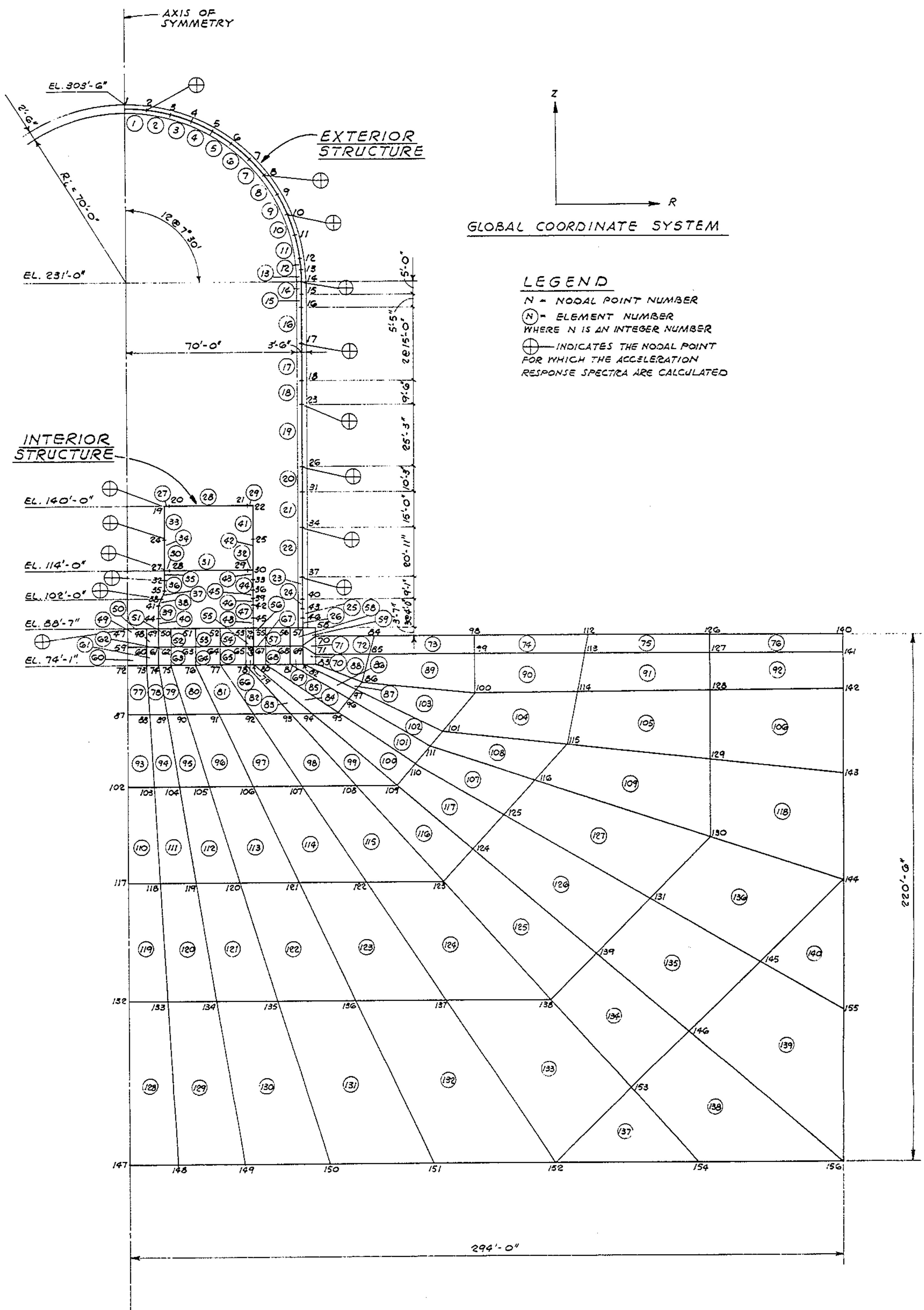


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7-5

CONTAINMENT STRUCTURE

FINITE ELEMENT MODEL

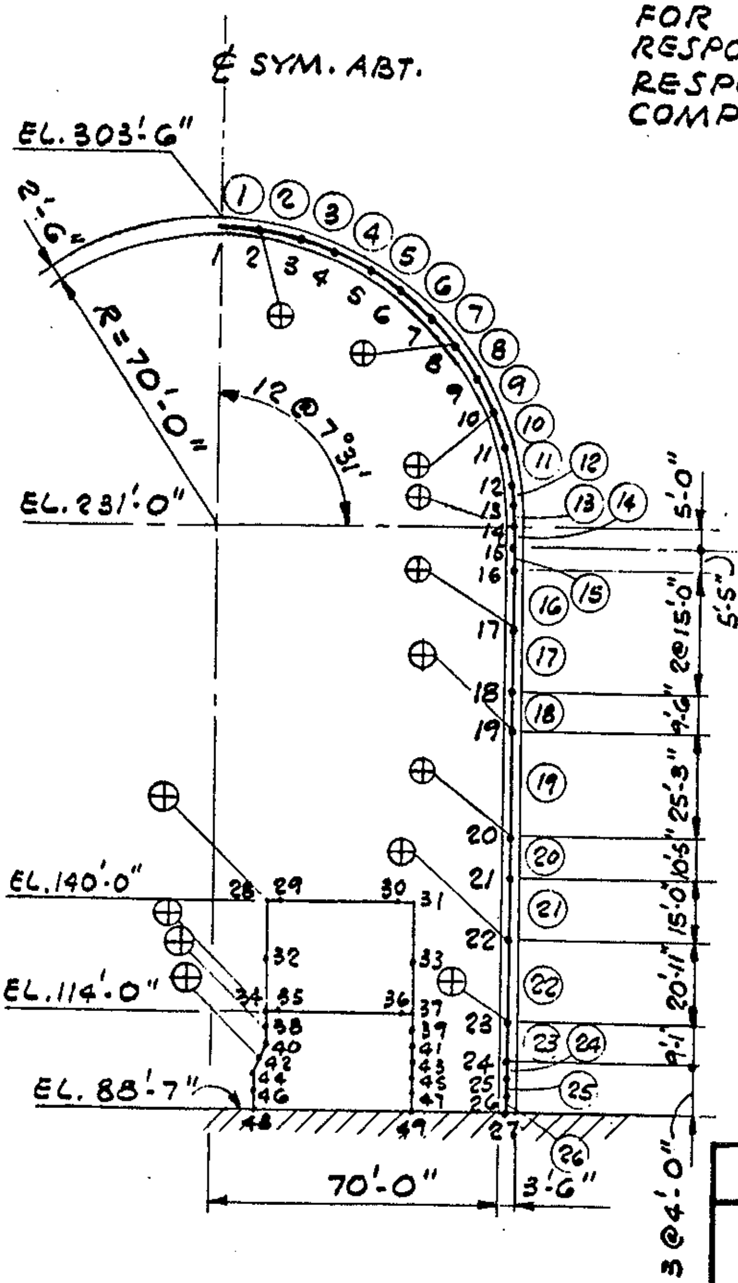
Revision 11 November 1996

LEGEND

10 NODAL POINT NUMBER

(7) ELEMENT NUMBER

⊕ INDICATES NODAL POINTS FOR WHICH STRUCTURE RESPONSES AND ACCELERATION RESPONSE SPECTRA ARE COMPUTED

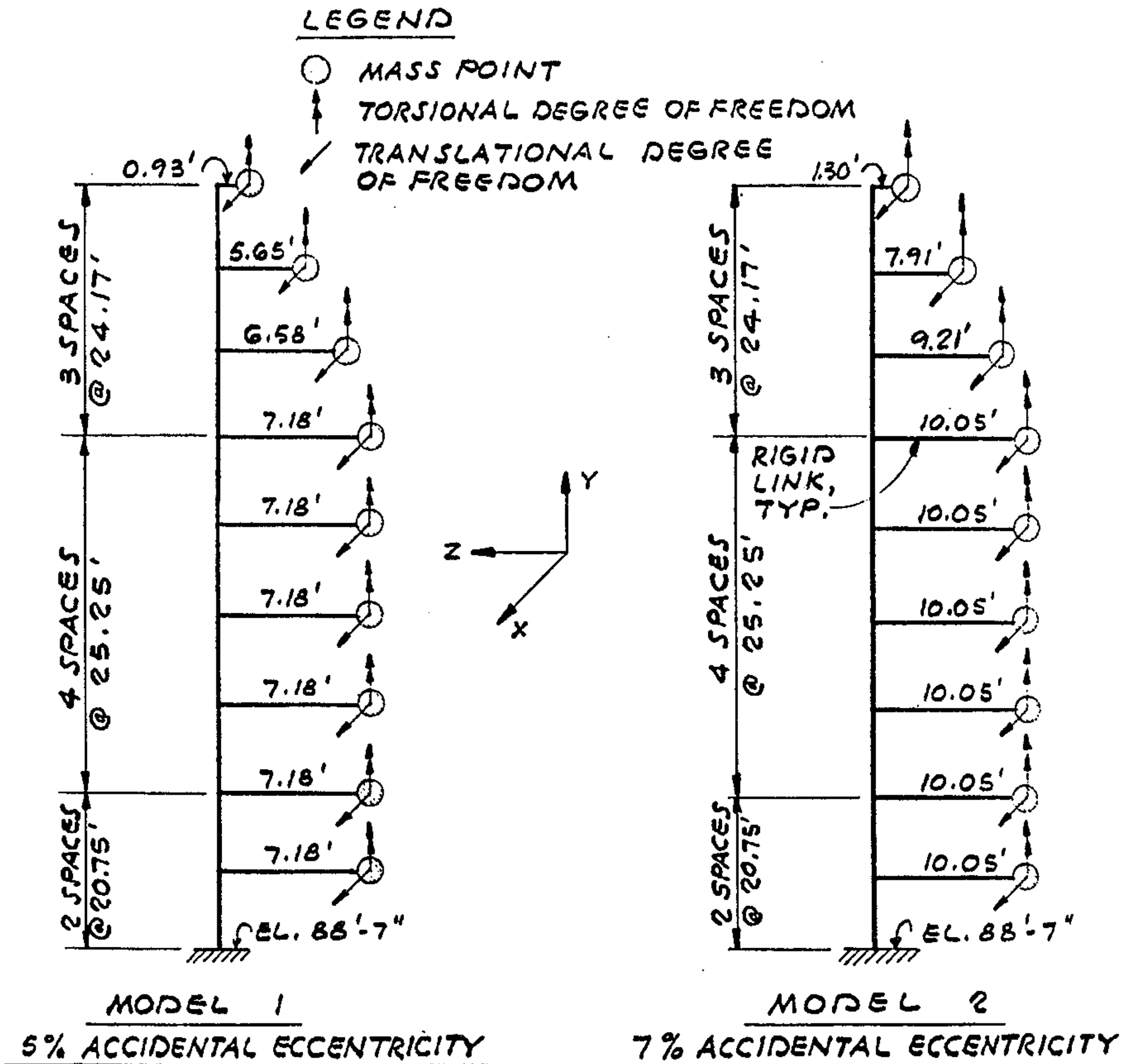


Note: Used for horizontal and vertical analysis of exterior shell and horizontal analysis of internal structure

FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

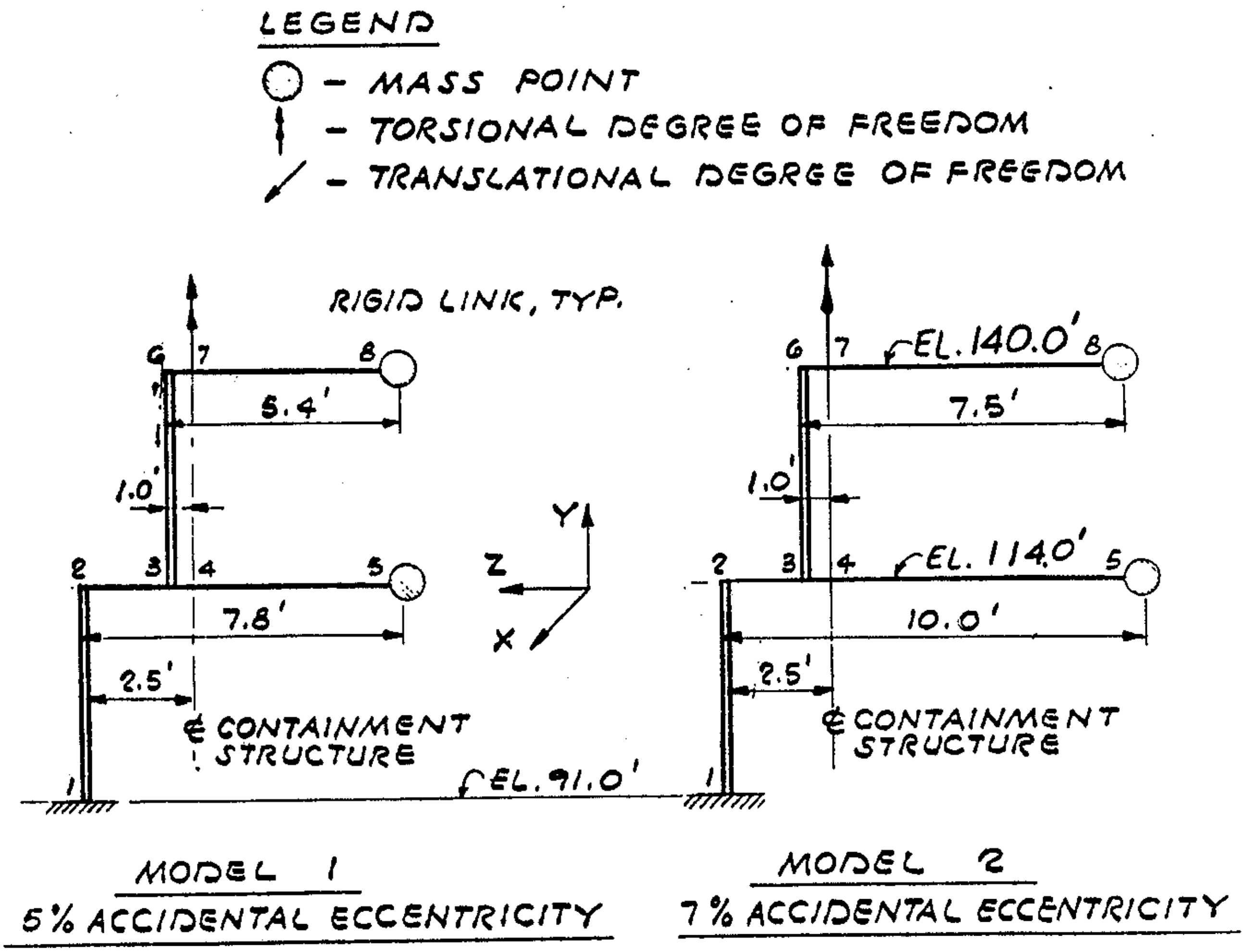
FIGURE 3.7 - 5 A
CONTAINMENT STRUCTURE
FINITE ELEMENT MODEL



FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

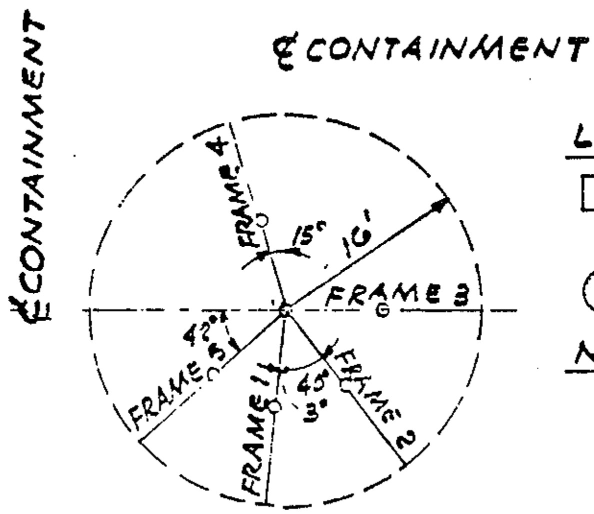
FIGURE 3.7-5 B
CONTAINMENT STRUCTURE EXTERIOR SHELL MATHEMATICAL MODELS FOR TORSIONAL ANALYSIS



FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

FIGURE 3.7 - 5 C
CONTAINMENT INTERIOR STRUCTURE MATHEMATICAL MODEL FOR HORIZONTAL AND TORSIONAL ANALYSIS



LEGEND:

[1] — ELEMENT NUMBER

2 — NODE NUMBER

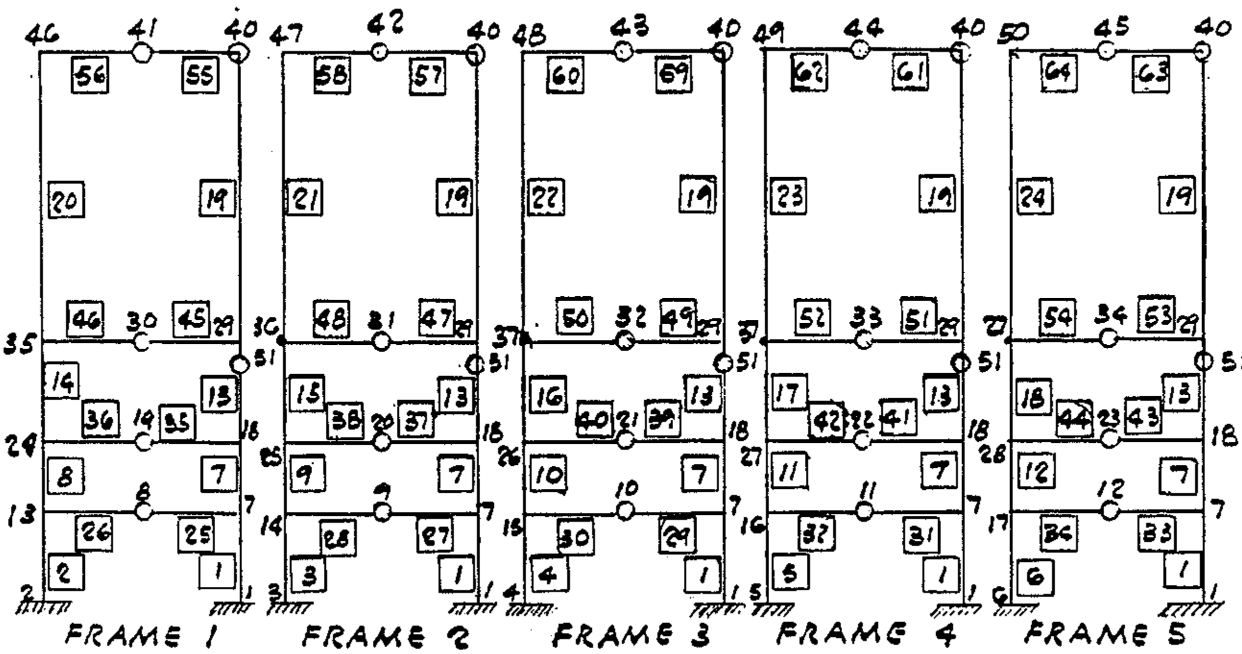
○ — MASS POINT

NOTE:

NODES 1, 7, 18, 29, 40 & 51 ARE ALONG ℄ OF STRUCTURE AND ARE COMMON TO ALL FIVE FRAMES

PLAN

UNIT 2

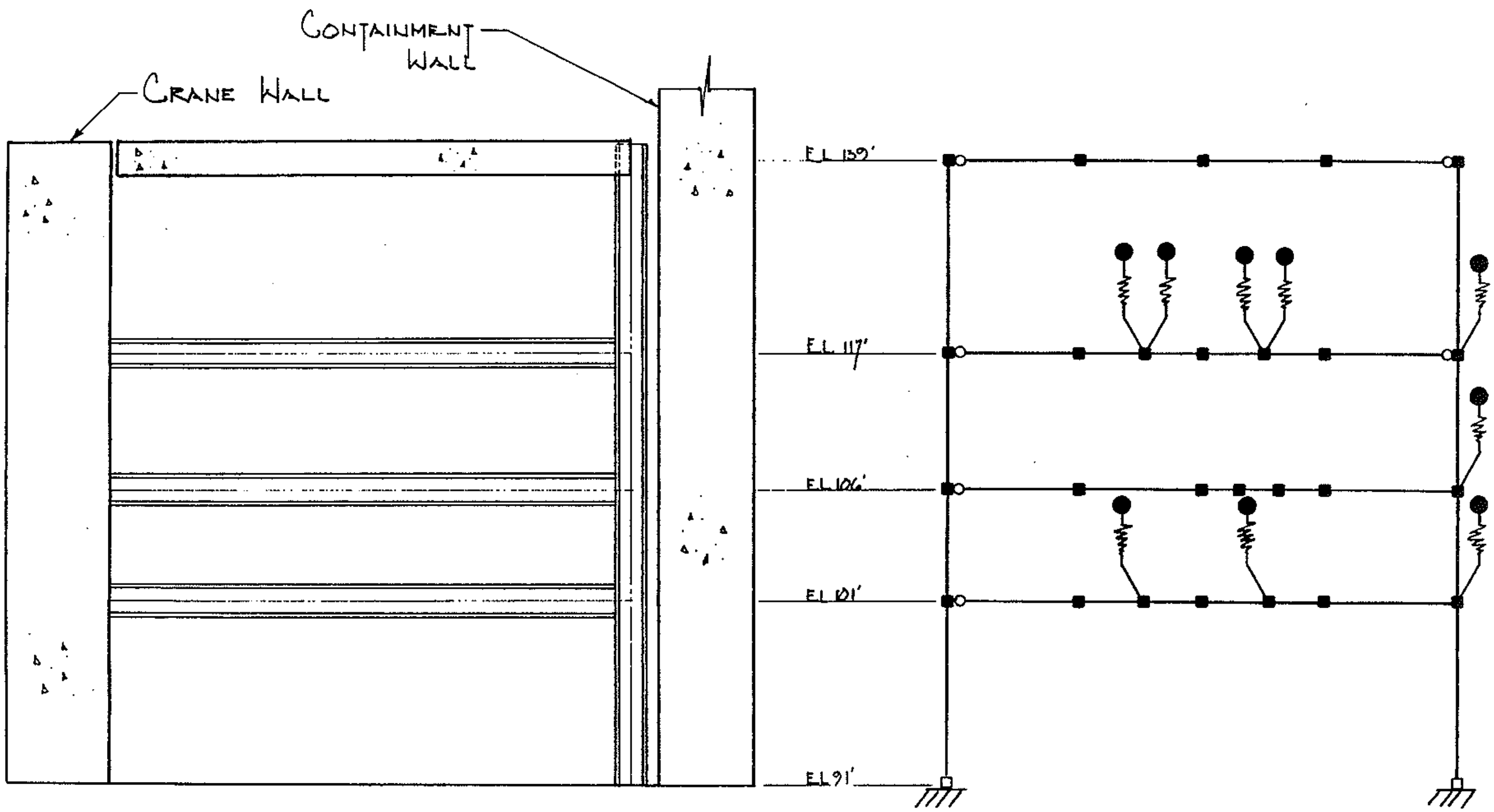


ELEVATIONS

FSAR UPDATE

UNIT 2
DIABLO CANYON SITE

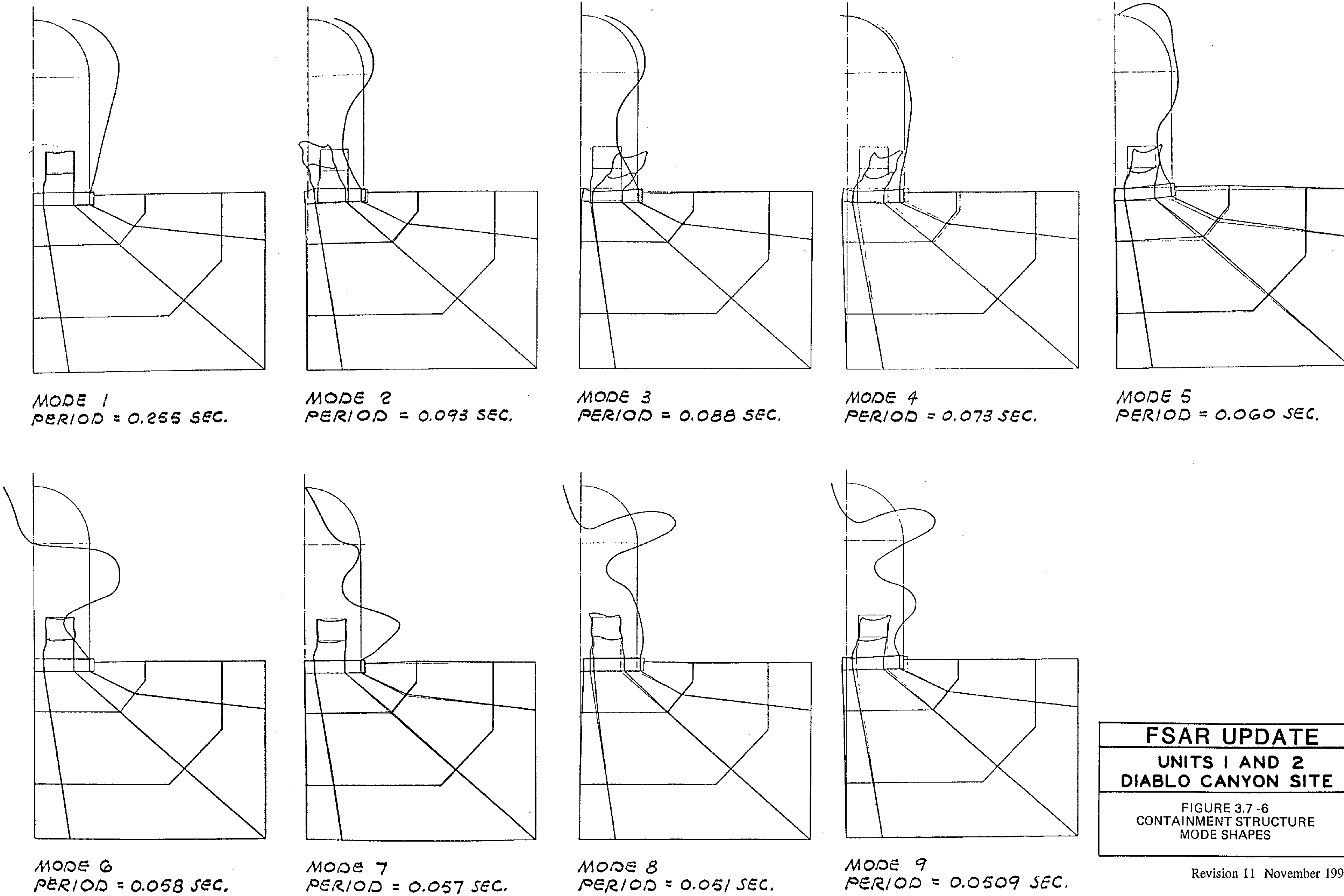
FIGURE 3.7 - 5 D
MATHEMATICAL MODEL FOR VERTICAL ANALYSIS OF CONTAINMENT INTERIOR STRUCTURE



FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

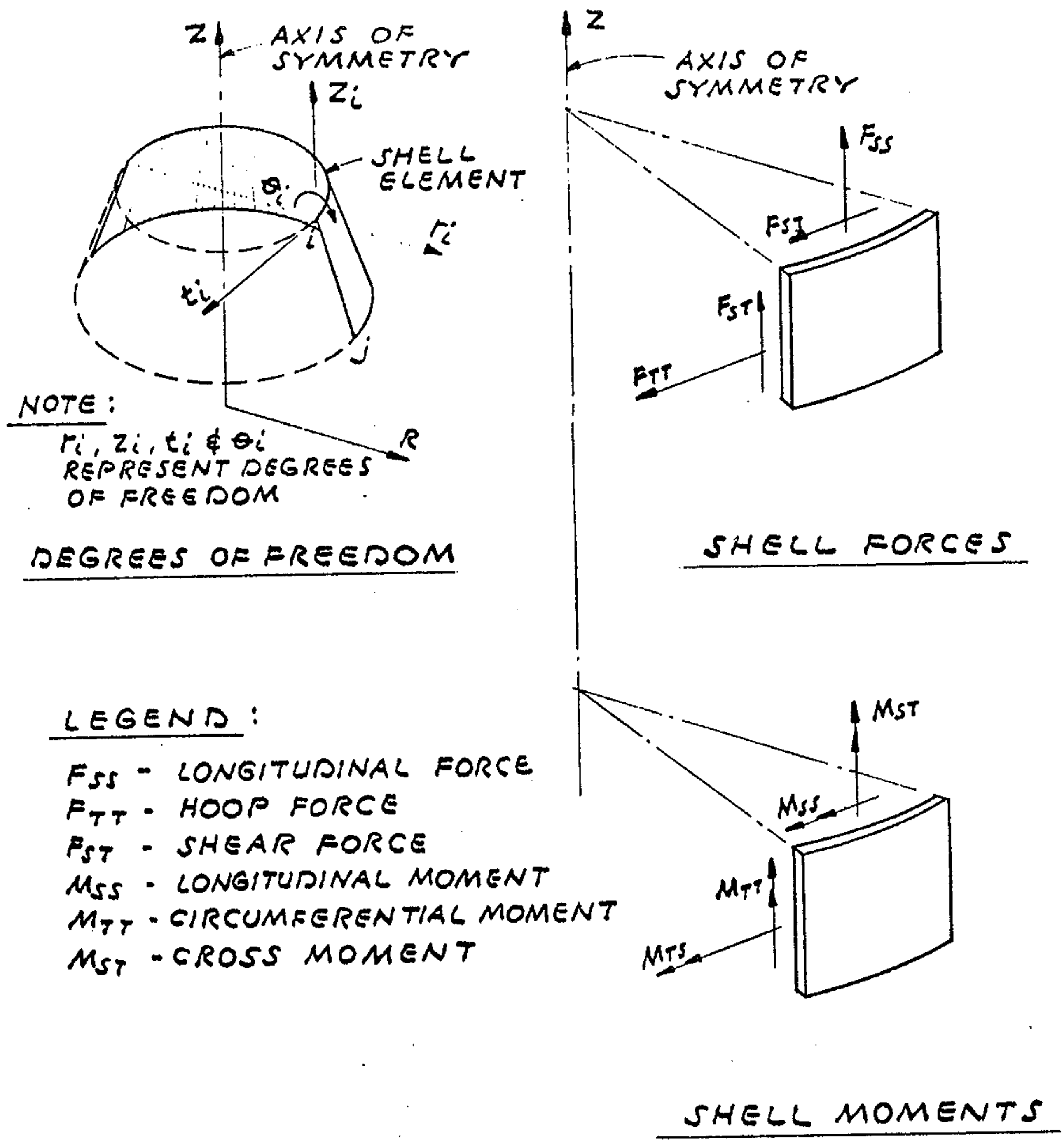
FIGURE 3.7 - 5 E
FRAME ANALYSIS FOR
VERTICAL RESPONSE
COLUMN LINE 6
(FRAME 6)



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

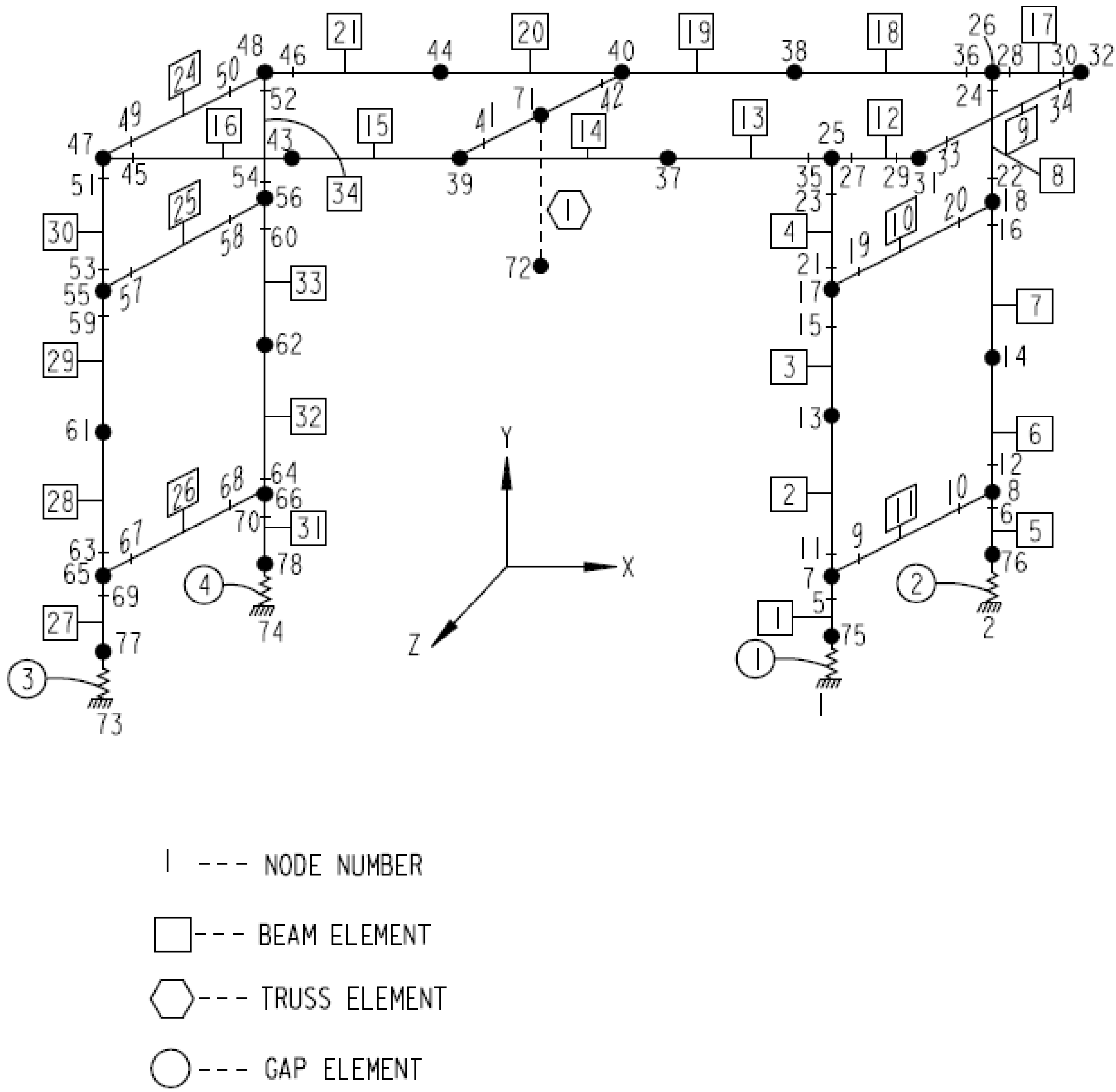
FIGURE 3.7-6
CONTAINMENT STRUCTURE
MODE SHAPES



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7-7
CONTAINMENT STRUCTURE
SHELL FORCES AND MOMENTS
AND ELEMENT DEGREES OF FREEDOM

