup can maintain. This would preclude the possibility of the occurrence of a small break loss of coolant

accident in the head vent system. (A rupture in the existing manual head vent line is covered by the small break LOCA discussion in Chapter 15 of the FSAR and by Westinghouse WCAP-9600 on the same subject which has been submitted to the NRC staff by Westinghouse.)

In a Westinghouse reactor coolant system, the head vent will also serve to remove non-condensible gases from the "hot leg" and "cold leg" reactor coolant system piping. Should the existence of non-condensible gases in the tubes of a steam generator be suspected, it is proposed to "bump" the related reactor coolant pump to move the gases to the reactor vessel, where the gases may be removed by the head vent system.

Equipment and piping for Reactor Coolant System venting will be installed, procedures finalized and operator training completed by January 1, 1981. Preliminary calculations confirm that a gas volume greater than one-half the reactor coolant system volume could be vented by either train in less than one hour. On the other hand, the procedure will call for venting to be terminated before the hydrogen concentration in the containment could exceed 4% under the most adverse assumptions. Venting would not be continued until the actual containment hydrogen concentration achieved had been determined.

The head vent system described would vent into the area immediately surrounding the reactor vessel head. This area is swept by ventilating air flow and gases released would be mixed into the containment volume by this air flow.

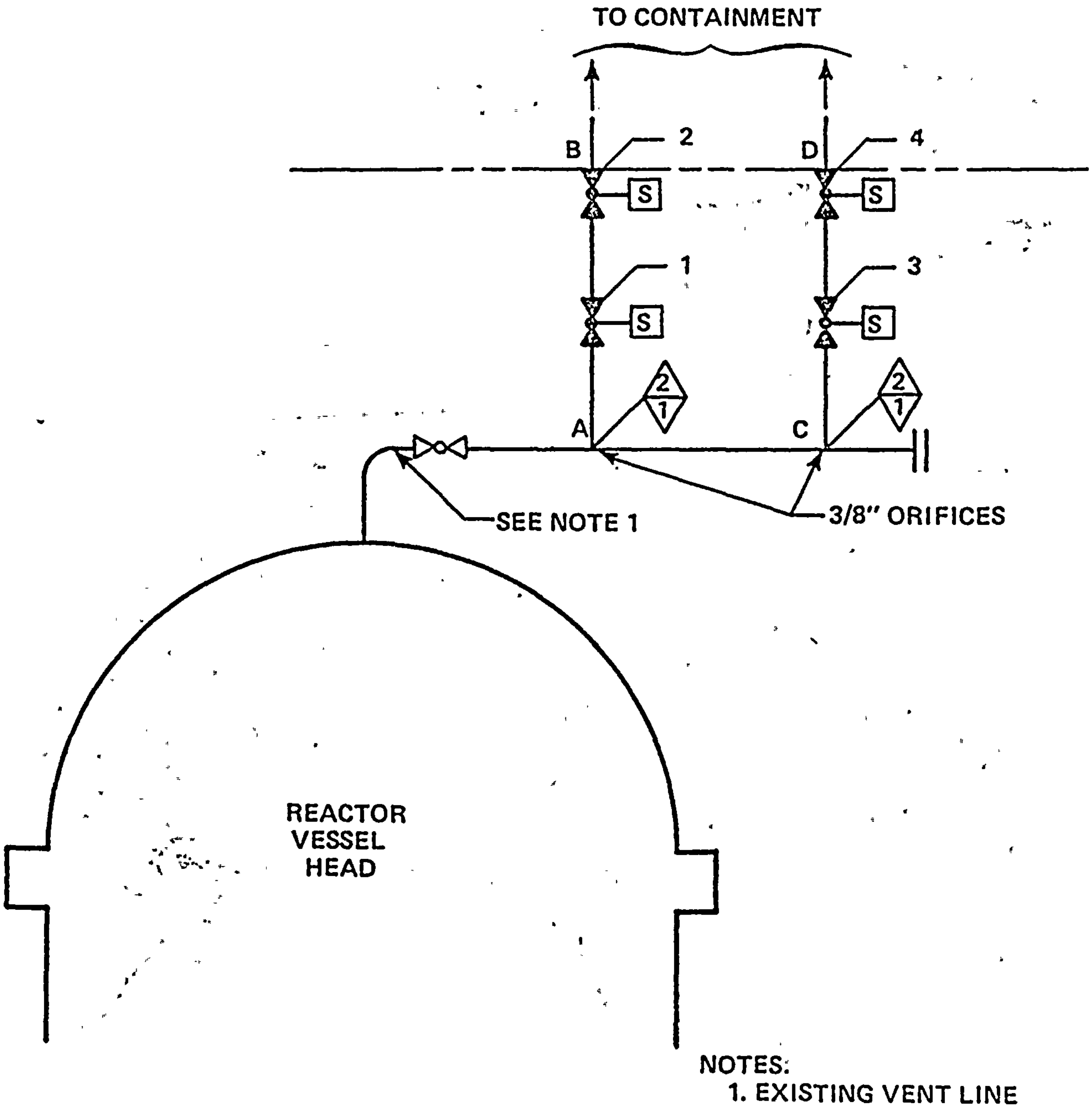
ACRS Comment No. 4 (Continued)

Consideration has been given to piping the vented gases to other locations, for example, the pressurizer relief tank. At this time, the identification or advantage of such an alternate vent release location is not known. However, should an alternate location be required in the future, an extension of the described system could be added.

Inadvertent opening of the head vent system would be detected by the valve position lights in the control room and by the leakage monitoring system which is described in Section 5.2.4 of the FSAR.

Venting of the pressurizer, should that be necessary, can be carried out by the use of the pressurizer power operated relief valves, which at Diablo Canyon are seismically qualified and have qualified control circuits.

Procedures for the use of the vent will be developed as detailed design of the system progresses. The procedures will provide guidelines for initiating and terminating usage of the head vent and will address the information available to the operator to use the system. System installation will be completed by January 1, 1981.



FLOW DIAGRAM OF THE REACTOR VESSEL HEAD VENT SYSTEM

Section 2.2.1.a - Shift Supervisor's Responsibilities

Task Force Position

1. The highest level of corporate management of each licensee shall issue and periodically reissue a management directive that emphasizes the primary management responsibility of the Shift Supervisor for safe operation of the plant under all conditions on his shift and that cleary establishes his command duties.

2. Plant procedures shall be reviewed to assure that the duties, responsibilities, and authority of the Shift Supervisor and control room operators are properly defined to effect the establishment of a definite line of command and clear delineation of the command decision authority of the shift supervisor in the control room relative to other plant management personnel. Particular emphasis shall be placed on the following:

   a. The responsibility and authority of the Shift Supervisor shall be to maintain the broadest perspective of operational conditions affecting the safety of the plant as a matter of highest priority at all times when on duty in the control room. The idea shall be reinforced that the shift supervisor should not become totally involved in any single operation in times of emergency when multiple operations are required in the control room.

Section 2.2.1.a (Continued)

b. The shift supervisor, until properly relieved, shall remain in the control room at all times during accident situations to direct the activities of control room operators. Persons authorized to relieve the shift supervisor shall be specified.

c. If the shift supervisor is temporarily absent from the control room during routine operations, a lead control room operator shall be designated to assume the control room command function. These temporary duties, responsibilities, and authority shall be clearly specified.

3. Training programs for shift supervisors shall emphasize and reinforce the responsibility for safe operation and this management function the shift supervisor is to provide for assuring safety.

4. The administrative duties of the shift supervisor shall be reviewed by the senior officer of each utility responsible for plant operations. Administrative functions that detract from or are subordinate to the management responsibility for assuring the safe operation of the plant shall be delegated to other operations personnel not on duty in the control room. (Category A: Implementation complete prior to OL or January 1, 1980, whichever is later.)

Section 2.2.1.a (Continued)

CLARIFICATION

This Table provides clarification to the above position.

SHIFT SUPERVISOR RESPONSIBILITY (2.2.1.a)

NUREG-0578 POSITION (POSITION NO.)	CLARIFICATION
Highest Level of Corporate Management (1.)	V.P. for Operations
Periodically Reissue (1.)	Annual Reinforcement of Company Policy
Management Direction (1.)	Formal Documentation of Shift Personnel, All Plant Management, Copy to IE Region
Properly Defined (2.0)	Defined in Writing in a Plant Procedure
Until Properly Relieved (2.B)	Formal Transfer of Authority, Valid SRO License, Recorded in Plant Log
Temporarily Absent (2.C)	Any Absence
Control Room Defined (2.C)	Includes Shift Supervisor Office Adjacent to the Control Room
Designated (2.C)	In Administrative Procedures
Clearly Specified	Defined in Administrative Procedures
SRO Training	Specified in ANS 3.1 (Draft) Section 5.2.1.8
Administrative Duties (4.)	Not Affecting Plant Safety
Administrative Duties Reviewed (4.)	One Same Interval as Reinforcement: i.e., Annual by VP for Operations

Section 2.2.1.a (Continued)

PG&E Response and Status

Prior to OL and at annual intervals thereafter, the Vice President - Nuclear Power Generation will issue a management directive that emphasizes the primary management responsibility of the Shift Foreman for safe operation of the plant under all conditions on his shift and that clearly establishes his command duties as defined by the Administrative Procedures described below.

Administrative Procedures are established which define the responsibilities and authorities of the Shift Foreman, and establish lines of succession. However, these procedures will be revised to more explicitly address the Task Force concerns, particularly those dealing with retaining breadth of perspective of operational conditions affecting safety and remaining in the control room under accident conditions to direct control room operational activities. These new provisions, as are all applicable administrative requirements, will be incorporated into the training program for the Shift Foreman.

A list of administrative duties of the Shift Foreman has been provided to the Vice President - Nuclear Power Generation, for his review and action.

A review of the administrative procedures defining the Shift Foreman's (shift supervisor) responsiblities is under way. The review includes the subject of chain of command in the event of temporary absence of the Shift Foreman.

Section 2.2.1.a (Continued)

A review of the administrative procedures defining the shift supervisors' responsiblities is under way. The review includes the subject of chain of command in the event of temporary absence of the shift supervisor. These procedures will be completed and approved by March 1, 1980.

Section 2.2.1.b - Shift Technical Advisor

Task Force Position

Each licensee shall provide an on-shift technical advisor to the shift supervisor. The shift technical advisor may serve more than one unit at a multi-unit site if qualified to perform the advisor function for the various units.

The shift technical advisor shall have a bachelor's degree or equivalent in a scientific or engineering discipline and have received specific training in the response and analysis of the plant for transients and accidents. The shift technical advisor shall also receive training in plant design and layout, including the capabilities of instrumentation and controls in the control room. The licensee shall assign normal duties to the shift technical advisors that pertain to the engineering aspects of assuring safe operations of the plant including the review and evaluation of operating experience. (Shift Technical Advisor on duty - Category A: Implementation shall be completed prior to OL, or January 1, 1980, whichever is later. Complete training for shift technical advisor - Category B: Implementation shall be completed by January 1, 1981.)

Section 2.2.1.b (Continued)

Clarification

1. Due to the similarity in the requirements for dedication to safety, training and onsite location and the desire that the accident assessment function be performed by someone whose normal duties involve review of operating experiences, our preferred position is that the same people perform the accident and operating experience assessment functions. The performance of these two functions may be split if it can be demonstrated the persons assigned the accident assessment role are aware, on a current basis, of the work being done by those reviewing operating experience.

2. To provide assurance that the STA will be dedicated to concern for the safety of the plant, our position has been that STA's must have a clear measure of independence from duties associated with the commercial operation of the plant. This would minimize possible distractions from safety judgments by the demands of commercial operations. We have determined that, while desirable, independence from the operations staff of the plant is not necessary to provide this assurance. It is necessary, however, to clearly emphasize the dedication to safety associated with the STA position both in the STA job description and in the personnel filling this position. It is not acceptable to assign a person, who is normally the immediate supervisor of the shift supervisor to STA duties as defined herein.

Section 2.2.1.b (Continued)

3. It is our position that the STA should be available within 10 minutes of being summoned and therefore should be onsite. The onsite STA may be in a duty status for periods of time longer than one shift, and therefore asleep at some times, if the ten minute availability is assured. It is preferable to locate those doing the operating experience assessment onsite. The desired exposure to the operating plant and contact with the STA (if these functions are to be split) may be able to be accomplished by a group, normally stationed offsite, with frequent onsite presence. We do not intend, at this time, to specify or advocate a minimum time onsite.

4. The implementation schedule for the STA requirements is to have the STA on duty by January 1, 1980, and to have STAs, who have all completed training requirements, on duty by January 1, 1981. While minimum training requirements have not been specified for January 1, 1980, the STAs on duty by that time should enhance the accident and operating experience assessment function at the plant.

PG&E Response and Status

PG&E believes that its present shift operating organization, augmented by on-call nuclear engineers, represents a suitable alternative for accomplishing the objectives of the Task Force position with respect to the control room accident assessment function.

Section 2.2.1.b (Continued)

PG&E's Senior Reactor Operator Licensing Training Program provides the Shift Foremen with the same training as is received by our nuclear engineers. This training provides them with a broader knowledge of plant design, reactor core cooling and transient and accident analysis than is currently required by NRC operator licensing requirements. Continuing, additional training is being provided to our Shift Foremen and nuclear engineers based on evaluations of the lessons learned from the TMI accident being performed by the Company, industry and governmental groups. PG&E is actively supporting the development of the Institute of Nuclear Power Operation. We expect that the Institute will provide programs for enhanced technical training for on-shift supervisory personnel.

A formal on-call system for the Diablo Canyon Power Plant is used on weekends, holidays, or in any abnormal situation where the Plant Superintendent considers it necessary. In addition, trips away from the plant and vacations by key supervisory personnel are scheduled so that the necessary number of supervisory and technical personnel are available to respond to an emergency.

The individuals on-call include a nuclear engineer on the plant staff or higher level plant staff person with a nuclear engineering background. There are ten positions on the plant staff normally filled by personnel who possess both a broad technical knowledge of the plant design and operation and possess a background in nuclear engineering. All of these individuals either possess or will obtain an NRC Senior Operator's License.

Section 2.2.1.b (Continued)

The on-call nuclear engineer is available to assist the Shift Foreman as requested. In addition, a nuclear engineer is in the control room for all approaches to critical and at all times during physics testing and refueling operations. It has been PG&E's policy to deploy nuclear engineers in this manner ever since initial startup of Humboldt Bay Unit No. 3 in the early 1960s. Recall of on-call personnel is effected through commercial telephone or through PG&E's private radio system using paging devices. The paging devices are actuated and are capable of receiving a voice message from the plant control room.

With respect to the Task Force position concerning the operating experience assessment function, PG&E has always considered this to be an extremely important function. Prior to the TMI accident, we have believed that our organization and procedures for accomplishing this function were adequate. As a result of our reassessment of requirements of this function, we are adding additional personnel to the staff of the Supervisor of Operations in the plant organization including a Senior Nuclear Engineer and an additional member for the training staff. In addition, a fifth shift of operators will be added to provide required shift coverage for our expanded training program. One of the principal functions of the Senior Nuclear Engineer will be that of assuring that plant and industry operating experience is imparted to shift operations supervision in a timely manner.

Section 2.2.1.b (Continued)

The Shift Technical Advisor employment positions have been identified and authorized by PG&E. PG&E is attempting to locate six qualified individuals to hire for these positions. Every effort will be made to fill these positions as rapidly as possible. In any event, these positions will be filled and the personnel trained to allow operations by May 1, 1980. The STA job description is as follows:

Basic Responsibility

To ensure increased plant safety by providing an accident assessment function in the control room at all times and to provide on-shift operating experience assessment capability.

Specific Duties

1. Provides sound technical advice to the Shift Foreman during transient or accident conditions.

2. Evaluates plant equipment performance and makes recommendations for improvement.

3. Reviews operating experience and equipment performance at other nuclear plants.

4. Ensures that operating and emergency procedures are revised and operators trained based on his review of operating experience.

Section 2.2.1.b (Continued)

5. Provides assistance to the Shift Foreman in reviewing surveillance test results.

6. Assists the Shift Foreman in first aid and fire protection training.

7. Advises the Shift Foreman on the plant Technical Specifications.

8. Conducts operator training as specified by the Training Coordinator when his shift is on a training assignment.

9. Assist the Shift Foreman in the preparation of Special Work Permits.

10. May perform independent audits of operating practices and procedures.

11. Provides a critique of fire and other emergency drills.

12. Provides liaison between the operating and technical groups at the plant.

Relationships

1. Reports directly to the Shift Foreman and is responsible and accountable to him in his advisory capacity.

Section 2.2.1.b (Continued)

2. Reports indirectly to the Senior Power Production Engineer (Operations Engineer) and is responsible and accountable to him in administrative and technical matters.

3. Maintains close working relations with the Maintenance and Technical Departments.

4. At the direction of the Shift Foreman or Operations Engineer, confers with other departments and agencies both inside and outside the Company.

<u>Authorities</u>

1. To carry out his assigned duties.

2. To take action in an emergency to the full extent justified. Such action will be reported to the Shift Foreman and Operations Engineer as soon as practical.

3. To consult with and/or advise other plant supervisors on activities related to plant operations.

Section 2.2.1.c - Shift and Relief Turnover Procedures

Task Force Position

The licensees shall review and revise as necessary the plant procedure for shift and relief turnover to assure the following:

1. A checklist shall be provided for the oncoming and offgoing control room operators and the oncoming shift supervisor to complete and sign. The following items, as a minimum, shall be included in the checklist:

    a. Assurance that critical plant parameters are within allowable limits (parameters and allowable limits shall be listed on the checklist).

    b. Assurance of the availability and proper alignment of all systems essential to the prevention and mitigation of operational transients and accidents by a check of the control console (what to check and criteria for acceptance status shall be included on the checklist);

    c. Identification of systems and components that are in a degraded mode of operation permitted by the Technical Specifications. For such systems and components, the length of time in the degraded mode shall be compared with the Technical Specifications action statement (this shall be recorded as a separate entry on the checklist).

Section 2.2.1.c (Continued)

2. Checklists or logs shall be provided for completion by the offgoing and oncoming auxiliary operators and technicians. Such checklists or logs shall include any equipment under maintenance of test that by themselves could degrade a system critical to the prevention and mitigation of operational transients and accidents or initiate an operational transient (what to check and criteria for acceptable status shall be included on the checklist); and

3. A system shall be established to evaluate the effectiveness of the shift and relief turnover procedure (for example, periodic independent verification of system alignments). (Category A: Implementation shall be completed prior to OL, or January 1, 1980, whichever is later.)

PG&E Response and Status

Existing shift and relief turnover procedures will be revised to incorporate the recommendations of the Task Force.

In addition, a system will be established to evaluate the effectiveness of the procedures which involves periodic independent verification of system alignments by the senior members of the Supervisor of Operations' staff (Relief Shift Supervisor, Senior Power Production Engineer (Operations)). This will be accomplished prior to initial fuel loading which is the earliest time these procedures are needed.

These procedures will be completed and approved by April 1, 1980.

Section 2.2.2.a - <u>Control Room Access</u>

<u>Task Force Position</u>

The licensee shall make provisions for limiting access to the control room to those individuals responsible for the direct operation of the nuclear power plant (e.g., operations supervisor, shift supervisor, and control room operators), to technical advisors who may be requested or required to support the operation, and to predesignated NRC personnel. Provisions shall include the following:

1. Develop and implement an administrative procedure that establishes the authority and responsibility of the person in charge of the control room to limit access.

2. Develop and implement procedures that establish a clear line of authority and responsibility in the control room in the event of an emergency. The line of succession for the person in charge of the control room shall be established and limited to persons possessing a current senior reactor operator's license. The plan shall clearly define the lines of communication and authority for plant management personnel not in direct command of operations, including those who report to stations outside of the control room. (Category A: Implementation shall be completed prior to OL, or January 1, 1980, whichever is later.)

Section 2.2.2.a - Control Room Access (Continued)

PG&E Response and Status

An Administrative Procedure will be written to formalize existing policies which allow the Shift Foreman to restrict access to the control room during both normal operations and emergencies.

Existing Emergency Procedures establish authority and responsibilities in the control room in the event of an emergency, and provide for succession for the person in charge of the plant operations to possess a current NRC Senior Operator's License. Existing procedures also specify the locations to which all on-site personnel are to report in the event of an emergency. However, these procedures will be revised to more explicitly address the Task Force recommendations, and to incorporate the changes necessitated by the establishment of the On-Site Technical and Operational Support Centers. These procedures will be developed and implemented prior to fuel loading which is the earliest time such procedures are needed.

These procedures will be completed and approved by April 1, 1980.

Section 2.2.2.b - Onsite Technical Support Center

Task Force Position

Each operating nuclear power plant shall maintain an onsite technical support center separate from and in close proximity to the control room that has the capability to display and transmit plant status to those individuals who are knowledgeable of and responsible for engineering and management support of reactor operations in the event of an accident. The center shall be habitable to the same degree as the control room for postulated accident conditions. The licensee shall revise his emergency plans as necessary to incorporate the role and location of the technical support center. (Category A: Establish center prior to OL, or January 1, 1980, whichever is later.)

Task Force Position (Errata No. 9)

Records that pertain to the as-built conditions and layout of structures, systems and components shall be stored and filed at the site and accessible to the technical support center under emergency conditions. Examples of such records include system descriptions, general arrangement drawings, piping and instrument diagrams, piping system isometrics, electrical schematics, wire and cable lists, and single line electrical diagrams. It is not the intent that all records described in ANSI N45.2.9-1974 be stored and filed at the site and accessible to the technical support center under emergency conditions; however, as stated in that standard, storage systems shall provide for accurate retrieval of all pertinent information without undue delay. (Category A: Implementation shall be completed prior to OL, or January 1, 1980, whichever is later.)

Section 2.2.2.b (Continued)

Clarification

1. By January 1, 1980, each licensee should meet items A-G that follow. Each licensee is encouraged to provide additional upgrading of the TSC (items 2-10) as soon as practical, but no later than January 1, 1981.

   a. Establish a TSC and provide a complete description,

   b. Provide plans and procedures for engineering/management support and staffing of the TSC,

   c. Install dedicated communications between the TSC and the control room, near site emergency operations center, and the NRC. Provide, between the TSC and the control room, a capability for the transmittal of some data. This requirement could be satisfied by closed circuit television or process computer printout,

   d. Provide monitoring (either portable or permanent) for both direct radiation and airborne radioactive contaminants. The monitors should provide warning if the radiation levels in the support center are reaching potentially dangerous levels. The licensee should designate action levels to define when protective measures should be taken (such as using breathing apparatus and potassium iodide tablets, or evacuation to the control room),

Section 2.2.2.b (Continued)

e. Assimilate or ensure access to Technical Data, including the licensee's best effort to have direct display of plant parameters, necessary for assessment in the TSC,

f. Develop procedures for performing this accident assessment function from the control room should the TSC become uninhabitable, and

g. Submit to the NRC a longer range plan for upgrading the TSC to meet all requirements.

2. <u>Location</u>

It is recommended that the TSC be located in close proximity to the control room to ease communications and access to technical information during an emergency. The center should be located onsite, i.e., within the plant security boundary. The greater the distance from the CR, the more sophisticated and complete should be the communications and availability of technical information. Consideration should be given to providing key TSC personnel with a means for gaining access to the control room.

Section 2.2.2.b (Continued)

3. Physical Size and Staffing

The TSC should be large enough to house 25 persons, necessary engineering data and information displays (TV monitors, recorders, etc.). Each licensee should specify staffing levels and disciplines reporting to the TSC for emergencies of varying severity.

4. Activation

The center should be activated in accordance with the "Alert" level as defined in the NRC document "Draft Emergency Action Level Guidelines, NUREG-0610" dated September, 1979, and currently out for public comment. Instrumentation in the TSC should be capable of providing displays of vital plant parameters from the time the accident began (t = 0 defined as either reactor or turbine trip). The Shift Technical Advisor should be consulted on the "Notification of Unusual Event" however, the activation of the TSC is discretionary for that class of event.

Section 2.2.2.b (Continued)

5. Instrumentation

The instrumentation to be located in the TSC need not meet safety-grade requirements but should be qualitatively comparable (as regards accuracy and reliability) to that in the control room. The TSC should have the capability to access and display plant parameters independent from actions in the control room. Careful consideration should be given to the design of the interface of the TSC instrumentation to assure that addition of the TSC will not result in any degradation of the control room or other plant functions.

6. Instrumentation Power Supply

The power supply to the TSC instrumentation need not meet safety-grade requirements, but should be reliable and of a quality compatible with the TSC instrumentation requirements. To insure continuity of information at the TSC, the power supply provided should be continuous once the TSC is activated. Consideration should be given to avoid loss of stored data (e.g., plant computer) due to momentary loss of power or switching transients. If the power supply is provided from a plant safety-related power source, careful attention should be given to assure that the capability and reliability of the safety-related power source is not degraded as a result of this modification.

Section 2.2.2.b (Continued)

7. Technical Data

Each licensee should establish the technical data requirements for the TSC, keeping in mind the accident assessment function that has been established for those persons reporting to the TSC during an emergency. As a minimum, data (historical in addition to current status) should be available to permit the assessment of:

Plant Safety Systems Parameters for:

- Reactor Coolant System
- Secondary System (PWRs)
- ECCS Systems
- Feedwater and Makeup Systems
- Containment

In-Plant Radiological Parameters for:

- Reactor Coolant System
- Containment
- Effluent Treatment
- Release Paths

Section 2.2.2.b (Continued)

Offsite Radiological

- Meteorology
- Offsite Radiation Levels

8. Data Transmission

In addition to providing a data transmission link between the TSC and the control room, each licensee should review current technology as regards transmission of those parameters identified for TSC display.

Although there is not a requirement at the present time, each licensee should investigate the capability to transmit plant data offsite to the Emergency Operations Center, the NRC, the reactor vendor, etc.

9. Structural Integrity

a. The TSC need not be designed to seismic Category I requirements. The center should be well built in accordance with sound engineering practice with due consideration to the effects of natural phenomena that may occur at the site.

Section 2.2.2.b (Continued)

b. Since the center need not be designed to the same stringent requirements as the Control Room, each licensee should prepare a backup plan for responding to an emergency from the control room.

10. Habitability

The licensee should provide protection for the technical support center personnel from radiological hazards including direct radiation and airborne contaminants as per General Design Criterion 19 and SRP 6.4.

a. Licensee should assure that personnel inside the technical support center (TSC) will not receive doses in excess of those specified in GDC 19 and SRP 6.4 (i.e., 5 Rem whole body and 30 Rem to the thyroid for the duration of the accident). Major sources of radiation should be considered.

b. Permanent monitoring systems should be provided to continuously indicate radiation dose rates and airborne radioactivity concentrations inside the TSC. The monitoring systems should include local alarms to warn personnel of adverse conditions. Procedures must be provided which will specify appropriate protective actions to be taken in the event that high dose rates or airborne radioactive concentrations exist.

c. Permanent ventilation systems which include particulate and charcoal filters should be provided. The ventilation systems need not be qualified as ESF systems. The design and testing guidance of Regulatory Guide 1.52 should be followed except that the systems do not have to be redundant, seismic, instrumented in the control room or automatically activated. In addition, the HEPA filters need not be tested as specified in Regulatory Guide 1.52 and the HEPA's do not have to meet the QA requirements of Appendix B to 10 CFR 50. However, spare parts should be readily available and procedures in place for replacing failed components during an accident. The systems should be designed to operate from the emergency power supply.

d. Dose reduction measures such as breathing apparatus and potassium iodide tablets cannot be used as a design basis for the TSC in lieu of ventilation systems with charcoal filters. However, potassium iodide and breathing apparatus should be available.

Section 2.2.2.b (Continued)

PG&E Response and Status

The permanent onsite technical support center will be located in the Turbine Building buttresses. The design criteria has been formulated. Detailed design is being issued with construction and installation of equipment to be completed by January 1, 1981 as shown on the schedule in Figure 2.2.2.b-1. A complete description of the permanent onsite technical support center is presented below. A discussion of the temporary onsite technical support center follows the discussion of the permanent center. The schedule for the completion of the temporary TSC is shown in Figure 2.2.2.b-2.

PERMANENT TECHNICAL SUPPORT CENTER:

The permanent onsite technical support center (TSC) (common to both units) is located on the upper level of the Unit 2 end of the buttresses on the west side of the turbine building. The floor of the TSC is at elevation +104. Access to the control room is via the east door of the TSC, across the Unit 2 turbine building at elevation +104, and then to the control room at elevation +140 via the elevator or stairway on the east side of the turbine building. It takes approximately three minutes at normal walking speed to go from the TSC, via the stairway, to the control room.

1. Emergency Function:

The principal function of the permanent onsite technical support center (TSC) (once activated) is to serve as the headquarters of the Site Emergency Coordinator, Liaison Coordinator, Evaluations Coordinator and their

staffs throughout an emergency. Provisions have also been made for the establishment of an onsite NRC emergency headquarters in the TSC. The TSC is sized to accommodate a minimum of 20 Company personnel and five NRC personnel. The floor plan of the TSC is shown on Figure 2.2.2.b-3.

It is planned that following activation of the TSC, the overall onsite assessment and recovery programs will be directed from this location. In addition, most communications with offsite locations will be handled through the TSC.

One section of the TSC has been outfitted to serve as a radiological counting room. This facility is intended to be a backup location for this type of work in the event that the normal counting room is unuseable due to high background radiation levels.

2. Habitability Objectives:

The TSC is designed to be habitable throughout the course of a design basis accident. In accordance with NUREG-0578, as clarified on November 9, 1979, the TSC shielding was designed to limit all direct radiation exposure to 10 mRem/hr assuming TID 14844 source terms (from Section 2.1.6.b studies) and to limit all airborne particulate and gaseous exposures (internal to the TSC) to 5 mRem/hr. The total exposure to any individual in the TSC would be limited to less than 15 mRem/hr from a time period beginning one hour after the start of the accident to 30 days later. Over the quarter (3 months)

beginning at the start of the accident this design will assure that personnel inside the TSC, will not receive quarterly doses in excess of those specified in GDC 19 and SRP 6.4.