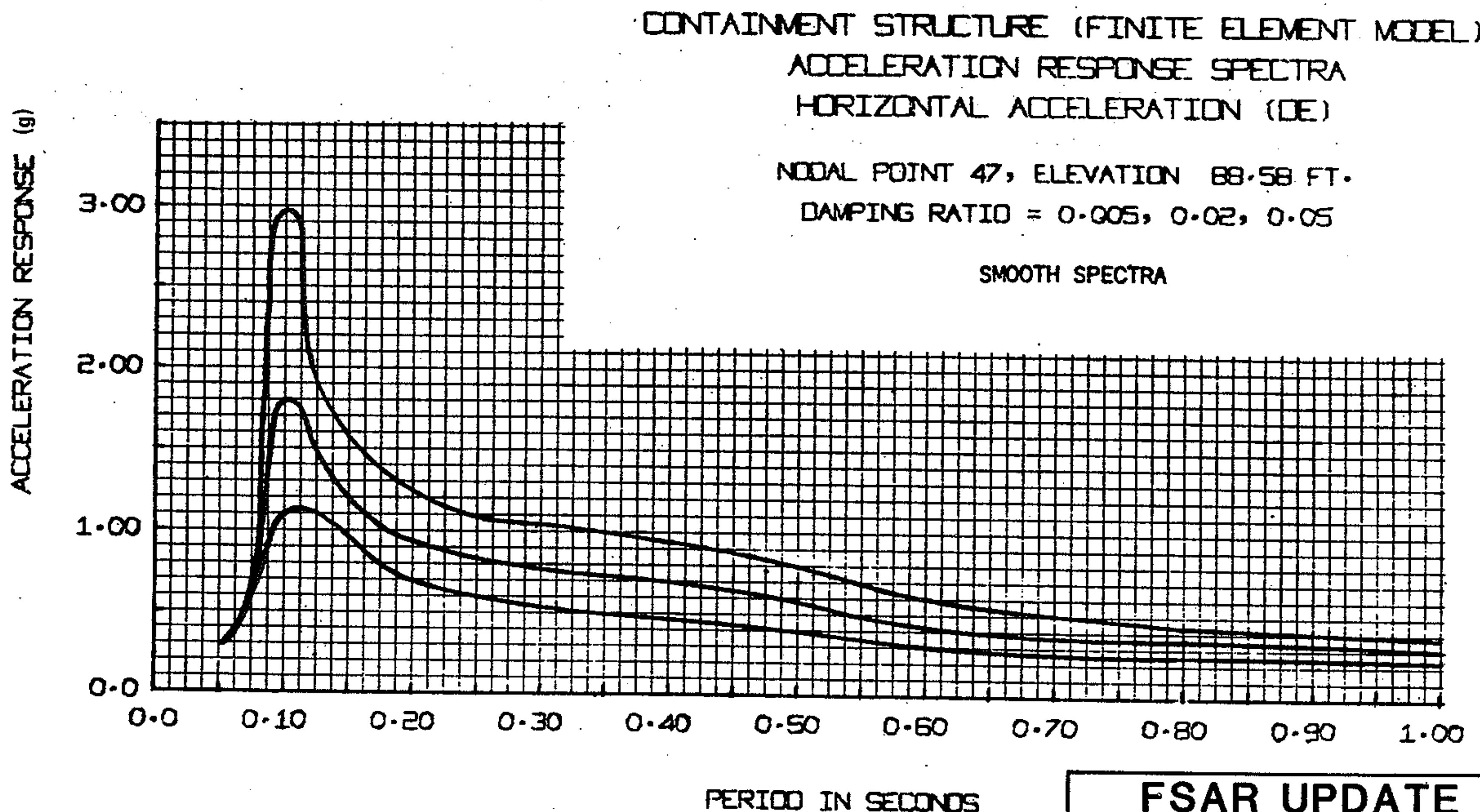


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7-7A

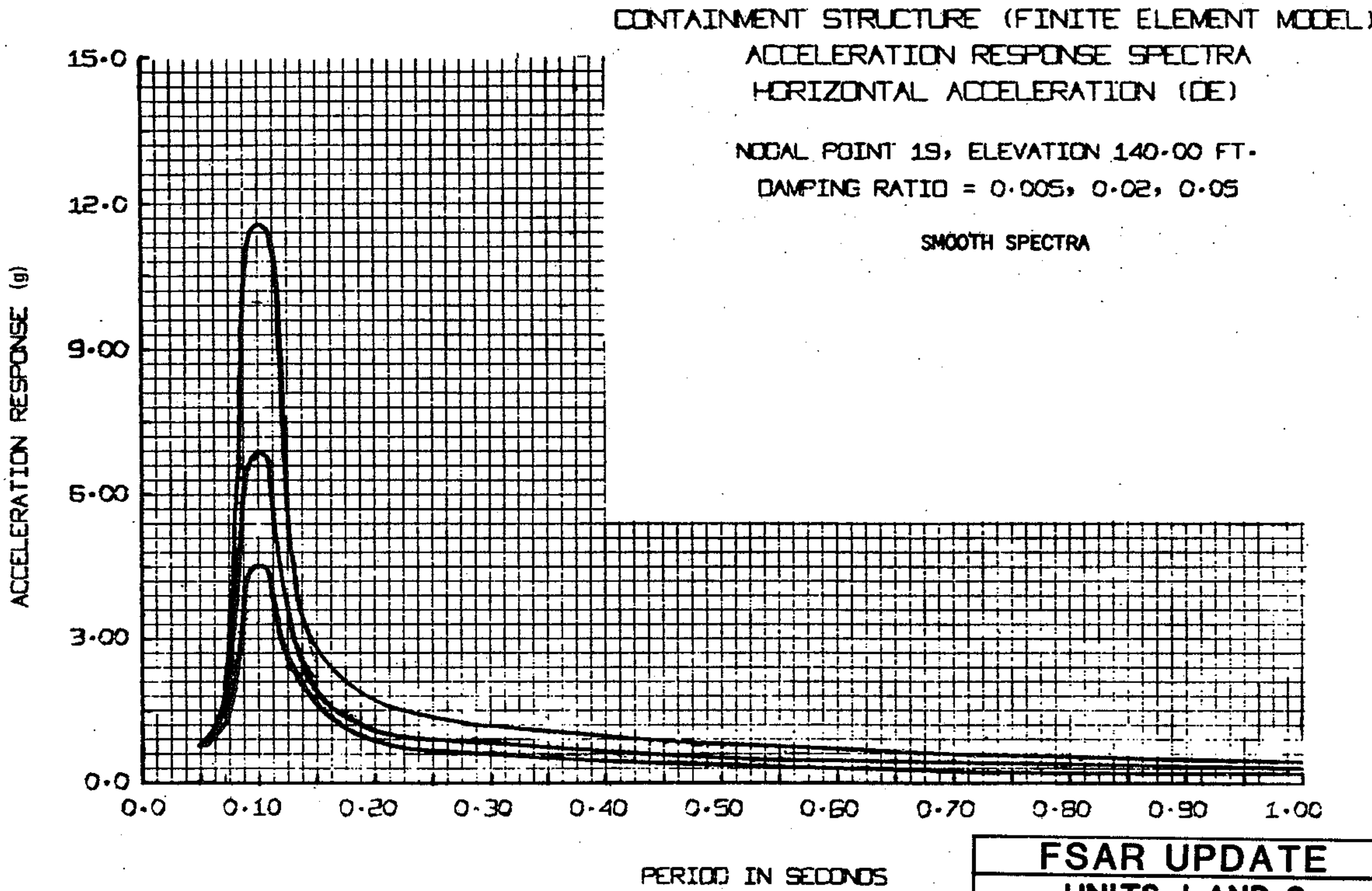
POLAR CRANE THREE DIMENSIONAL NONLINEAR MODEL



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

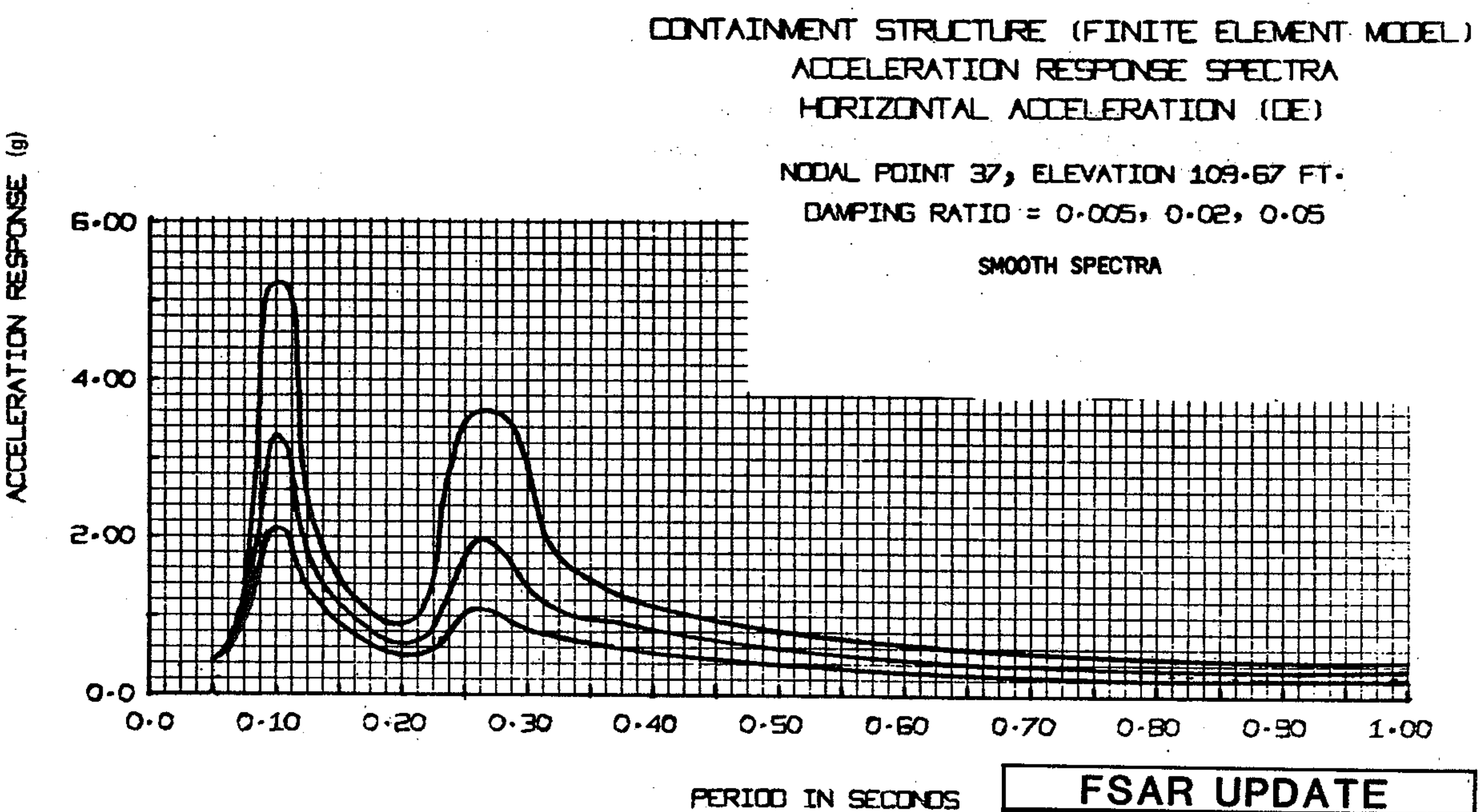
FIGURE 3.7-8
CONTAINMENT STRUCTURE
TYPICAL SPECTRA



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

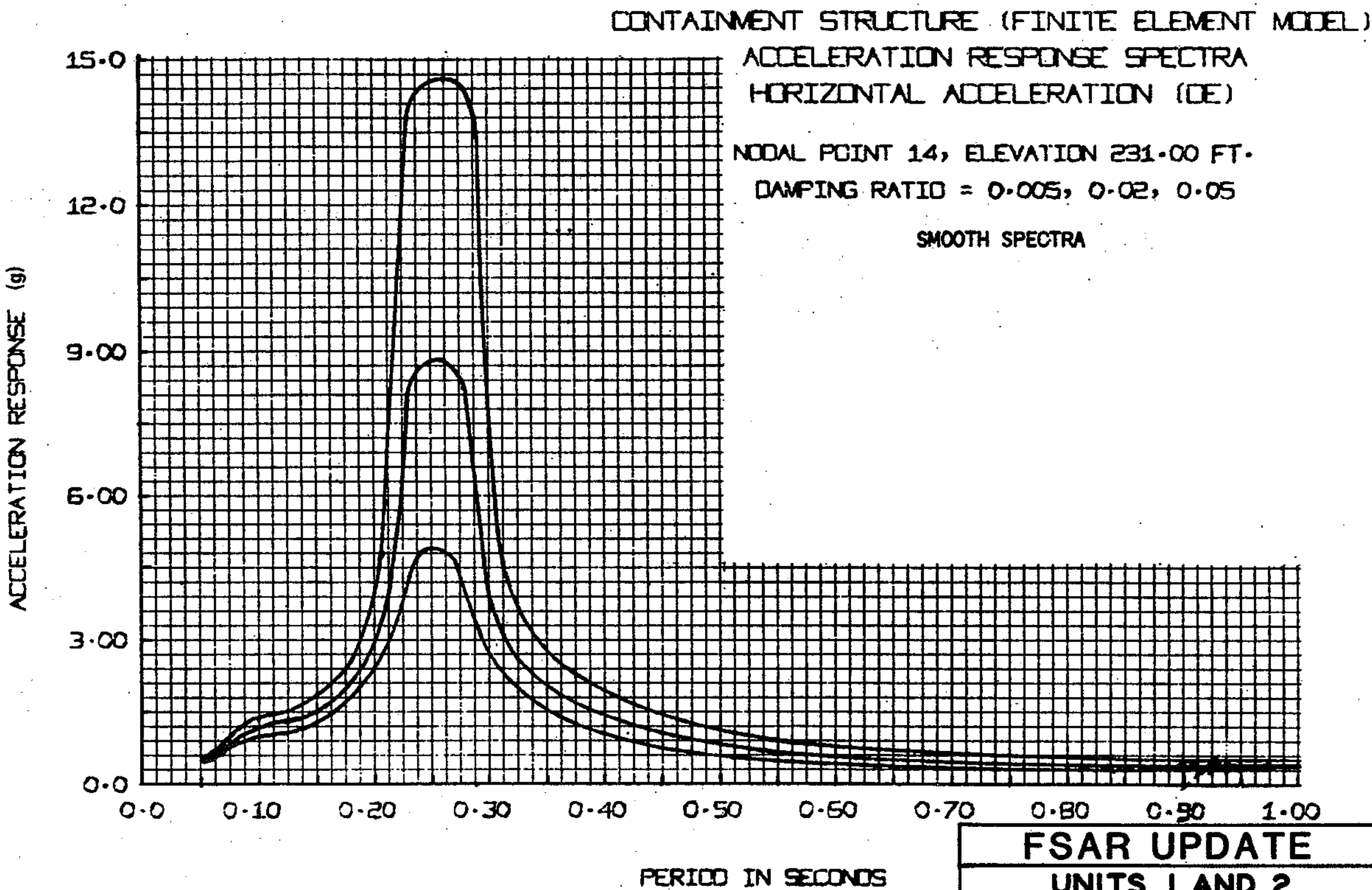
FIGURE 3.7 - 9
CONTAINMENT STRUCTURE
TYPICAL SPECTRA



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

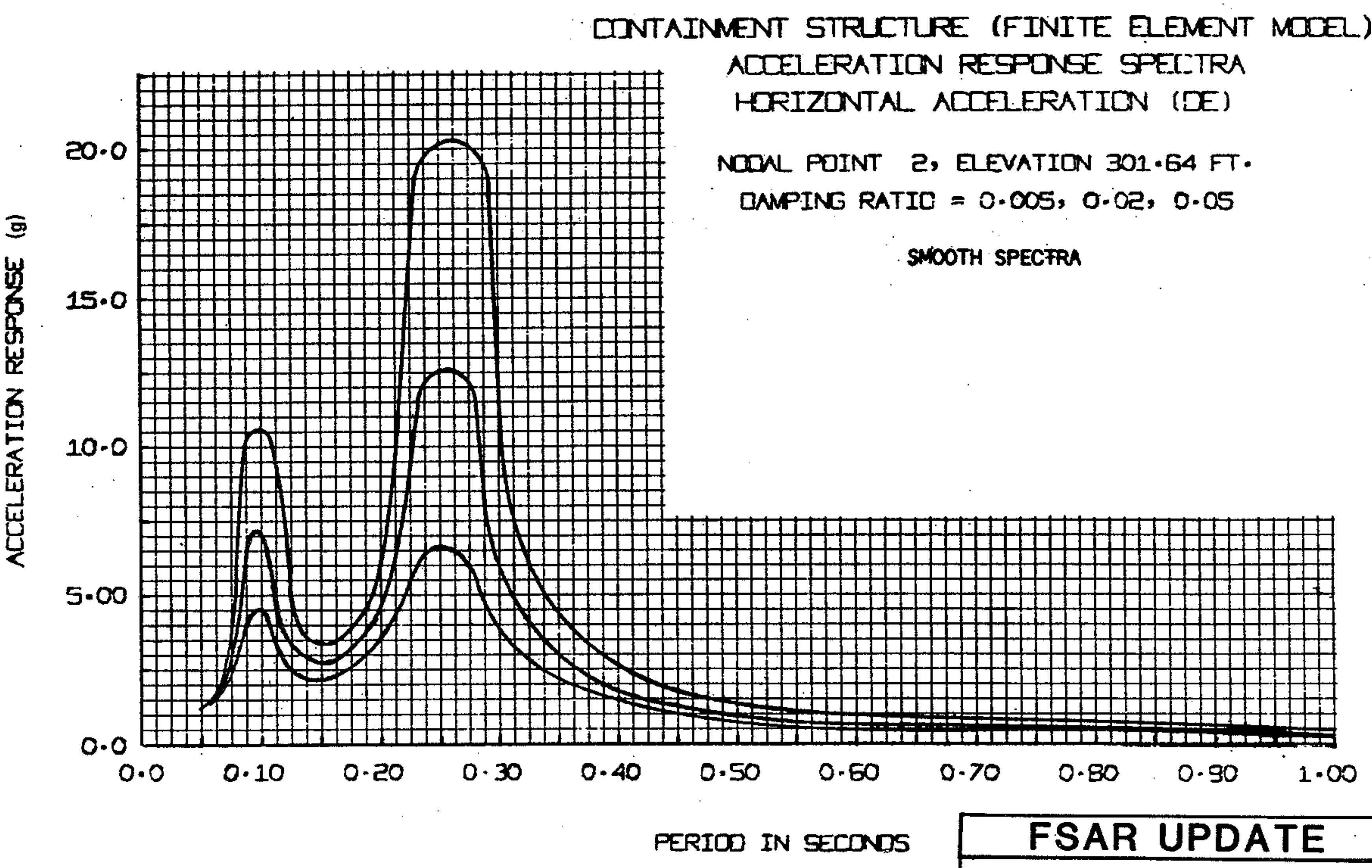
FIGURE 3.7 - 10
CONTAINMENT STRUCTURE
TYPICAL SPECTRA



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

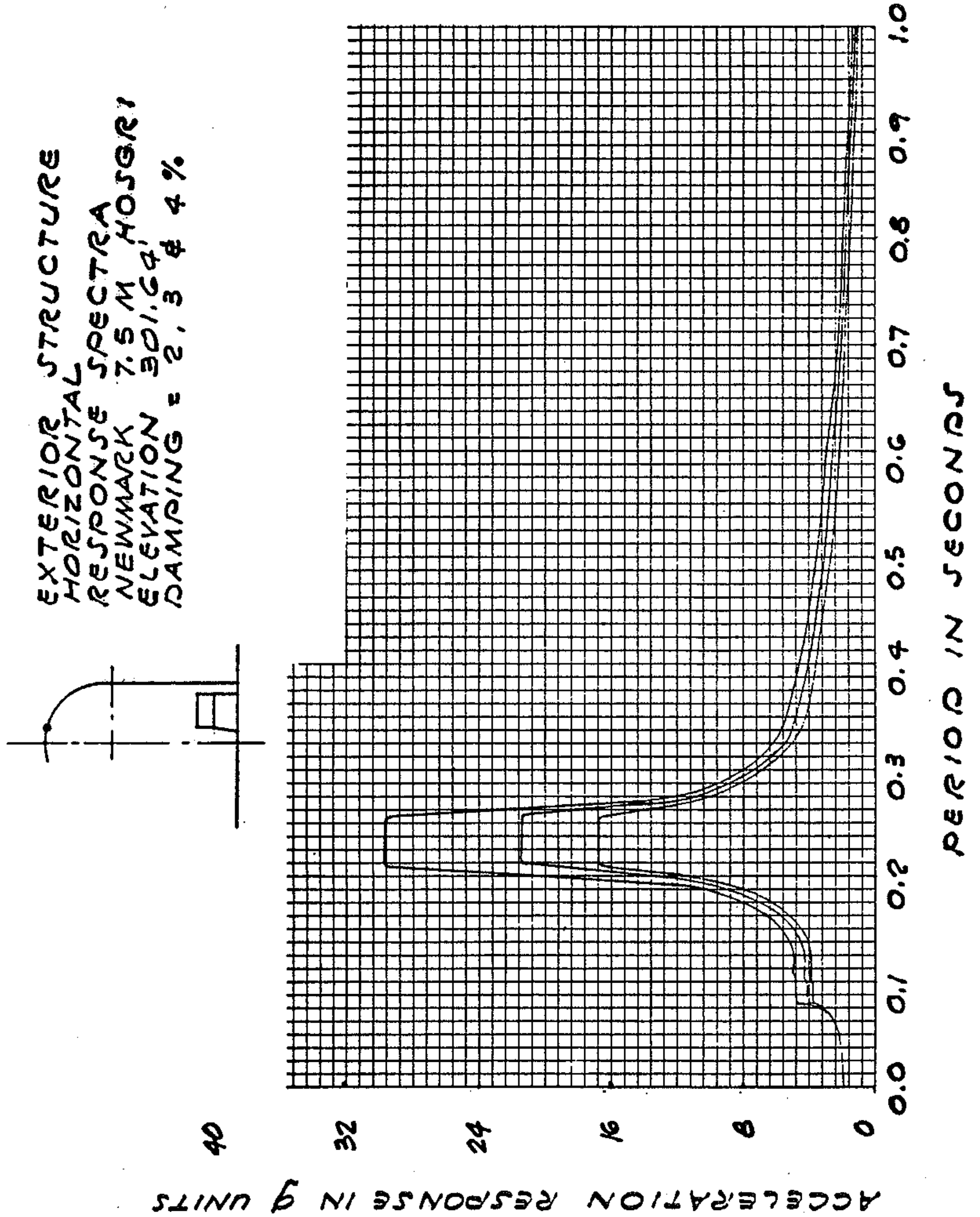
FIGURE 3.7 - 11
CONTAINMENT STRUCTURE
TYPICAL SPECTRA



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

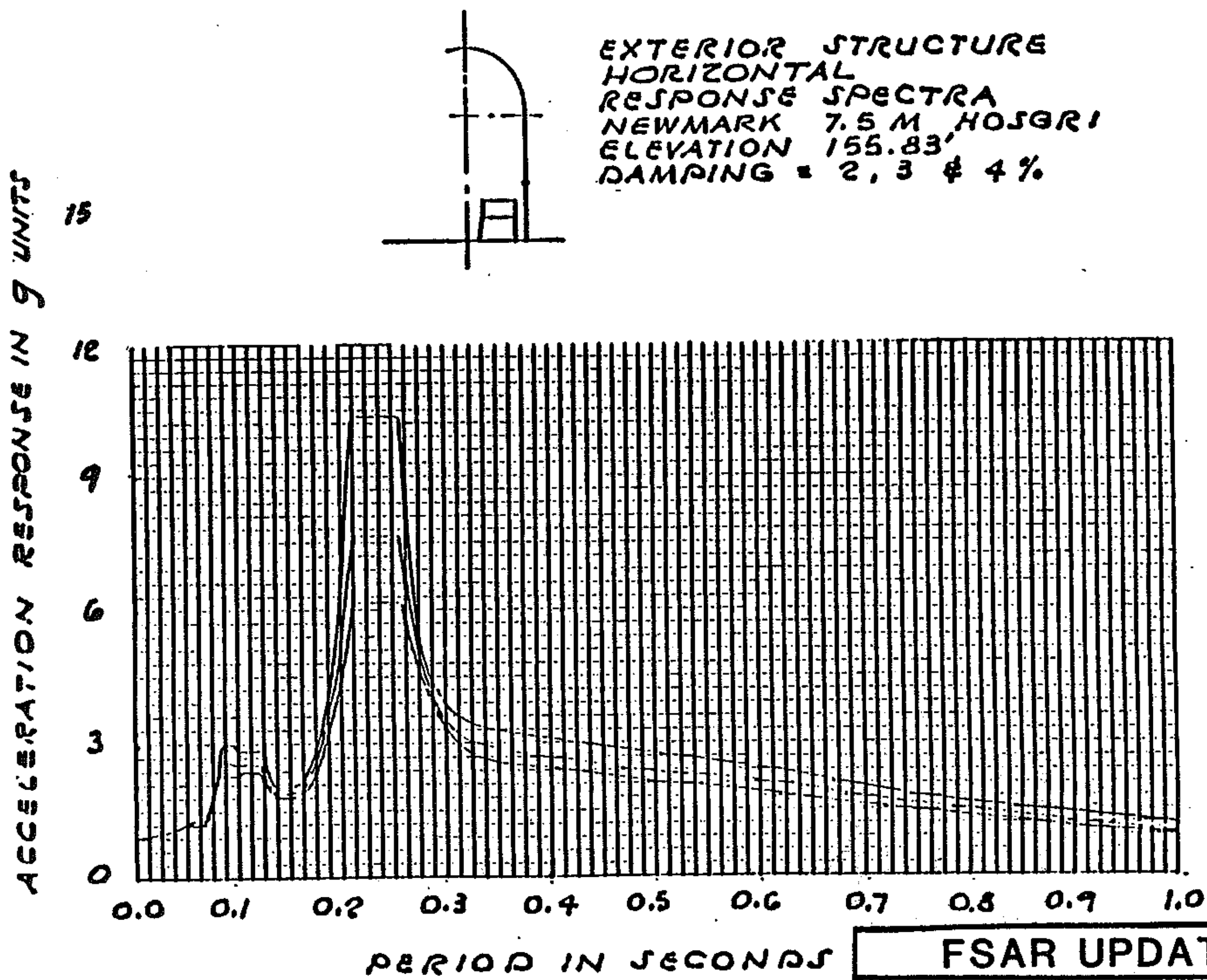
FIGURE 3.7 - 12
CONTAINMENT STRUCTURE
TYPICAL SPECTRA



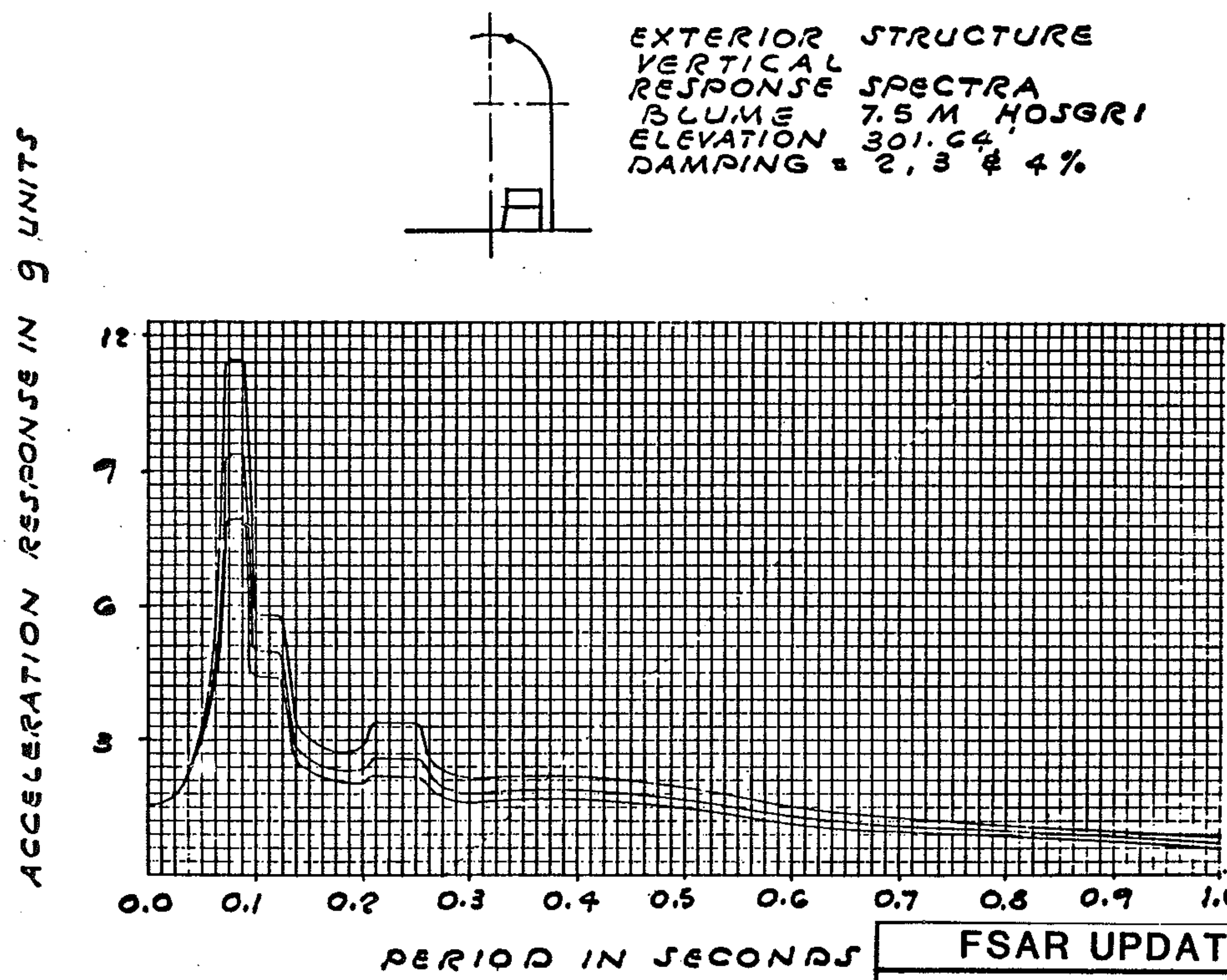
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7 - 12 A
CONTAINMENT STRUCTURE



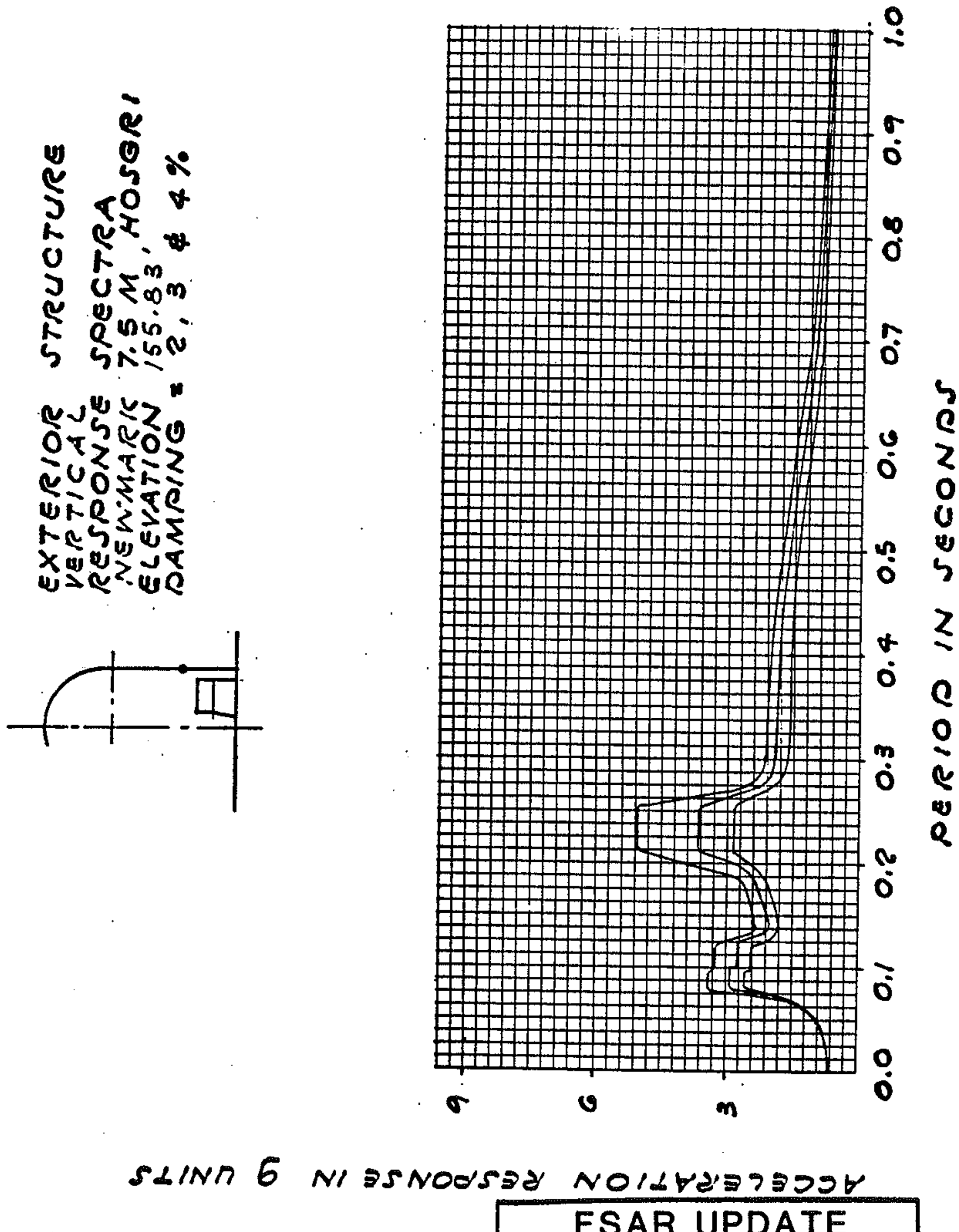
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.7 - 12B CONTAINMENT STRUCTURE



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

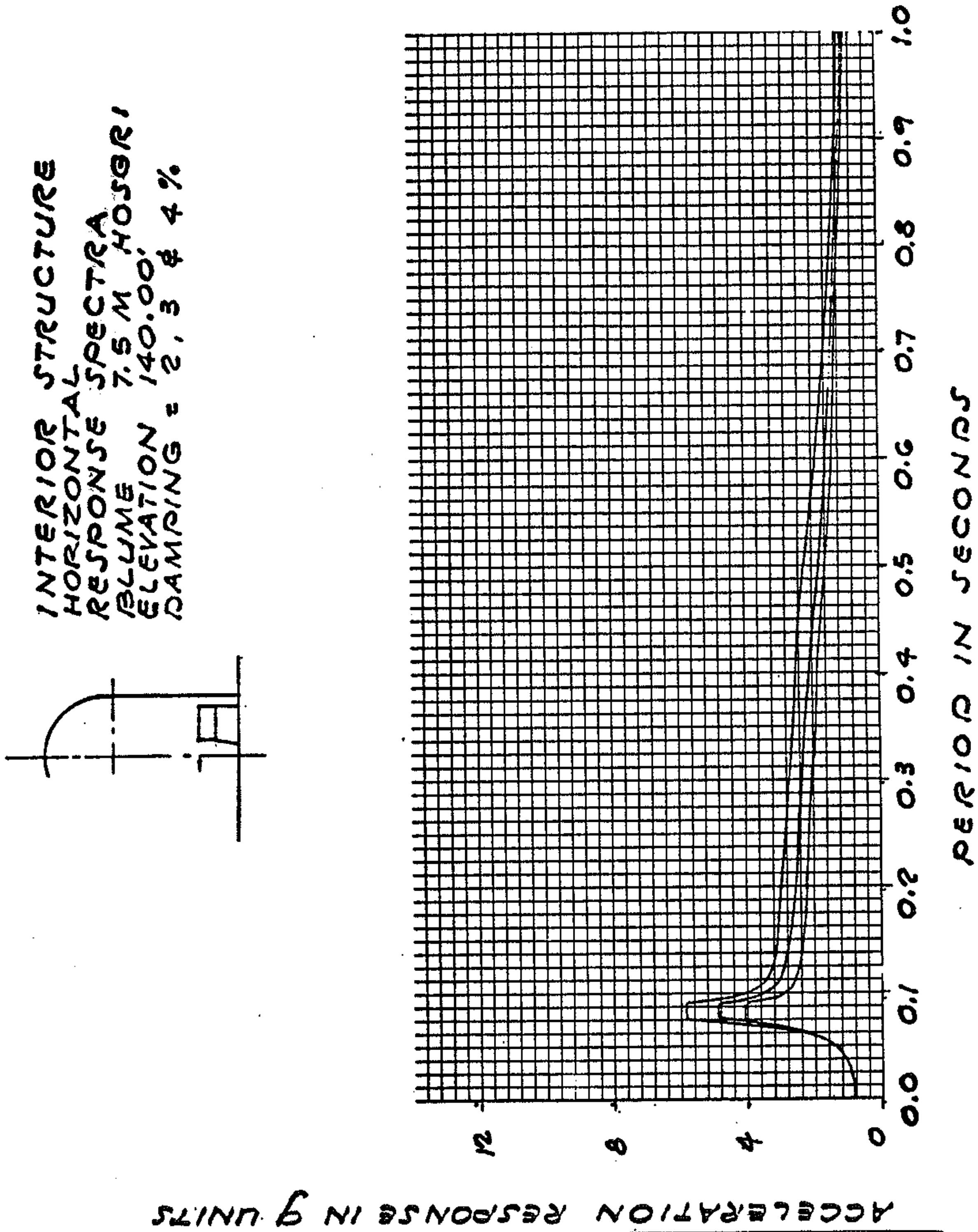
FIGURE 3.7 - 12C
CONTAINMENT STRUCTURE



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

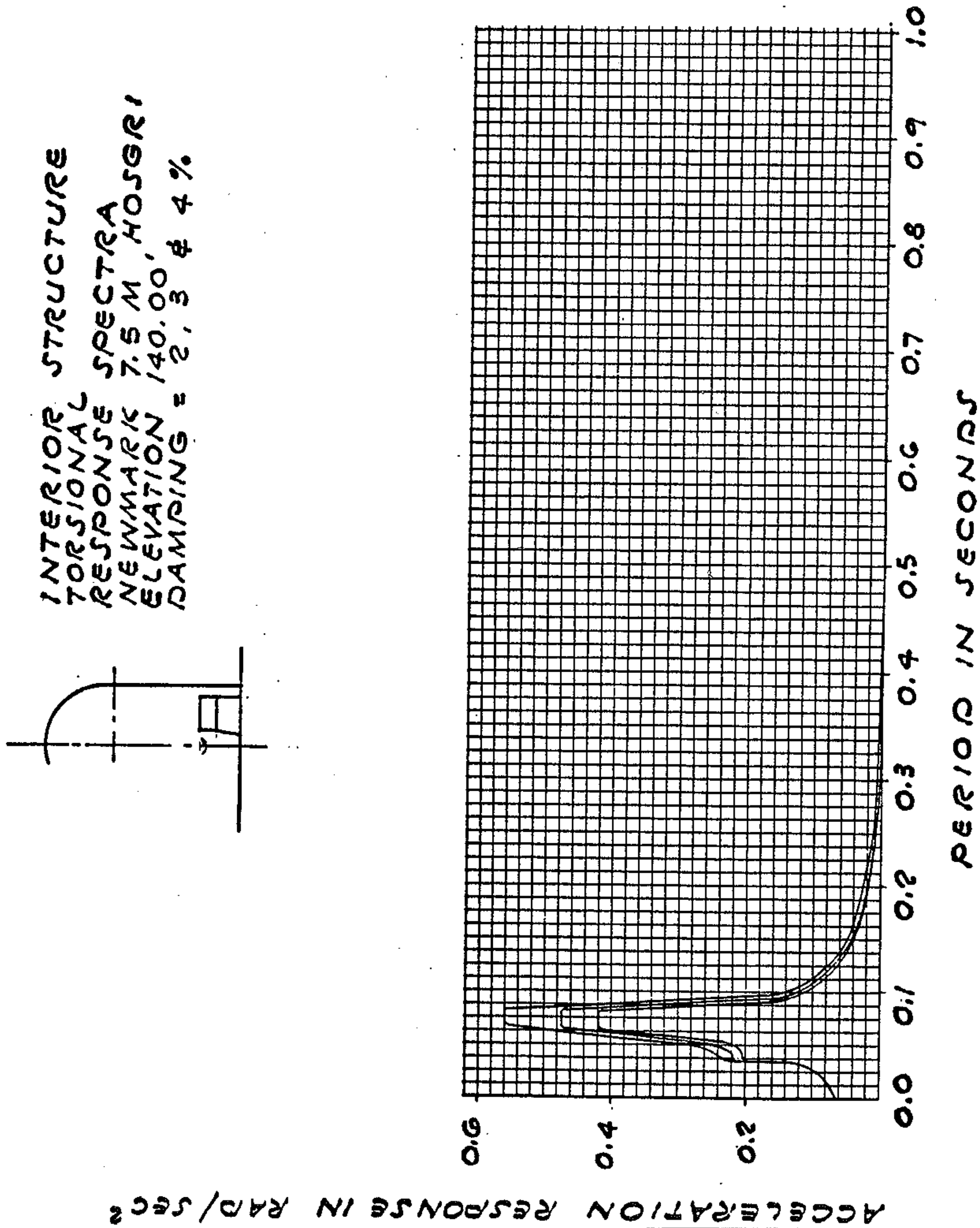
FIGURE 3.7 - 12D
CONTAINMENT STRUCTURE



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

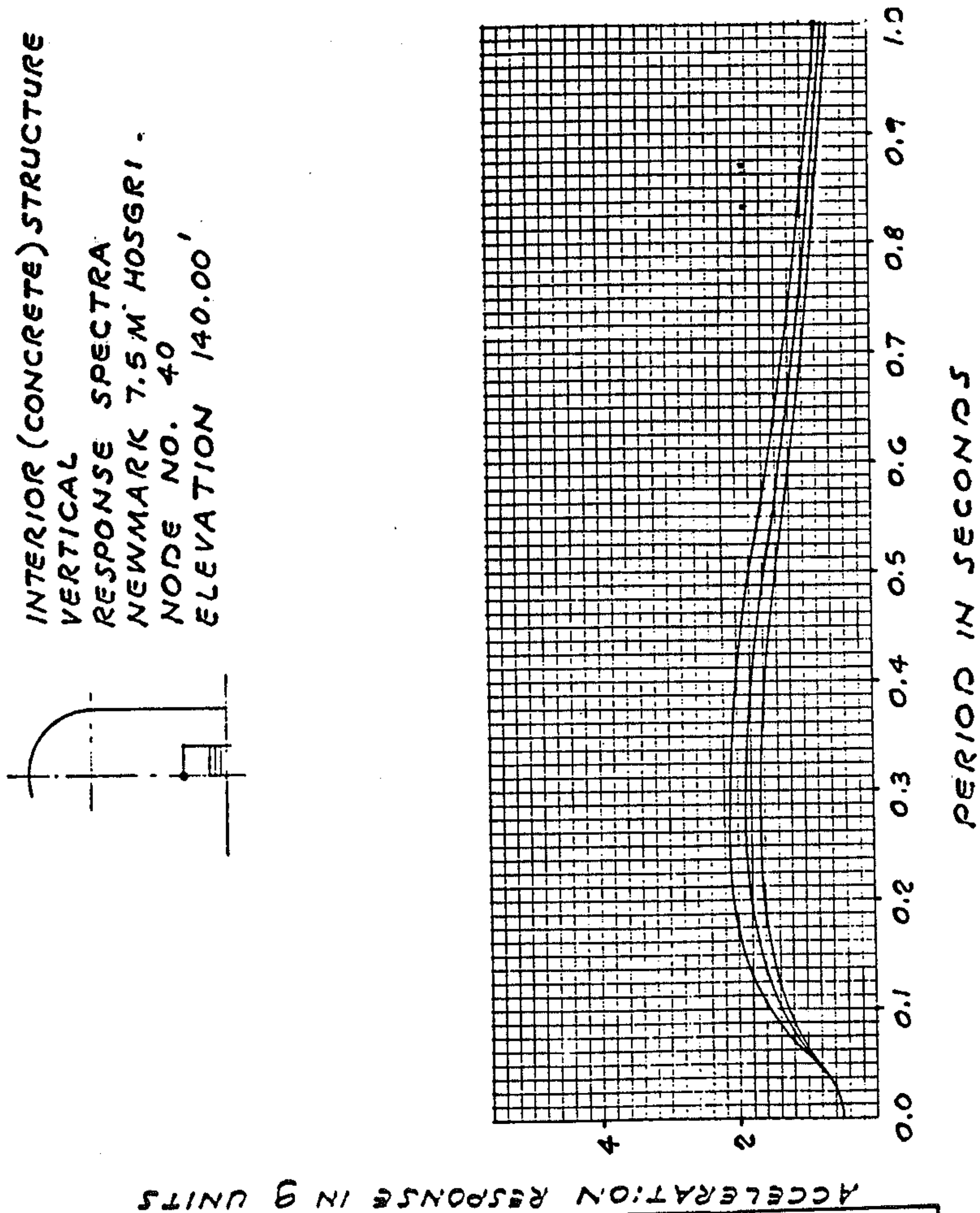
FIGURE 3.7 - 12E
CONTAINMENT STRUCTURE



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

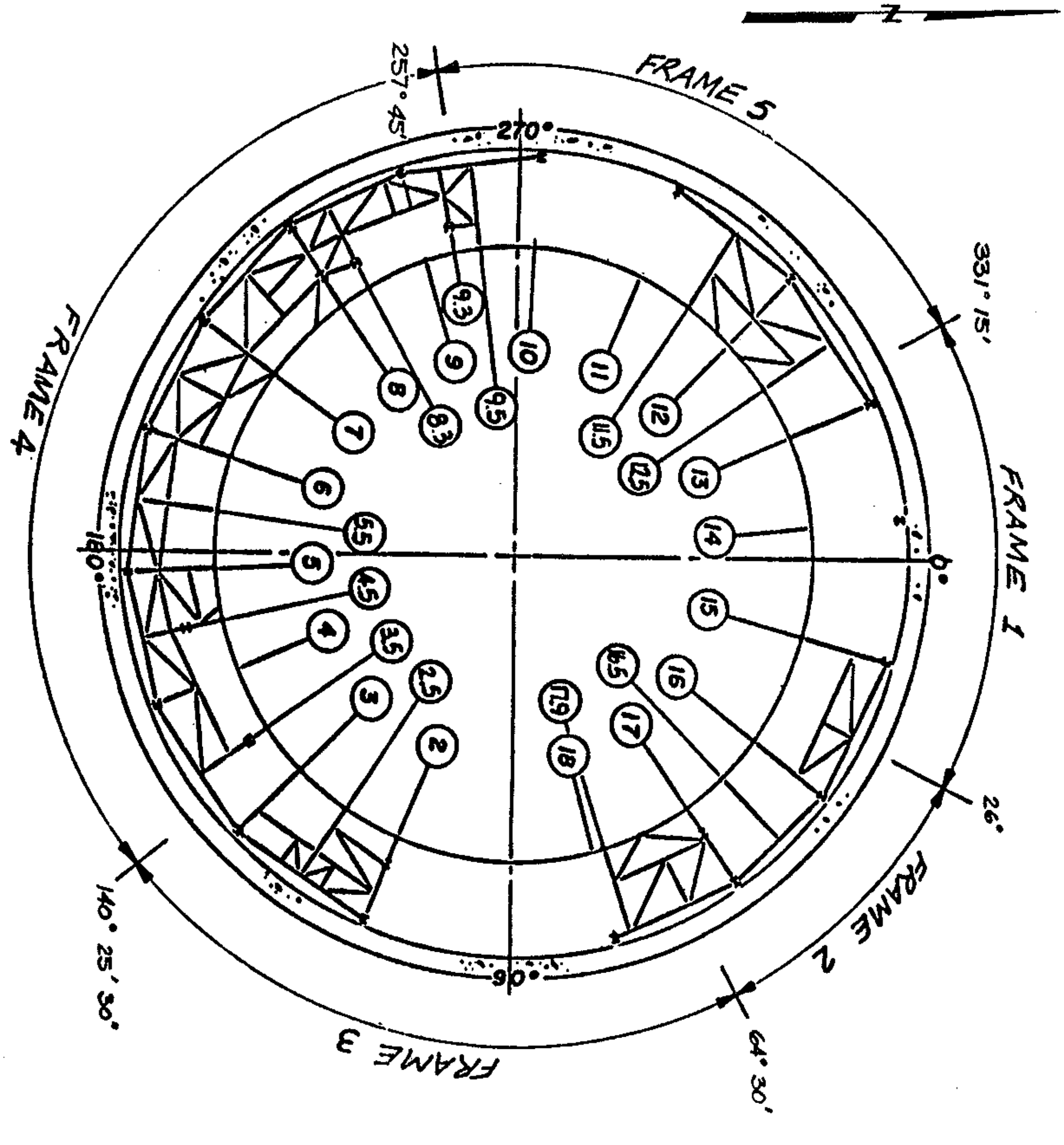
FIGURE 3.7 - 12 F
CONTAINMENT STRUCTURE



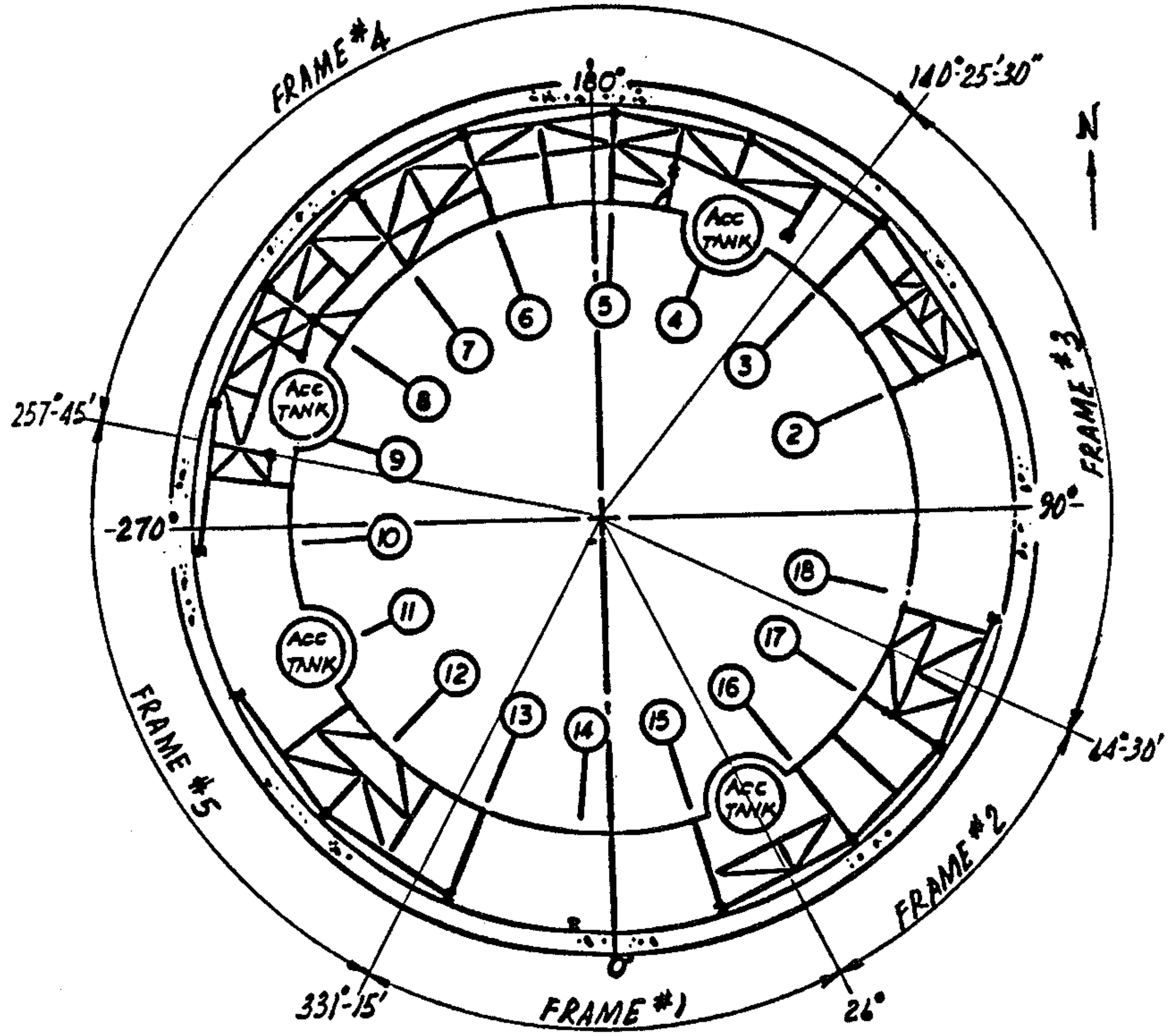
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7 - 12G
CONTAINMENT STRUCTURE



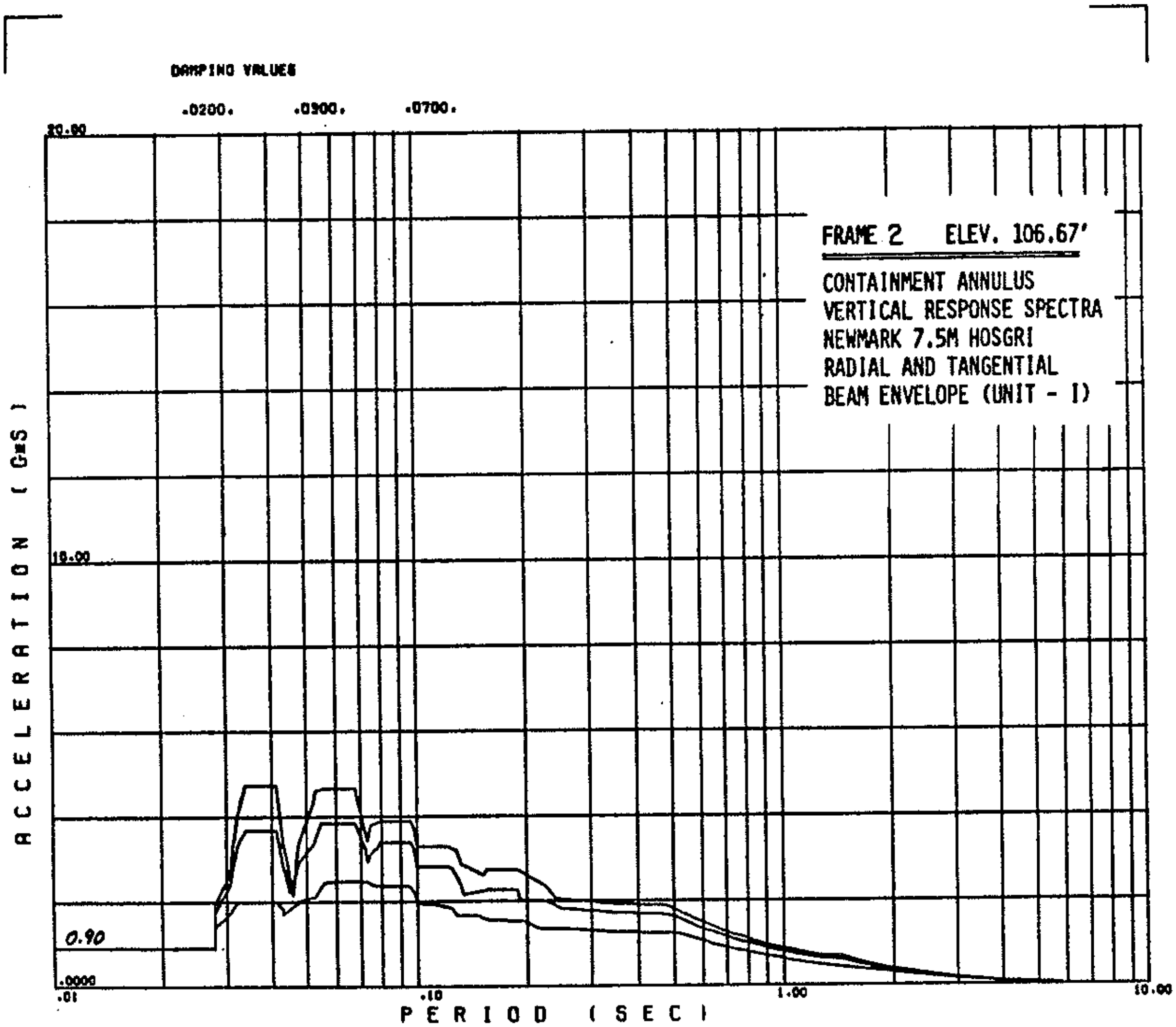
FSAR UPDATE
UNIT 1 **DIABLO CANYON SITE**
FIGURE 3.7 - 12 H CONTAINMENT – ANNULUS STRUCTURE



FSAR UPDATE

UNIT 2
DIABLO CANYON SITE

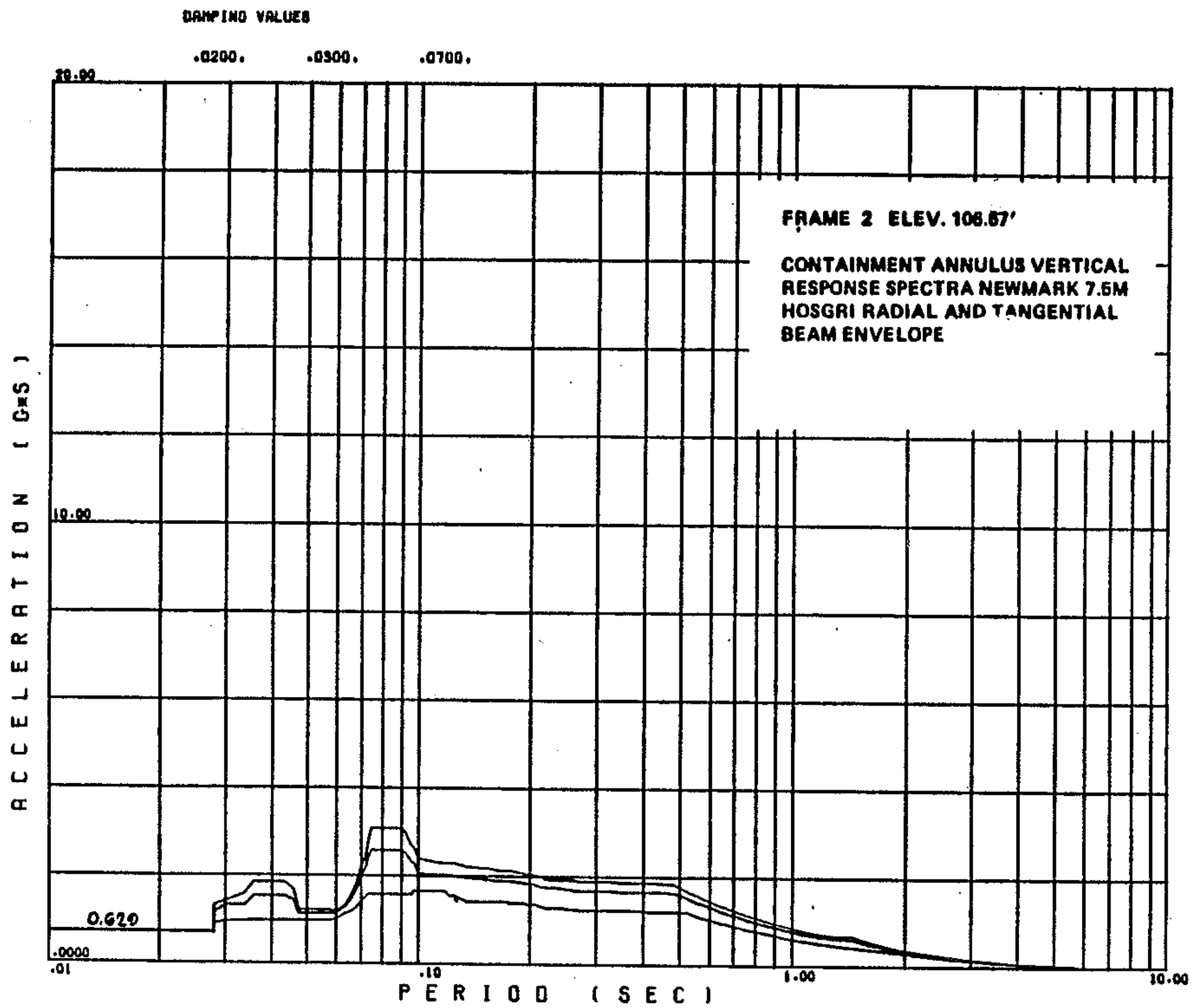
FIGURE 3.7 - 12 I
CONTAINMENT – ANNULUS STRUCTURE



FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

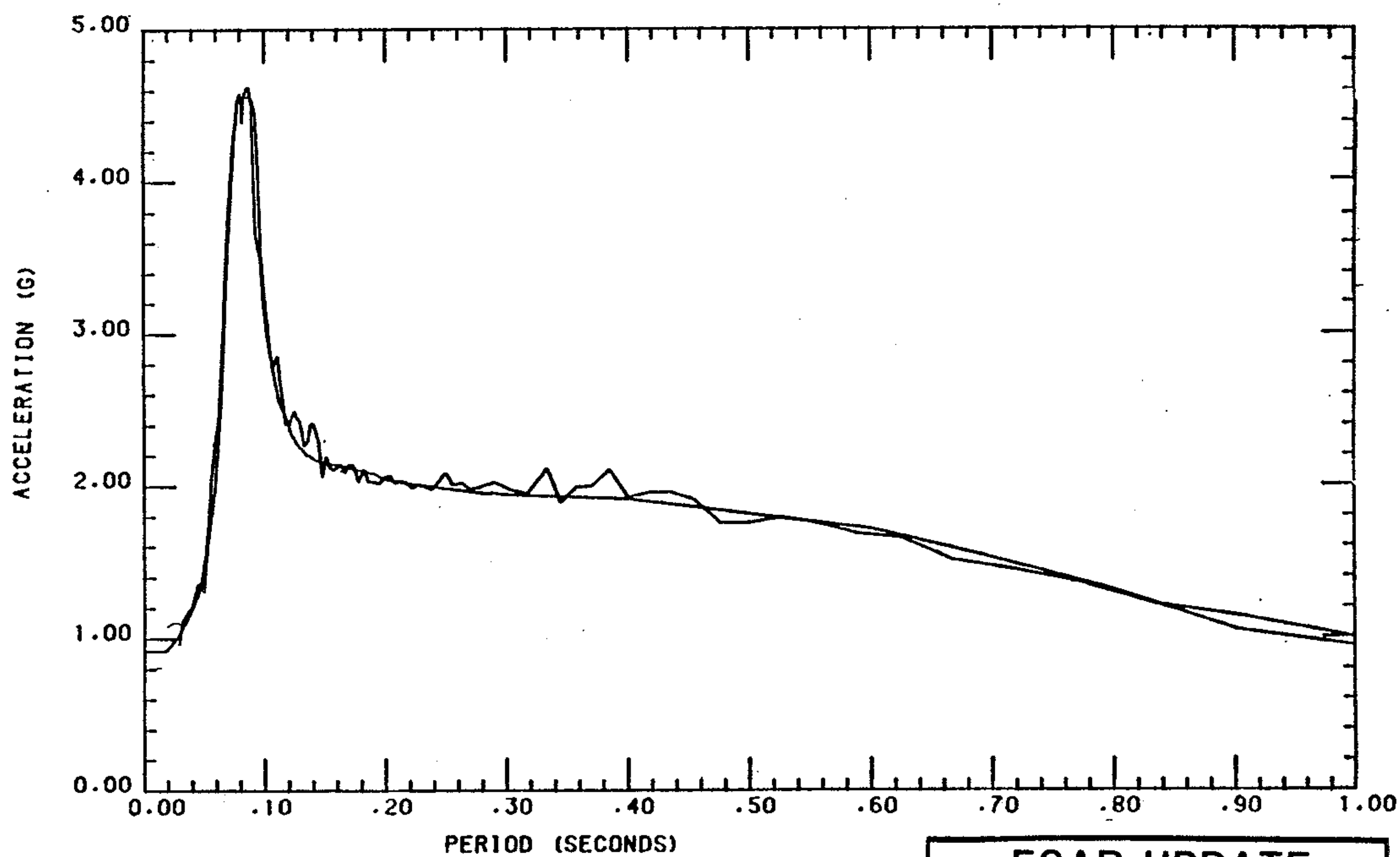
FIGURE 3.7 - 12 J
CONTAINMENT ANNULUS SPECTRA



FSAR UPDATE

UNIT 2
DIABLO CANYON SITE

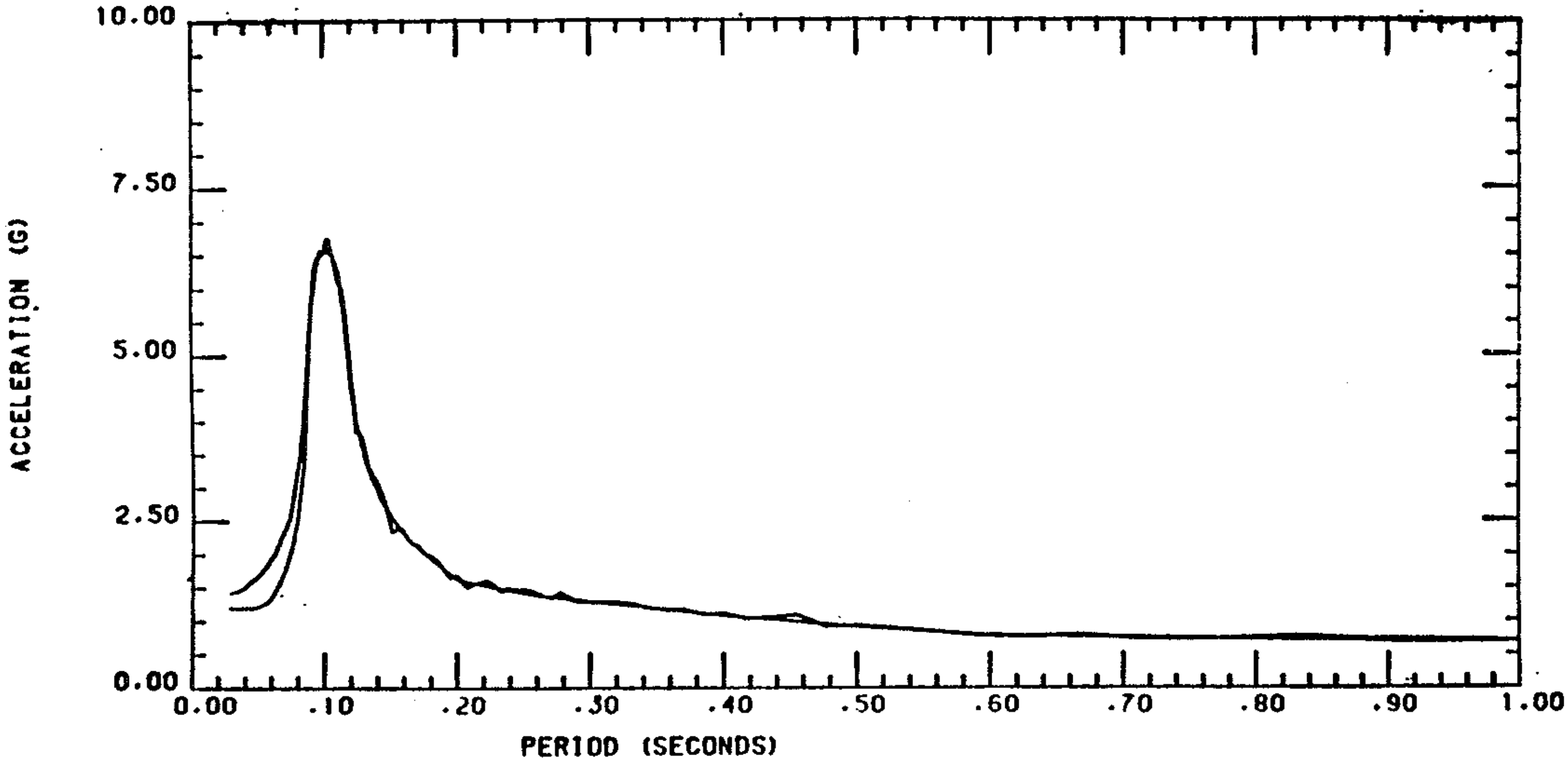
FIGURE 3.7 - 12 K
CONTAINMENT ANNULUS SPECTRA



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

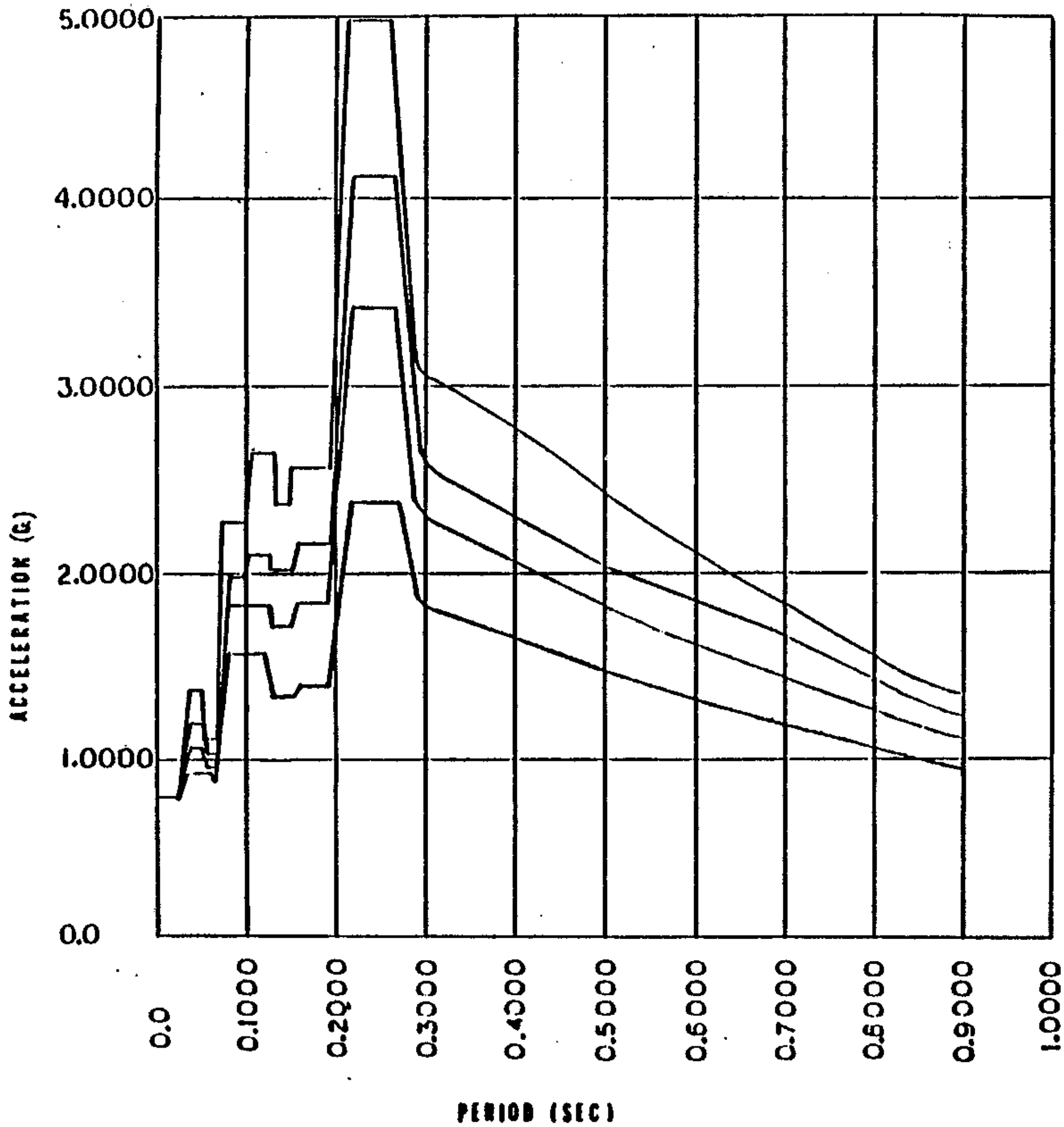
FIGURE 3.7 - 12 L
POLAR CRANE HOSGRI HORIZONTAL SPECTRUM IN X DIRECTION WITH 4% DAMPING AT EL. 140'



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

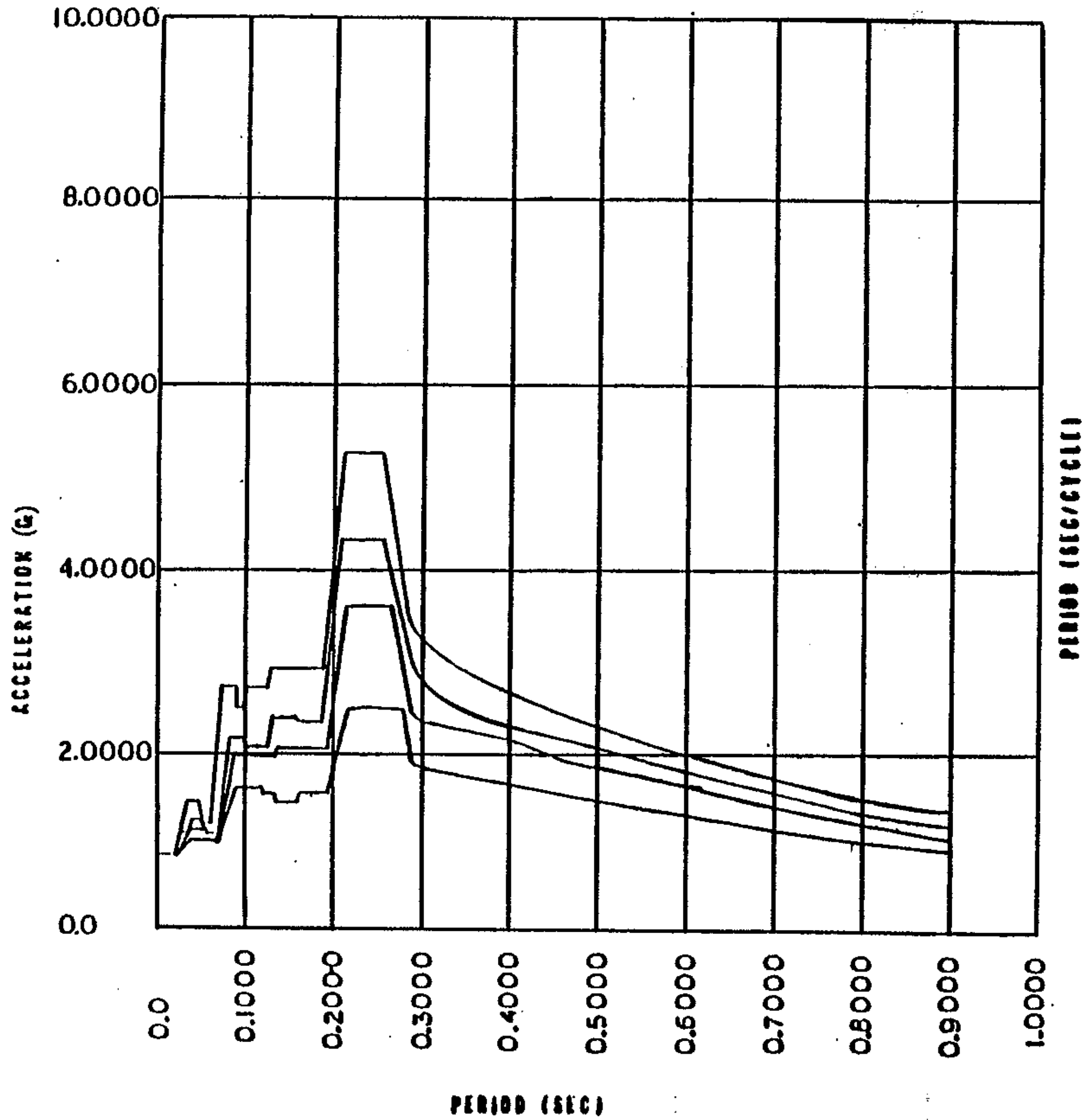
FIGURE 3.7 - 12 M
POLAR CRANE DDE HORIZONTAL
SPECTRUM IN Z DIRECTION
WITH 5% DAMPING AT EL. 140'



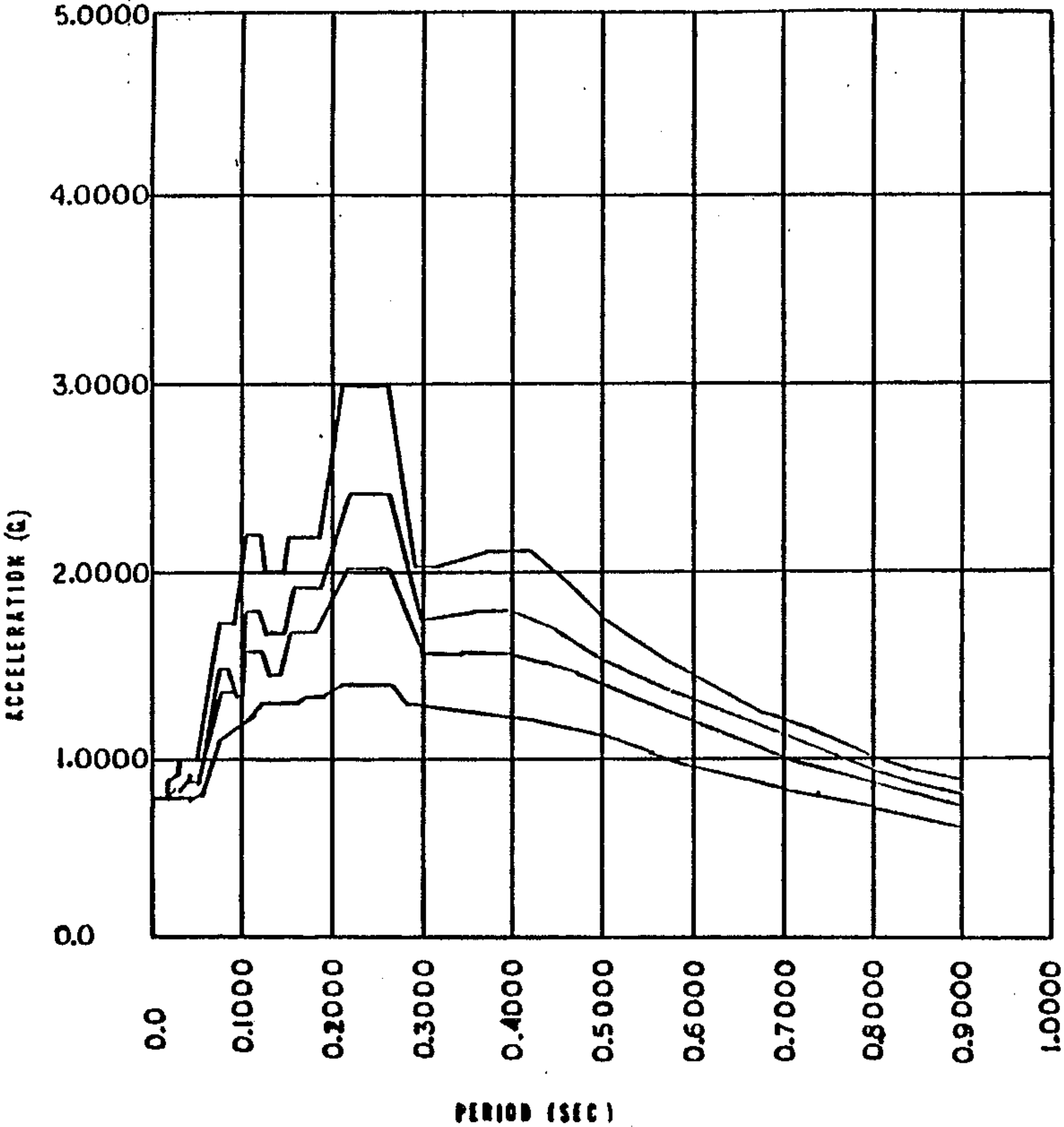
FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

FIGURE 3.7 - 12 N
PIPEWAY STRUCTURE
HOSGRI BLUME N-S
RESPONSE SPECTRA
% DAMPING 2,3,4,7
ELEVATION 109'4"
NODE 893



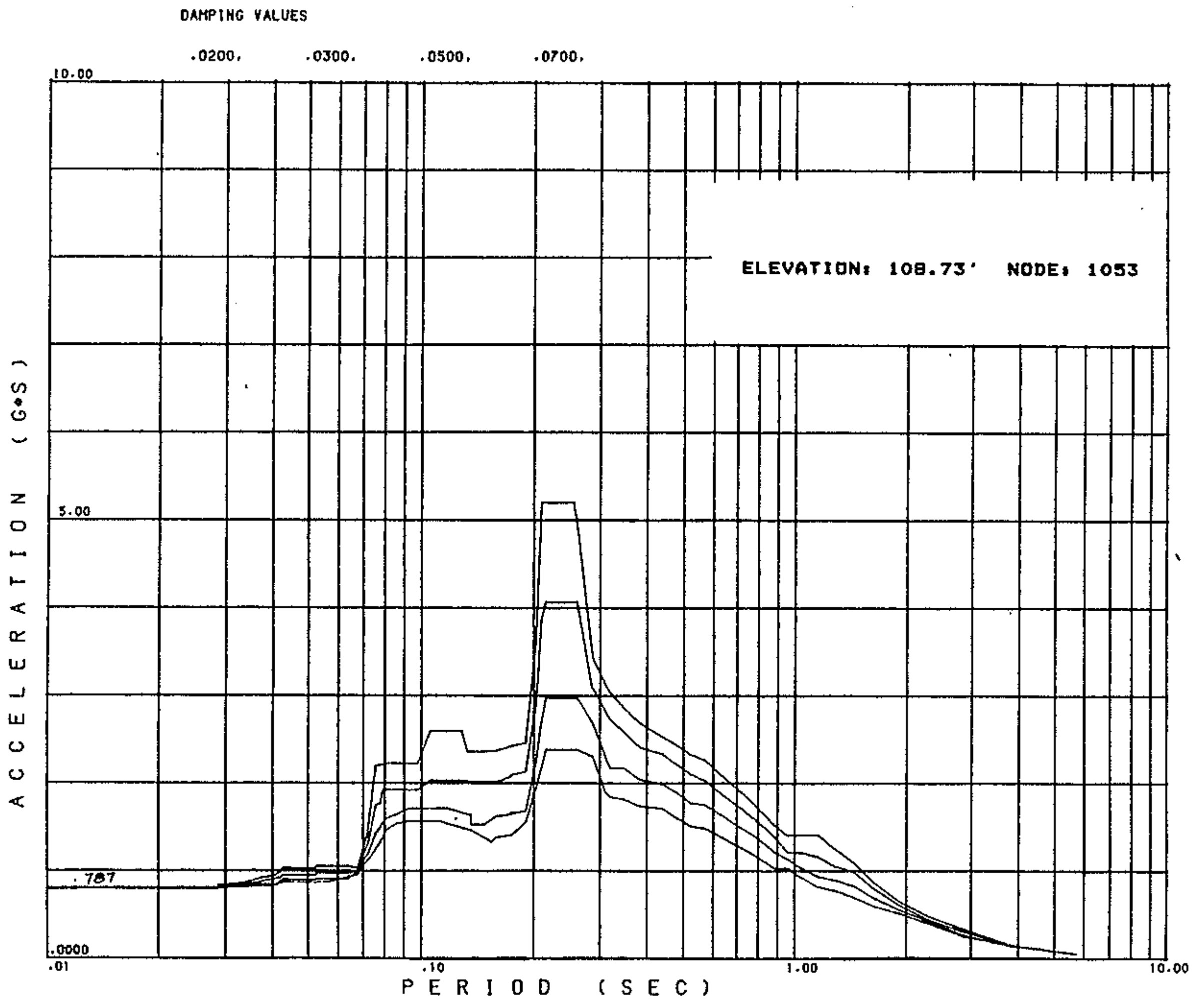
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 3.7 - 12 O PIPEWAY STRUCTURE HOSGRI BLUME E-W RESPONSE SPECTRA % DAMPING 2, 3 , 4, 7 ELEVATION 109'- 4" NODE 893



FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

FIGURE 3.7 - 12P
PIPEWAY STRUCTURE
HOSGRI BLUME VERTICAL
RESPONSE SPECTRA
% DAMPING 2,3,4,7
ELEVATION 109'-4"
NODE 893

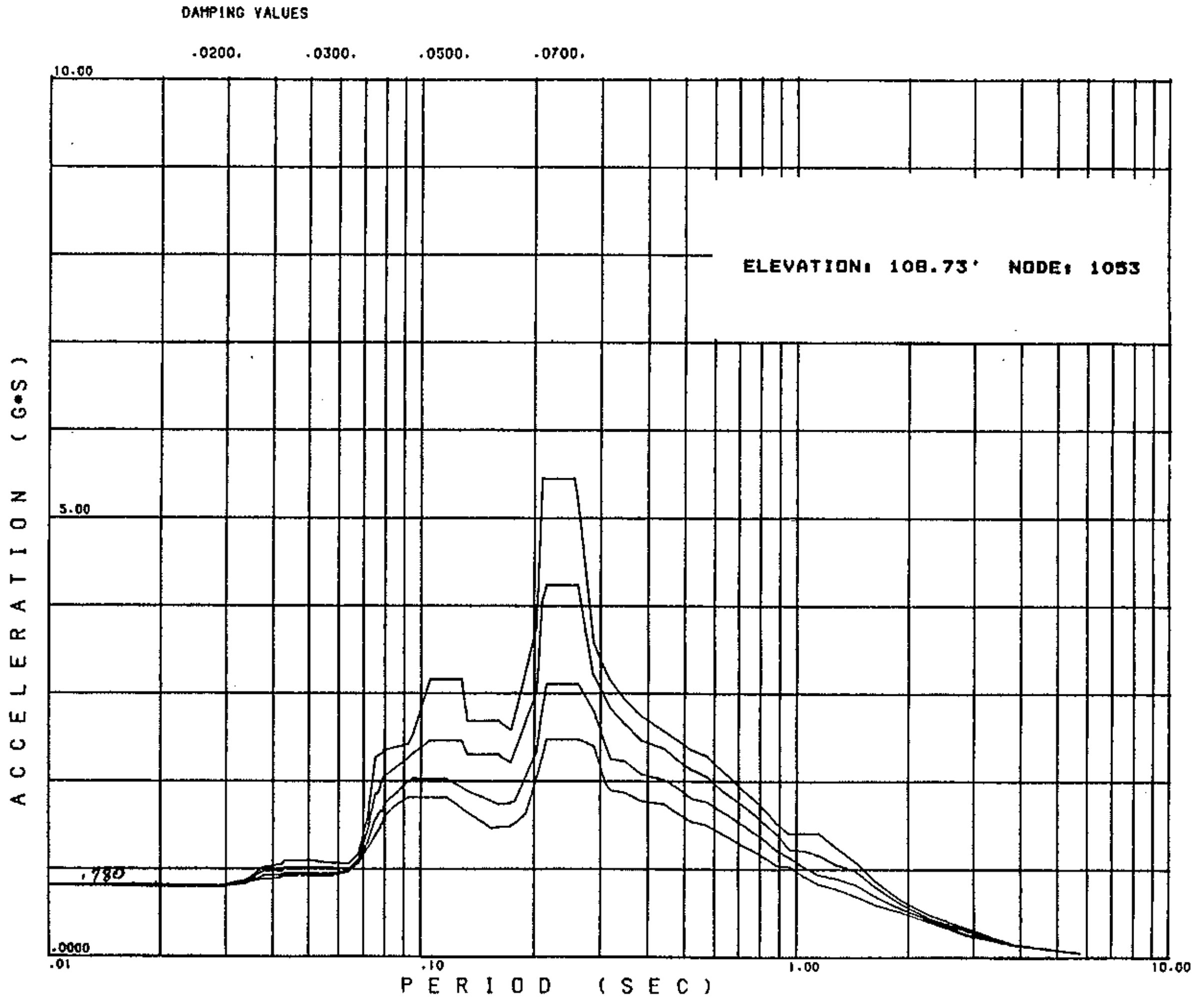


FSAR UPDATE

UNIT 2
DIABLO CANYON SITE

FIGURE 3.7 - 12Q
PIPEWAY STRUCTURE
HOSGRI BLUME N-S
RESPONSE SPECTRA

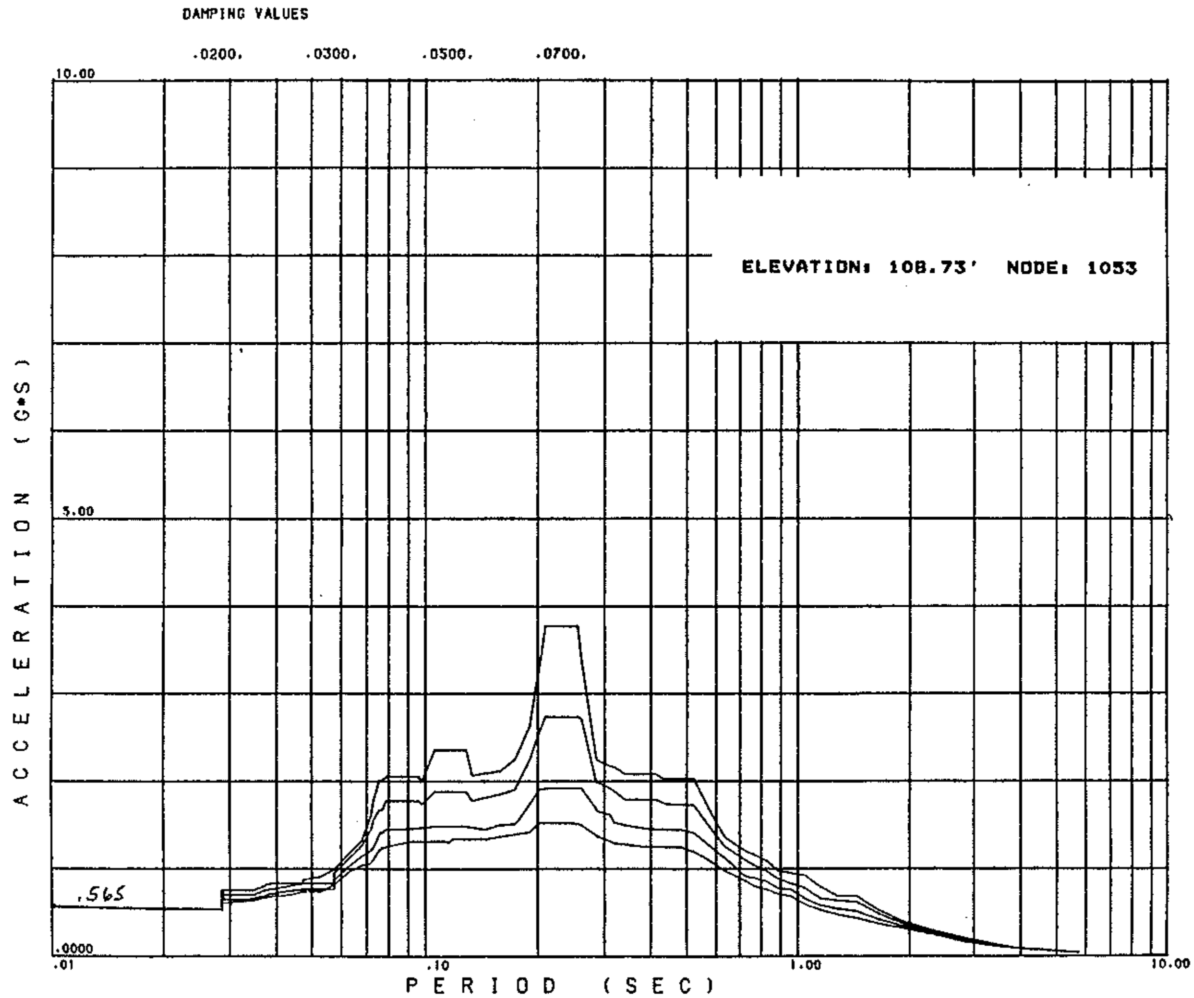
Revision 11 November 1996



FSAR UPDATE

UNIT 2
DIABLO CANYON SITE

FIGURE 3.7 - 12R
PIPEWAY STRUCTURE
HOSGRI BLUME E- W
RESPONSE SPECTRA



FSAR UPDATE

UNIT 2
DIABLO CANYON SITE

FIGURE 3.7 - 12 S
PIPEWAY STRUCTURE
HOSGRI BLUME VERTICAL
RESPONSE SPECTRA

LEGEND:

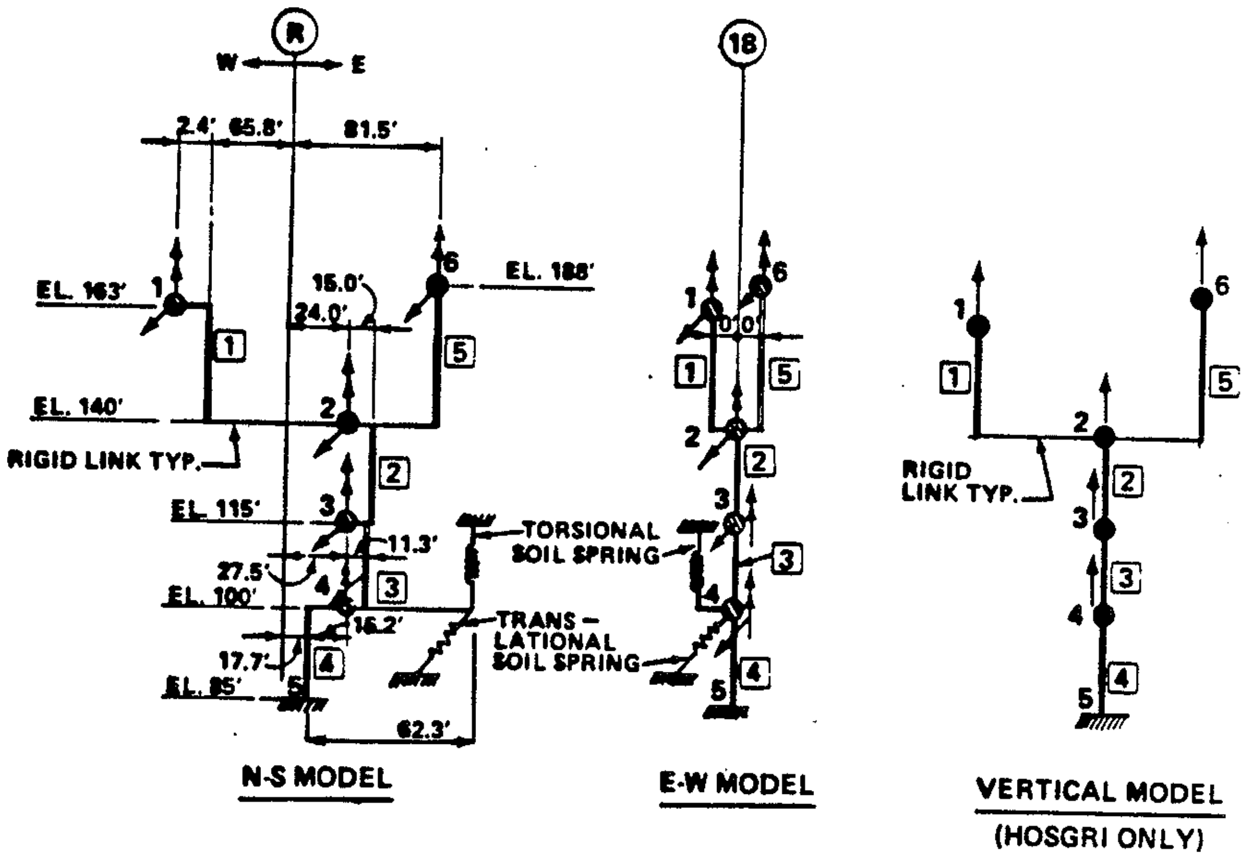
2 – NODE NUMBER

[1] – ELEMENT NUMBER

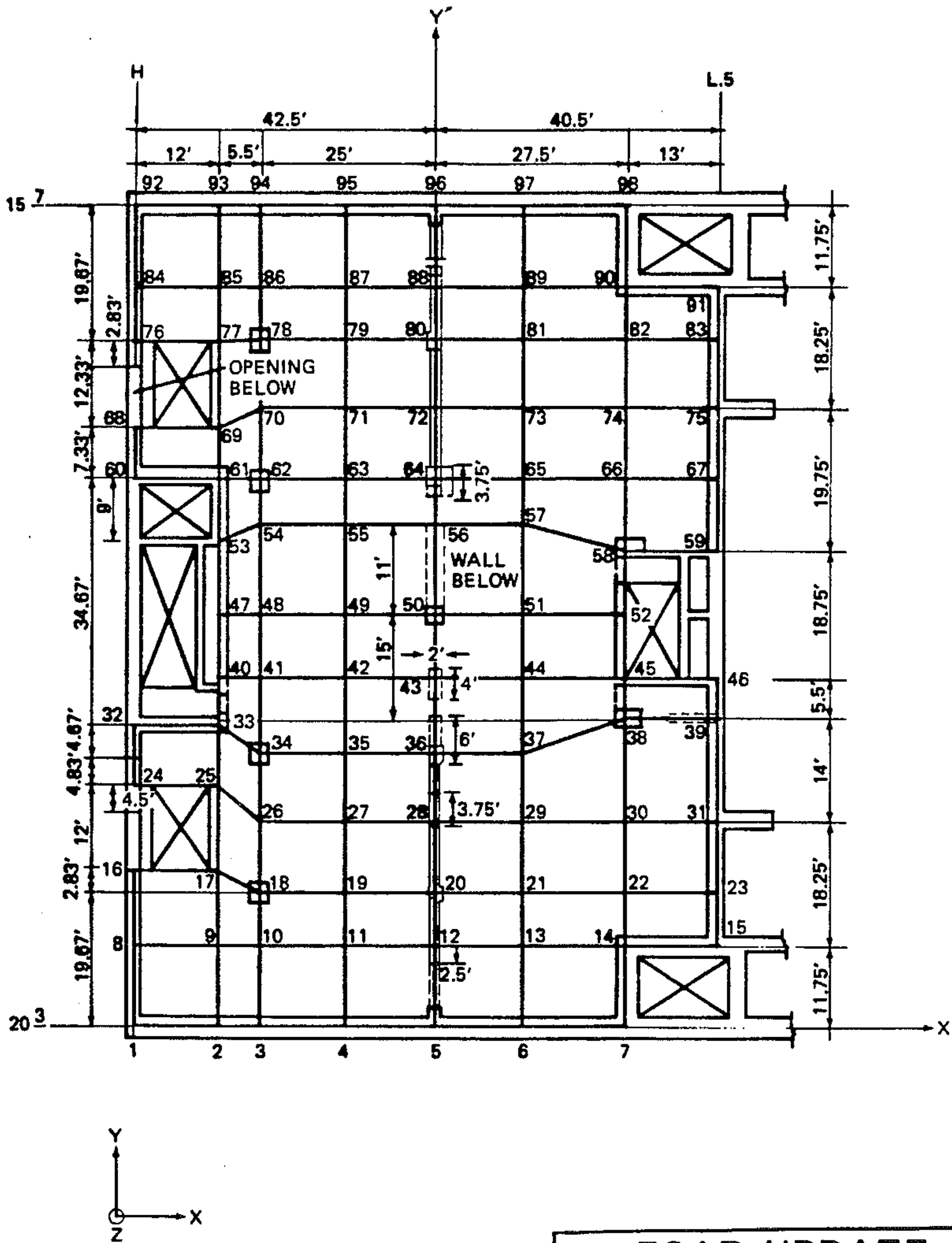
– ROTATIONAL DEGREE OF FREEDOM

– TRANSLATIONAL DEGREE OF FREEDOM

– MASS POINT



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.7 - 13 AUXILIARY BUILDING MATHEMATICAL MODEL

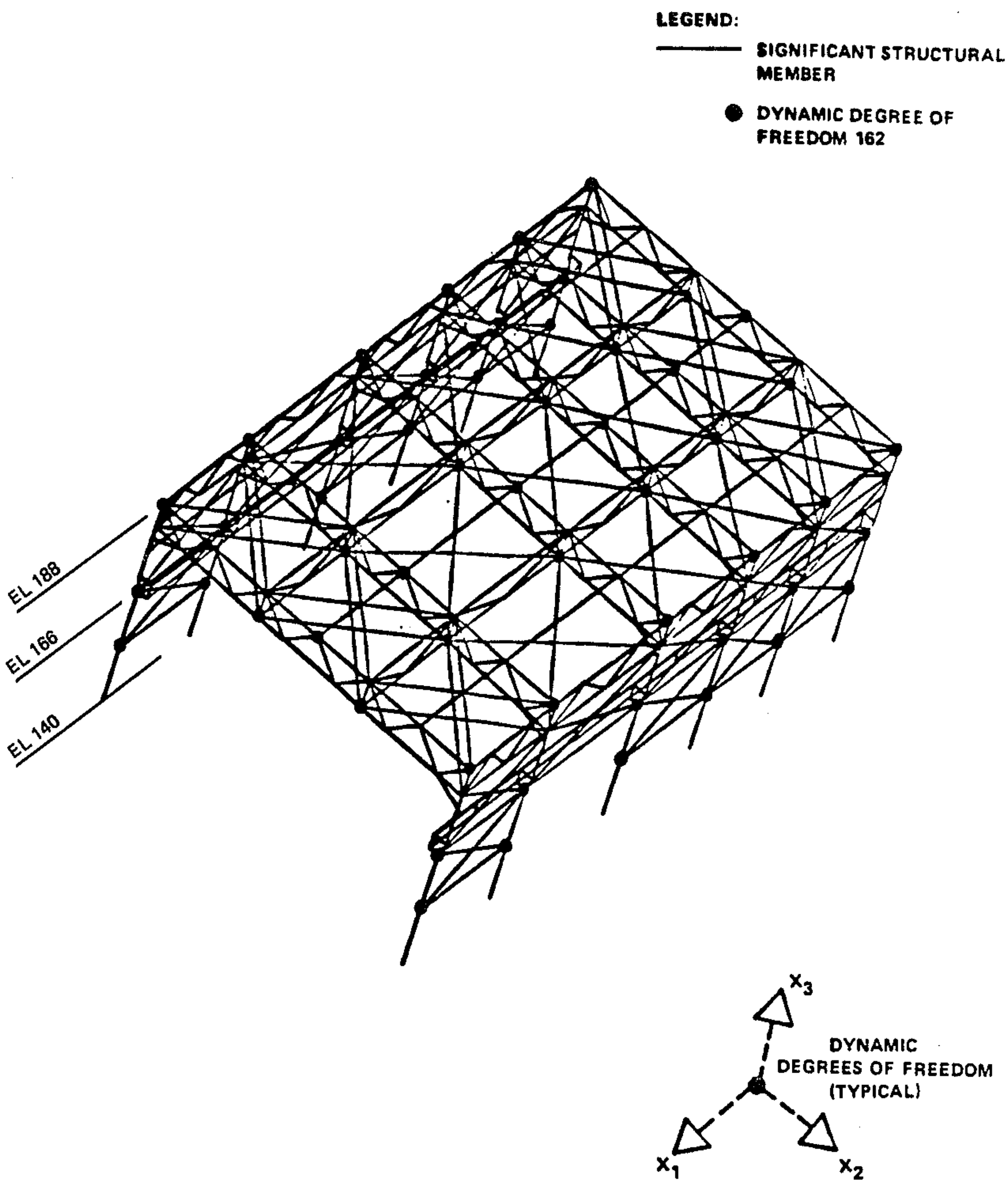


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7–13A

AUXILIARY BUILDING
FLEXIBLE SLAB MODEL

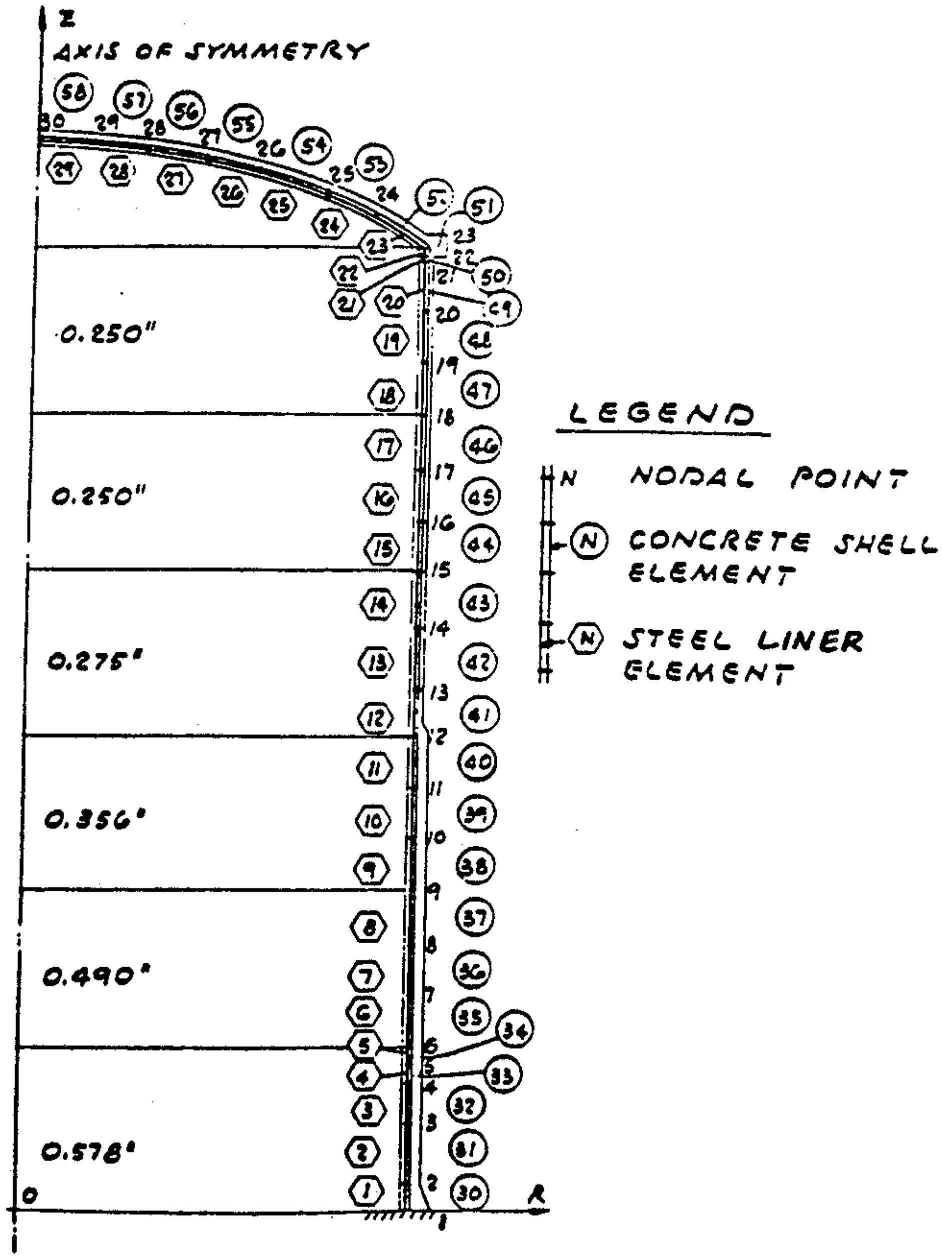


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7–13B

AUXILIARY BUILDING
FUEL HANDLING
CRANE SUPPORT STRUCTURE
MODEL NO. 2.2

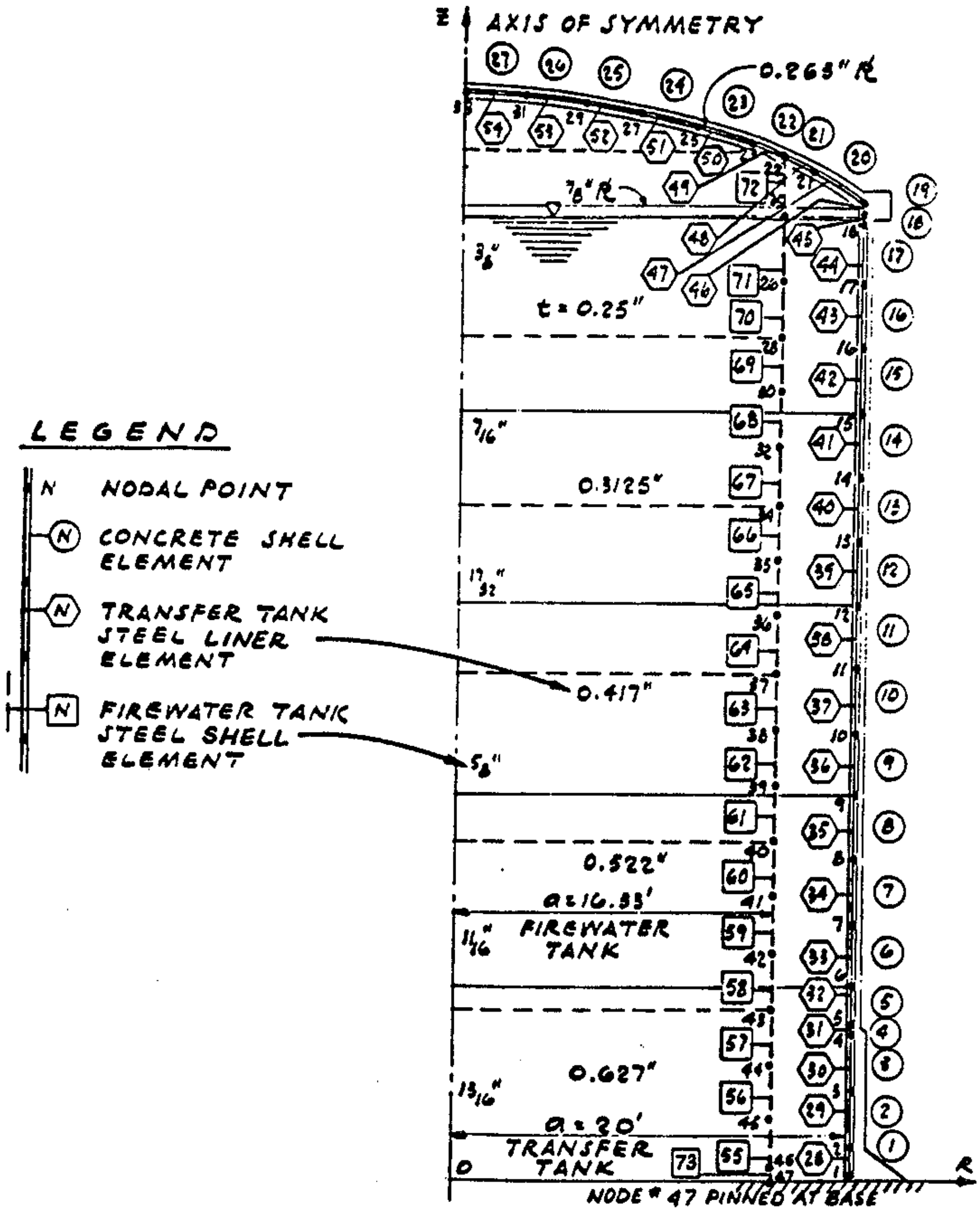


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7-14

OUTDOOR WATER STORAGE TANKS: REFUELING WATER TANK, AXISYMMETRIC MODEL

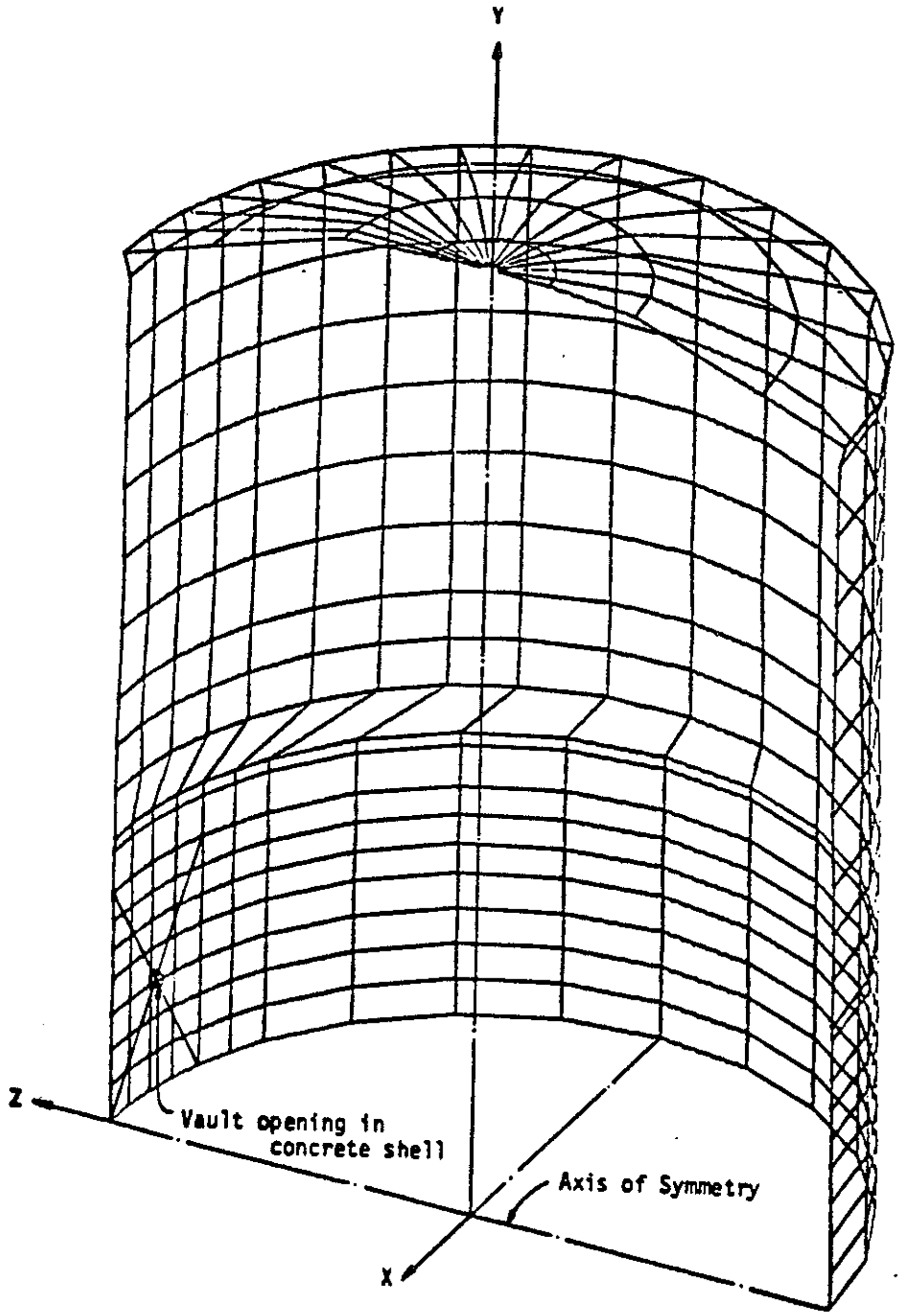


FSAR UPDATE

UNITS 1 AND 2 DIABLO CANYON SITE

FIGURE 3.7-15

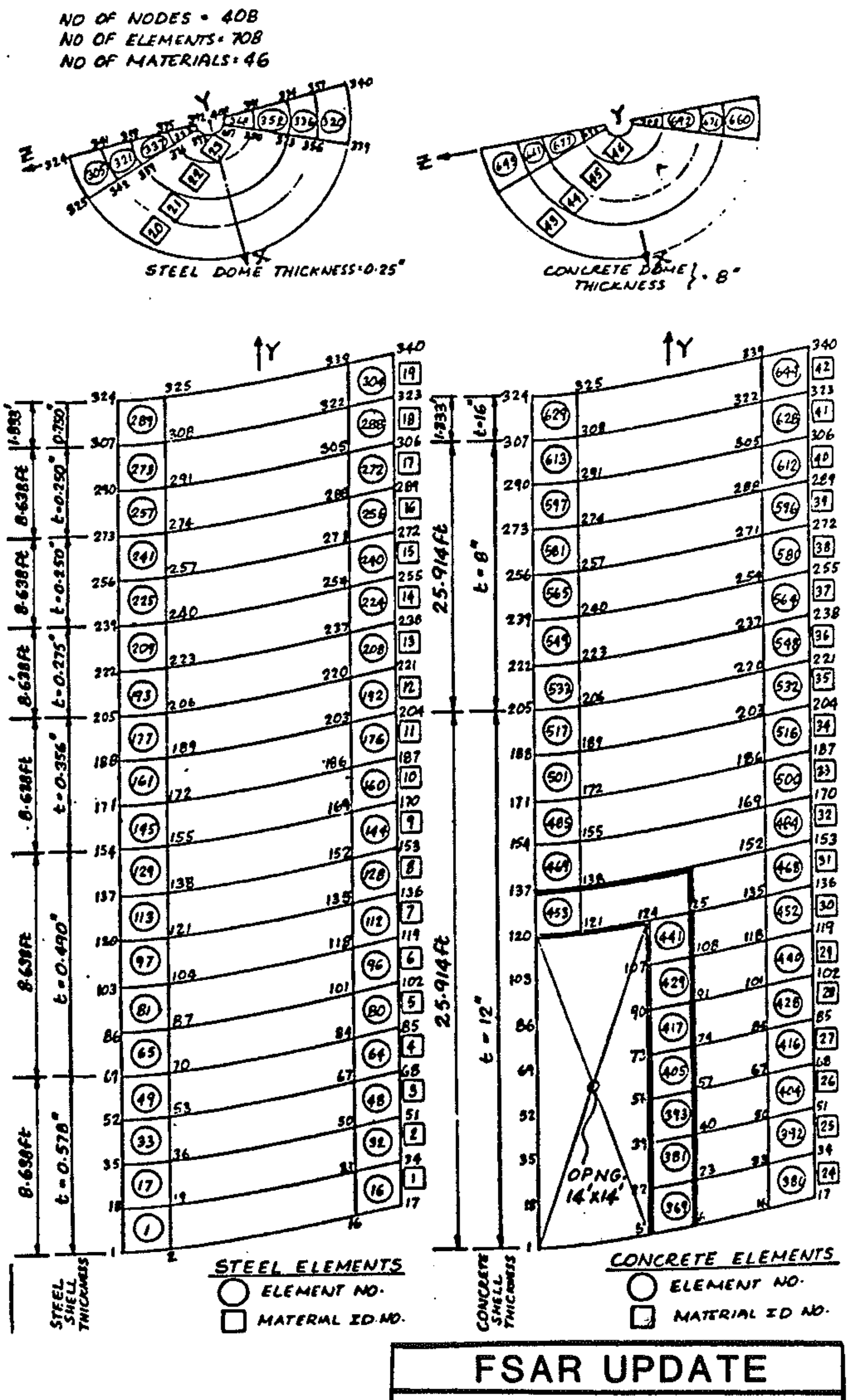
OUTDOOR WATER STORAGE TANKS: FIREWATER AND TRANSFER TANK, AXISYMMETRIC MODEL



FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

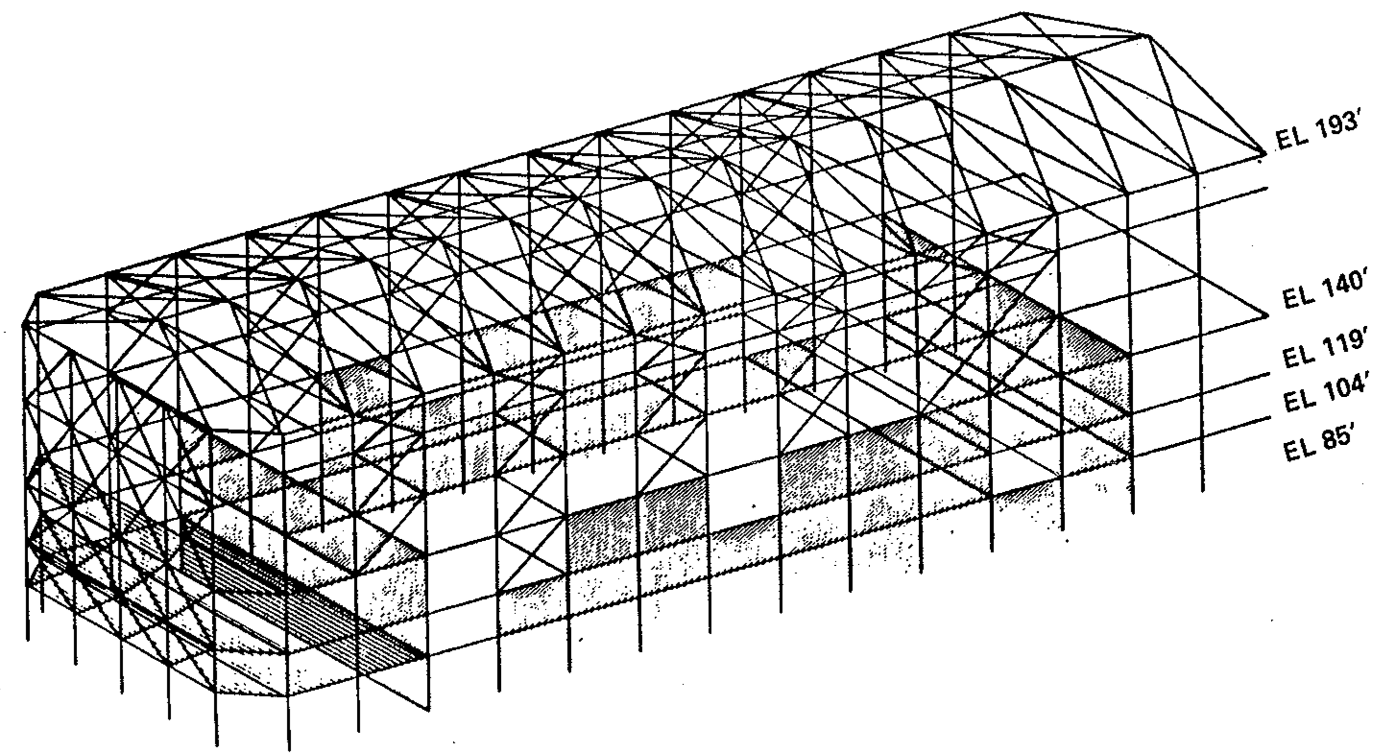
FIGURE 3.7 - 15 A
OUTDOOR WATER STORAGE TANKS:
REFUELING WATER TANK,
PERSPECTIVE VIEW OF
HALF-TANK MODEL



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7 - 15 B
HALF-TANK COMPUTER
MODEL