The TSC is provided with its own ventilation system, shown schematically in Figure 2.2.2.b-4. Both redundant Class I pressurization fans provide the TSC and related HVAC room at a minimum pressure of approximately 1/8" water gage. Both pressurization air and return air (1000 CFM total) are passed through HEPA and charcoal filters. The pressurization air exfiltrates from the TSC to the outside atmosphere. A self contained air conditioning unit is provided for the TSC. The air conditioner is not seismically qualified and is powered from a normal power source. The duct work, ventilation fans and filter units are designed to Seismic Class I criteria.

The laboratory is provided with its own ventilation system, shown schematically in Figure 2.2.2.b-4. One fan provides ventilation air for the lab hood and provides enough pressurization air to maintain the lab and related HVAC room at a minimum pressure of approximately 1/8" water gage. Both lab hood air and pressurization air are passed through HEPA and charcoal filters. The pressurization air exfiltrates from the laboratory to the outside atmosphere. The exhaust air from the hood passes through HEPA and charcoal filters before being discharged to the atmosphere. A self contained

air conditioning unit is provided for the laboratory. The air conditioner is not seismically qualified and is fed from a normal power source. The duct work, ventilation fans and filter units are designed to Seismic Class I criteria.

The normal lighting for the TSC is provided from the emergency AC lighting transformers. Backup DC lights are also provided.

3. Special Equipment:

Provisions are included to permit persons in the TSC to monitor important plant parameters. The output from each Unit's P-250 computer is sent to the TSC using a hard-wired interface to a Harris time-share terminal in the administration building, then to the TSC via acoustic coupler. Figure 2.2.2.b-5 shows the flow of information (plant parameters and health physics data) between the plant process computer, health physics computer, TSC computer and various peripheral equipment. The figure exhibits the capability of the TSC computer to provide all the necessary plant and health physics data to offsite facilities. To provide backup for the plant computer, closed circuit TV cameras are located in the control room in a such a manner that the console, main vertical boards, and the post-accident monitoring panel can be scanned from the TSC.

Section 2.2.2.b (Continued)

The TSC is tied into the emergency radiological monitoring network such that one compartment in the TSC is set aside for analytical work. The principal purpose of this facility is to provide minimum onsite analytical capability in the event that the normal facilities in and around access control are unavailable. Multichannel analysis capability similiar to that in the counting room is provided. A thermoluminescent dosimeter reader is also provided. Two radiological emergency kits are stored in the TSC. Contents of these kits are indicated in Table 2.2.2.b-1. Finally, the TSC is provided with a terminal and printer for the Company's computerized records management system. This provides the ability to inspect and print the latest copies of all prints and records involving the plant. Also current hard copies of the most frequently referenced drawings are maintained in the TSC.

4. Communications:

The focal point of communications for the Technical Support Center will be a central communications console located in the computation area. The permanent onsite technical support center (TSC) has been designated 25 CBX lines. This console will house three communication facilities. The first facility, a CBX telephone control center, is called a turret. From this location, all incoming calls can be answered and/or transferred to designated personnel for response. The turret can also be used to obtain an outgoing trunk line for use by the TSC, even if all should be busy, by intercepting the busy line and asking the parties to discontinue their conversation. This turret will normally be shut off except during an emergency. Normal day-to-day operations

will be handled via a similar turret in the plant administration building. The second facility, a telephone answering station, will house those telephone circuits not accessible via the CBX. As shown in Figure 2.2.2.b-6 these circuits are labeled with a "B," "E," or "G" symbol. A "B" symbol represents an extension from the exchange at the PGandE San Luis Obispo exchange. This circuit will provide direct dial communications into PGandE's Los Padres District Service Area, without the need to use one of the eight trunks of the Private Dial System. The "E" circuit automatically rings the party shown upon lifting the handset and depressing the button of the location desired to be called. There will be one button for each dedicated line to the control room, NRC Headquarters, and the Offiste Recovery Center. The "G" symbolizes a standard unlisted telephone from the Pacific Telephone Network. This telephone will provide direct access to an offsite location in the event the Company exchange system is not available. The third facility is for control of the power plant's VHF and UHF radio systems.

TEMPORARY TECHNICAL SUPPORT CENTER:

The administration building located west of the Turbine Building has been designated as a temporary onsite technical support center. This facility, with the addition or extension of some telephone circuits, portable radiation monitors, and the provision of a portable closed circuit television camera, will be functional from June 1, 1980 until the permanent TSC is completed no later than January 1, 1981. Figure 2.2.2.b-7 is a diagram of the layout of the temporary TSC.

Section 2.2.2.b (Continued)

The administration building presently contains a Records Management System terminal providing access to plant design documents and a time share terminal capable of providing output of important plant parameters from each Unit's P-250 computer.

Portable area type radiation monitors with a range of 0.1 to 1,000 millirems per hour with alarms (Model GA-2TO by Nuclear Measurements Corp.) are available onsite. One of these monitors will be placed in the temporary technical support center. Airborne radioactivity concentrations will be monitored with a CAM (constant air monitor) which will be made available for placement in the temporary technical support center.

The closed circuit television system equipment to be located in the permanent technical support center is expected to be onsite by June 1, 1980. It is intented to install the cameras in the control room and to initially install the monitors in the temporary technical support center. However, should delivery be delayed and to provide backup capability a portable television camera would be procured for the temporary technical support center. This camera would be utilized by a camera man in communication with the temporary TSC to scan the control room as requested to provide specific plant parametric information.

Section 2.2.2.b (Continued)

Telephone communication circuits currently exist between the administration building and the control room, the Corporate Incident Response Center in San Francisco, the NRC site office, and the NRC Operations Center in Bethesda. Additional telephone circuit modifications will be made to provide dedicated communications between the temporary TSC and the offsite Emergency Response Center in San Luis Obispo near-site Emergency Operations Center, Control Room, and NRC Operations Center by June 1, 1980.

TABLE 2.2.2.b-1

CONTENTS OF RADIOLOGICAL EMERGENCY KITS

ITEM	QUANTITY 1(MBPP)	2(INF.CTR.)	3(SHRF)	4(DCPP)	5(DCPP)
1. Instruction Binder					
a. Assorted Pens	8	8	8	8	8
b. San Luis Obispo County Map	1	1	1	1	1
c. Equipment Location Dwgs. (sets)	1	1	1	1	1
d. Emergency Environmental Monitoring Field Data Sheet (Form 18-9259)	100	100	100	100	100
e. Appropriate Environmental Monitoring Procedures from Emergency Procedure R-2 (sets)	1	1	1	1	
f. "Emergency Kits" (G.A.6 to Emergency Procedures)	1	1	1	1	1
g. Corporation Key (3A90909)	1	1	1	1	1
h. Pocket Calculator	1	1	1	1	1
2. Monitoring Equipment					
a. Dose Rate Meter	0	1	0	0	0
b. Dose Rate Meter	1	1	1	1	1
c. Survey Meter	1	1	1	1	1
d. Standard G-M Probe	1	1	1	1	1
e. Pancake G-M Probe	1	1	1	1	1
f. Pocket Dosimeters	3	3	3	3	3
g. Dosimeter Charger	1	1	1	1	1
3. Air Sampling Equipment					
a. 12V Air Sampler	1	1	1	0	0
b. 12V Air Sampler (w/battery)	0	0	0	1	1
c. 120V AC Air Sampler	0	1	1	0	0
d. Air Sample Particulate Filters (pkg.)	10	10	10	10	10
e. Iodine Filter Cartridges (pkg.)	3	3	3	3	3

TABLE 2.2.2.b-1 (Continued)

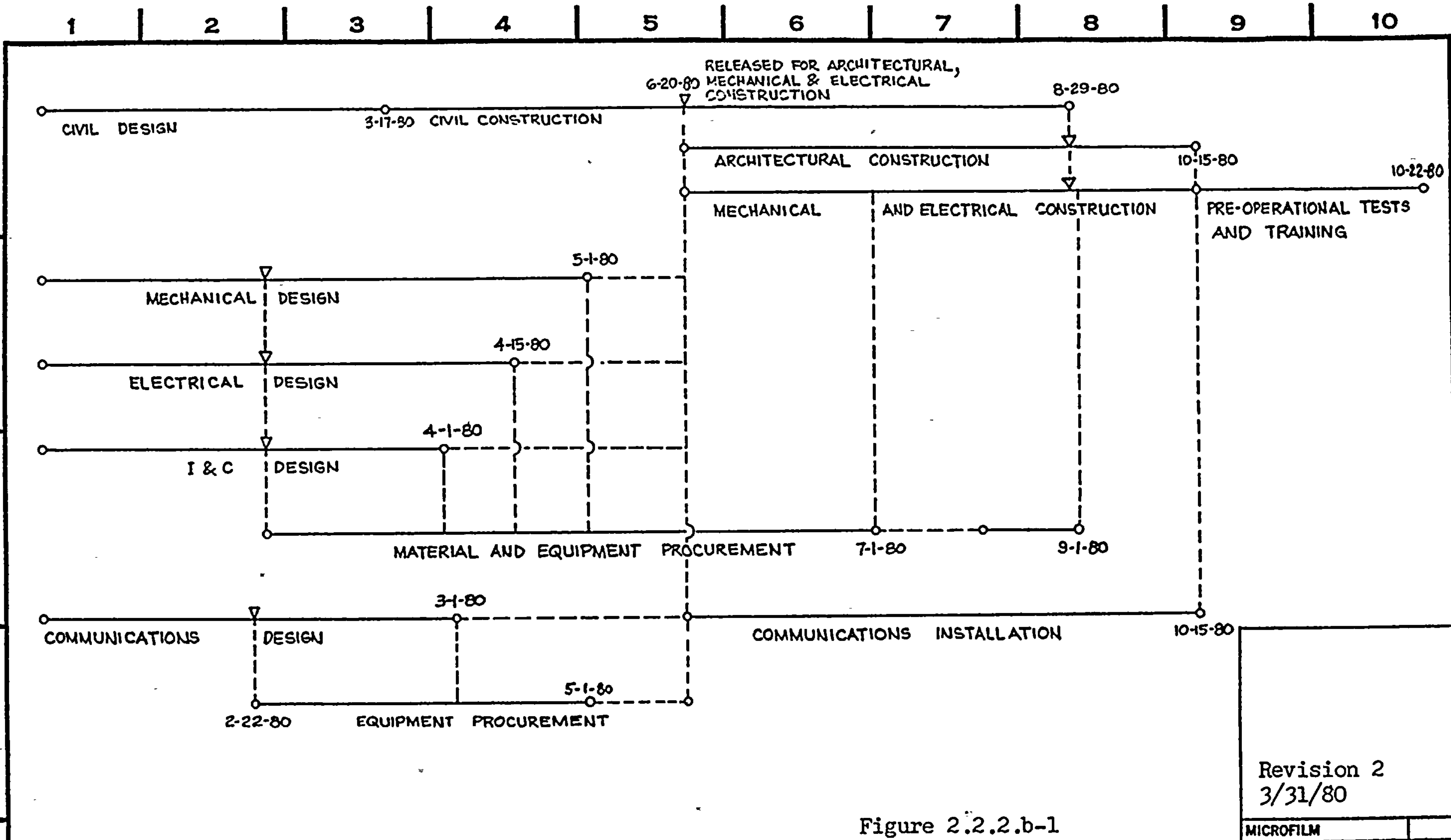
CONTENTS OF RADIOLOGICAL EMERGENCY KITS

ITEM	QUANTITY 1(MBPP)	2(INF.CTR.)	3(SHRF)	4(DCPP)	5(DCPP)
f. Paper Envelopes for Samples	100	100	100	100	100
g. Plastic Envelopes for Iodine Cartridges (pkg. of 30)	1	1	1	1	1
h. Forceps	1	1	1	1	1
i. Compressed Air Cylinder	2	2	2	2	2
j. Sample Head w/adapter to fit Air Cylinder	1	1	1	1	1
k. Air Cylinder Regulator	1	1	1	1	1
4. Protective Clothing/Decontamination					
a. Protective Clothing Sets	2	2	2	2	2
b. Full Face Mask	2	2	2	2	2
c. Type H Ultra Filters for Face Masks	2	2	2	2	2
d. Skin Decontamination Soap	1	1	1	1	1
e. Brush	1	2	1	2	2
f. Paper Towels (pkg)	0	1	0	1	1
g. Smear Pads (pkg of 10)	1	3	1	1	1
h. Plastic Bags	3	3	3.	3	3
i. Bucket (10 quart)	0	1	0	1	1
j. Decontamination Agent	1	1	1	1	1
5. Signs/Barriers					
a. Radiation Signs	2	4	2	4	4
b. Radiation Barricade Tape	2	2	2	2	2
6. Sampling Equipment					
a. Sample Bottles	2	6	2	4	4
b. Plastic Bags	15	15	15	15	15
c. Trowel	1	1	1	1	1
d. Gummed Labels (pkg)	1	1	1	1	1

TABLE 2.2.2.b-1 (Continued)

CONTENTS OF RADIOLOGICAL EMERGENCY KITS

ITEM	QUANTITY 1(MBPP)	2(INF.CTR.)	3(SHRF)	4(DCPP)	5(DCPP)
7. Miscellaneous Equipment					
a. First Aid Kit	1	1	1	1	1
b. Screwdriver	1	1	1	1	1
c. Crescent Wrench (8")	1	1	1	1	1
d. Scissors	1	1	1	1	1
e. Stopwatch	1	1	1	1	1
f. Roll of Dimes	1	1	1	1	1
g. Masking Tape	2	2	2	2	2
h. Flashlights w/Batteries	1	2	1	2	2
i. Extra Batteries	2	4	2	4	4
j. Battery Powered Lantern	1	1	1	1	1
k. Bolt Cutter	0	0	0	1	1



Revision 2
3/31/80

Figure 2.2.2.b-1

NO.	DATE	DESCRIPTION	GM	DWN.	CHKD.	SUPV.	APVD.