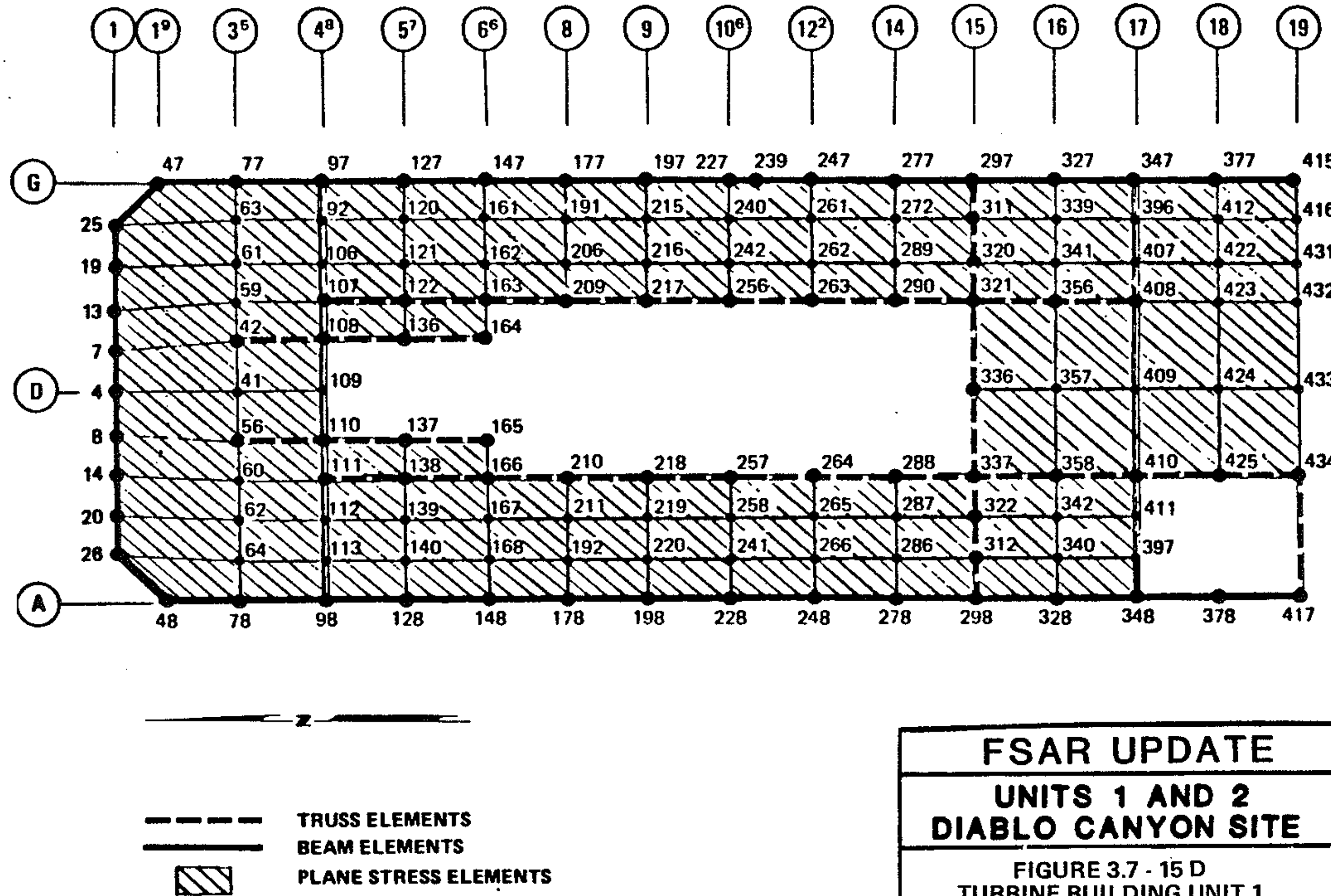


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7 - 15C
TURBINE BUILDING
UNIT 1 PORTION
HORIZONTAL MODEL
ISOMETRIC

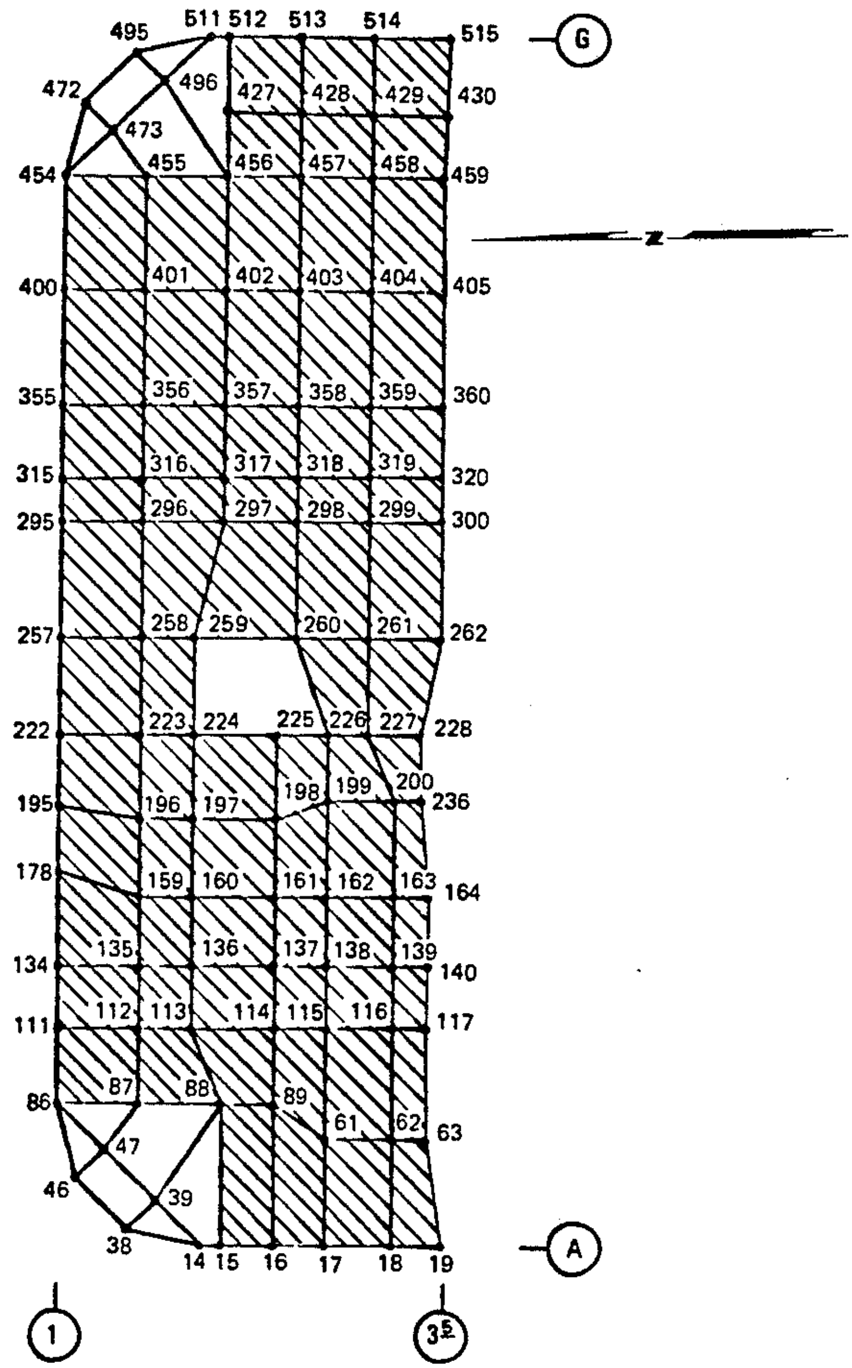
Revision 11 November 1996



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7 - 15 D
TURBINE BUILDING UNIT 1
PORTION HORIZONTAL
MODEL PLAN AT ELEV. 140′

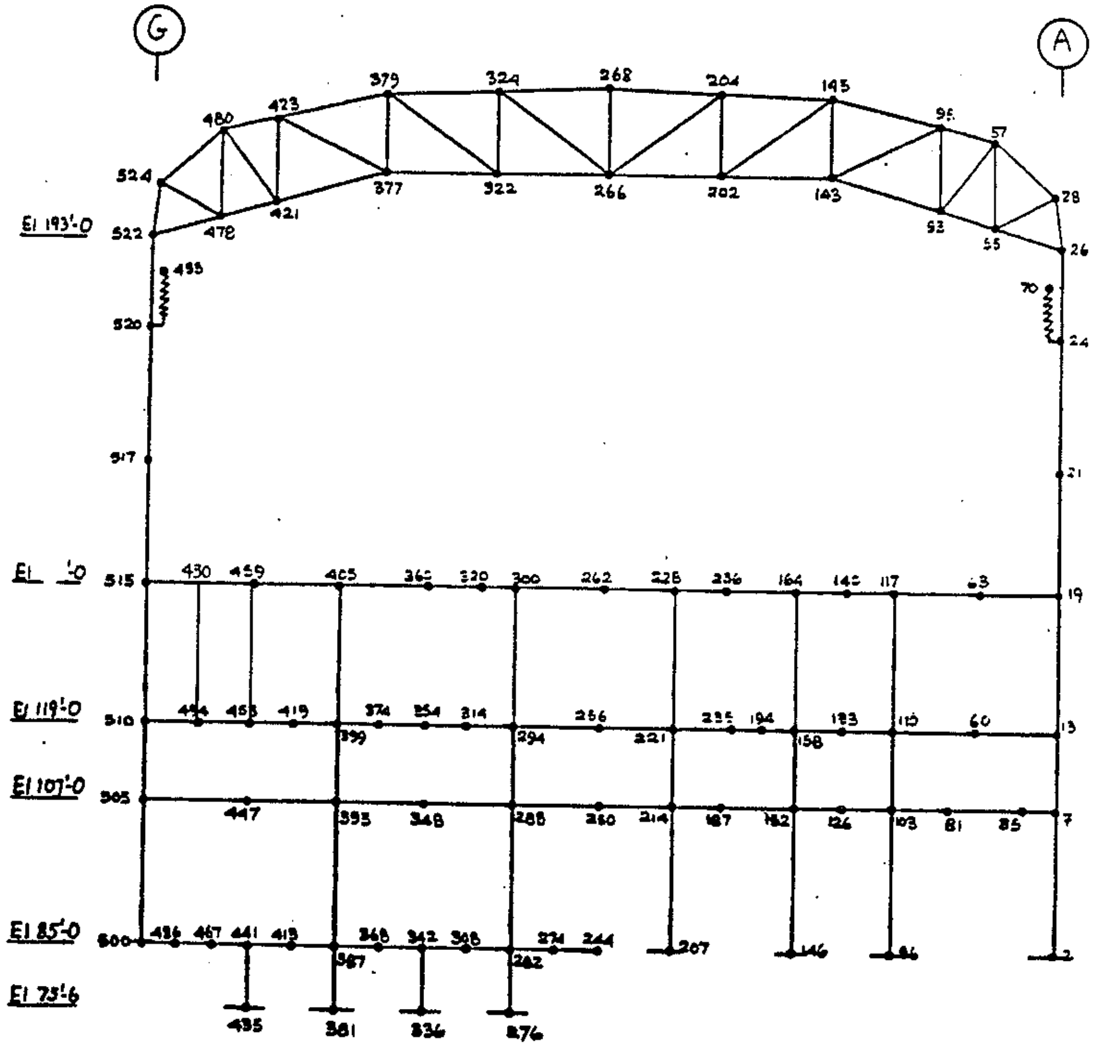


℄ ELEMENT

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7 -15 E
TURBINE BUILDING
VERTICAL MODEL NO. 1
PLAN AT ELEVATION 140'

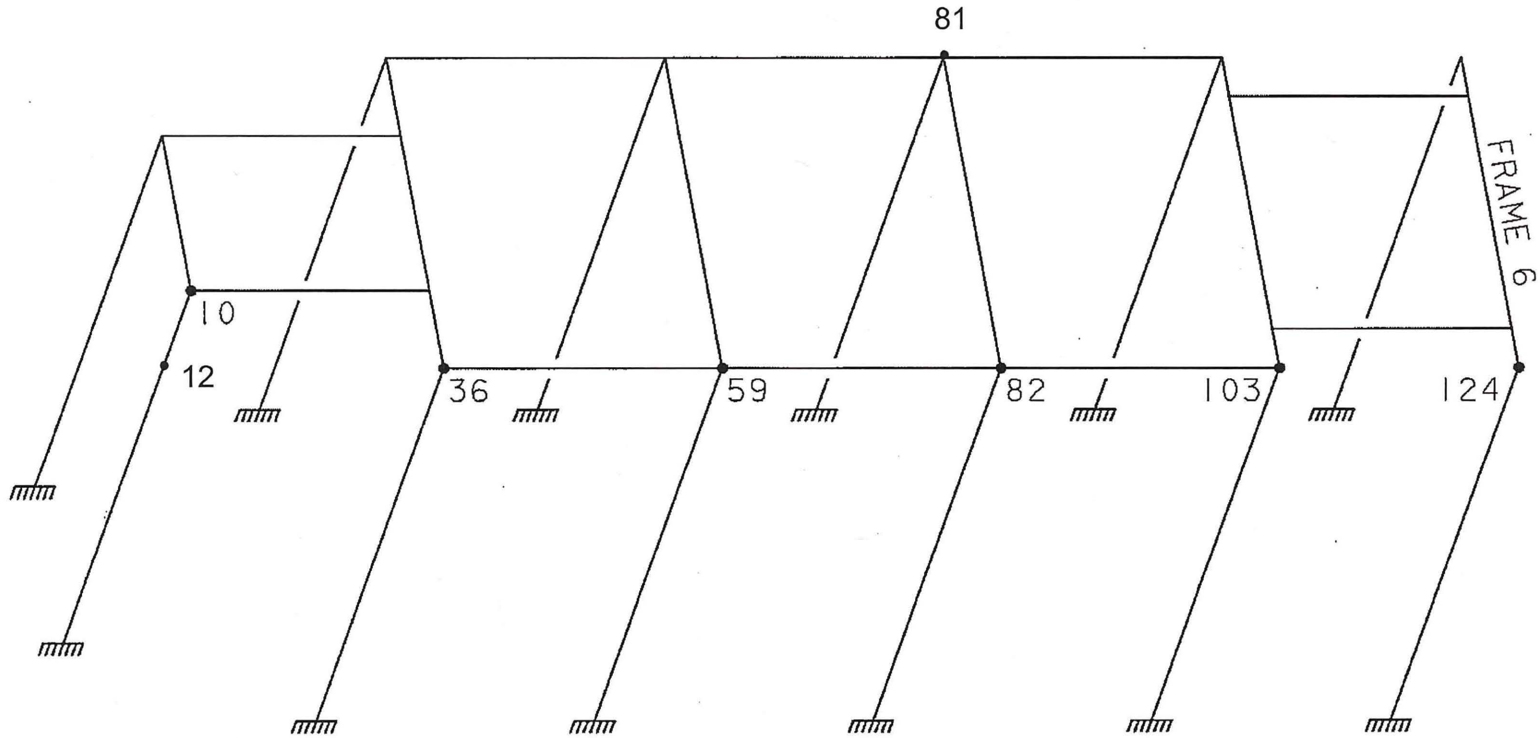


FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

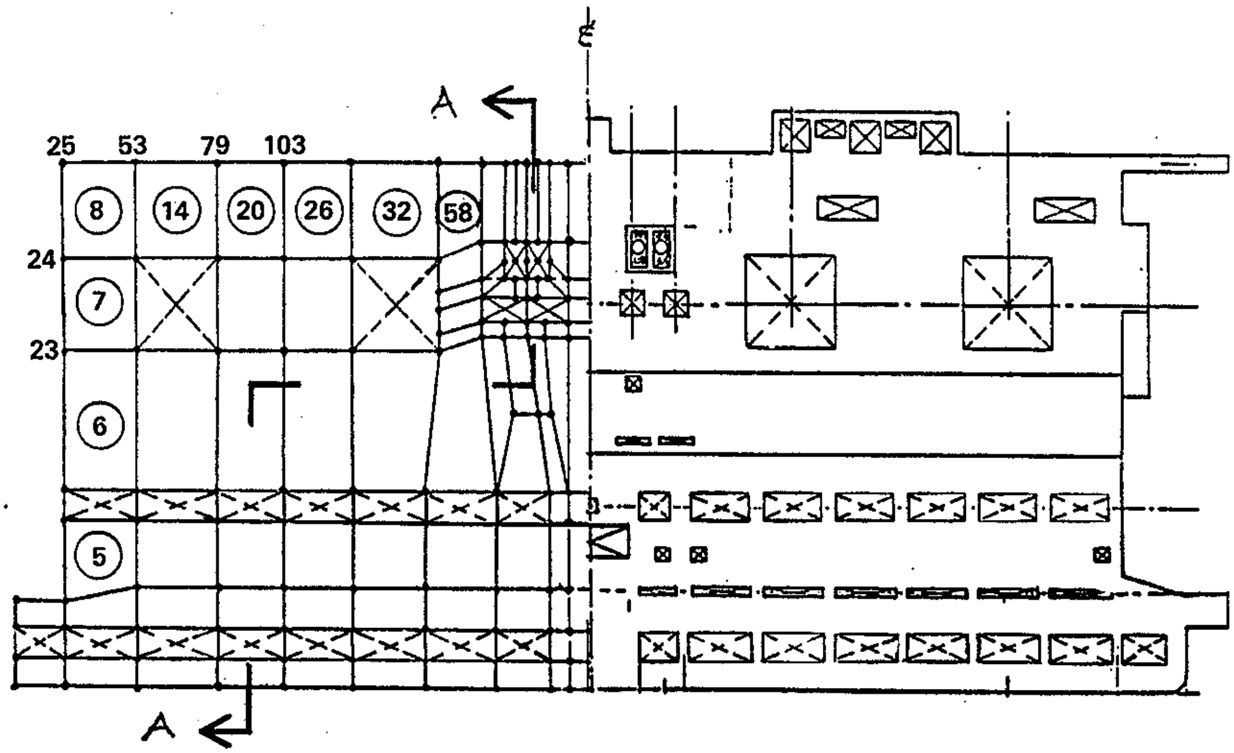
FIGURE 3.7 - 15 F
TURBINE BUILDING
VERTICAL MODEL NO.1
ELEVATION AT LINE 3.5

Revision 11 November 1996



FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 3.7-15G TURBINE PEDESTAL SEISMIC ANALYSIS MODEL

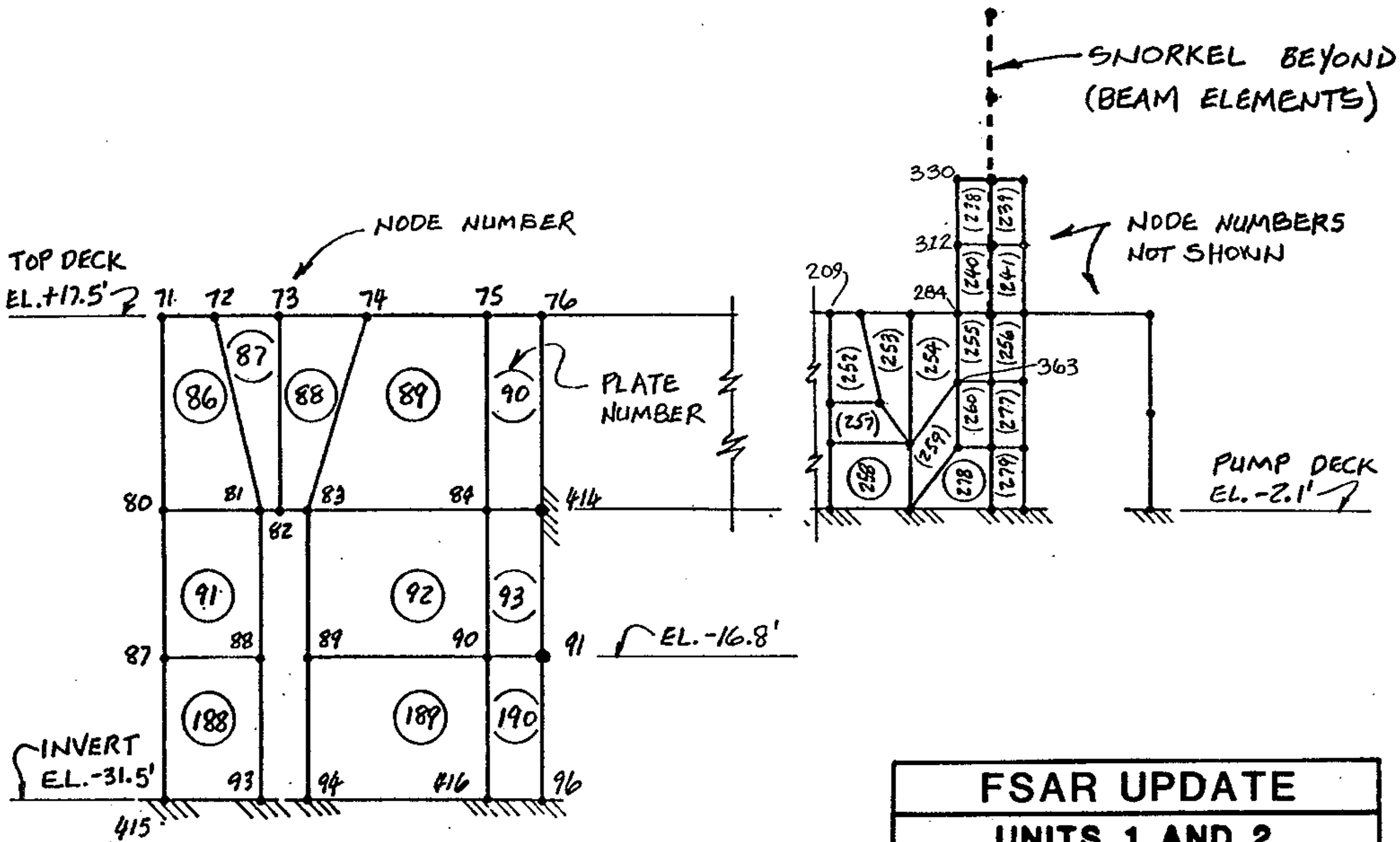
Revision 22 May 2015



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7 - 15 H
INTAKE STRUCTURE
TOP DECK MATHEMATICAL MODEL,
ELEVATION + 17.5 FT.

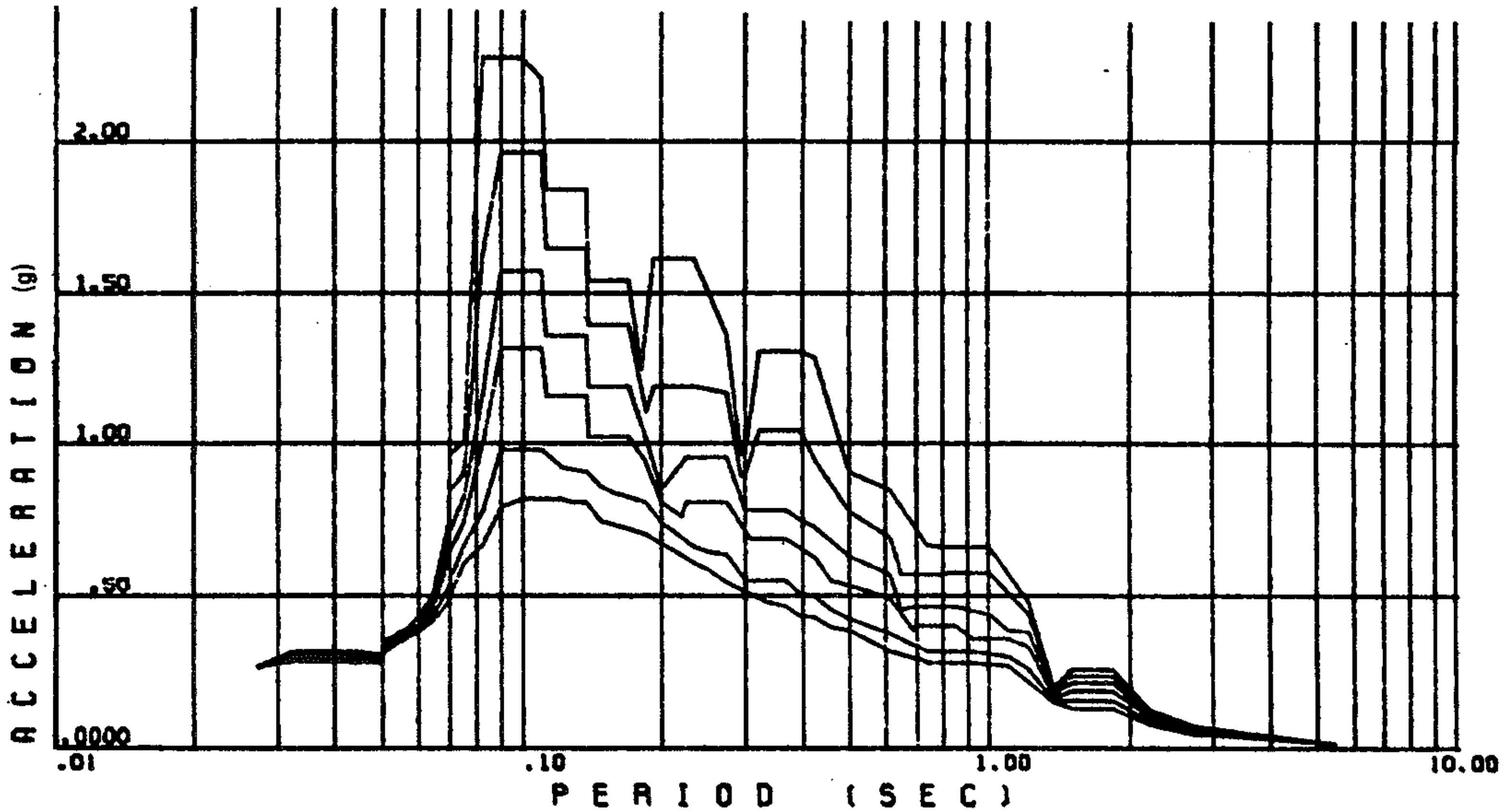


SEE FIG. 3.7-15 H FOR LOCATION OF SECTION A--A

FSAR UPDATE

UNITS 1 AND 2 DIABLO CANYON SITE

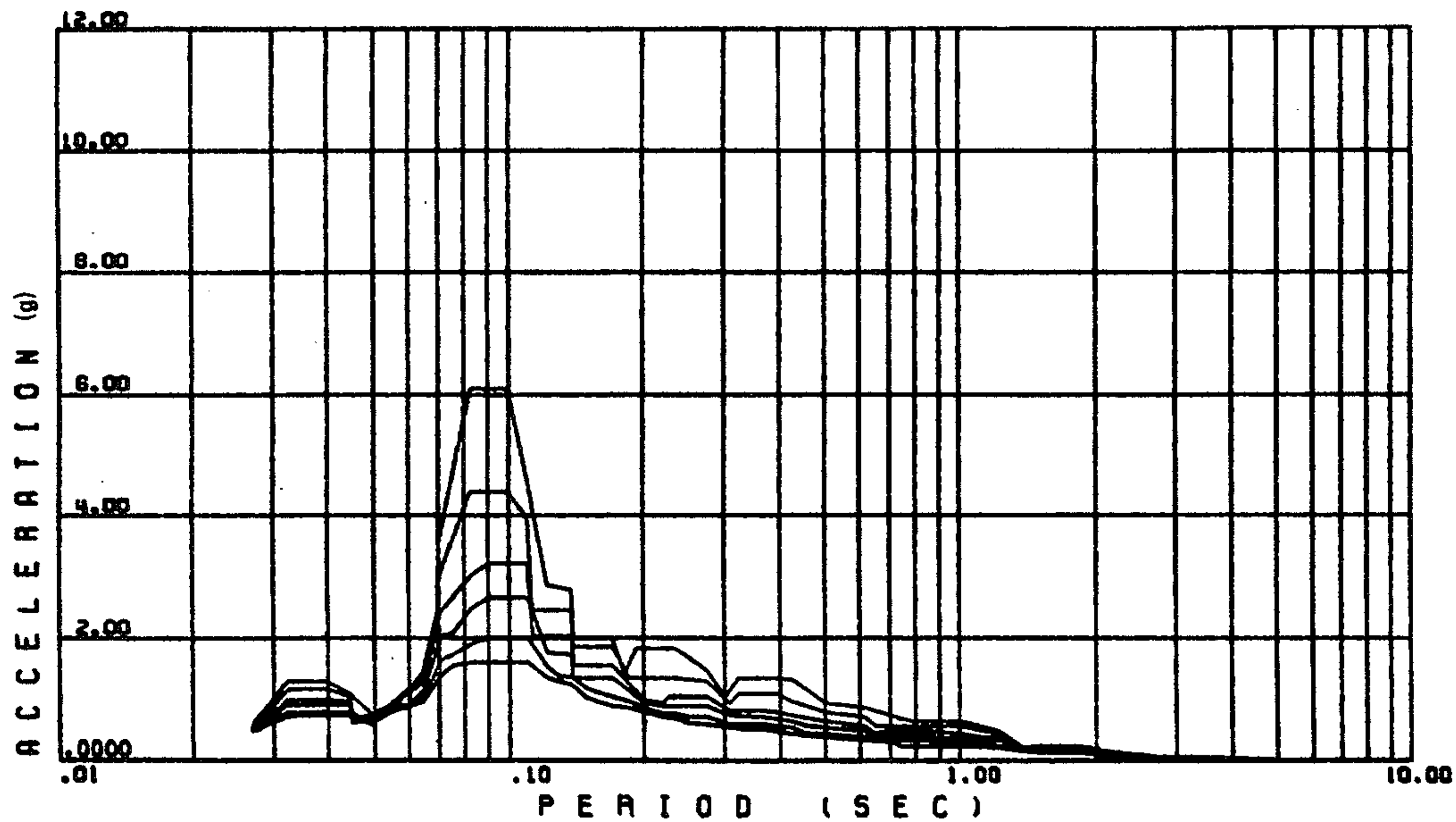
FIGURE 3.7-15I
INTAKE STRUCTURE
TRANSVERSE SECTION A-A
MATHEMATICAL MODEL



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

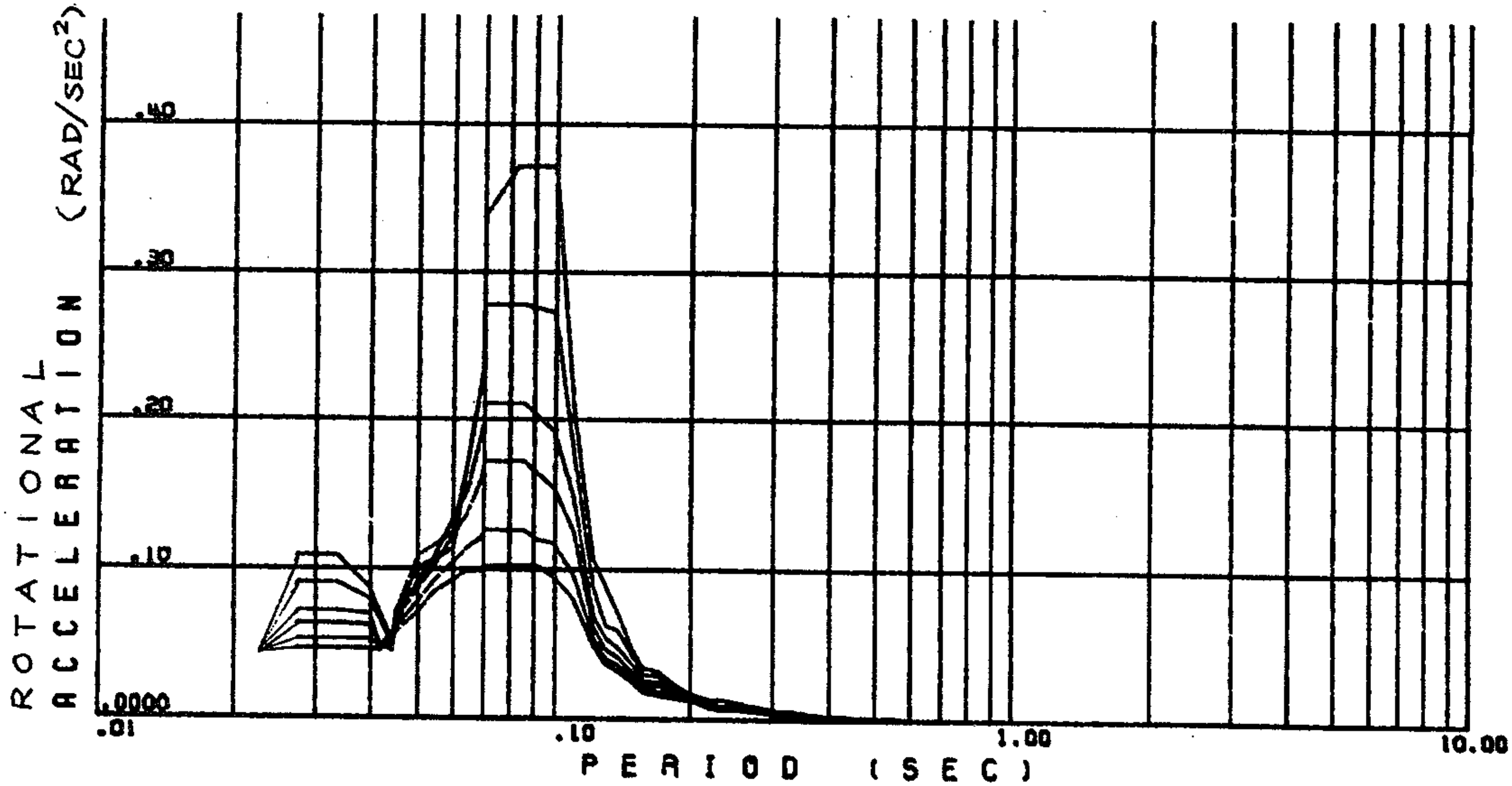
FIGURE 3.7-16
AUXILIARY BUILDING
FLOOR ELEV. 100'–0" N–S
HORIZONTAL SPECTRA
DESIGN EARTHQUAKE
½, 1, 2, 3, 5, 7% DAMPING



FSAR UPDATE

UNITS 1 AND 2 DIABLO CANYON SITE

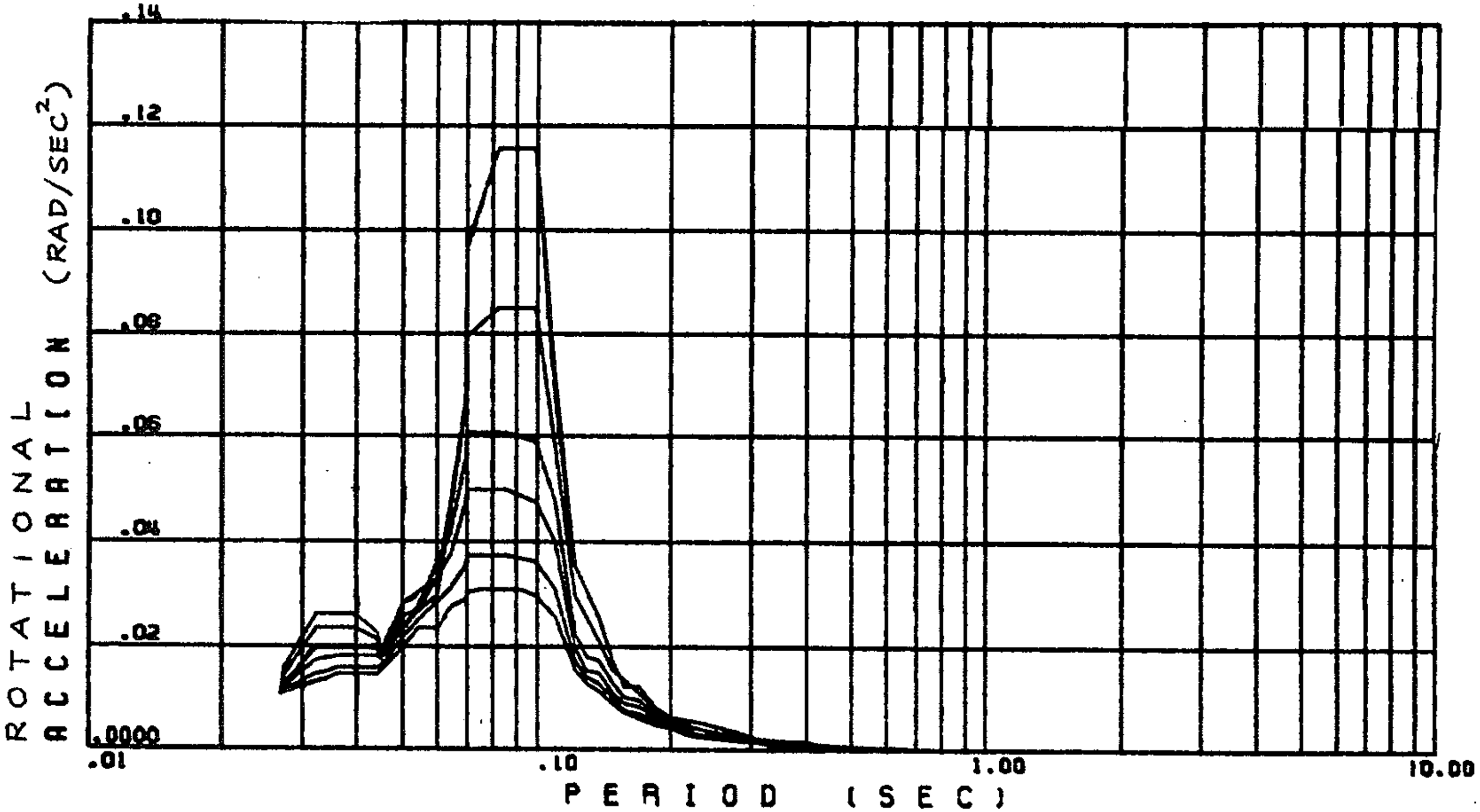
FIGURE 3.7-17
AUXILIARY BUILDING
FLOOR ELEV. 163'–0" N–S
HORIZONTAL SPECTRA
DESIGN EARTHQUAKE
½, 1, 2, 3, 5, 7% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

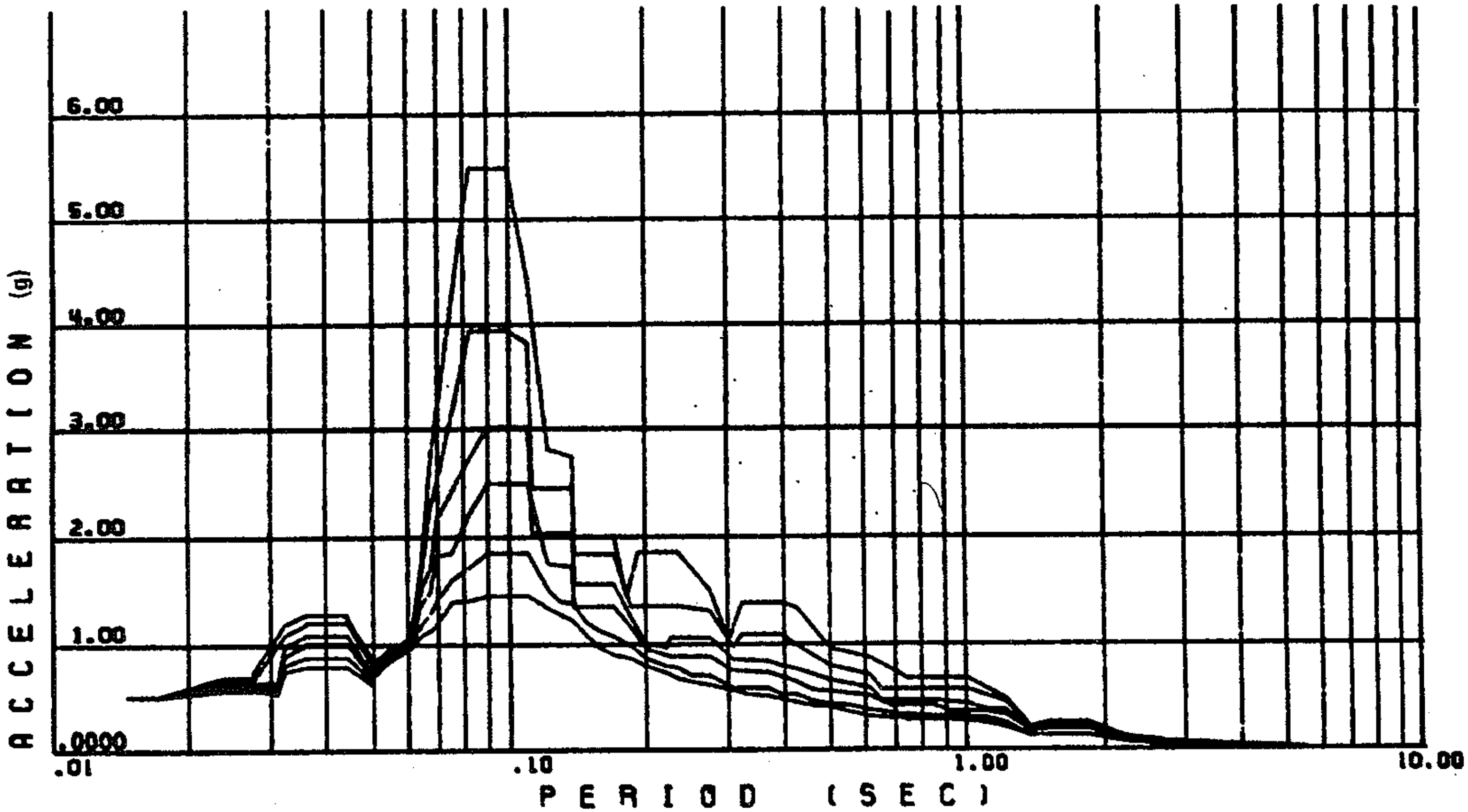
FIGURE 3.7-18
AUXILIARY BUILDING
FLOOR ELEV. 163'–0"
N–S TORSIONAL SPECTRA
DESIGN EARTHQUAKE
½, 1, 2, 3, 5, 7% DAMPING



FSAR UPDATE

UNITS 1 AND 2 DIABLO CANYON SITE

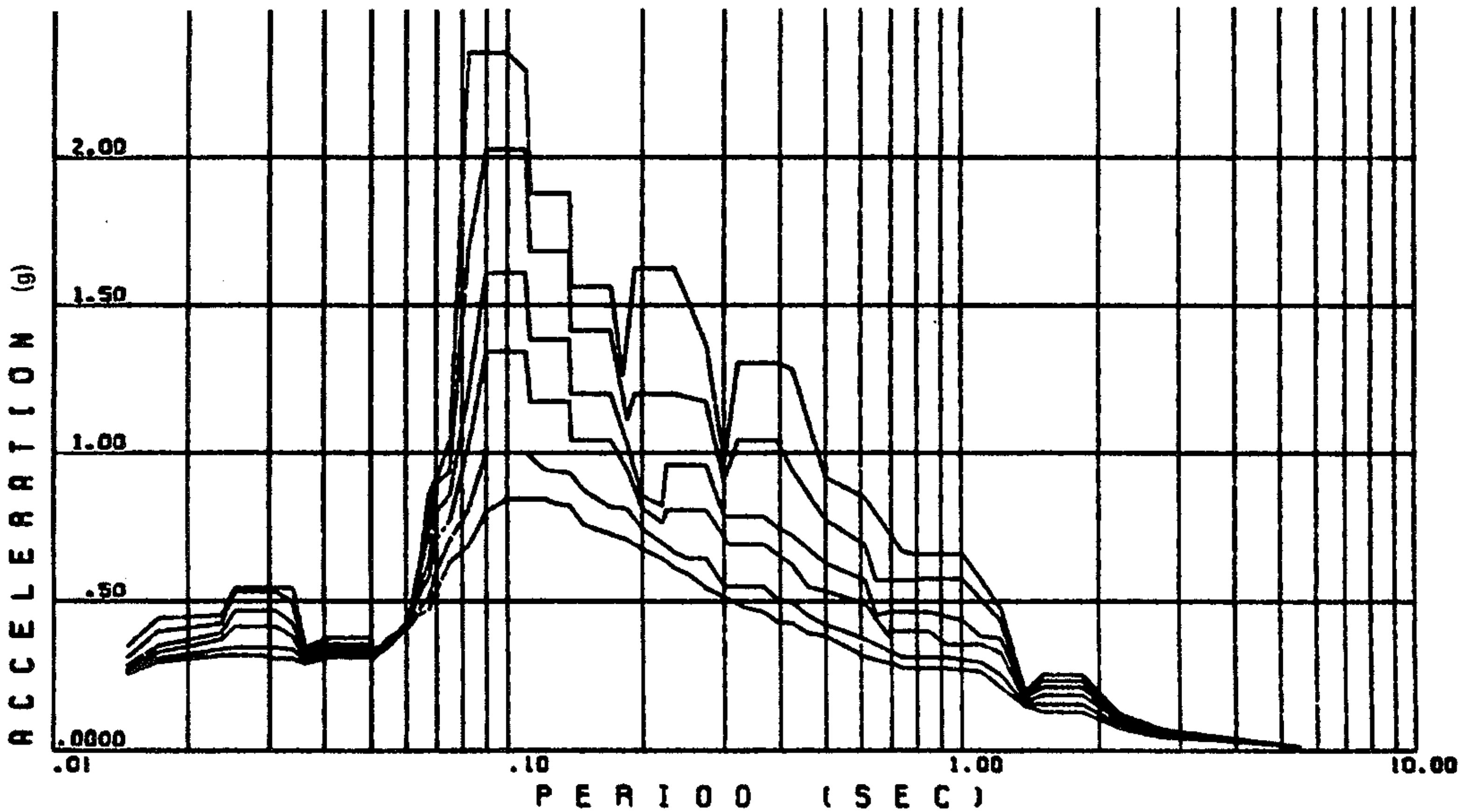
FIGURE 3.7-19
AUXILIARY BUILDING
FLOOR ELEV. 100'–0"
N–S TORSIONAL SPECTRA
DESIGN EARTHQUAKE
½, 1, 2, 3, 5, 7% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

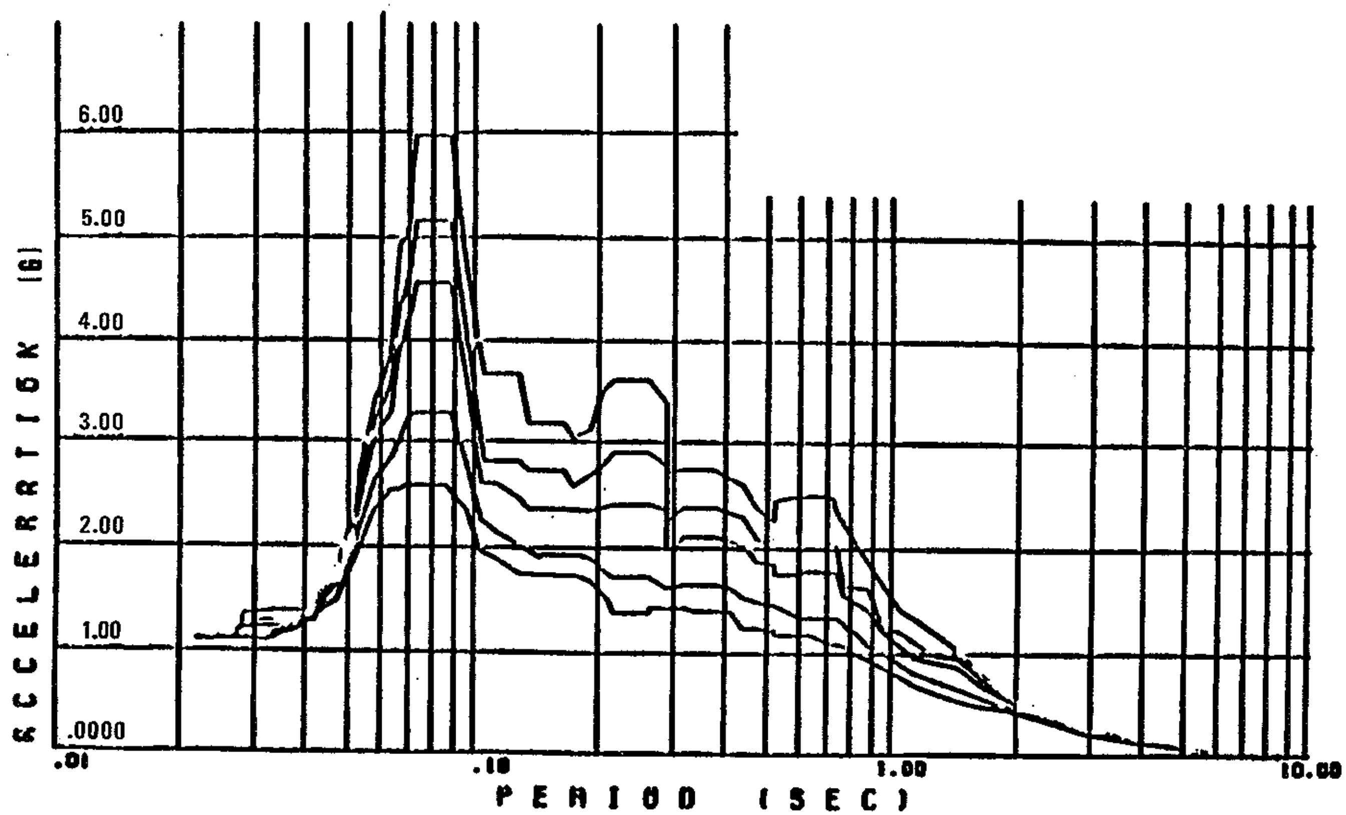
FIGURE 3.7-20
AUXILIARY BUILDING
FLOOR ELEV. 163'–0" E–W
HORIZONTAL SPECTRA
DESIGN EARTHQUAKE
½, 1, 2, 3, 5, 7% DAMPING



FSAR UPDATE

UNITS 1 AND 2 DIABLO CANYON SITE

FIGURE 3.7-21
AUXILIARY BUILDING
FLOOR ELEV. 100'–0"
E–W HORIZONTAL SPECTRA
DESIGN EARTHQUAKE
½, 1, 2, 3, 5, 7% DAMPING

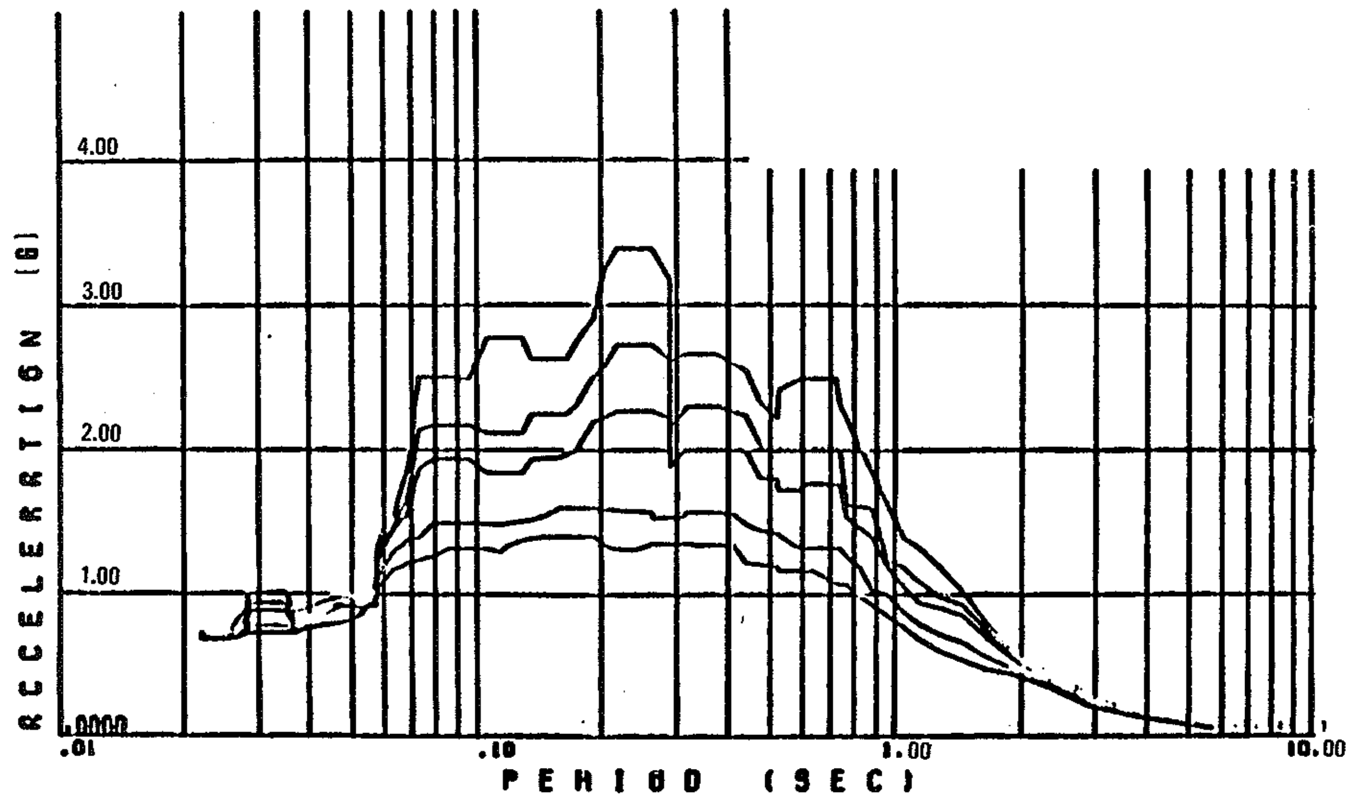


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7–21A

AUXILIARY BUILDING
E–W HOSGRI
HORIZONTAL FLOOR SPECTRA
AT EL 140′–0″
2,3,4,7, AND 10% DAMPING

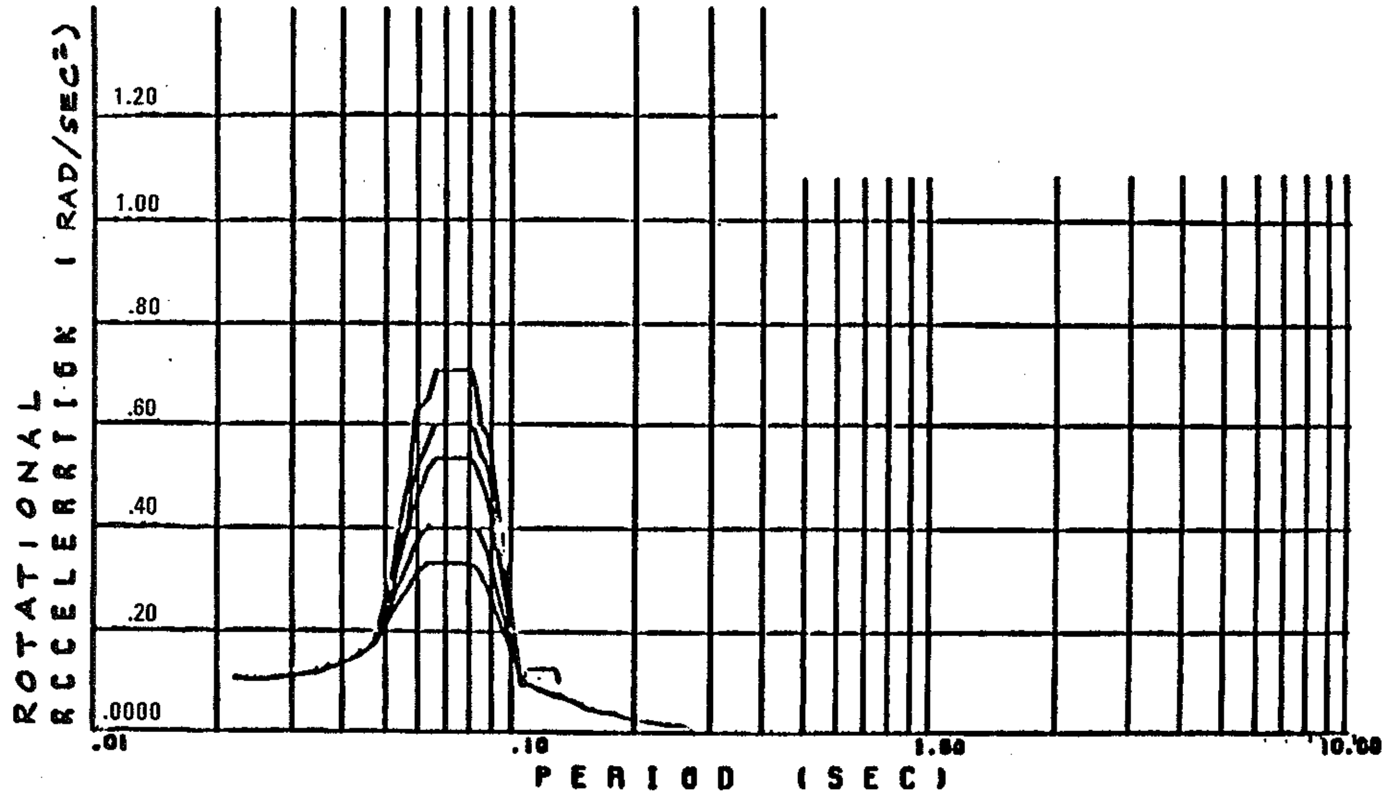


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7–21B

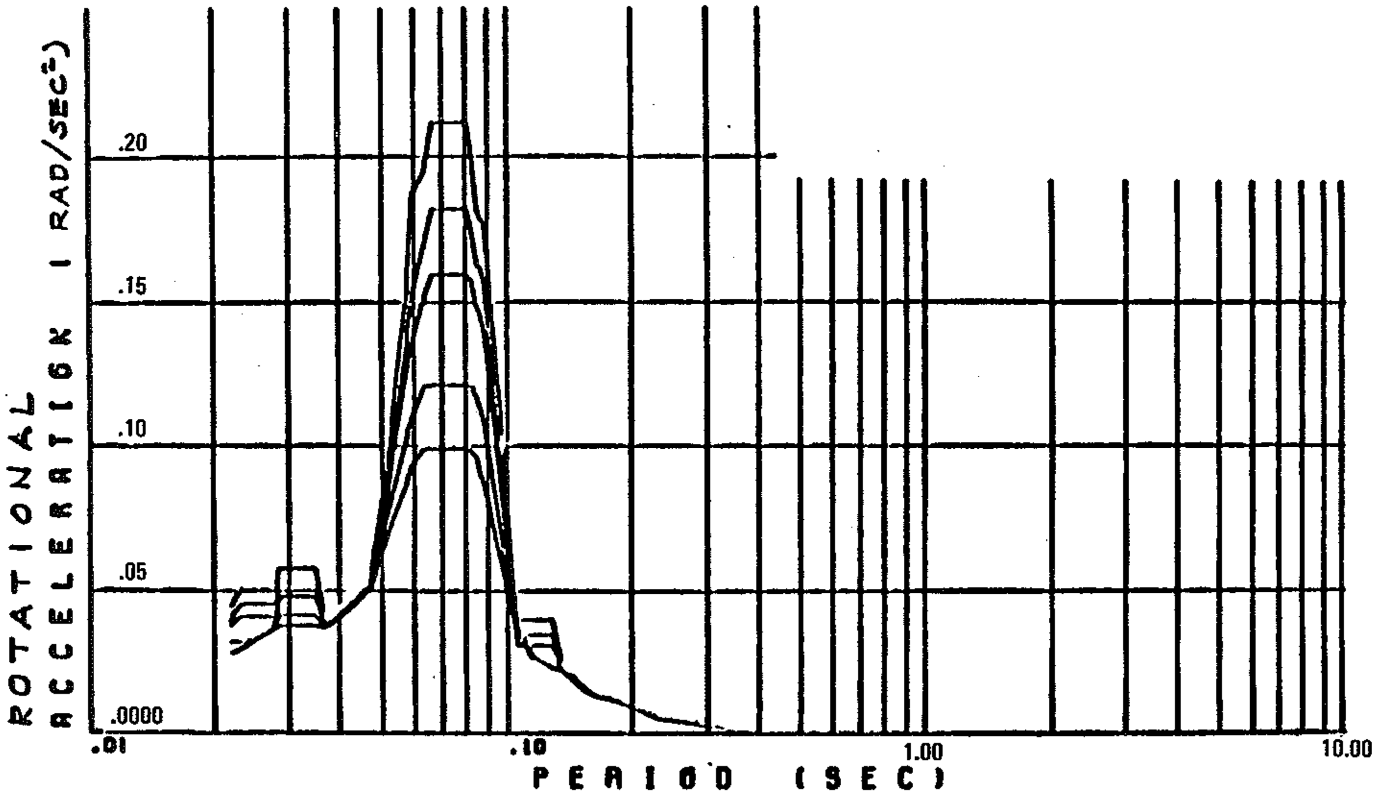
AUXILIARY BUILDING
E–W HOSGRI
HORIZONTAL FLOOR SPECTRA
AT EL 100′–0″
2,3,4,7, AND 10% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7–21C
AUXILIARY BUILDING
E–W HOSGRI
TORSIONAL FLOOR SPECTRA
AT EL 140′–0″
2,3,4,7 and 10% DAMPING