REVISIONS

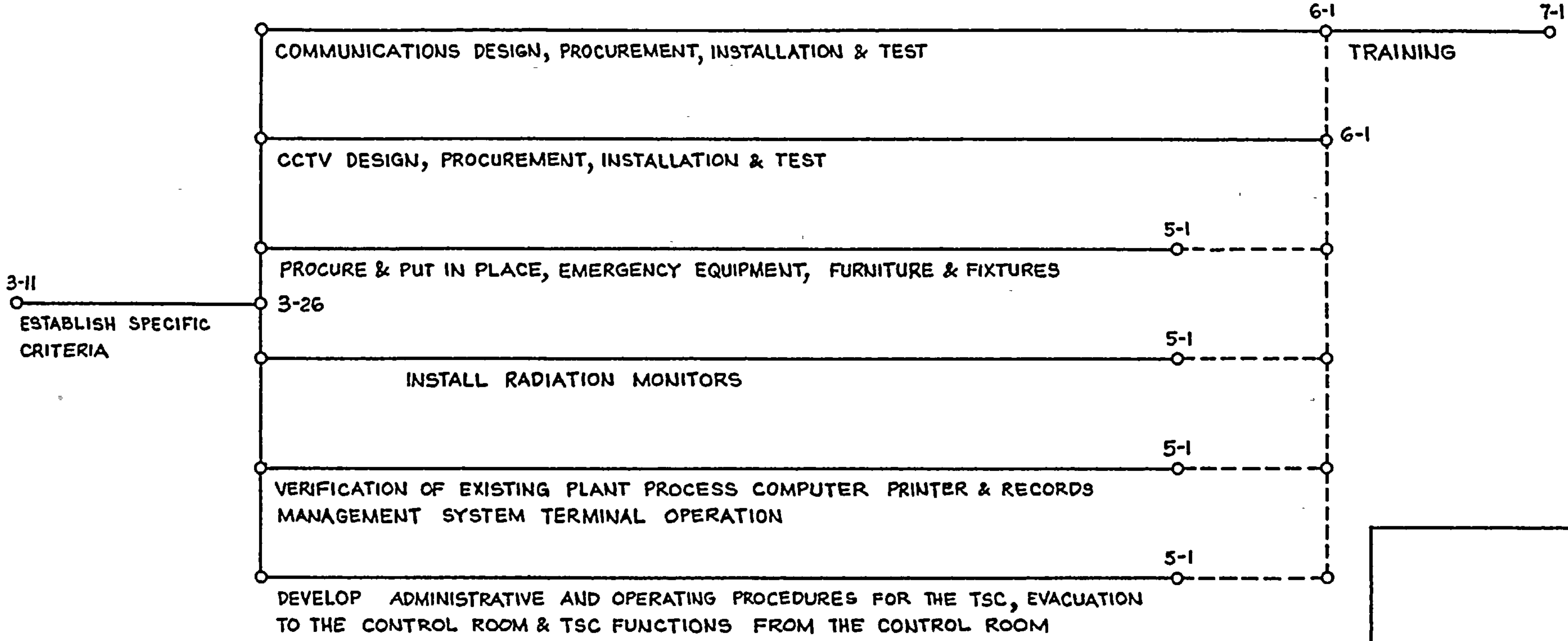
APPROVED BY

GM
SUPV. MRT
DSGN.
DWN. RGB
CHKD.
O.K.
DATE 3-17-80
SCALES N/A

TECHNICAL SUPPORT CENTER
1-1-81 REQUIREMENTS
SUMMARY SCHEDULE

PACIFIC GAS AND ELECTRIC COMPANY
SAN FRANCISCO, CALIFORNIA

MICROFILM
BILL OF MATL
DWG LIST
SUPSDS
SUPSD BY
SHEET NO. 1 OF 1 SHEETS
REV. 0
SAN-12-001



Revision 2
3/31/80

Figure 2.2.2.b-2

NO.	DATE	DESCRIPTION	GM	DWN.	CHKD.	SUPV.	APVD.

REVISIONS

APPROVED BY MRT

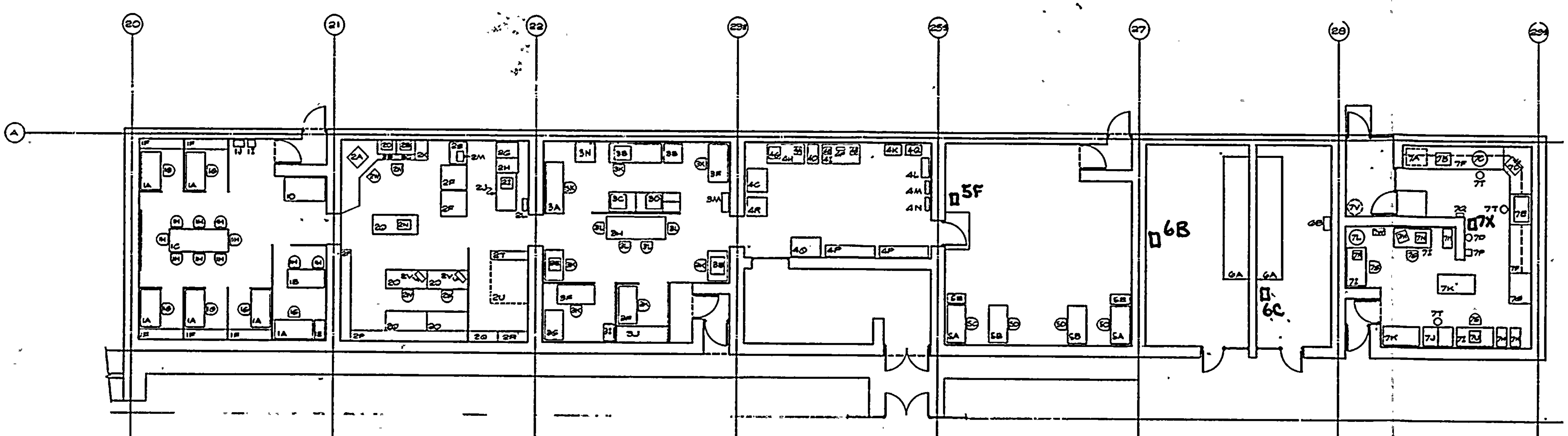
GM
SUPV. MRT
DSGN.
DWN. RGB
CHKD.
O.K.
DATE 3-19-80
SCALES N/A

TECHNICAL SUPPORT CENTER
(TEMPORARY)

SUMMARY SCHEDULE

PACIFIC GAS AND ELECTRIC COMPANY
SAN FRANCISCO, CALIFORNIA

MICROFILM
BILL OF MATL
DWG LIST
SUPSDS
SUPSD BY
SHEET NO. 1 OF 1 SHEETS
SAN-63-001 REV. 0



OFFICE 1

ITEM	QTY.	DESCRIPTION
1A	6	DESK (DOUBLE PEDESTAL W/ LOCK)
1B	1	TABLE (2'-6"X 5'-0")
1C	1	TABLE (3'-0" X 8'-0")
1D	1	DRAWING FILE
1E	1	5-DRAWER FILE W/ LOCK
1F	5	SIDE-LOAD FILE
1G	6	CHAIR (SWIVEL)
1H	10	CHAIR (GUEST)
1I	1	RADIATION MONITOR
1J	1	TELEPHONE CABING CABINET

OPERATIONS CENTER 2

ITEM	QTY.	DESCRIPTION
2A	1	CCTV MONITOR
2B	1	P-250 REMOTE CONSOLE
2C	1	PROCESSOR CONTROL CONSOLE
2D	1	P-250 DATA MONITOR
2E	1	OFF-SITE DATA MONITOR
2F	2	PRINTER
2G	1	DISC DRIVE
2H	1	TAPE DRIVE
2I	1	READER
2J	1	PROCESSOR
2K	1	CONSOLE PRINTER
2L	1	RADIATION MONITOR
2M	1	CASSETTE DECK
2N	1	PLOTTER
2O	5	TABLE (2'-6"X 5'-0")
2P	2	BOOKSHELVES
2Q	1	SHELVING FOR SPARE PARTS
2R	1	SHELVING FOR SUPPLIES
2S	1	COMMUNICATION CABINET
2T	1	LATERAL FILE FOR TAPE STORAGE
2U	1	FUTURE DATA LINK EQUIPMENT
2V	2	DATA ACCESS TERMINAL
2W	4	CHAIR (SWIVEL)

COMPUTATION CENTER 3

ITEM	QTY.	DESCRIPTION
3A	1	COMMUNICATIONS EQUIPMENT
3B	1	COMPUTER
3C	1	LINE PRINTER
3D	1	COLOR GRAPHIC TERMINAL
3E	2	TSO TERMINAL
3F	3	DESK (DOUBLE PEDESTAL W/ LOCK)
3G	1	TABLE (2'-6"X 4'-0")
3H	1	TABLE (3'-0"X 8'-0")
3I	1	ADJUSTABLE SHELVING
3J	1	SIDE LOAD FILE
3K	7	CHAIR (SWIVEL)
3L	4	CHAIR (GUEST)
3M	1	HVAC CONTROLS & RADIATION MONITOR PANEL
3N	1	COMMUNICATION CABINET

RECORDS MANAGEMENT SYSTEM REPRODUCTION 4

ITEM	QTY.	DESCRIPTION
		(RECORDS MANAGEMENT SYSTEMS)
4A	1	CRT TERMINAL
4B	1	CRT TERMINAL
4C	1	IMT 150 READER/PRINTER
4D	1	APCO FILE
4E	1	OCE TRI-LENS READER
4F	1	TELEPHONE / COUPLER
4G	1	CAROUSEL
4H	1	DESK (DOUBLE PEDESTAL W/ LOCK)
4I	1	TABLE (2'-6"X 5'-0")
4J	2	CHAIR (SWIVEL)
4K	1	LIGHTING TRANSFORMER
4L	1	480V. AC PANEL
4M	1	120 V. AC LIGHTING PANEL
4N	1	INSTRUMENT AC PANEL
		(REPRODUCTION)
4O	1	XEROX MACHINE
4P	2	OPEN SHELVING W/ ADJUSTABLE SHELVES
4Q	1	TELEPHONE CABLING CABINET
4R	1	COMMUNICATION CABINET

NRC OFFICE 5

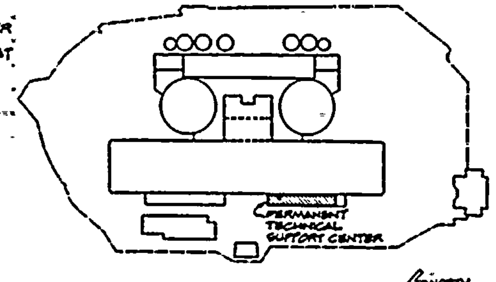
ITEM	QTY.	DESCRIPTION
5A	2	DESK (DOUBLE PEDESTAL W/ LOCK)
5B	2	TABLE (2'-6"X 5'-0")
5C	2	CHAIR (SWIVEL)
5D	2	CHAIR (GUEST)
5E	2	5-DRAWER FILE W/ LOCK
5F	1	Radiation Monitor

HVAC ROOM 6

ITEM	QTY.	DESCRIPTION
6A	3	HVAC UNIT
6B	2	AIR PARTICULATE /NOBLE GAS MONITORS
6C	1	AREA MONITOR

LABORATORY 7

ITEM	QTY.	DESCRIPTION
7A	1	SHIELDED STORAGE
7B	1	LEAD SHIELD ON COUNTER
7C	1	TITRATOR
7D	1	SINK (DEMINERALIZED)
7E	1	LAB HOOD
7F	–	COUNTER W/ CABINETS OVER
7G	1	WALL CASE
7H	3	5-DRAWER FILE W/ LOCK
7I	3	DESK (DOUBLE PEDESTAL W/ LOCK)
7J	1	TLD READER
7K	2	TABLE (2'-6"X 5'-0")
7L	1	GAMMA DETECTION SHIELD
7M	1	MCA
7N	1	COMPUTER & DISC
7O	1	EMERGENCY SHOWER
7P	1	EYE WASH
7Q	1	FIRE BLANKET
7R	1	N/K COUNTER
7S	8	CHAIR (SWIVEL)
7T	3	STOOL
7U	1	TI 733 TERMINAL
7V	1	ELECTRIC WATER HEATER
7W	1	TELEPHONE CABLING CABINET
7X	1	Radiation Monitor



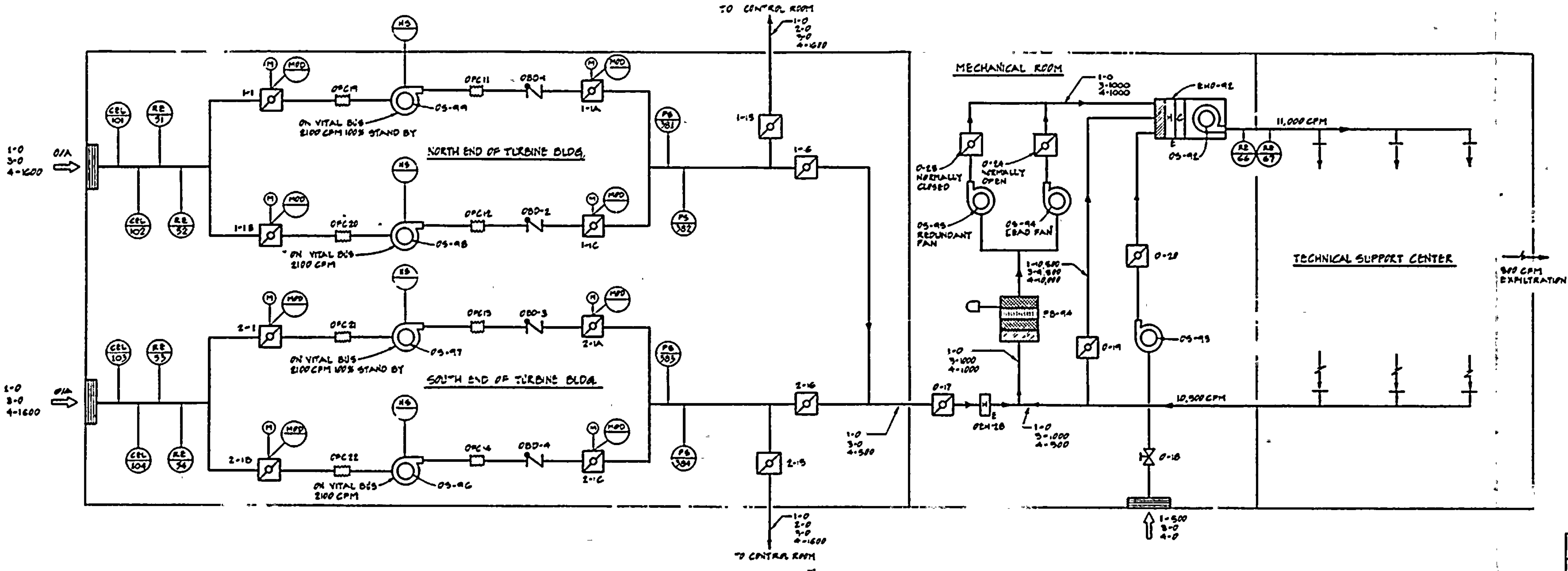
LOCATION PLAN
NO SCALE

0 1 2 4 6 8 10 20
SCALE IN FEET

FLOOR PLAN
TECHNICAL SUPPORT CENTER
MARCH 13, 1980 REV. NO.1

Figure 2.2.2.b-3
III-Z-23

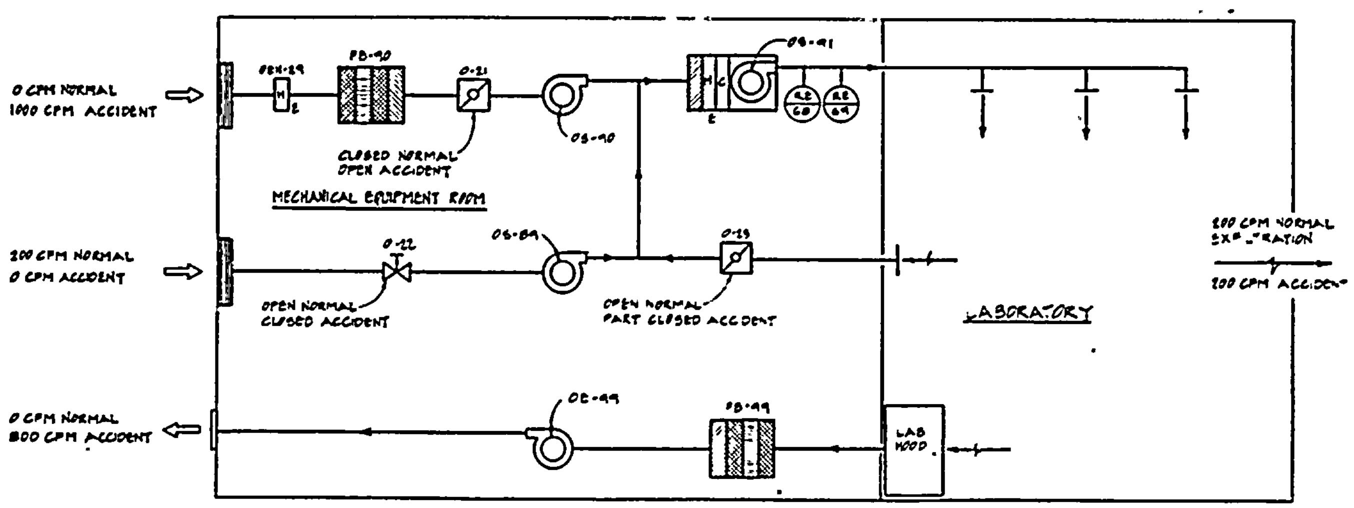
Revision 2
3/31/80



VENTILATION SCHEMATIC-TECHNICAL SUPPORT CENTER

	MODES OF OPERATION IN TECHNICAL SUPPORT CENTER
1	95.5% RECIRCULATED AIR OPERATION WITH 4.5% OUTSIDE AIR MAKE UP, 100% AIR THRU ROUGHING FILTER; FOR USE DURING NORMAL OPERATIONS
2	NOT APPLICABLE
3	100% RECIRCULATION AIR OPERATION WITH 9% AIR THRU HEPA AND CHARCOAL FILTERS; FOR USE IN THE EVENT OF HIGH AIRBORNE RADIOACTIVITY OR HIGH CHLORINE CONCENTRATIONS AT BOTH NORTH & SOUTH OUTSIDE AIR PRESSURIZATION INLETS
4	10,500 CFM RECIRCULATED AIR OPERATION WITH THE COMBINATION OF 500 CFM PRESSURIZATION AIR AND 500 CFM OF RECIRCULATION AIR FOR A TOTAL OF 1000 CFM THROUGH HEPA AND CARBON FILTERS; FOR USE IN THE EVENT OF AIRBORNE RADIOACTIVITY. NORTH AND SOUTH PRESSURIZATION TRAINS DO NOT OPERATE SIMULTANEOUSLY

NOTE:
FOR PARALLEL CONTROL ROOM MODES OF OPERATION SEE DWG 9H157



VENTILATION SCHEMATIC-LABORATORY SUPPORT CENTER

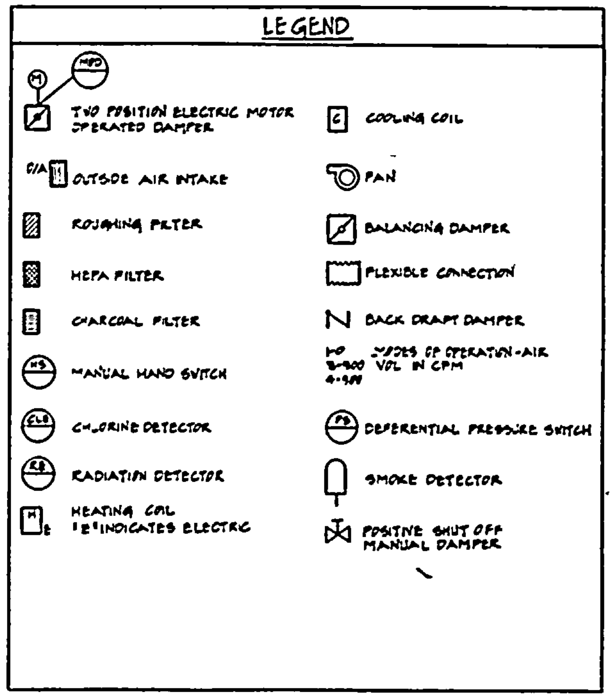


Figure 2.2.2.b-4 Revision 2
III-Z-24 3/31/80

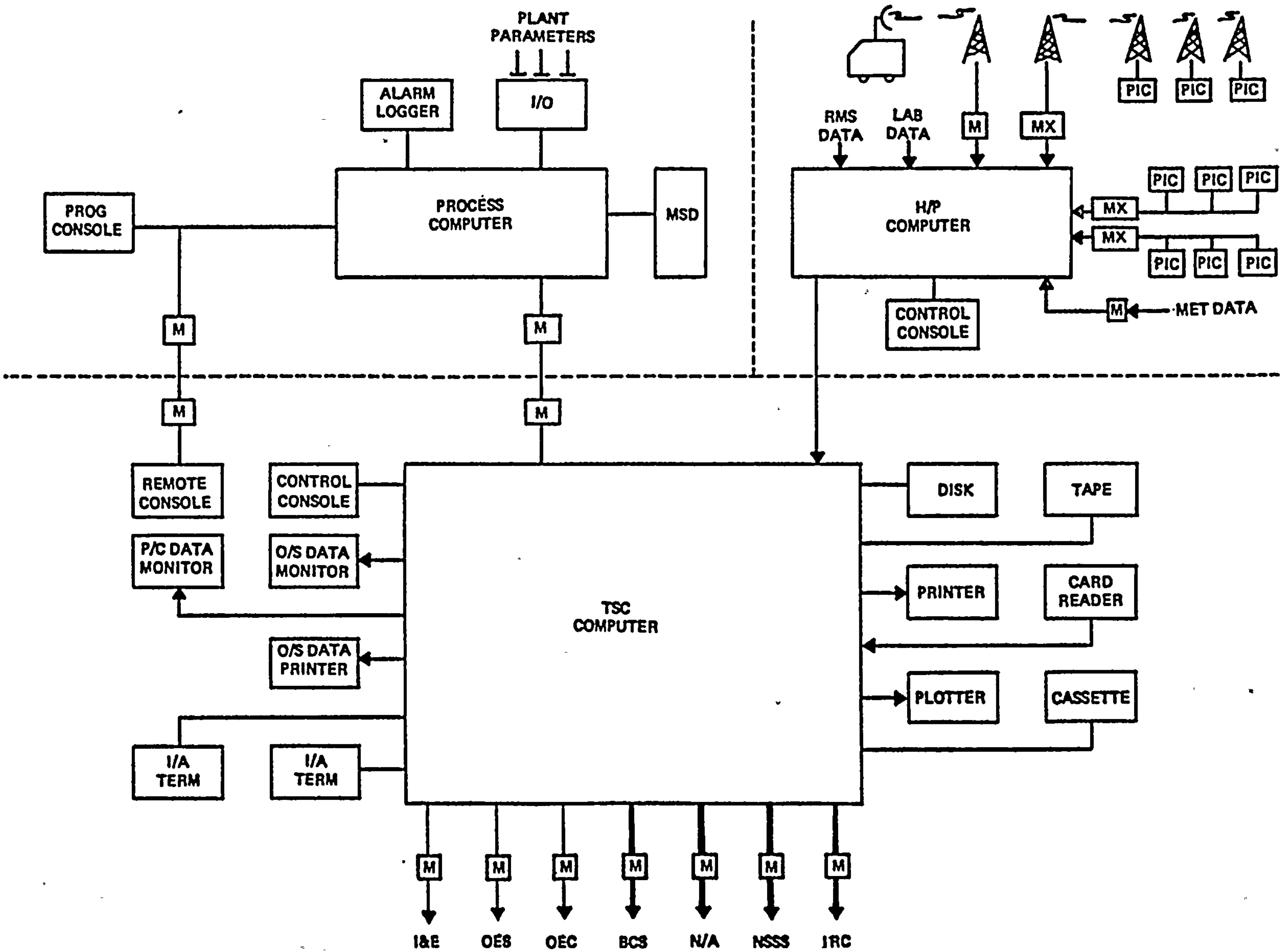


Figure 2.2.2.b-5 Revision 2

 3/31/80

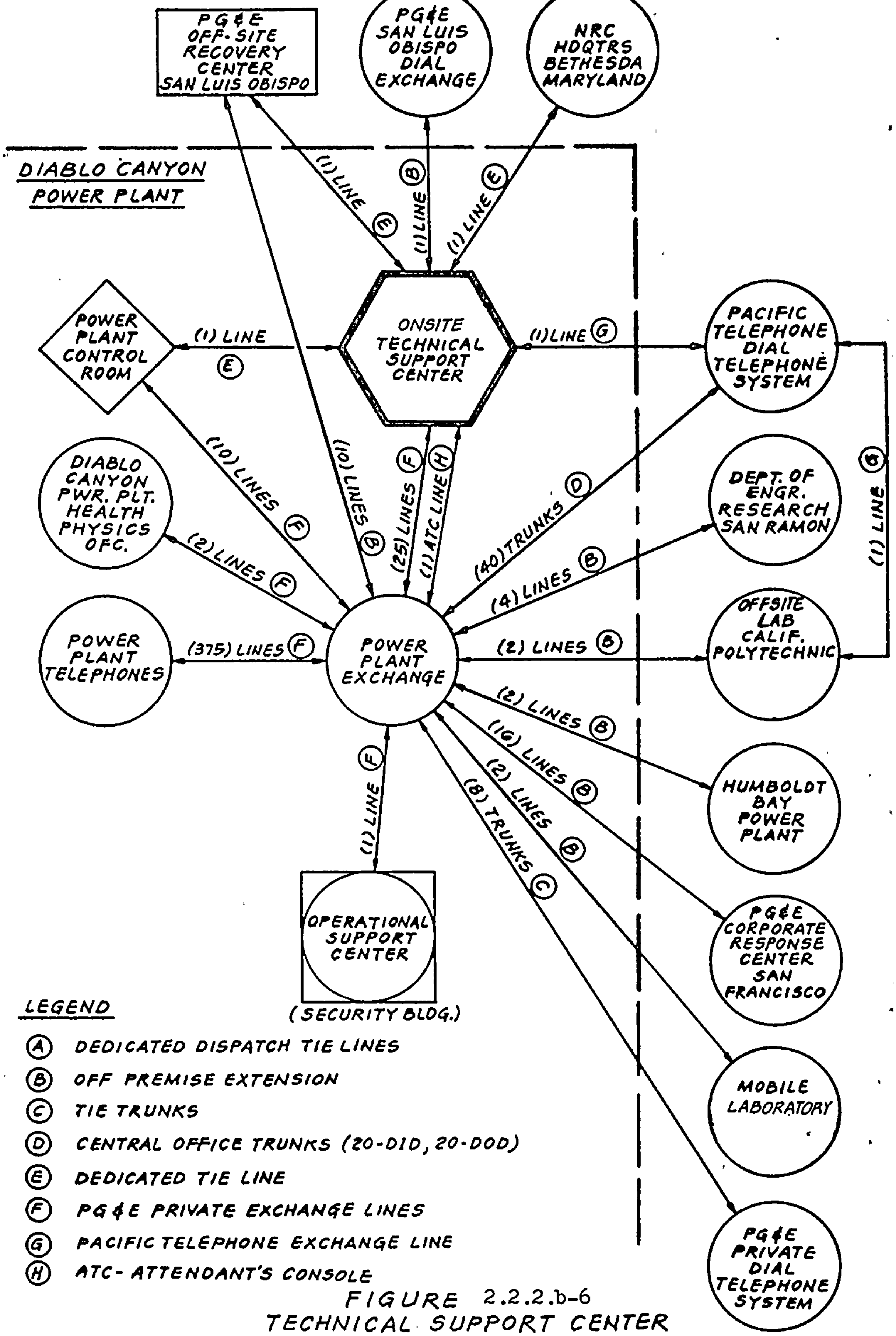
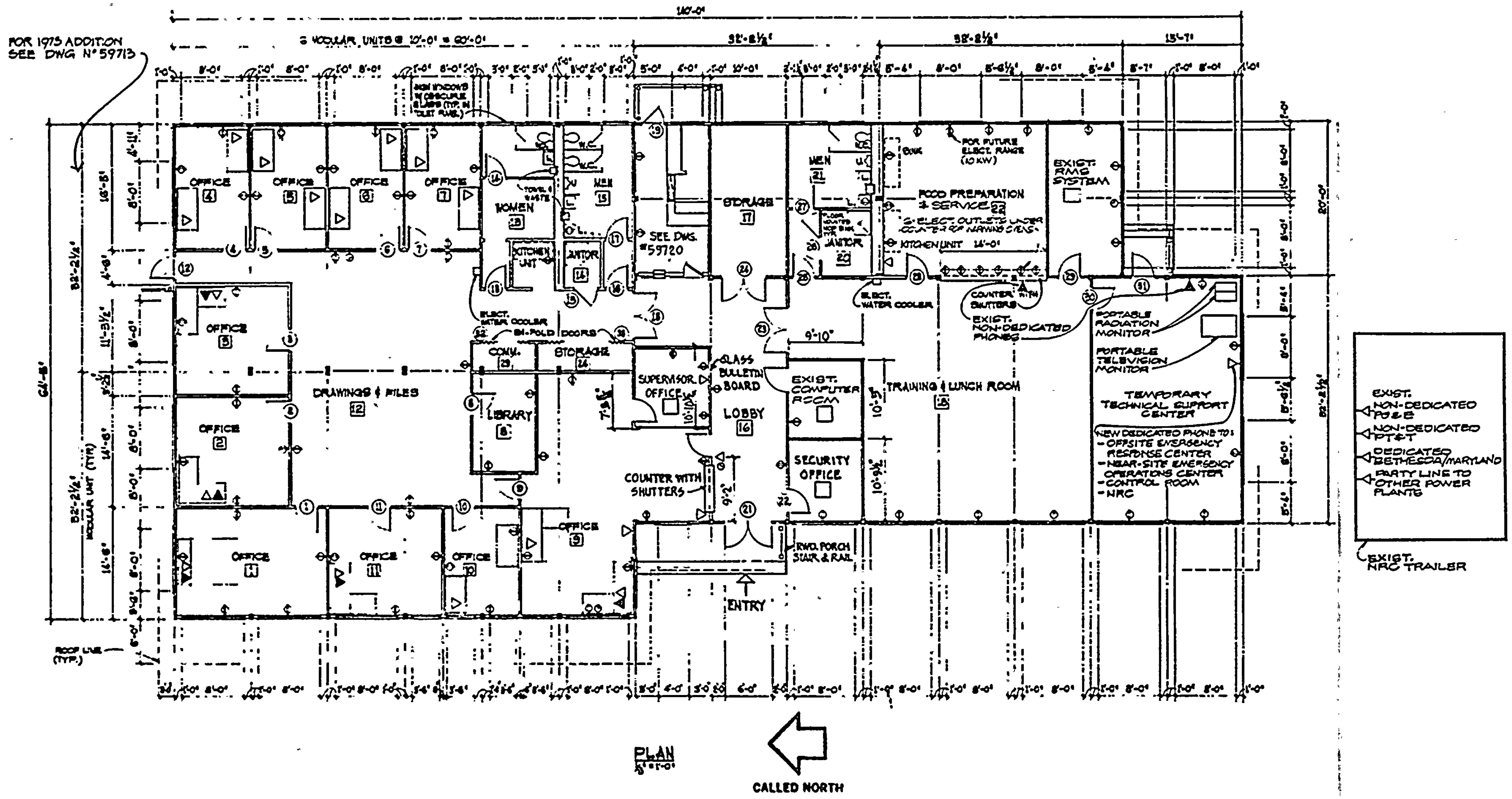


FIGURE 2.2.2.b-6
TECHNICAL SUPPORT CENTER
TELEPHONE COMMUNICATION SYSTEM

Revision 2
3/31/80



REFERENCE DWG.
SEE DWG. #466092 FOR LOCATION OF BUILDING ON THE SITE.