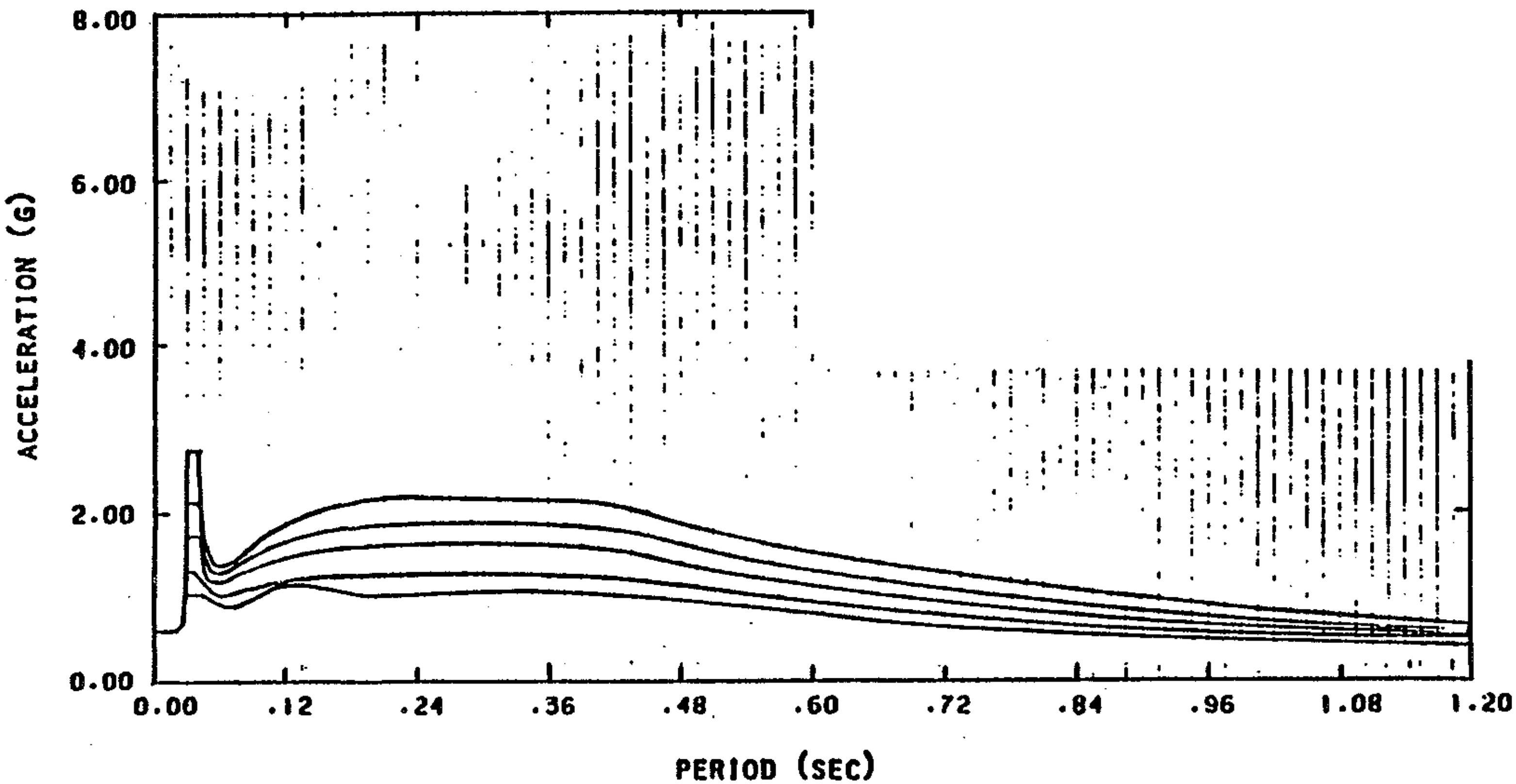


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7–21D

AUXILIARY BUILDING
E–W HOSGRI
TORSIONAL FLOOR SPECTRA
AT EL 100′–0″
2,3,4,7, AND 10% DAMPING

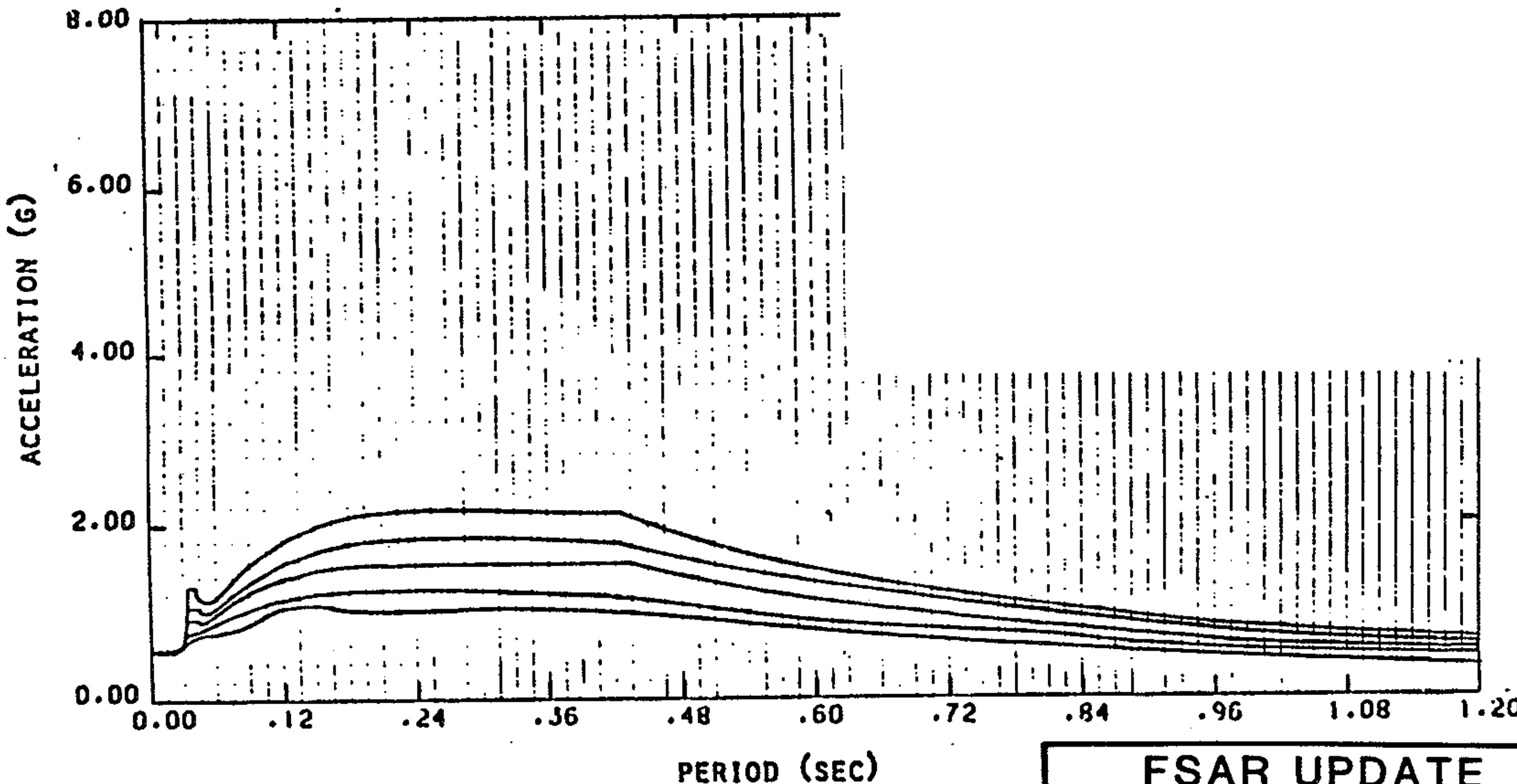


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7–21E

AUXILIARY BUILDING
HOSGRI VERTICAL SPECTRA
AT EL 140′–0″
2,3,4,7, AND 10% DAMPING

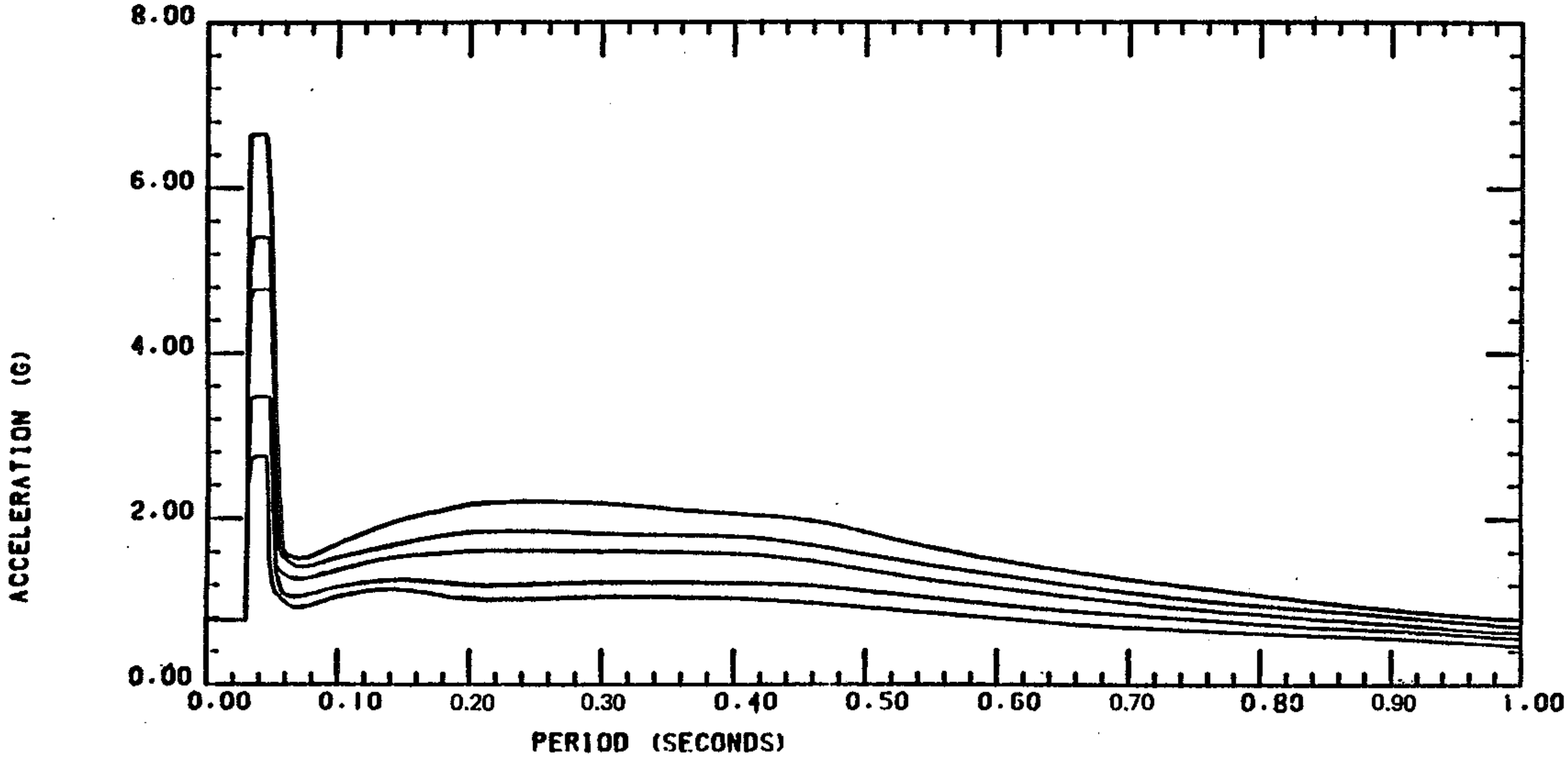


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7–21F

AUXILIARY BUILDING
HOSGRI VERTICAL SPECTRA
AT EL 100′–0″
2,3,4,7, AND 10% DAMPING

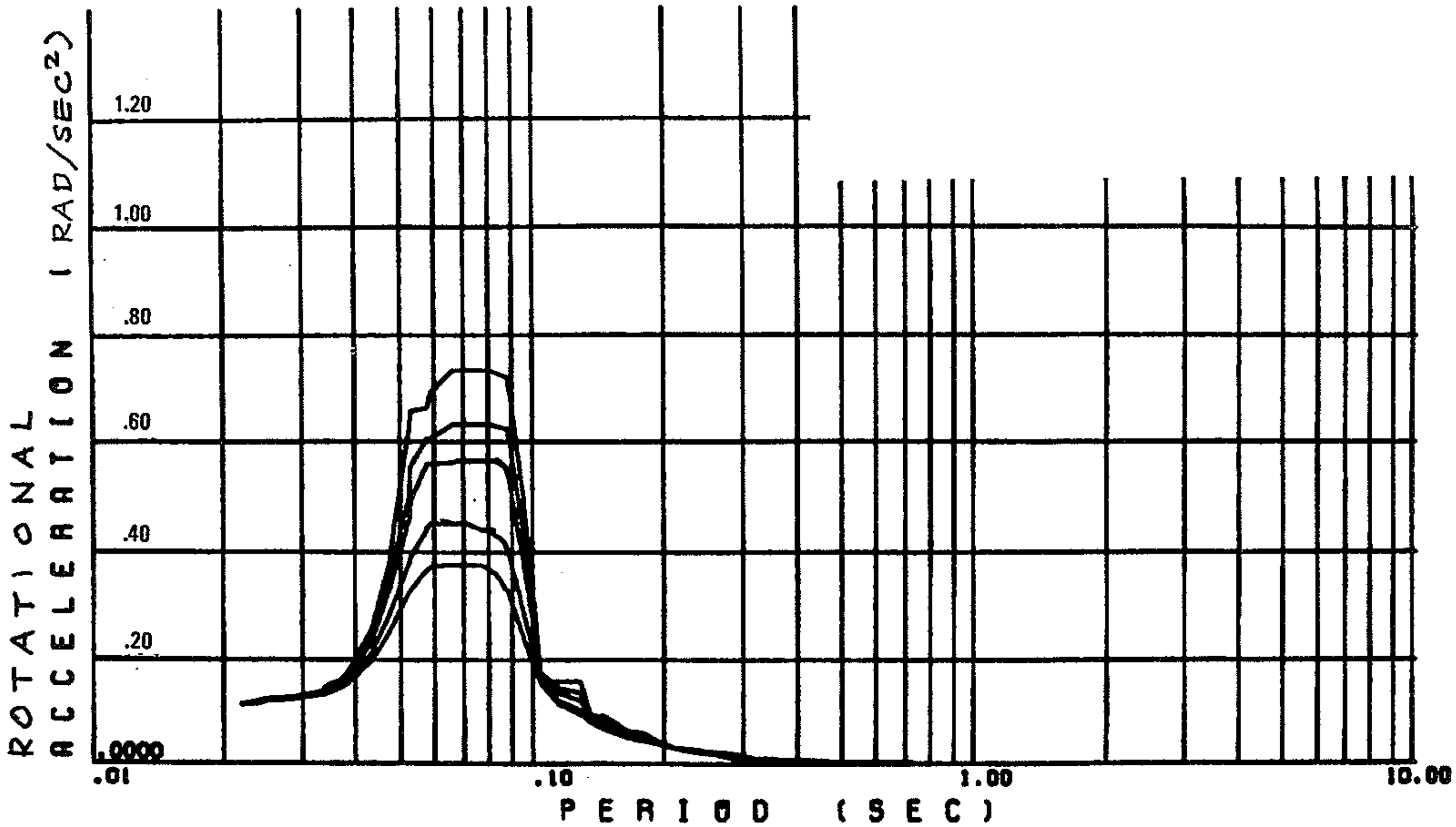


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7–21G

AUXILIARY BUILDING
HOSGRI VERTICAL SPECTRA
EL 100'–0" SLAB 2 NODE 51
2,3,4,7, AND 10%

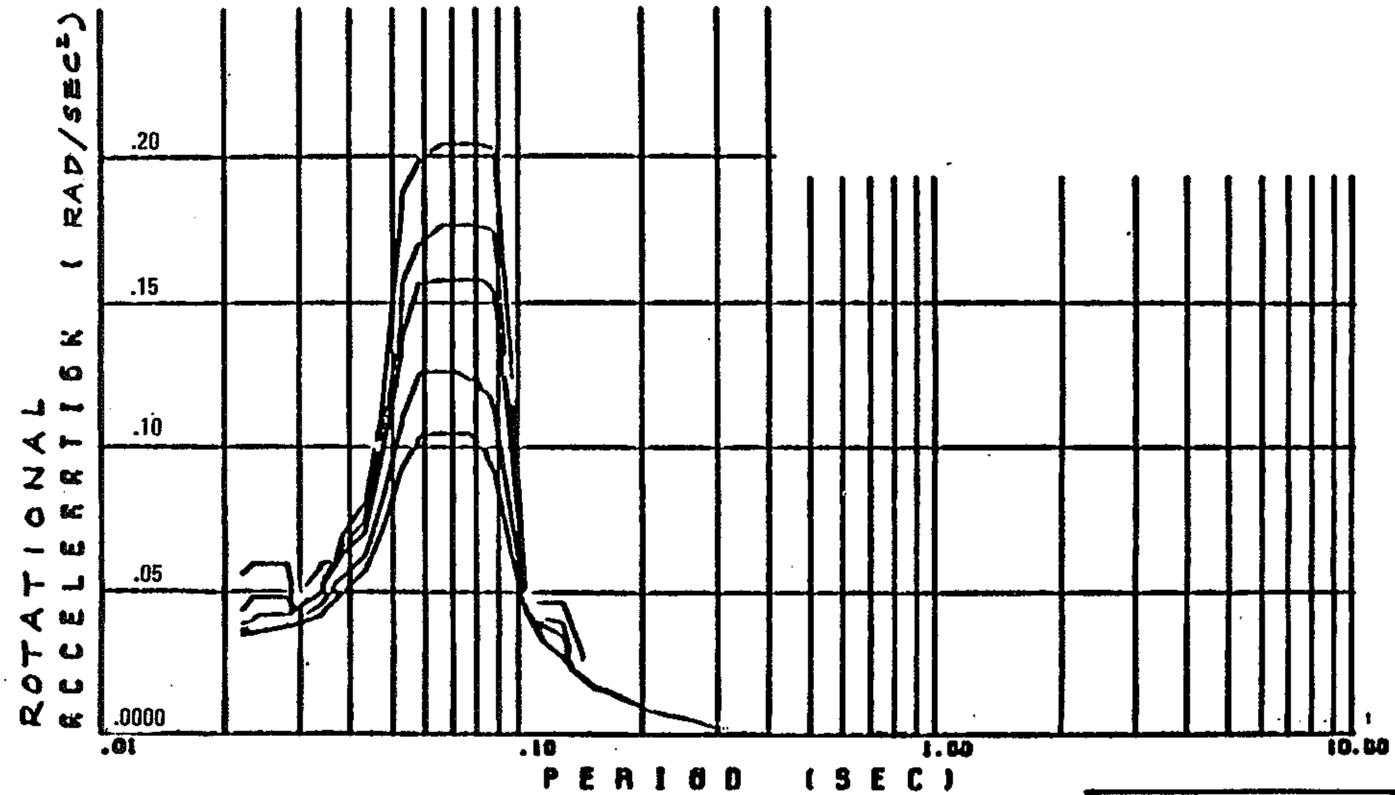


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7–21H

AUXILIARY BUILDING
N–S HOSGRI
TORSIONAL FLOOR SPECTRA
AT EL 140'–0"
2,3,4,7, AND 10% DAMPING

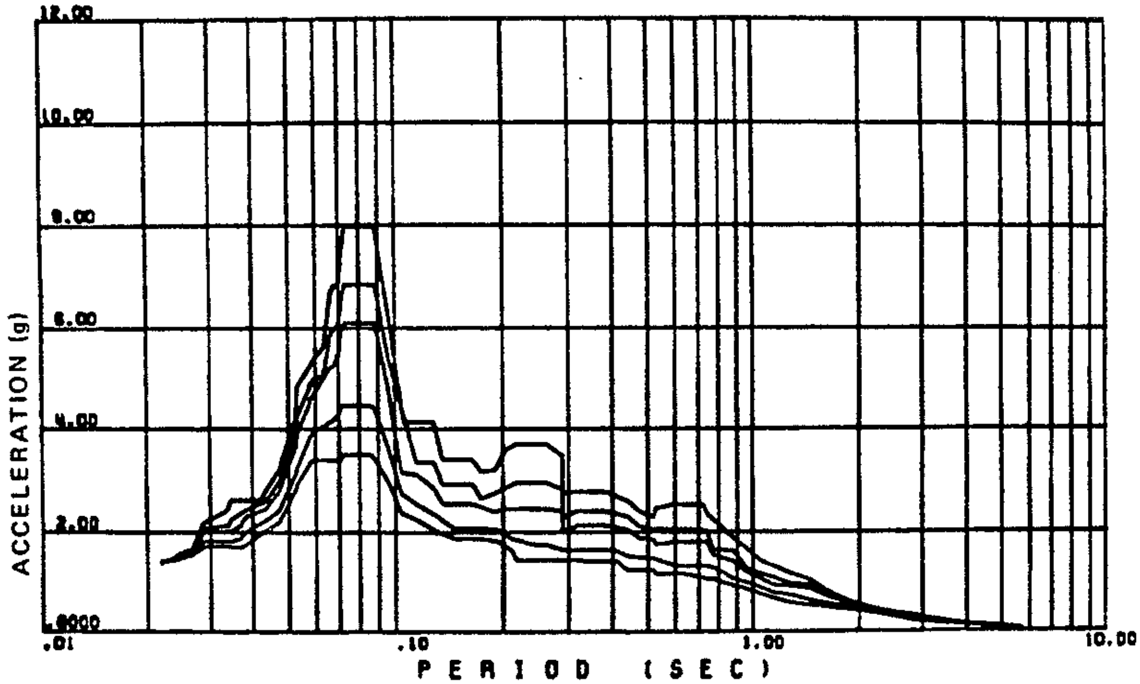


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7–21I

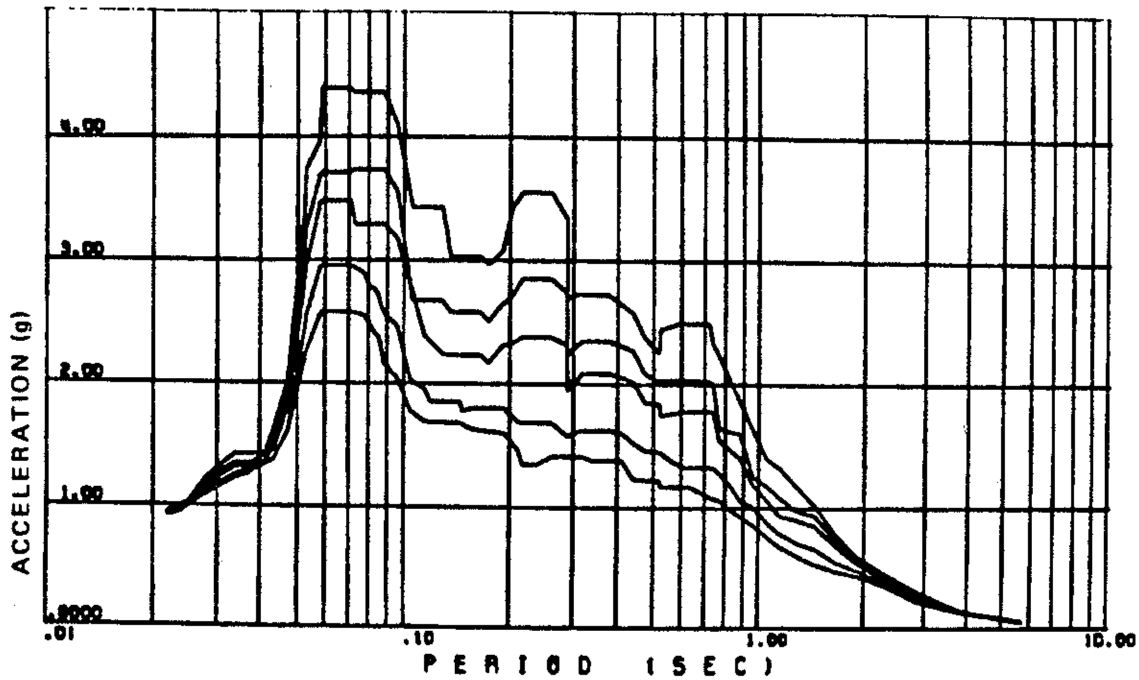
AUXILIARY BUILDING
N–S HOSGRI
TORSIONAL FLOOR SPECTRA
AT EL 100′–0″
2,3,4,7,AND 10% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

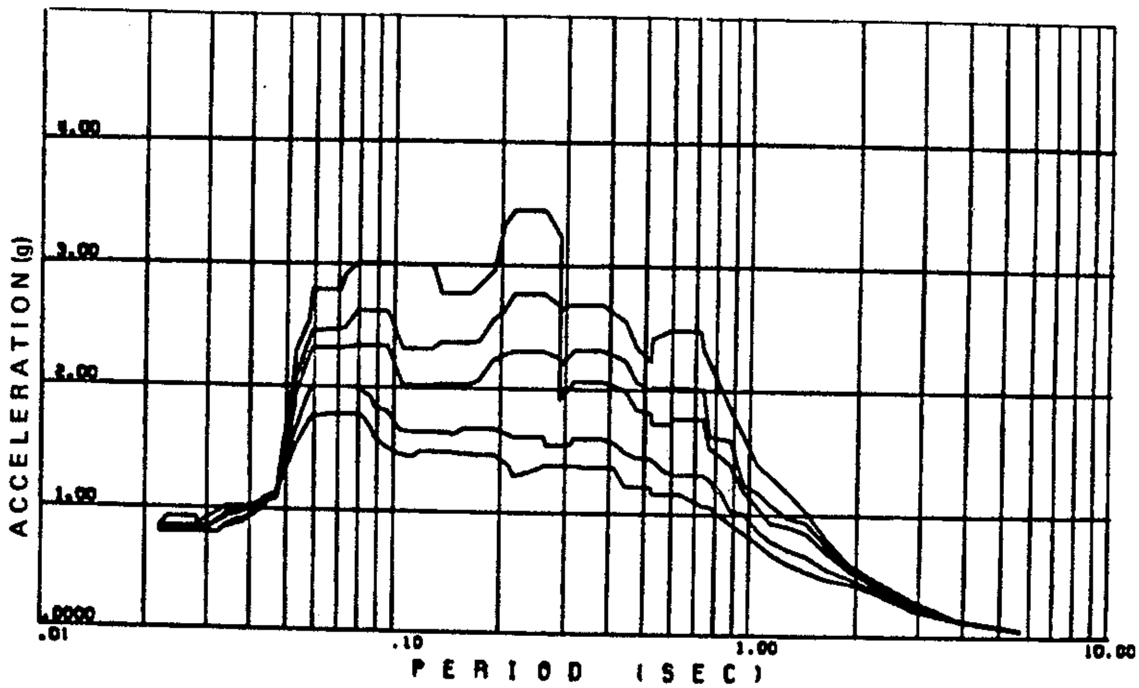
FIGURE 3.7-22
AUXILIARY BUILDING
N–S HOSGRI
HORIZONTAL FLOOR SPECTRA
AT EL 163'-0"
NODE 1
2, 3, 4, 7, AND 10% DAMPING



FSAR UPDATE

UNITS 1 AND 2 DIABLO CANYON SITE

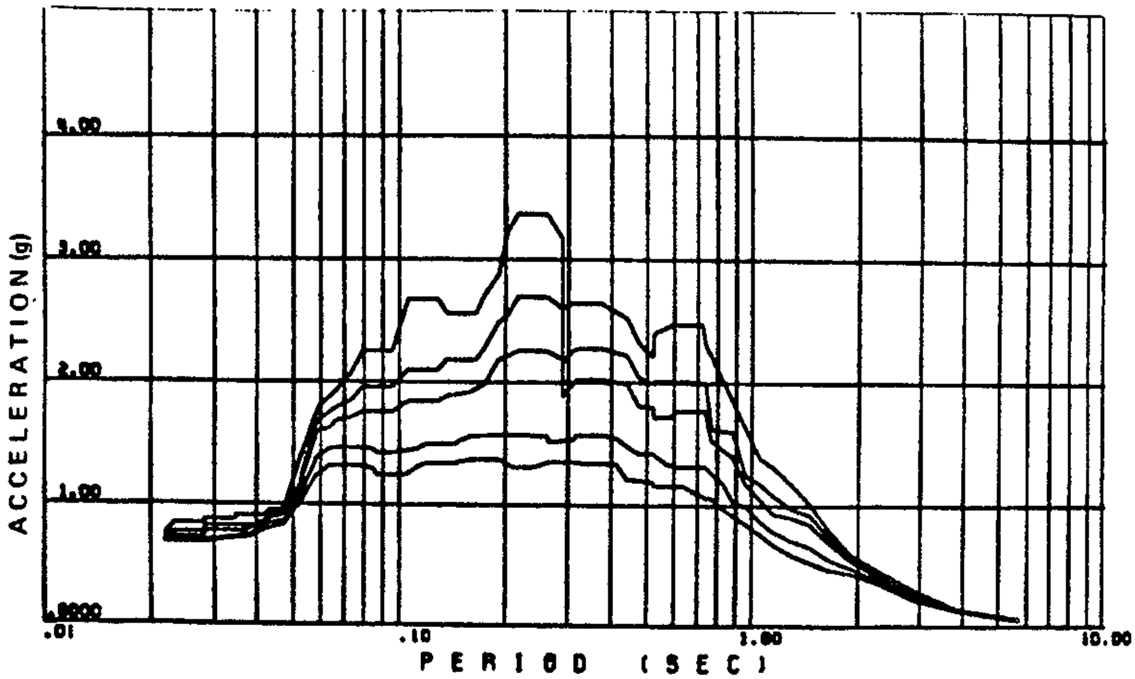
FIGURE 3.7-23
AUXILIARY BUILDING
N–S HOSGRI
HORIZONTAL FLOOR SPECTRA
AT EL 140'-0"
NODE 2
2, 3, 4, 7, AND 10% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

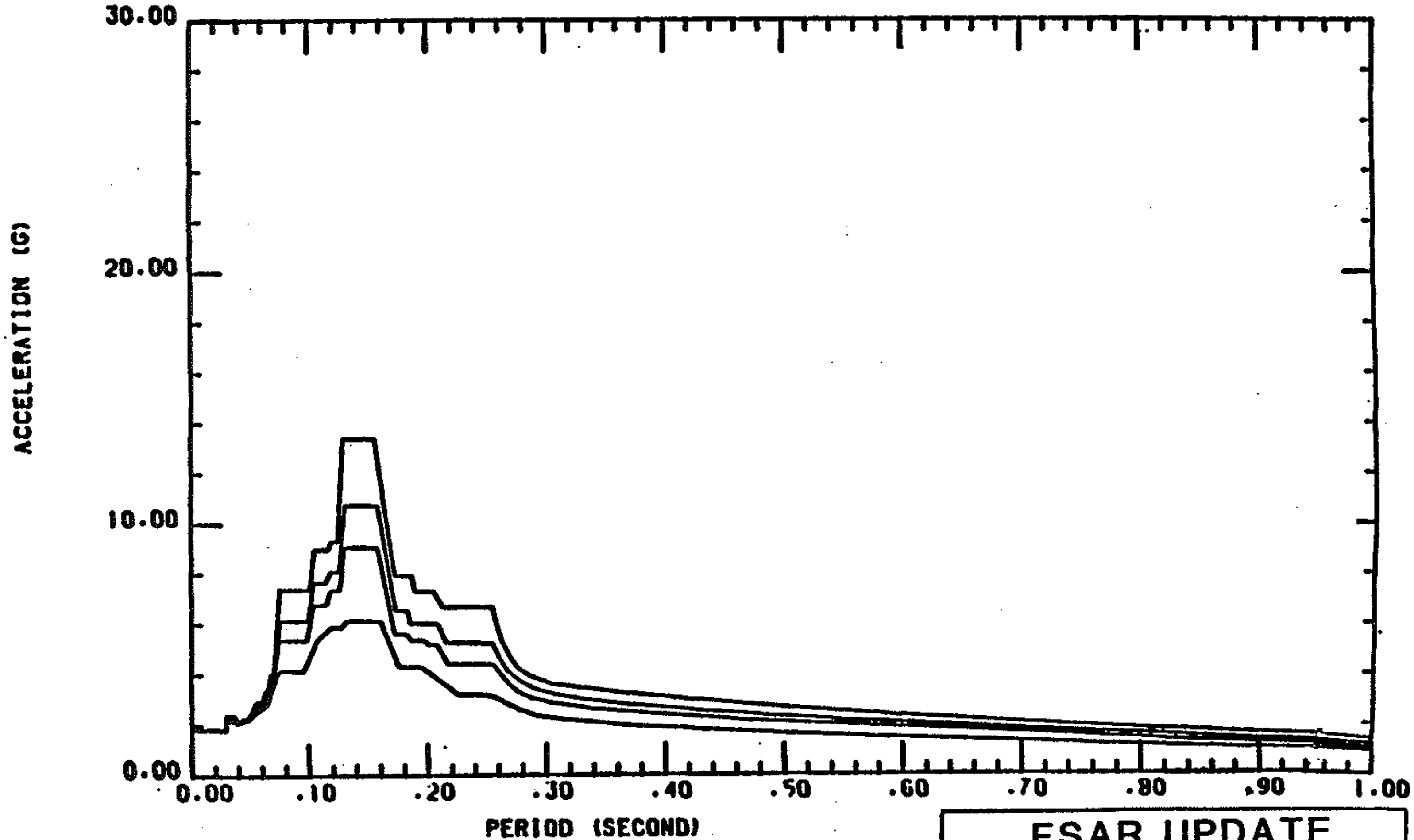
FIGURE 3.7-24
AUXILIARY BUILDING
N–S HOSGRI
HORIZONTAL FLOOR SPECTRA
AT EL 115'-0"
NODE 3
2, 3, 4, 7, AND 10% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

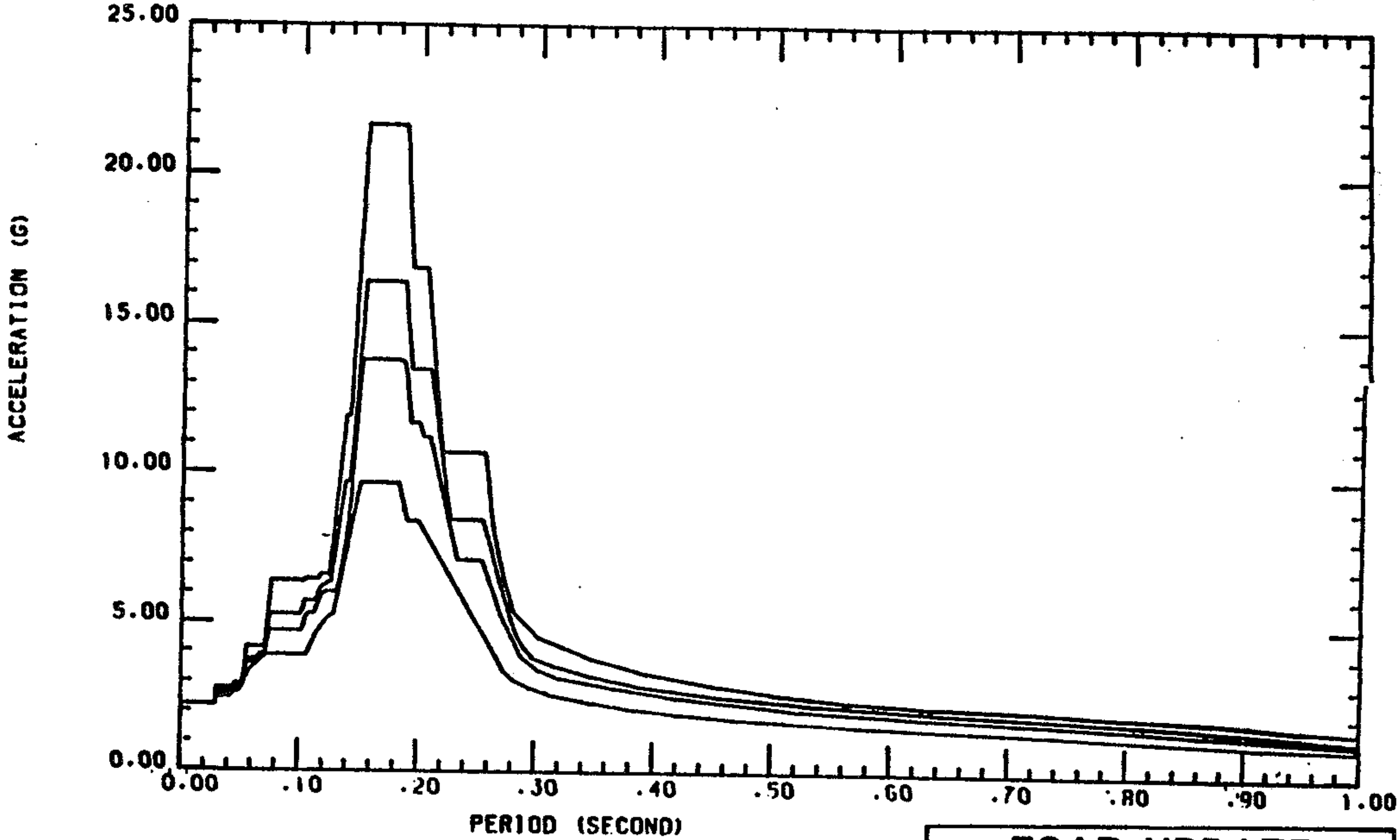
FIGURE 3.7-25
AUXILIARY BUILDING
N–S HOSGRI
HORIZONTAL FLOOR SPECTRA
AT EL 100'-0"
NODE 4
2, 3, 4, 7, AND 10% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

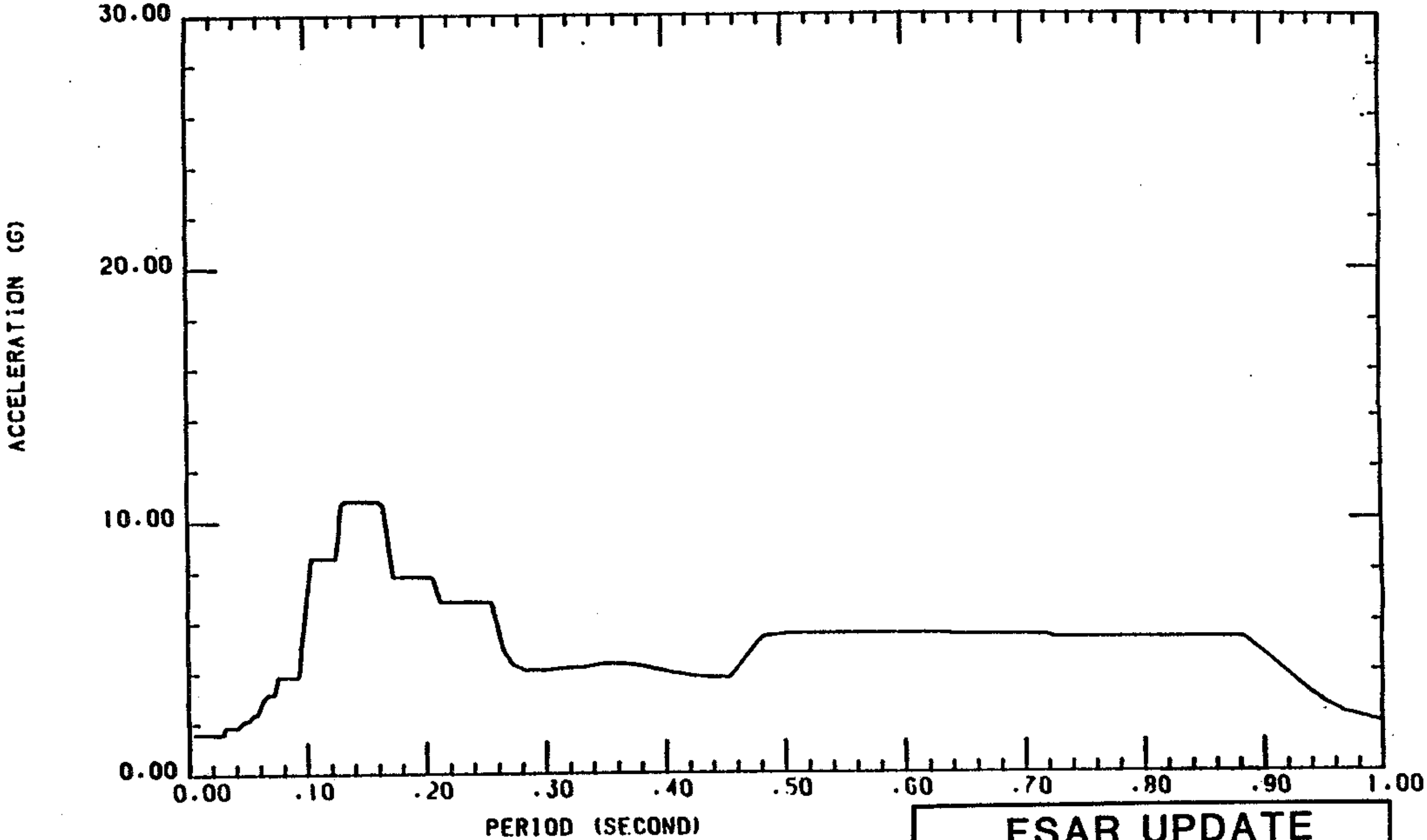
FIGURE 3.7 - 25 A
TURBINE BUILDING
EL. 119'
4 KV SWITCHGEAR AREA
COLUMN LINES 1-4, D-G
HOSGRI E-W SPECTRA
2,3,4,7% DAMPING



FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

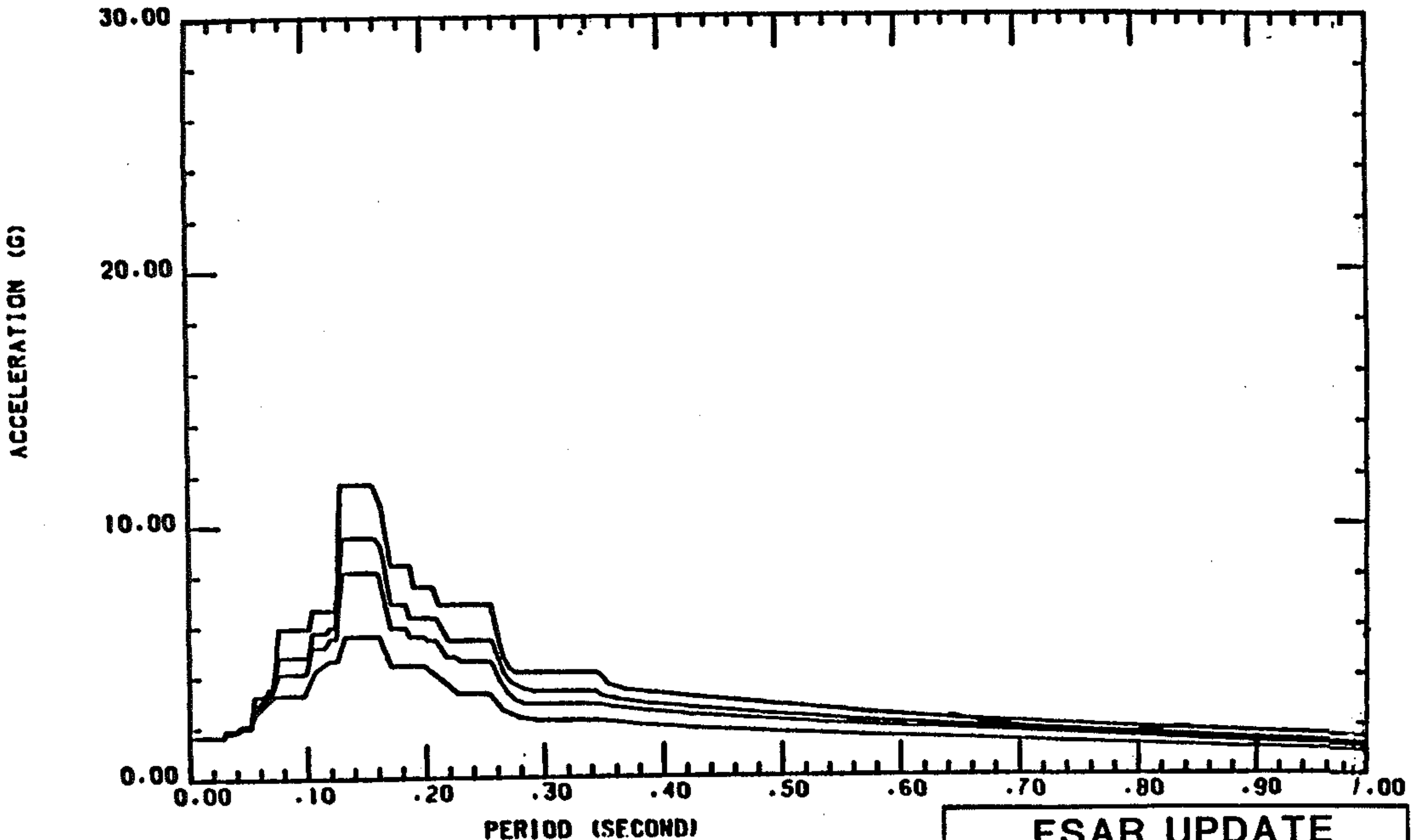
FIGURE 3.7 - 25B
TURBINE BUILDING EL. 140'
COLUMN LINES 5-15
HOSGRI E-W SPECTRA
2, 3, 4, 7% DAMPING



FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

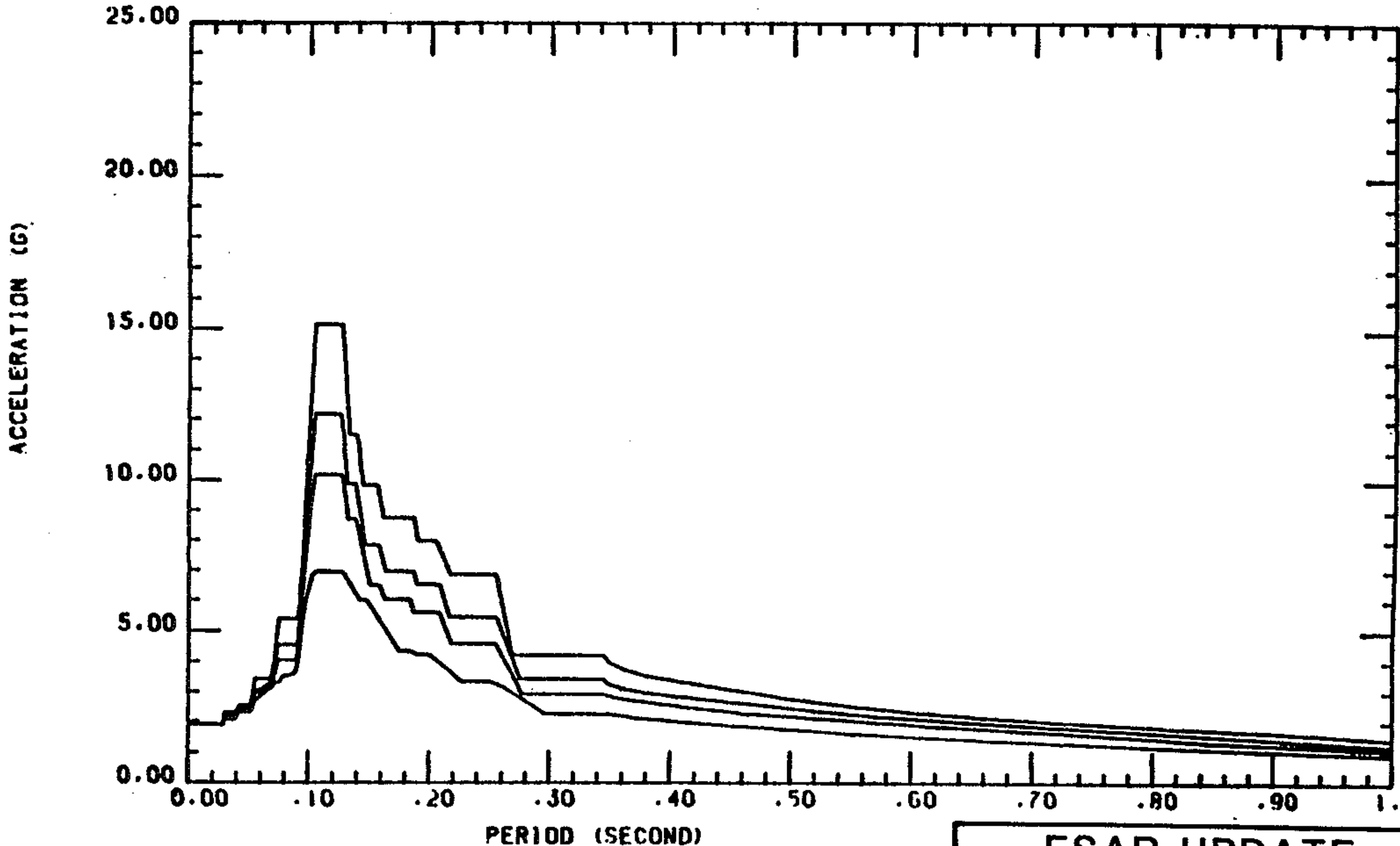
FIGURE 3.7 - 25 C
TURBINE BUILDING
ROOF LEVEL
COLUMN LINES 1 to 1.9, A-D
HOSGRI E - W SPECTRA
3% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

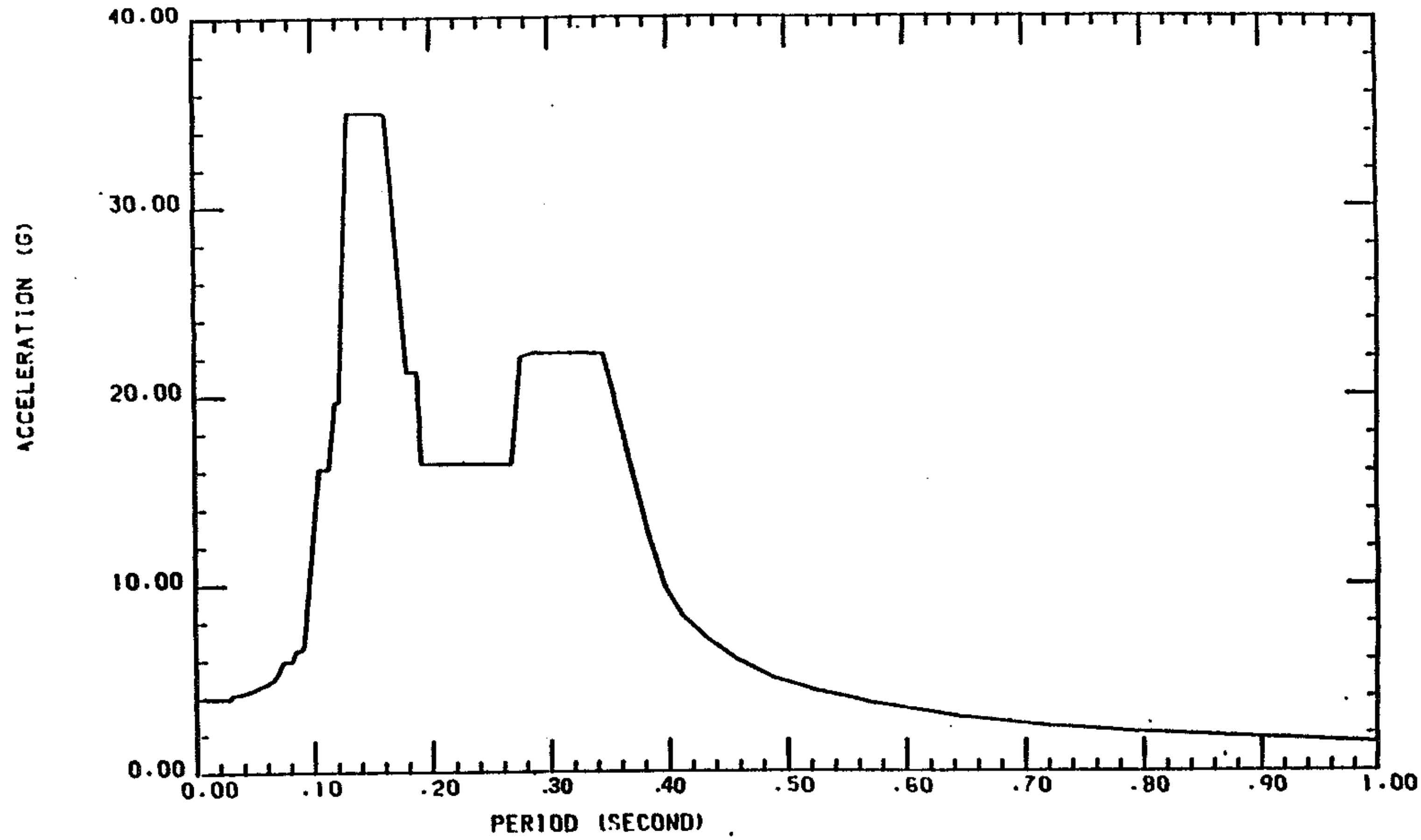
FIGURE 3.7 - 25 D
TURBINE BUILDING
EL. 119'
4 KV SWITCHGEAR AREA
COLUMN LINES 1-4. D-G
HOSGRI N-S SPECTRA
2, 3, 4, 7% DAMPING



FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

FIGURE 3.7 - 25 E
TURBINE BUILDING
EL. 140'
COLUMN LINES 1-19
HOSGRI N-S SPECTRA
2, 3, 4, 7% DAMPING



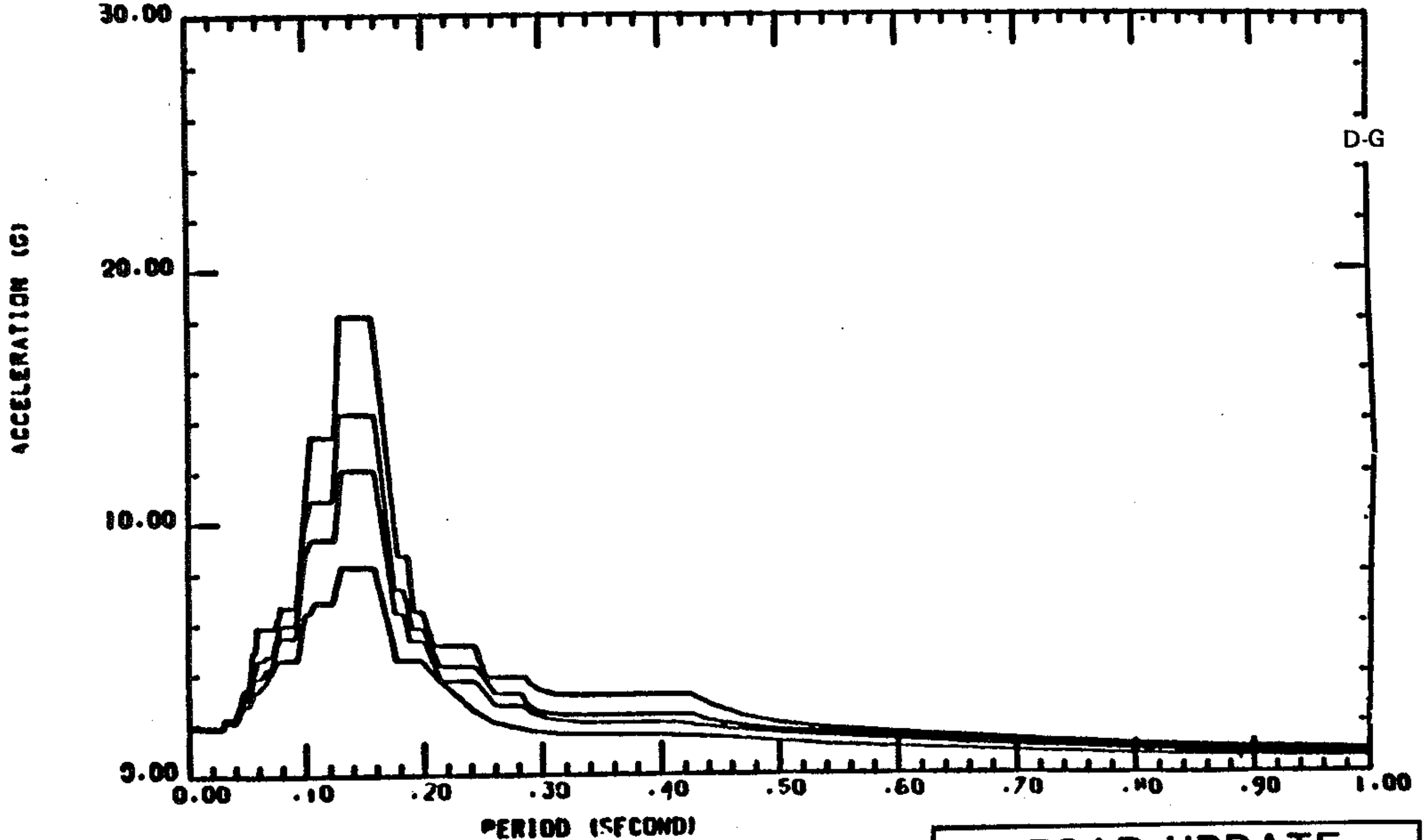
*SPECTRUM ENVELOPING THE SPECTRA AT FOUR LOCATIONS:

COLUMN LINES 1 & D, EL. 193'
COLUMN LINES 1 & A', EL. 193'
COLUMN LINES 1.9 & A, EL. 193'
COLUMN LINES 1.9 & D, EL. 210.69'