SYMBOLS
- CLOCK OUTLET
- 125V DUPLEX RECEPTACLE
- SPECIAL POWER OUTLET FOR EQUIPMENT
- PG. & E. TELEPHONE OUTLET BOX
- PT. & T. TELEPHONE OUTLET BOX

Figure 2.2.2.b-7 Revision 2
III-Z-27 3/31/80

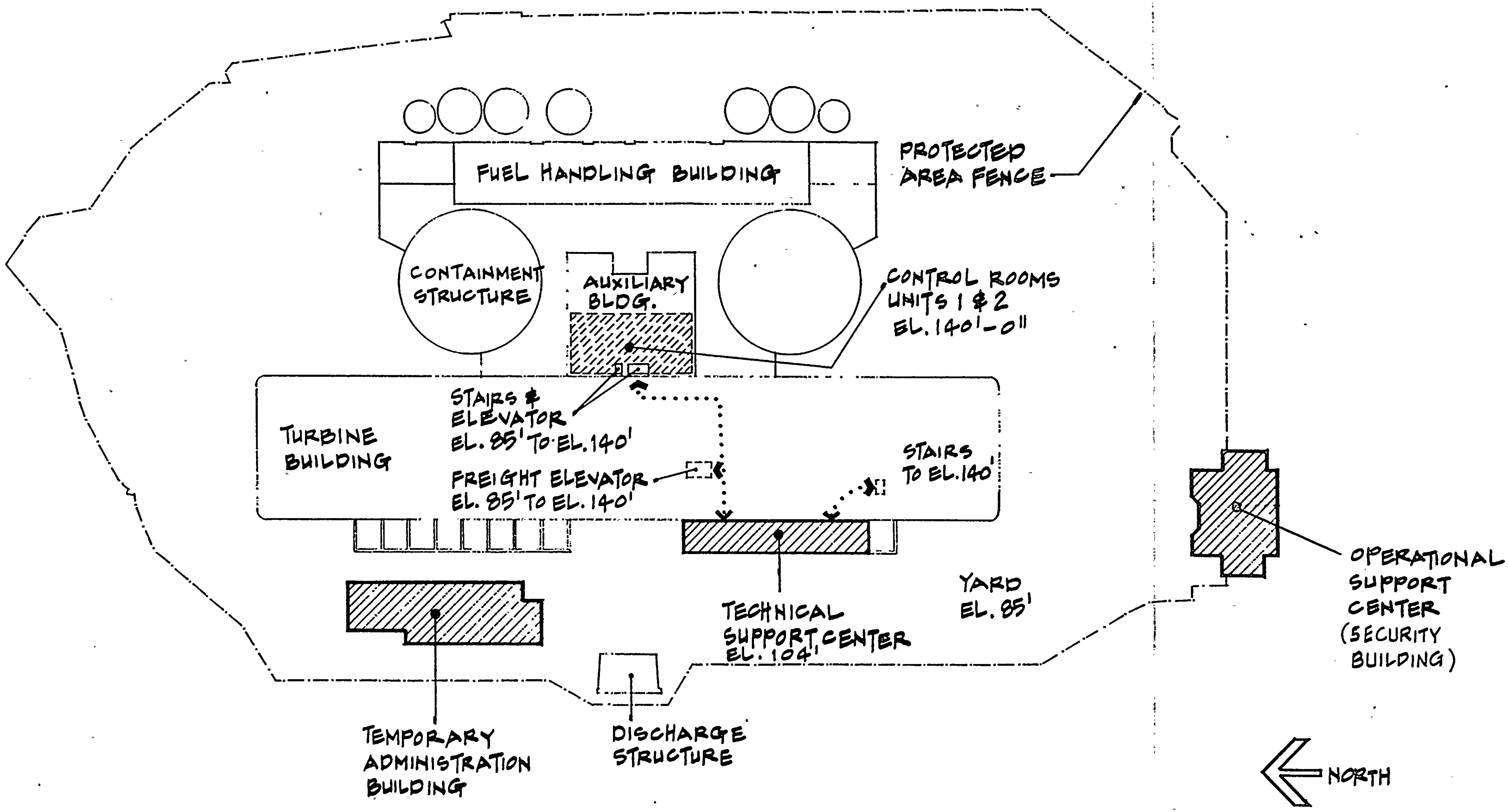
NO	DATE	DESCRIPTION	GM	BY	CH.	APPD
3	5-16-79	SUPERSEDES DWG. #59609				
2	12-1-73	AS BUILT				
1	11-13-72	APPROVED FOR CONST. (SPEC. 1623)				
0	9-5-72	ISSUED FOR BIDS (SPEC. 1623)				

TABLE OF CHANGES

UNITS 1&2

TEMPORARY ADMINISTRATION BUILDING REQUIREMENTS
DIABLO CANYON
DEPARTMENT OF ENGINEERING
PACIFIC GAS AND ELECTRIC COMPANY
SAN FRANCISCO, CALIFORNIA

SCALE AS NOTED
SUPERSEDES 59609
SHEET NO. 1 of 1 SHEETS
333090 3



GENERAL SITE PLAN

MARCH 13, 1980 REV. NO. 1

Figure 2.2.2.b-8

Revision 2

 3/31/80

Section 2.2.2.c - Onsite Operational Support Center

Task Force Position

An area to be designated as the onsite operational support center shall be established. It shall be separate from the control room and shall be the place to which the operations support personnel will report in an emergency situation. Communications with the control room shall be provided. The emergency plan shall be revised to reflect the existence of the center and to establish the methods and lines of communication and management. (Category A: Implementation shall be completed prior to OL, or January 1, 1980, whichever is later.)

PG&E Response and Status

1. Location and Description:

   The security building serves as the onsite Operational Support Center (OSC). The security building is located on the southern perimeter of the Protected Area. The OSC can handle approximately 38 individuals at desks in its nominal 1,600 square feet area. The OSC contains kitchen and lavatory facilities.

2. Emergency Function:

   The OSC serves as a staging area for support personnel who are called to the site to provide support activities. Use of the OSC eliminates unnecessary congestion in the control room and TSC, and enhances the implementation of personnel accountability measures.

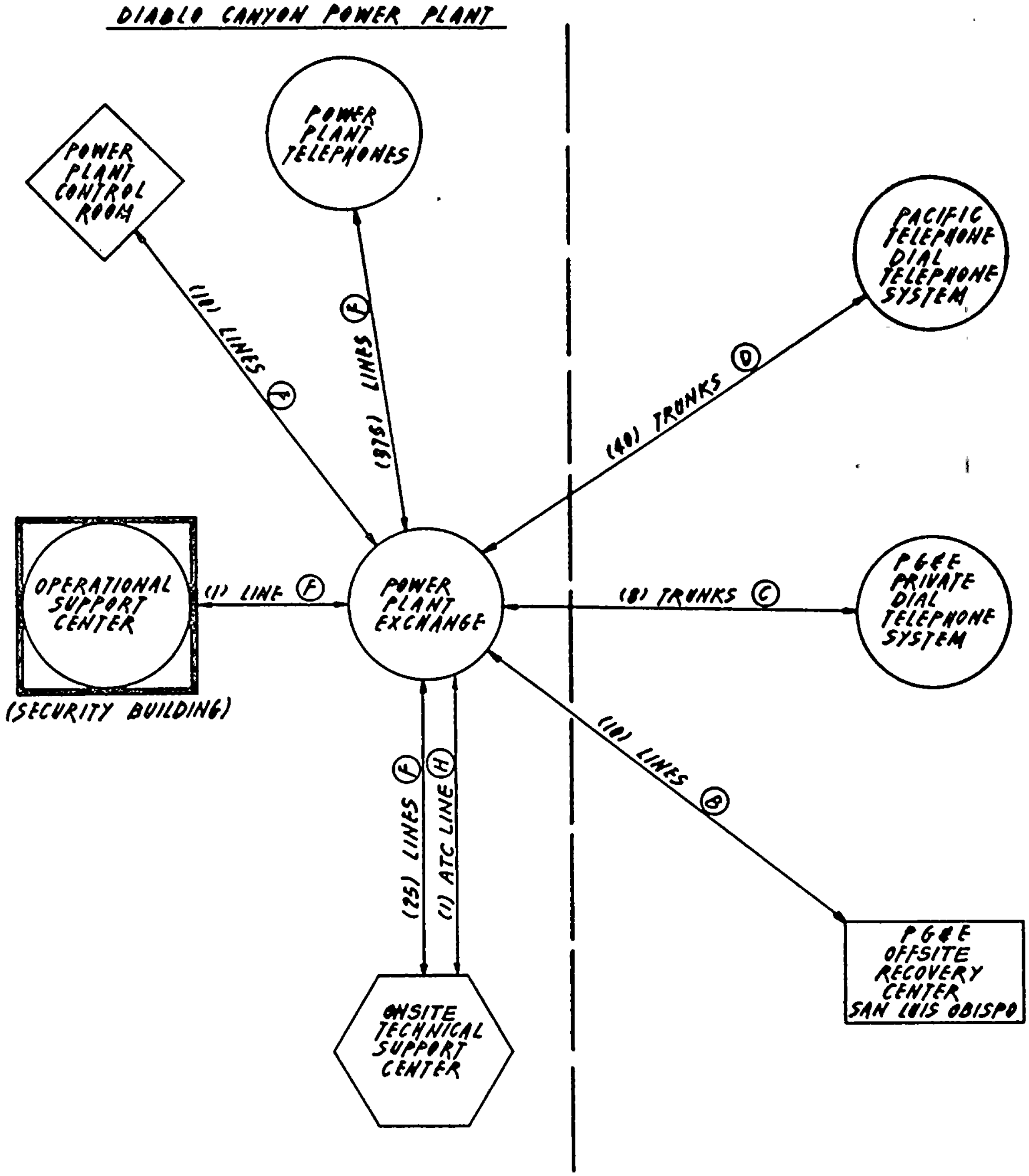
3. Special Equipment:

The OSC, located in the Security Building complex, is provided with PG&E and PT&T telephone facilities as well as radio communications. This center will contain one CBX line as indicated on Figure 2.2.2.C-1. The CBX will be programmed to allow the telephone serving the Operation Support Center to have sole access to critical telecommunication lines. This feature insures that the Operational Support Center will be able to maintain an open line with the control room. Two "evacuation kits," containing portable radiological monitoring equipment, and other equipment useful in an evacuation are stored in the OSC. The contents of these kits are listed in Table 2.2.2.C-1.

TABLE 2.2.2.c-1

CONTENTS OF EVACUATION KITS

	ITEM	QUANTITY PER KIT
1.	Survey meter with standard G-M probe	1
2.	Dose rate meter	1
3.	Self reading dosimeter pencils, 0-200 mR range	4
4.	Dosimeter charger	1
5.	Barricade tape, 100 foot rolls	2
6.	Packages of 2" filters (10 filters/pkg)	50
7.	Bullhorn	1
8.	Plastic bag (14"x24")	3
9.	Pens	4
10.	Flashlight	1
11.	Pocket Calculator	1
12.	Corporation key (3A90909)	1
13.	Information Center emergency room key	1
14.	Instruction book with evacuation procedure and data sheets	1



LEGEND:

Ⓐ DEDICATED DISPATCH TIE LINES
Ⓑ OFF PREMISE EXTENSION
Ⓒ TIE TRUNKS
Ⓓ CENTRAL OFFICE TRUNKS (20-DID, 20-DOD)
Ⓔ DEDICATED TIE LINE
Ⓕ PG&E PRIVATE EXCHANGE LINES
Ⓗ ATC- ATTENDANT'S CONSOLE

FIGURE 2.2.2.c-1
OPERATIONAL SUPPORT CENTER TELEPHONE COMMUNICATION SYSTEM
(SECURITY BUILDING)

Section 2.2.3 - Revised Limiting Conditions for Operation of Nuclear Power Plants Based Upon Safety System Availability

Task Force Position

All NRC nuclear power plant licensees shall provide information to define a limiting operational condition based on a threshold of complete loss of safety function. Identification of a human or operational error that prevents or could prevent the accomplishment of a safety function required by NRC regulations and analyzed in the license application shall require placement of the plant in a hot shutdown condition within 8 hours and in a cold shutdown condition within 24 hours.

The loss of operability of a safety function shall include consideration of the necessary instrumentation, controls, emergency electrical power sources, cooling or seal water, lubrication, operating procedures, maintenance procedures, test procedures and operator interface with the system, which must also be capable of performing their auxiliary or supporting functions. The limiting conditions for operation shall define the minimum safety functions for modes 1, 2, 3, 4 and 5 of operation.

The limiting conditions of operation shall require the following:

1. If the plant is critical, restore the safety function (if possible) and place the plant in a hot shutdown condition within 8 hours.

Section 2.2.3 (Continued)

2. Within 24 hours, bring the plant to cold shutdown.

3. Determine the cause of the loss of operability of the safety function. Organizational accountability for the loss of operability of the safety system shall be established.

4. Determine corrective actions and measures to prevent recurrence of the specific loss of operability for the particular safety function and generally for any safety function.

5. Report the event within 24 hours by telephone and confirm by telegraph, mailgram or facsimile transmission to the Director of the Regional Office, or his designee.

6 Prepare and deliver a Special Report to the NRC's Director of Nuclear Reactor Regulation and to the Director of the appropriate regional office of the Office of Inspection and Enforcement. The report shall contain the results of Steps 3 and 4, above, along with a basis for allowing the plant to return to power operation. The senior corporate executive of the licensee responsible and accountable for safe plant operation shall deliver and discuss the contents of the report in a public meeting with the Office of Nuclear Reactor Regulation and the Office of Inspection and Enforcement at a location to be chosen by the Director of Nuclear Reactor Regulation.

Section 2.2.3 (Continued)

7. A finding of adequacy of the licensee's Special Report by the Director of Nuclear Reactor Regulation will be required before the licensee returns the plant to power. (Implementation schedules will be established by the Commission in the course of the immediately effective rulemaking. The Task Force recommends that the rulemaking process be initiated promptly.)

PG&E Status

When this Task Force Position or some alternate becomes a regulation, PG&E will comply.

Task I.A.1.3(a) - SRO/RO in Control Room

Position

Requirements on the number and qualifications of operators to be present in the control room include the present more conservative staff practice for minimum shift staffing of licensed plants, as described in the Standard Review Plan, Section 13.1.2, NUREG-75/087, subject to the condition that there be one reactor operator and one senior operator in the control room at all times other than during cold shutdown conditions. These interim shift manning requirements will also include provision of an aide to the shift supervisor. Operating license applicants will complete personnel requirements before fuel load.

PG&E Response and Status

Pending receipt of an NRC letter containing specific instructions in this area, PG&E will meet the manning requirements specified in Section 13.1.2 of the Standard Review Plan (issued April 1979).

Task I.A.1.3(b) - Restrictions on the Use of Overtime

Position

Each licensee and applicant are required to review and revise the plant administrative procedures to assure that a sound policy is established covering working hours for reactor operators and senior reactor operators. As general guidance, it is expected that the administrative procedures will make it unlikely that personnel would have to be used for more than two consecutive work periods in excess of 12 hours and that a 12-hour rest period would be required between work periods. In the event that special circumstances arise that would cause extended periods of work in excess of 12 hours for more than two consecutive days, such work should be authorized by the Station Manager with appropriate documentation of the cause. Operating license applicants will complete the procedures before fuel load.

PG&E Response and Status

An administrative procedure has been prepared which places restrictions on the amount of overtime employees are permitted to work. This procedure specifies the requirements for limiting overtime endorsed in the latest draft of the revised ANS 3.1 standard.

Task I.A.3.1 - Prepare Applicants for New Exams

Position

There will be new scopes for the examinations and criteria for the issuance of reactor operator (RO) and senior reactor operator (SRO) based upon Commission Action on SECY 79-330E. There will be a new category on the operator and senior operator examination dealing with thermodynamics and related subjects. Time limits for applicants to complete the examination will be established. The passing grade will be increased to 80 percent overall with a minimum grade of 70 percent in each category. Senior operators will be required to take oral examinations and the requalification programs will be changed to reflect the new initial requirements for issuance of licenses. The licenses will prepare applicants for new examinations and will develop and implement new examination criteria and lecture schedules for the requalification program.

PG&E Response and Status

PG&E will implement the position as required by the NRC. The implementation will be completed before issuance of the operating license.

Task I.B.1.2 - Onsite Safety Engineering Group

Position

The licensee will accomplish the following items to implement the new criteria:

1. Establish an independent, onsite safety review group in accordance with the acceptance criteria and integrated with the operating experience evaluation function and management for operations function. This group may include personnel from the operating experience group and the shift technical advisor.

2. Provide the necessary and qualified personnel to implement the functions of the new group.

3. Prepare the procedures to be utilized by the new group to perform its function.

Near-term operating license applicants will respond to inspection findings before the license is issued.

Task I.B.1.2 (Continued)

PG&E Response and Status

PG&E believes that current review and audit organizations (plant staff review committee (PSRC), general office nuclear plant review and audit committee (GONPRAC), and the Company QA and QC organizations) meet the criteria for an independent review function. In addition, a group within the Nuclear Generation Department will be established to provide independent review of operational safety matters and industry experience. This group will interface with the plant staff to assure that relevant experience is communicated to them and that plant programs and practices are current.

PG&E also wishes to emphasize the onsite safety engineering functions of the plant nuclear engineering organization. Included in the function of this organization is the assurance that the plant operates in a safe and efficient manner through the surveillance test program, daily review of operations, and other appropriate programs. The nuclear engineering organization is part of the technical department, which reports to the plant superintendent independent of the plant operating department. The department head is a member of the PSRC. Establishment of another safety engineering group onsite is therefore a duplication of an effective and established group whose responsibility includes nuclear safety evaluation.

Task I.B.1.4 - Licensee Onsite Evaluation Capability

Position

Each licensee will establish the onsite capability to evaluate the operating history of its plant and plants of similar design. This function should be part of the independent onsite safety engineering group and may include the shift technical advisor.

Applicants for operating licenses will complete requirement prior to fuel loading.

PG&E Response and Status

The onsite capability to evaluate operating experience at Diablo Canyon rests primarily with the Shift Technical Advisors. With their education, training and experience and their presence on shift they are in the best position to make this analysis. Backup for this function is provided by the plant engineering group, quality control group and maintenance engineer.

For many years PG&E has maintained at least two formal mechanisms for exchange of operating experience between all Company plants. These mechanisms include bi-monthly meetings between various disciplines to discuss problems and exchange information and required written reports on all personnel errors or significant equipment failures. These repots are disseminated to all Company plants.

Task I.B.1.4 (Continued)

Industry wide experience is gained by participation in various groups such as EEI and NPRDS. Bulletins from the NSSS supplier and LER's are carefully scrutinized for useful information.

Information from all the above sources is integrated into the various training and requalification programs.

PG&E is currently reviewing the applicable administrative procedures to ensure that adequate means exist to disseminate this information to all operations personnel.

Task I.B.2.2 - Resident Inspector At Operating Reactors

NRC Position and NRC Commitments

A. Description:

1. IE will implement the approved resident inspector program by recruiting, training, and assigning the resident inspectors to provide a minimum of two resident inspectors at each site (where there are one or two reactors) and an additional resident inspector for each additional reactor. IE will make the necessary organization changes to support this effort.

2. IE will study the resources needed to provide a resident inspector on all shifts (24 hour/7 days), and prepare a report to the Commission.

B. Schedule: IE will place a senior resident inspector at near-term operating plants by June 1980. The selection of inspectors to man the approved program will be completed by October 1980. IE will prepare a report for the Commission discussing the resources needed for a 24 hour/ 7 day resident program by February 1980.

Task I.B.2.2 (Continued)

PG&E Response and Status

There has been one NRC resident inspector at Diablo Canyon since September 1978. A second resident inspector has been assigned and will report to the site in the near future.

Task I.C.5 - Licensee Dissemination of Operating Experiences

Position

Each licensee will review its administrative procedures to assure that operating experience from within and outside its organization is continually provided to operators and other operations personnel and is incorporated in training programs.

Operating reactors will complete by September 1980. Operating license applicants will complete by September 1980 or prior to fuel loading.

PG&E Response and Status

For PG&E status, refer to the response to Item I.B.1.4.

Task III.A.1.2(c) - Emergency Operations Center

Position

Licensee will establish a nearsite Emergency Operations Center. The EOC is to be provided with dedicated capability for communication with the onsite Technical and Operational Support Centers, NRC and other agencies and organizations required to respond to and provide support during plant emergency conditions. The EOC is to be able to access information on plant parameters; it will be sized to provide space for support of responding agencies; and it will be able to operate as a base for logistical support of onsite operations and provide information to the public.

PG&E Response and Status

The nearsite Emergency Operations Center is designated as the Offsite Recovery Center at Diablo Canyon Power Plant.

Location and Description

The Offsite Recovery Center consists of one 10' x 55' trailer which is located adjacent to the San Luis Obispo County Sheriff's Operations Facility, approximately 12 miles northeast of the site. The Sheriff's office serves as the County Emergency Operations Center (EOC).

Emergency Function

The Offsite Recovery Center is initially activated by the plant staff's Advisor to County Emergency Organization. This location serves as the interface between the Company and the county and public. If the Corporate Emergency Response Plan is activated, the Company's Recovery Manager will utilize the Offsite Recovery Center as his headquarters to provide overall direction of the recovery effort.

Habitability Objectives

The distance from the plant to the Offsite Recovery Center, the very low frequency of winds in the direction from the site to this location, and the shielding and turbulence produced by the mountainous terrain between the two locations makes special habitability provisions unnecessary.

The Offsite Recovery Center is tied into the radiological monitoring network. In addition, a radiological emergency kit is stored at the Offsite Recovery Center.

Communication at the Recovery Center and County Emergency Operations Center

These facilities are located near the San Luis Obispo County Sheriff's Office and have four different types of communication circuits. The first circuit is the County Emergency Operations Center dedicated tie line between the Technical Support Center and the Diablo Canyon control room. This circuit is a common circuit to all three locations and can be accessed from each end.

The remaining types of circuits are at the Offsite Recovery Center and include 10 CBX lines from the power plant exchange, 5-standard unlisted telephones from the Pacific Telephone Network, and a radio control console for access to the plant's UHF radio system. Included in this radio system is the ability to communicate on PG&E's Los Padres District radio system.

Task III.A.3.3 - Plant/NRC Telephone Lines

Position

A NAWAS link to the State/NRC network will be installed to notify NRC of significant events at operating power reactors. Install direct dedicated telephone lines between the plant and the NRC.

PG&E Response and Status

Four direct dedicated telephones are installed and operable at the plant. A fifth unit is installed and operable at the temporary location of the emergency operations center. These phones communicate directly with the NRC emergency operations center in Bethesda.

A separate direct and dedicated line and telephone has been installed in the Control Room for health physics and environmental information purposes. This phone has the capability to communicate directly with either Bethesda or Region V headquarters.

Task I.D.1. - Control Room Design Review

Position

Perform comprehensive review of control room using NRC human factors design guidelines and evaluation criteria. Modify to correct significant deficiencies. Issue report describing methods of review, results of review, including bases for findings made, and implementation schedule. Applicants to be granted operating licenses prior to September 1981 must perform a preliminary assessment of their control rooms to identify and correct significant human factors and instrumentation deficiencies.

Licensees and applicants will complete review and implement short lead-time revisions by September 1981 or prior to issuance of operating license, whichever is later. Long lead-time revisions will be completed by April 1982 or prior to issuance of operating license, whichever is later.

PG&E Response and Status

During mid March 1980, PG&E reviewed the Diablo Canyon Unit 1 Control Room to identify and correct, if found, any significant human factors and instrumentation deficiencies. Additionally any modifications which could simplify and ease the operator's job were reviewed. The report of this review follows.

Task I.D.1 (Continued)

REVIEW METHODOLOGY:

The layout and design of the control room and control boards at Diablo Canyon was a cooperative effort between instrumentation and control system engineers and operating department personnel with nuclear power plant operating experience. As a result, the design placed emphasis on proper functional grouping rather than employing continuous rows of identical devices prevalent in other control boards of the same vintage. Experience gained during startup testing led to further improvements in the layout. In accomplishing the control room review, it was recognized that changes made over the years could have affected the original design intent. A review team was formed that included instrumentation and control system engineers, electrical engineers, and operating personnel. The operating personnel on the team were selected because they are directly responsible for operator training and are familiar with those control board features which were sometimes troublesome or confusing to operators during training and testing sessions.

The first step in the review was for the operator training personnel to review the control board layout and find any changes which might be desirable to eliminate possible confusion and to simplify the operator's job. This step took approximately 2 man-weeks to accomplish and resulted in proposed changes which included bolder labeling, more demarkations, module changes, label revisions, and annunciator window relocations and relabeling. Because of the care used in the original control board layout, most of the changes were minor. Many of the changes involved revisions as a result of experience at TMI or requirements of Regulatory Guide 1.97.

Task I.D.1 (Continued)

The next step in the review was the development of review and acceptance criteria. These criteria are listed in Attachment 1 and were developed by considering the documents referenced therein. This step required about twelve man-days of effort.

The last step prior to the actual walkdown was the review of each module relocation proposed in the first step in light of the criteria, revisions not yet finalized, and their effect on operation.

The actual control room walkdown required an effort of approximately nine man-days by the review team.

MAJOR FINDINGS OF THE CONTROL ROOM REVIEW:

A. General Control Room:

All lighting levels in the control room, ranging from full illumination by AC-powered fluorescent lights to the illumination provided only by battery-powered emergency lights, were found to be acceptable. Although there was no problem with the fully illuminated room, the most comfortable lighting level was with three banks of normal AC powered lights turned off.

The present furniture layout in the control room is for temporary use during construction. The permanent furniture layout will consider easy access to plant procedures and an adequate work area.

Task I.D.1 (Continued)

The tops of the control consoles were found to be well designed to provide laydown room for procedures and schematics for use at the vertical boards. It was noted that plasticized copies of schematics and location drawings were kept at these locations.

The control console writing surface was found to be inconvenient to use because the operator's telephone was located there.

1. Action Item: Mount the operator's telephone adjacent to, but not on, the control board writing surface by fuel loading.

Several annunciator lists were found to be obsolete. They were properly marked as obsolete, but the operator should have current lists.

2. Action Item: Provide current lists and schematics by fuel loading.

Each section of the control board as well as the RMS, NIS, and Incore Racks had a telephone jack.

The noise level in the control room was quite acceptable. Typewriters were the major source of noise, and normal conversations could be carried on at 15-20 feet. Personnel could communicate from corner to corner of the room using reasonably raised voices. The operators noted that, during startup testing, there was no appreciable rise in noise level.

Task I.D.1 (Continued)

B. Annunciator:

The two separate annunciator systems (main and computer) had distinct and readily identifiable audible alarms. No provisions for separate sounds for each panel were provided, and all operators polled during the walkdown opposed the addition of this feature.

Three colors are used for the annunciator panels; red for critical alarms, white for other alarms, and yellow for alarms which are normally on during full power operation. In all cases, the lit windows were quite visible against the background, even with one of the redundant bulbs burned out. Some red windows had faded with age, but no corrective actions appeared necessary other than routine maintenance. A yellow window with a burned-out bulb was found to be difficult to distinguish from a white window with a burned-out bulb unless the two are next to each other. Yellow is used elsewhere (on indicator faces) to denote caution areas instead of "normal" as used on the annunciator. Yellow lenses are also used on large tank level indicators.

3. Action Item: As a long-term item, investigate colors other than yellow for alarms normally on during full power operation.
4. Action Item: Remove yellow lens tints on indicator lenses by fuel loading.

All annunciator windows met the basic visibility criteria. Several lettering styles existed, and one was definitely inferior. The others were acceptable, but one, the heavy-lined style most recently adopted, was superior.

Task I.D.1 (Continued)

5. Action Item: All future windows will use the new heavy-lined lettering. All of the inferior lettering will be replace by fuel loading.

Labeling on some of the windows was not self-explanatory and did not conform to the PGandE approved standard abbrevations list.

6. Action Item: Revise annunciator windows to conform to PGandE approved standard abbreviations by fuel loading.

Some windows were not above the control panel that would be used to respond to the alarm.

7. Action Item: As a long-term item, relocate the annunciator windows to more nearby above the proper panel.

There are several peripheral annunciators in the control room which are related to the fire system and which alarm on the main annunciator. Several problems were found with window labeling and arrangement. The major problem identified with the peripheral annunciator was a lack of reflash capability.

8. Action Item: As a long-term item, relabel and rearrange fire system annunciators.

9. Action Item: As a long-term item, review reflash capability of fire system annunciators.

Task I.D.1 (Continued)

C. Main Control Board:

The layout revisions identified as desirable, in order to improve functional grouping, were reviewed for feasibility. All problems were resolved during the review.

10. Action Item: Proceed to implement layout revisions associated with TMI and Regulatory Guide 1.97 issues on a time schedule consistent with regulatory requirements. Other layout revisions will be implemented on a long-term basis.

Most of the existing demarkation lines on the main control board are adequate. However, large scale labeling and additional demarkations as described in EPRI NP-1118 would be an improvement.

11. Action Item: Add large scale labeling and more demarkations by fuel loading.

The same abbreviation inconsistency was found that was noted for the annunciators. All labels could be read at 4 feet, the acceptance criteria limit.

12. Action Item: Revise inconsistent main control board labeling by fuel loading.

All indicators had their labels immediately below them and all switches and controllers had their labels on the modules between the switches and the lights or indicators. This placement of switch labels assures nameplate visibility during switch operation.

Task I.D.1 (Continued)

Glare on the indicators had no effect on the ability to read any indicator or recorder at normal lighting levels. At lower lighting levels, the glare became more apparent. When using only battery-operated lights, glare was significant enough to require head movement to read portions of the scales. This head movement created no parallax problem for indicators, but did result in parallax problems with certain recorders above the eye level of short people. These recorders are all related to turbine startup, and would not be used under these lighting conditions.

Controls were examined to determine whether they could be operated by operators with differing physical characteristics, as well as whether inadvertent operation would be likely. It was determined that all operators would be able to reach all controls with ease. If operation requires leaning over a control board, inadvertent operation of controls is unlikely. The edges of all switch handles located on control boards with vertical sections were at least 3 inches from the edge of the board. Two switches related to generator voltage adjustment, located on the console, came within 2-1/2 inches of the edge of the board. Inadvertent operation is very improbable due to the lack of vertical sections on this board. Even if inadvertent operation occurred, it would have no detrimental effect on plant safety.

Task I.D.1 (Continued)

Even though most of the indicators would be above a short person's eye level, he would have no trouble reading the indicators and would not experience any parallax problems. This is due to the split-depth scale of the Westinghouse VX252 indicator which is used at Diablo Canyon. The indicator pointer is on the same plane as the scale itself, so parallax is eliminated.

A few indicators had black pointers instead of the normal fluorescent red.

13. Action Item: Paint black indicator pointers on VX252s fluorescent red by fuel loading.

All indicators had movement space below "zero". "Zero" is at 4 mA, so that on loss of signal the needle drops below scale.

Several problems were noted with scales that had minor divisions not equal to 1, 2, or multiples of 5, and in some cases had less than optimal designations (e.g., 0 - 150°C was used where 32 - 300°F should be used to be consistent).

14. Action Item: Modify non-optimal indicator scales by fuel loading.

Our present method of indicating acceptable ranges on indicators is with green, yellow, and orange transparent strips on the lens face over the scale. A short person would have parallax problems with this system on the gauges mounted higher on the panel. Placing these strips directly on the scale face would eliminate this problem.

15. Action Item: Move range demarkation strips from the indicator lens face to the gage face under the pointer by fuel loading.

Task I.D.1 (Continued)

There is a standard arrangement and meaning of indicator lights on switch modules. Several modules were found which violate this standard.

16. Action Item: As a long-term item, modify non-standard switch modules. In those cases where the standard is not applicable, label indicator lights, as required.

To replace a monitor or status light bulb, the entire indicator module must be removed. If two indicator modules were removed simultaneously, they could be replaced in the wrong positions.

17. Action Item: Write a procedure, by fuel loading, to administratively control indicator module removal, for light bulb replacement, to allow only one module at a time to be removed.

The monitor light boxes indicate when important valves are not in their required position or pumps are not operating as required. Three of the four light boxes have their light potential busses deenergized except when safeguards actuation has been initiated. When all lights are off all inputs are satisfactory. All lights would also be off if a power failure had occurred.

18. Action Item: As a long-term item, provide an indication of voltage availability.

The status light boxes provide an indication of the status of the reactor protection system. No indication of power availability is provided.

Task I.D.1 (Continued)

19. Action Item: As a long-term item, connect one window to indicate power availability. As the lights are related to separate channels each of which is powered from a different power source, a light for each source will be required.

There are identical lights and pushbuttons on the turbine control and valve test panels. The PGandE convention is to distinguish between lights and pushbuttons by using black barriers for lights and white barriers for pushbuttons.

20. Action Item: Replace black barriers with white barriers on lit pushbutton switches by fuel loading.

There is presently no means to test the by-pass and permissive light boxes.

21. Action Item: As a long-term item, add test capability to the by-pass and permissive light boxes.

There were several kinds of tags that may be attached to switches and indicators, and that could obstruct other switches or lights.

22. Action Item: Investigate alternative tags for control board switches and implement any required changes by fuel loading.

Task I.D.1 (Continued)

Conclusion

The control room review for Diablo Canyon was intended to identify and correct any significant human factor and instrumentation deficiencies. Additionally the review identified many changes which could be made to improve operator efficiency. Few, if any, deficiencies were found that could be categorized as significant, and certainly no deficiencies were found which could have an adverse effect on Reactor Safety. Implementation of the modifications identified is desirable to provide a more efficient and convenient control room design.

Summary of Action Items

The action items resulting from the review are as follows:

A. GENERAL CONTROL ROOM:

1. Mount the operator's telephone adjacent to, but not on, the control board writing surface by fuel loading.

2. Provide current lists and schematics by fuel loading.

Task I.D.1 (Continued)

B. ANNUNCIATOR:

3. As a long-term item, investigate colors other than yellow for alarms normally on during full power operation.

4. Remove yellow lens tints from indicator lenses by fuel loading.

5. Replace inferior annunciator labeling by fuel loading.

6. Revise annunciator windows to conform to PGandE approved standard abbreviations by fuel loading.

7. As a long-term item, relocate the annunciator windows to more nearly above the proper panel.

8. As a long-term item, relabel and rearrange fire system annunciators.

9. As a long-term item, review reflash capability of fire system annunciators.

C. MAIN CONTROL BOARD:

10. Proceed to implement layout revisions associated with TMI and R.G. 1.97 issues on a time schedule consistent with regulatory requirements. Other layout revisions will be implemented on a long-term basis.

Task I.D.1 (Continued)

11. Add large scale labeling and more to demarkations by fuel loading.

12. Revise inconsistent main control board labeling by fuel loading.

13. Paint black indicator pointers on VX252s fluorescent red by fuel loading.

14. Modify non-optimal indicator scales by fuel loading.

15. Move range demarkation strips from the indicator lens face to the gage face under the pointer by fuel loading.

16. As a long-term item, modify non-standard switch modules. In those cases where the standard is not applicable, label indicator lights, as required.

17. Write a procedure, by fuel loading, to administratively control indicator module removal, for light bulb replacement, to allow only one module at a time to be removed.

18. As a long-term item, provide an indication of voltage availability.

19. As a long-term item, connect one window to indicate power availability. As the lights are related to separate channels each of which is powered from a different power source, a light for each source will be required.

Task I.D.1 (Continued)

20. Replace black barriers with white barriers on lit pushbutton switches by fuel loading.

21. As a long-term item, add test capability to the by-pass and permissive light boxes.

22. Investigate alternative tags for control board switches and implement any required changes by fuel loading.

ATTACHMENT I

DIABLO CANYON POWER PLANT

CRITERIA FOR HUMAN ENGINEERING FACTORS

CONTROL ROOM EVALUATION

I. CONTROL ROOM - GENERAL

A. The general layout and equipment in the control room should provide:

1. Adequate space for personnel and their equipment to perform necessary tasks for normal and emergency operations.

2. Adequate illumination for the performance of operation, emergency operation and training.

3. Satisfactory temperatures for operator comfort (75°F), protection against airborne toxic gases (specifically chlorine), airborne radioactivity, smoke from fires inside or outside of the control room, and provision to control CO_2 buildup during periods when airborne contaminates prevent use of outside air.

4. An acceptable range of background noise level to minimize stress and allow adequate internal communication.

5. Adequate physical, visual, auditory, and other communication between personnel and their equipment.

6. Provisions for exclusion of unauthorized personnel to prevent overcrowding, and confusion.

7. Minimal operator fatigue during intended shift time, i.e., eye pleasing colors should be used, adequate comfortable furnishings and meal preparation equipment provided.

B. Procedures:

1. Storage: Adequate space and facilities should be provided for proper storage and use of all procedures, documents, and reference drawings necessary for operation.

2. Indexing: All the above materials should be properly indexed in a manner consistent with the requirements for use of the materials.

3. Priority: Often used materials, or materials of an emergency nature, (such as emergency procedures) should be marked such that they are readily distinguished from lesser used or less important materials.

4. Format: All operating procedures should be written in consistent, approved format.

II. CONTROL - BOARDS

A. Labeling. Existing control board labeling should be examined for:

1. Accuracy: Does printed matter on label clearly and accurately describe identified component.

2. Visibility: Labeling should be sized to be readable at a minimum distance of 4 feet from the label.

3. Association: Labels shall be consistently placed so the association of labels with their corresponding panel elements is unmistakable.

4. Abbreviations: All abbreviations should be clear and consistent with approved abbreviation list.

5. Coding practices: Any color coding or other form of coding should remain consistent and clear throughout the control board.

B. Controls. Control selection and arrangement (valves, circuit breakers, selectors, process controls) should provide:

1. Functional Grouping: Functionally related controls should be located in proximity to one another. The boundaries of these functional groups should be well identified.

2. Sequencing: Except on mimic portions of the control board, a group of identical function controls (such as feedwater valves to each steam generator) should be arranged from top to bottom or from left to right.

3. Association: Controls or functional groups of controls should be located as near as possible to indications or instrumentation necessary for proper control operation.

4. Consistency of Location: Location of recurring functional groups of controls should be consistent from group to group.

5. Inadvertent Operation: All controls should be protected against inadvertent operation, either by design or location.

6. Consistency of Operation: Identical control units should perform intended function in the same manner, i.e., all circuit breakers should be closed by turning control to right. All valves should be opened by turning control to right. Any necessary exceptions should be unmistakably labeled as such.

7. Importance: Controls affecting critical operations, or whose accidental operation could have severe consequences, should be consistently and unmistakably identified.

8. Feedback: Instrumentation or indication should be provided to display control response.

9. Movement Relationships: Feedback and control must have compatible motion, i.e., if control is moved to the right or raised, the feedback must change to the right or raise. Any necessary exceptions should be clearly and unmistakably labeled.

C. Instrumentation and indications

1. Location and Arrangement

a. Accuracy: Instruments should be located where they can be read in the degree of accuracy required by operators in the normal operating positions. (Using no ladders - stools, etc.)

b. Orientation: Display faces should be perpendicular to the operators normal line of site whenever possible. Location should be proper to minimize parallax.

c. Grouping: Displays should be arranged in functional groups, with boundaries of these groups well defined.

d. Display-Control Relationship: Any displays, instruments or groups of displays should be located as close as possible to any controls directly affecting those displays.

e. Importance: Very important or critical displays should be placed in a privileged location or otherwise highlighted.

f. Consistency: The arrangement of displays should be consistent from application to application.

2. <u>Indicating Lights</u>

a. Equipment Response: Lights shall display actual equipment response and not control position or demand signals.

b. Positive feedback: The absence or loss of illumination on indicating lights should not be used to denote a go ahead, ready, in tolerance, malfunction or out of tolerance condition.

c. Location: When indicating lights are associated with a control, those lights shall be located as to be immediately and unambiguously associated with the control and visible during control operation.

d. Luminance: The brightness of display lights should at all times be clearly brighter than background levels.

e. Reflection: Provision should be made to prevent lighting from causing reflection that makes displays appear lighted or extinguished when they are not.

f. Color coding: The color coding of indicator lights shall be consistent throughout the control room.

g. Lighted pushbuttons: Where indication only lights are mixed with indicator/pushbuttons, the differences should be clearly indicated.

3. Scale Indicators (Direct Reading Instrument)

a. Linear Scales: Except where system requirements clearly dictate non-linearity, only linear scales should be used.

b. Graduations: Scale graduations should progress by 1, 2 or 5 units or multiples thereof.

c. Intermediate Marks: The number of minor or intermediate marks between numbered scale marks should not exceed 9.

d. Major Marks: Except for measurements normally expressed in decimal form, all major marks should be expressed in whole numbers.

e. Starting Point: Display scale should start at zero, where appropriate.

f. Pointers: Pointers should be sized as to not obscure graduation marks on the scale, and be mounted as close to the scale as possible to minimize parallax.

g. Calibration Information: Provision should be made for placing calibration information on gauge without obscuring any part of gauge display.

h. Coding: Scale faces should be coded, where applicable, to indicate:

desirable range - green
undesirable range - yellow
caution or action area - orange

coding shall be consistent.

i. Consistency: All instruments shall move up (vertical) or to the right (horizontal) or clockwise (circular) to indicate an increase in measured parameter.

4. Printers and Recorders

a. Form of Information: Printed information should be presented in a usable form.

b. Insertion/Removal of Materials: Printers should be designed for quick and easy insertion/removal of materials.

c. Visibility: Printed matter should be arranged so it is readable immediately after printing and available for review any time subsequent to being printed.

d. Illumination: The printer should be arranged with internal illumination if printed matter is not compatible with expected lighting in printer area.

III. ANNUNCIATORS

A. Audio Signals: Audio signals for annunciators should clearly direct the operator to the appropriate annunciator system.

B. Printed Matter: Printed matter on annunciator windows should clearly and unmistakably relay the message intended by the window. Any abbreviations should be clear and consistently used.

C. Visibility: All main annunciators should be visible and readable from a minimum of 20 feet from the panel.

D. Location: Annunciator windows should be located so they "draw" the operator to the area of the control board necessary to check or correct conditions causing the alarm.

E. Lamp Failures: Annunciator lights should be provided with dual bulbs so a burned out bulb will not prevent operation. Provisions to test lamps should be provided.

F. Priority: Annunciator windows representing serious or important alarms should be colored red.

G. Normally Lit Annunciators: Annunciator and status light windows which are normally lit at power should be color coded yellow.

H. Status Lights: Panels containing status lights should have black painted frames to clearly separate these panels from annunciator panels.

REFERENCES

1. EPRI Reports NP-1118 and NP-1118-SY.

2. Rogavin Report, Pp. 180-234 and 335-398, Volume II.

3. Military Standard 1472B.

4. Transactions ANS, Volume 33, Pp. 556-567.

5. IEEE Standard 566-1977.

6. PGandE Standard Drw. 023607.

Task I.G.1 - Training Requirements During Preoperational and Low-Power Testing

Position

Near-term operating license facilities will be required to develop and implement intensified training exercises during the low power testing programs. Licenses will (1) define training plan prior to loading fuel, and (2) conduct training prior to full-power operation.

PG&E Response and Status

See attached letter from PG&E to NRR of February 7, 1980.