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

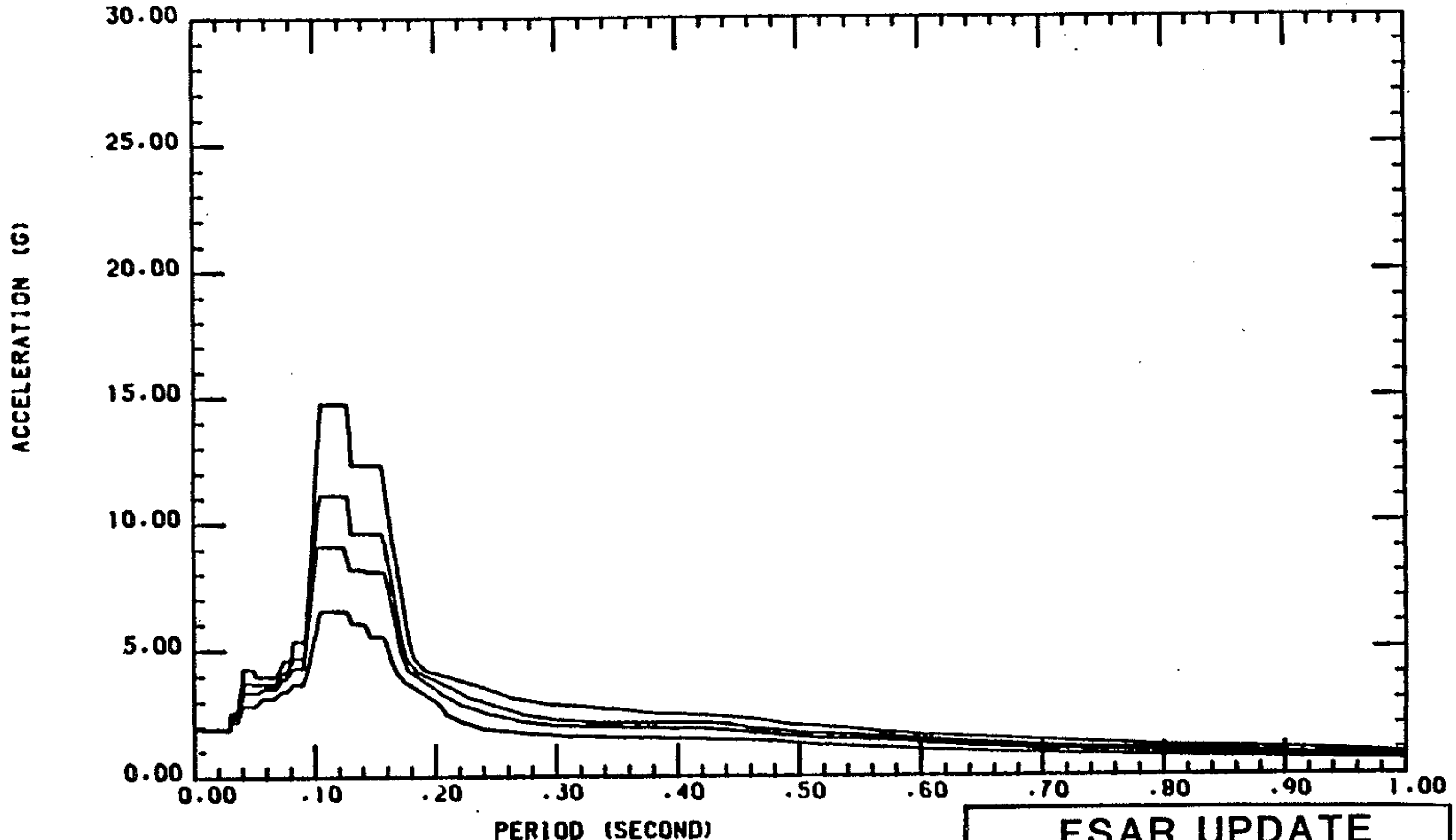
FIGURE 3.7 - 25 F
TURBINE BUILDING ROOF LEVEL
COLUMN LINES 1 to 1.9, A-D
HOSGRI N-S SPECTRA 3% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

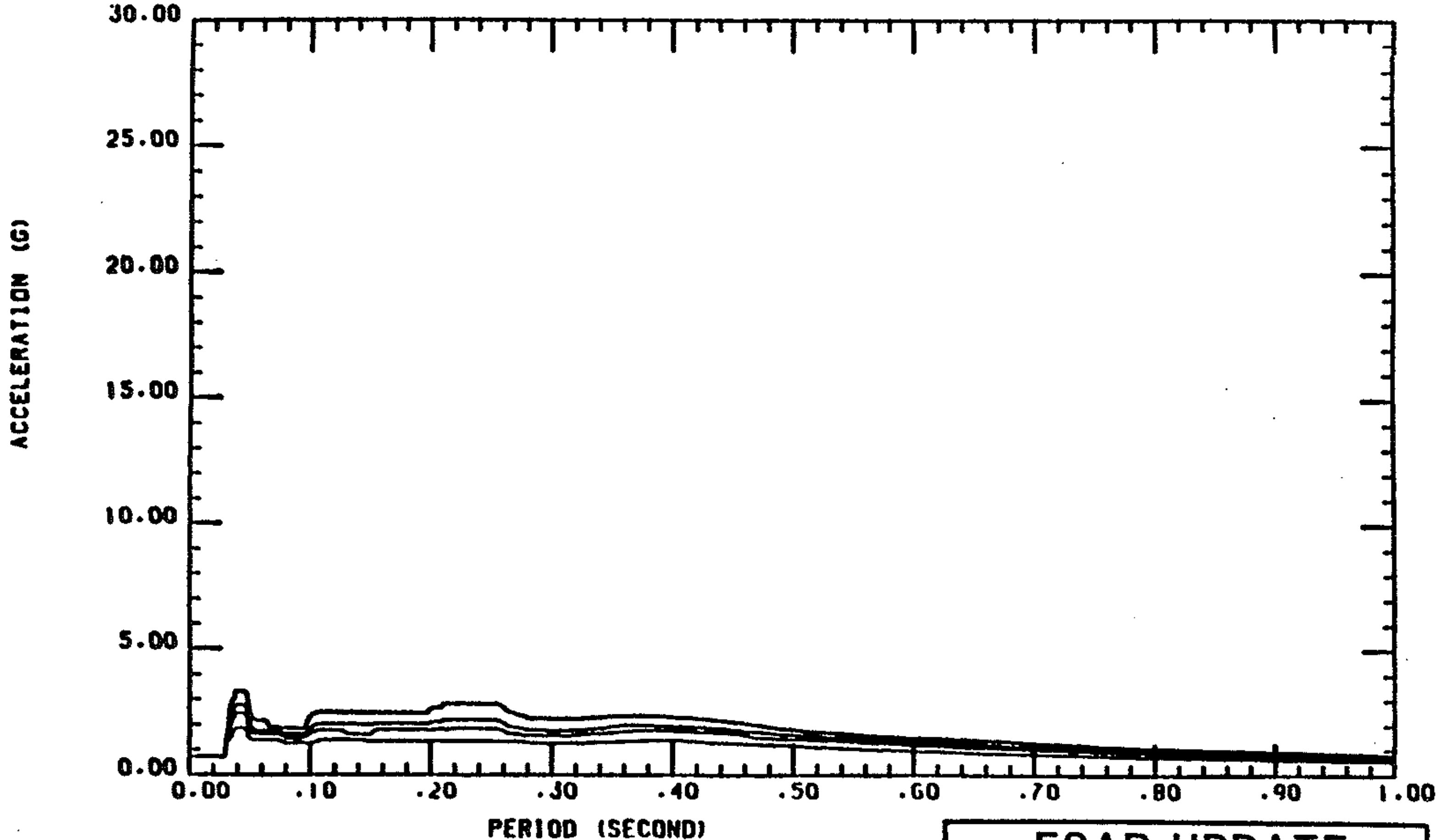
FIGURE 3.7 - 25 G
TURBINE BUILDING
EL.119'
COLUMN LINES 1-4 & 32-35
D G 4 KV SWITCHGEAR AREA
HOSGRI VERTICAL SPECTRA
2, 3. 4, 7% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

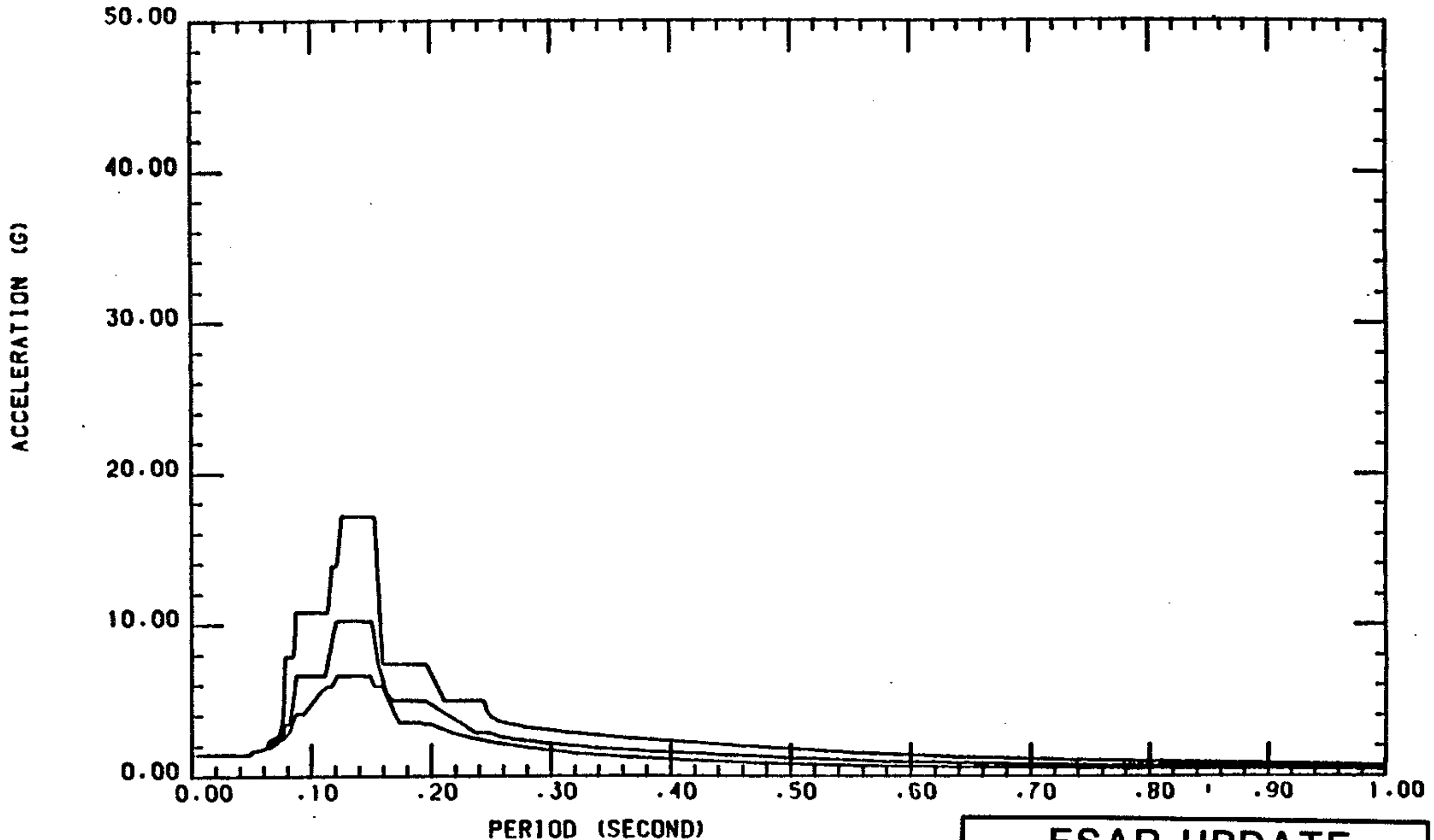
FIGURE 3.7 - 25 H
TURBINE BUILDING
EL. 140'
COLUMN LINES
5- 15, 21 -31
HOSGRI VERTICAL SPECTRA
2, 3, 4, 7% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

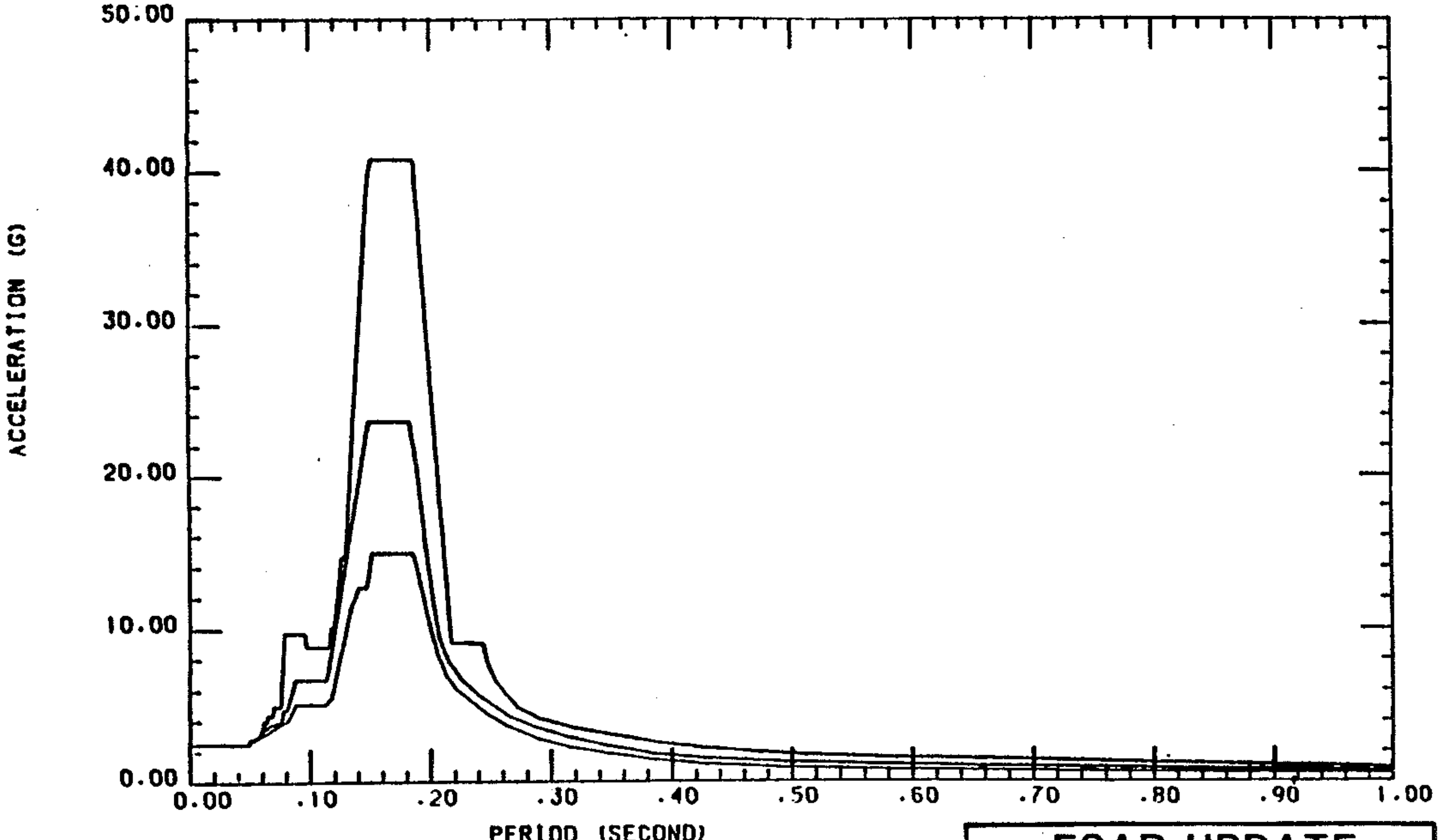
FIGURE 3.7-25I
TURBINE BUILDING
EL. 193'
BUILT UP COLUMNS ON LINE
A&G FROM 5.7 TO 15 & 21 TO 30.3
HOSGRI VERTICAL SPECTRA
2, 3, 4, 7% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

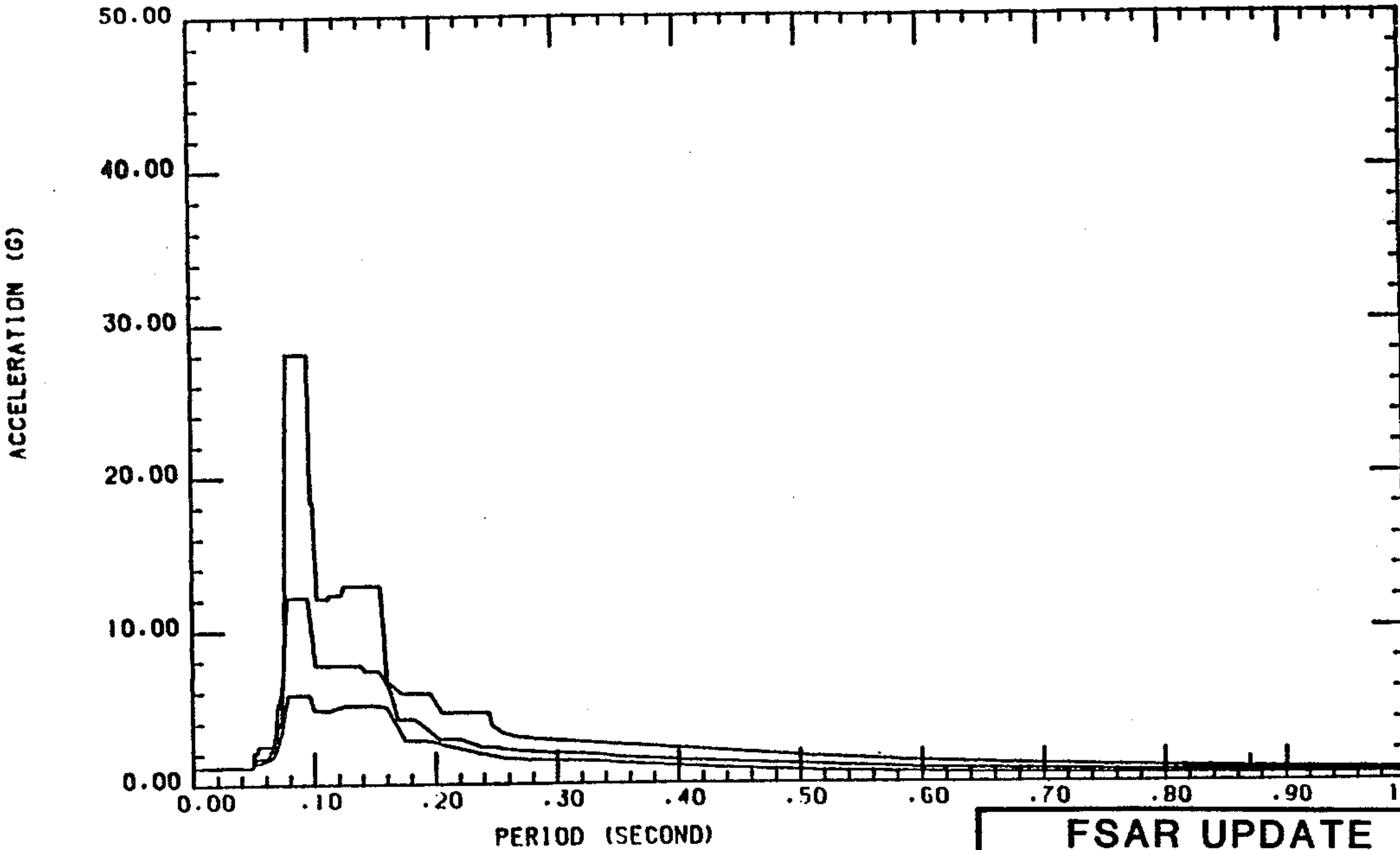
FIGURE 3.7 - 25 J
TURBINE BUILDING
ELEV. 104'
COLUMN LINES 5 to 15
DDE E-W SPECTRA
1/2, 2, 5% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

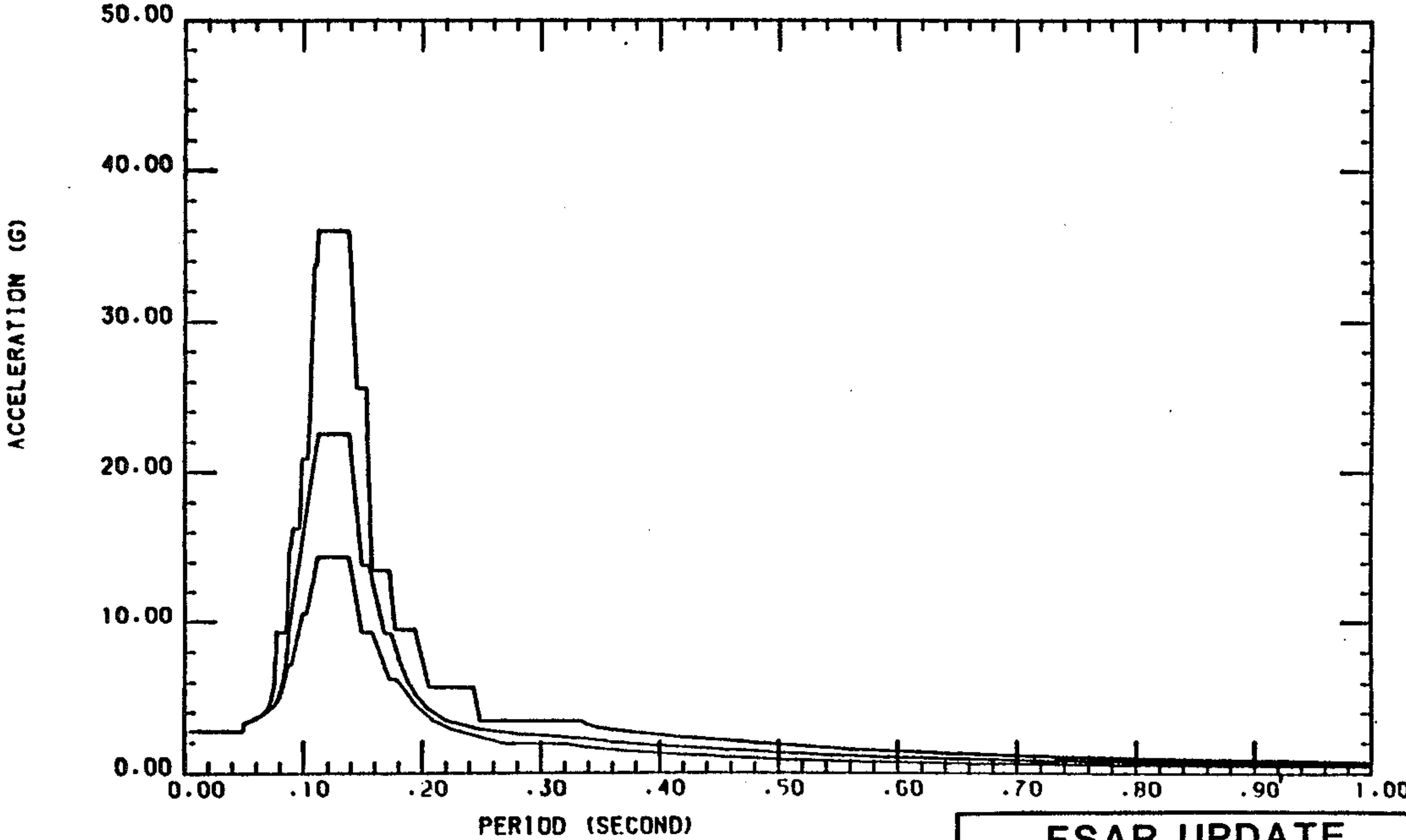
FIGURE 3.7 - 25 K
TURBINE BUILDING
ELEV. 140'
COLUMN LINES 5-15
DDE E-W SPECTRA
1/2,2,5% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

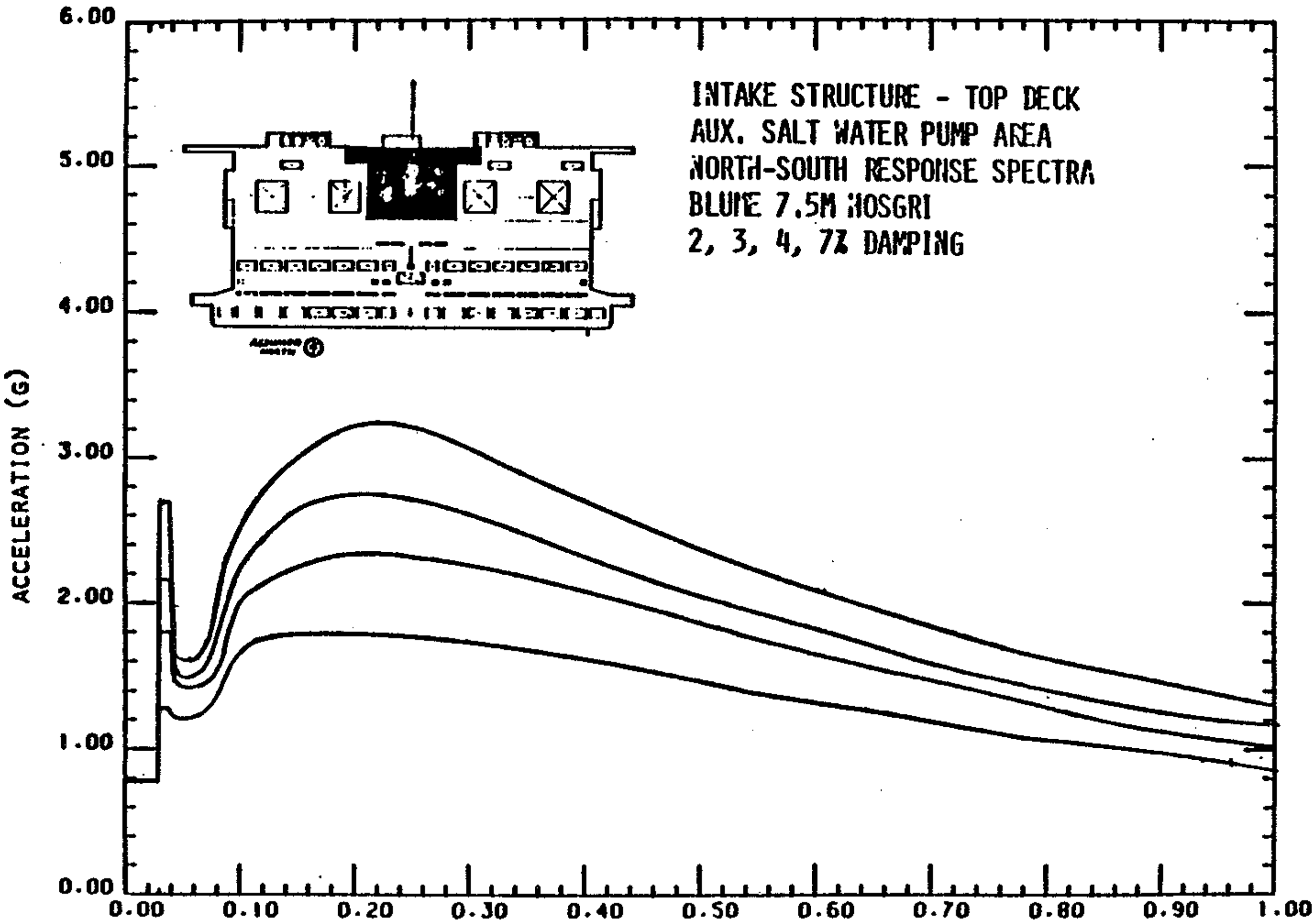
FIGURE 3.7 - 25 L
TURBINE BUILDING
ELEV 104' & 107'
COLUMN LINES 1-19
DDE N-S SPECTRA
1/2, 2, 5% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

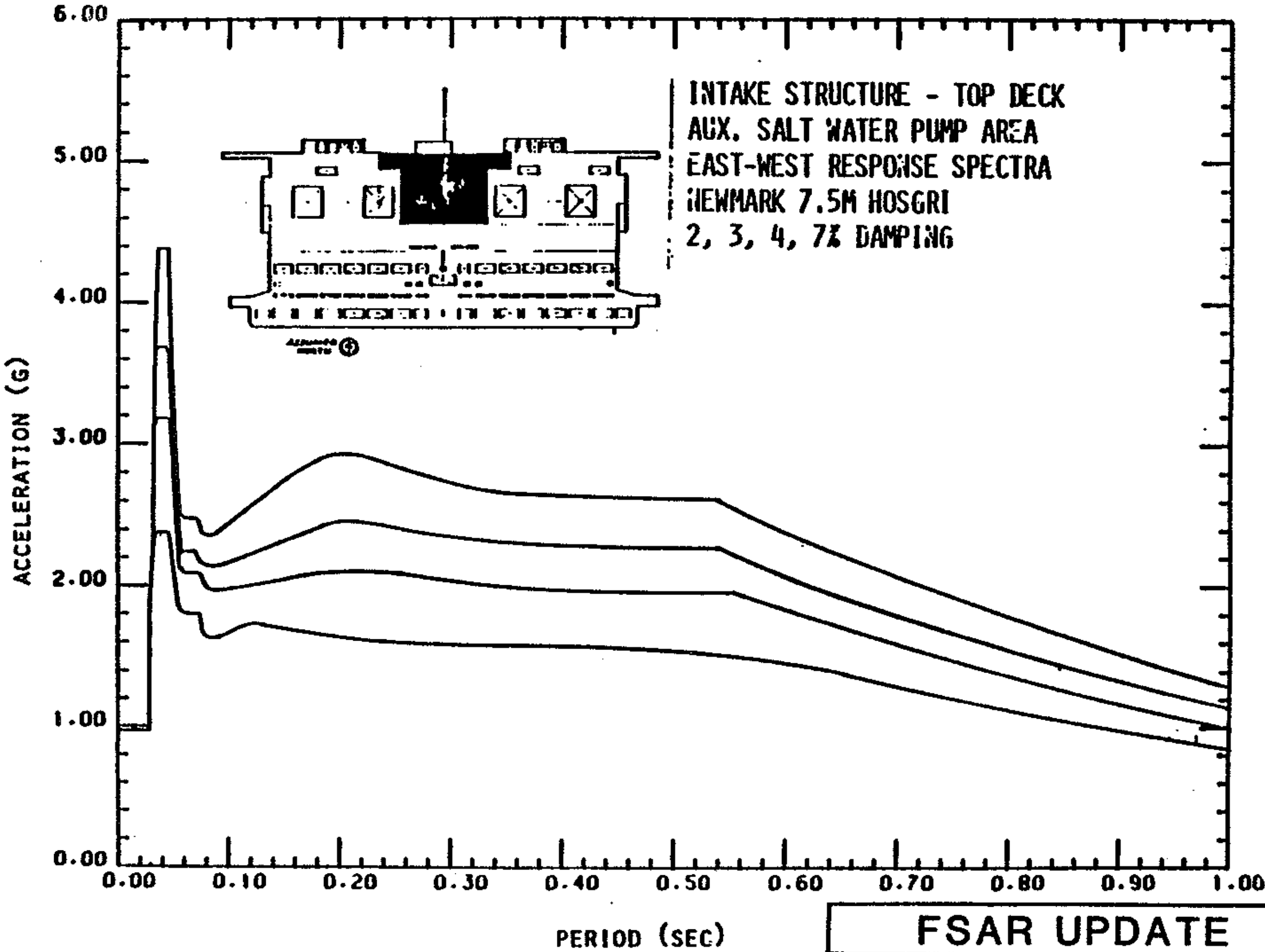
FIGURE 3.7 - 25 M
TURBINE BUILDING
ELEV 140'
COLUMN LINES 1-19
DDE N-S SPECTRA
1/2, 2, 5% DAMPING



FSAR UPDATE

UNITS 1 AND 2 DIABLO CANYON SITE

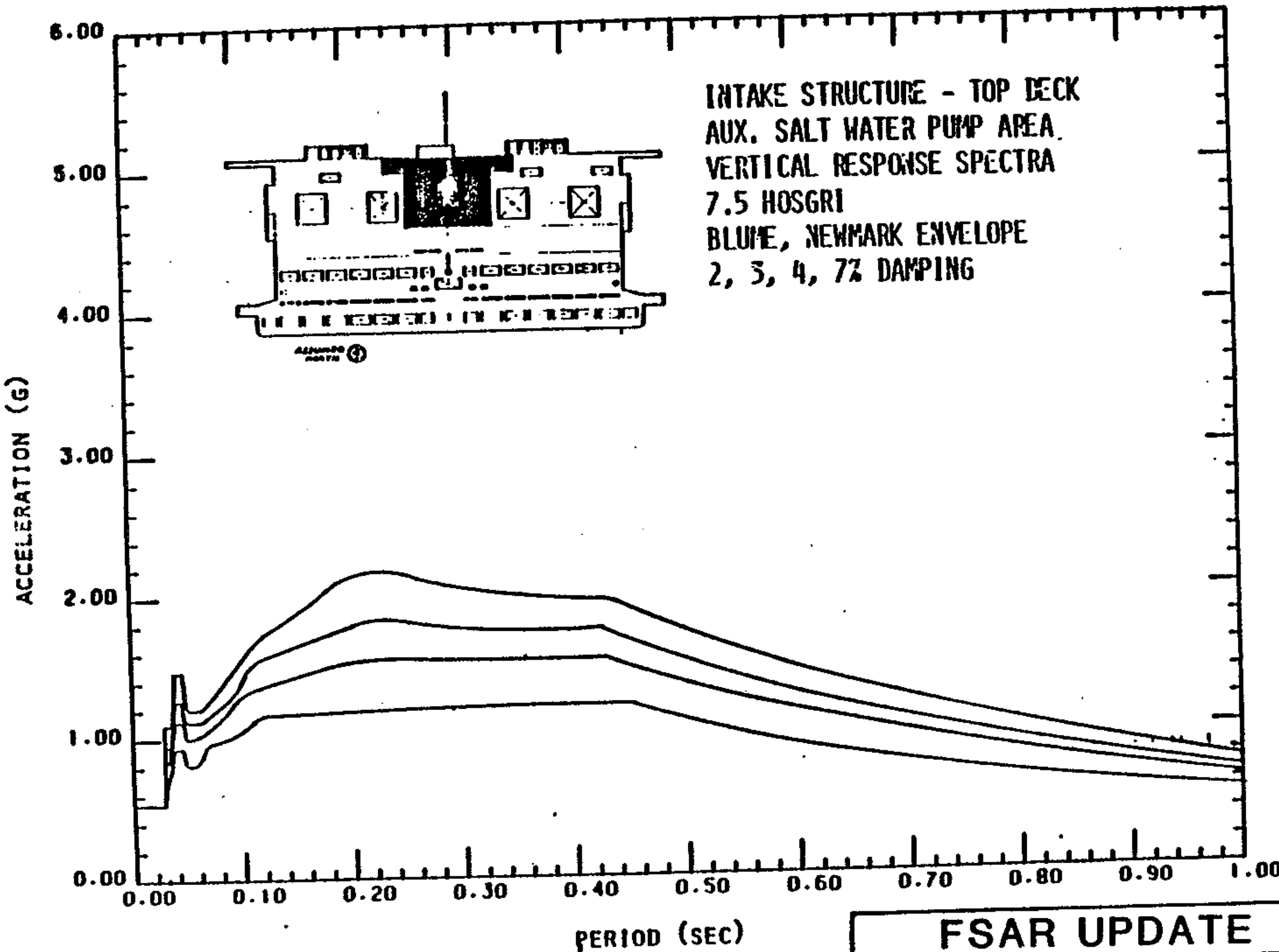
FIGURE 3.7 - 25 N
INTAKE STRUCTURE
RESPONSE SPECTRA
BLUME 7.5 M HOSGRI



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

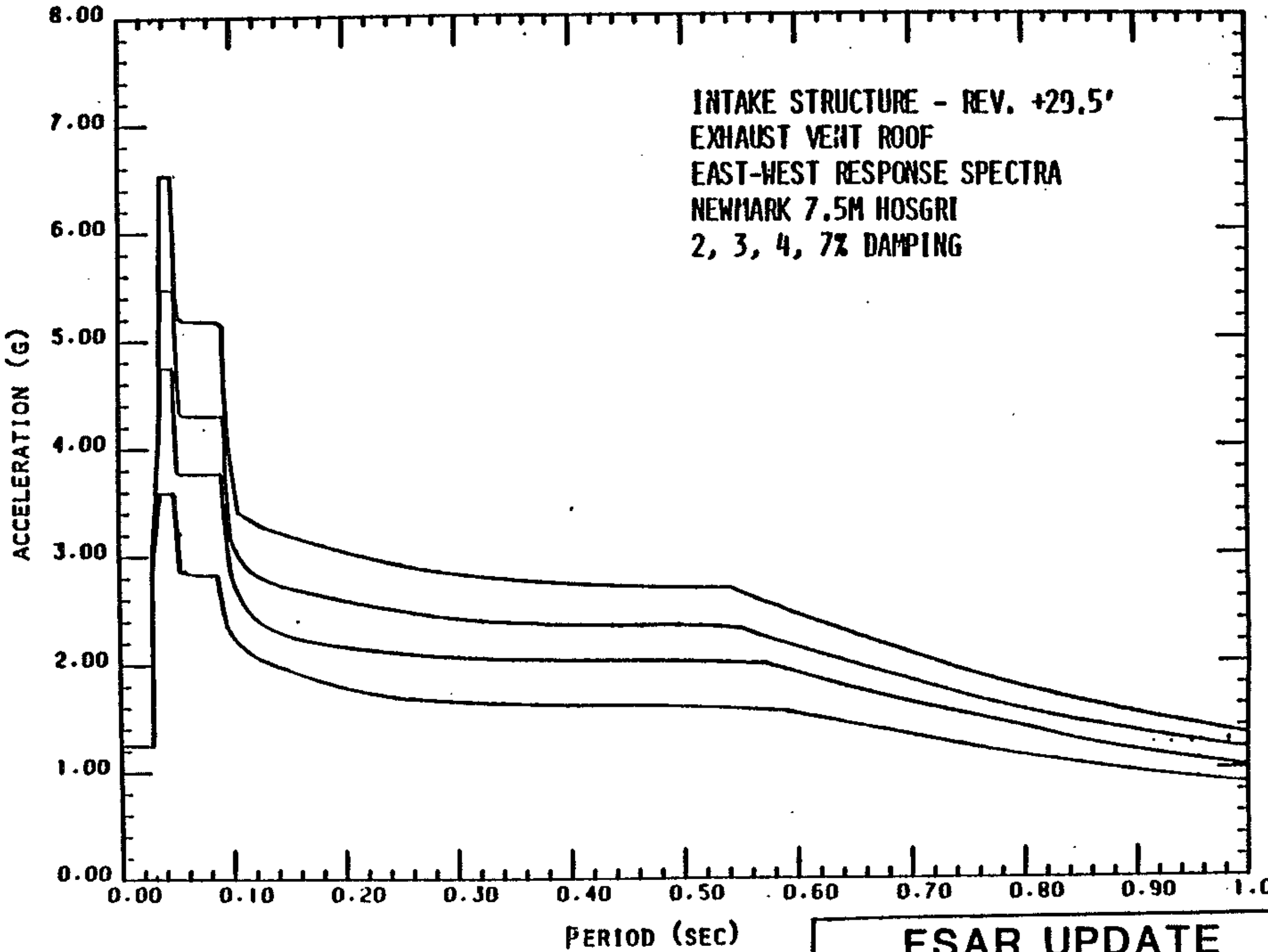
FIGURE 3.7 - 25 O
INTAKE STRUCTURE
RESPONSE SPECTRA
NEWMARK 7.5 M HOSGRI



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

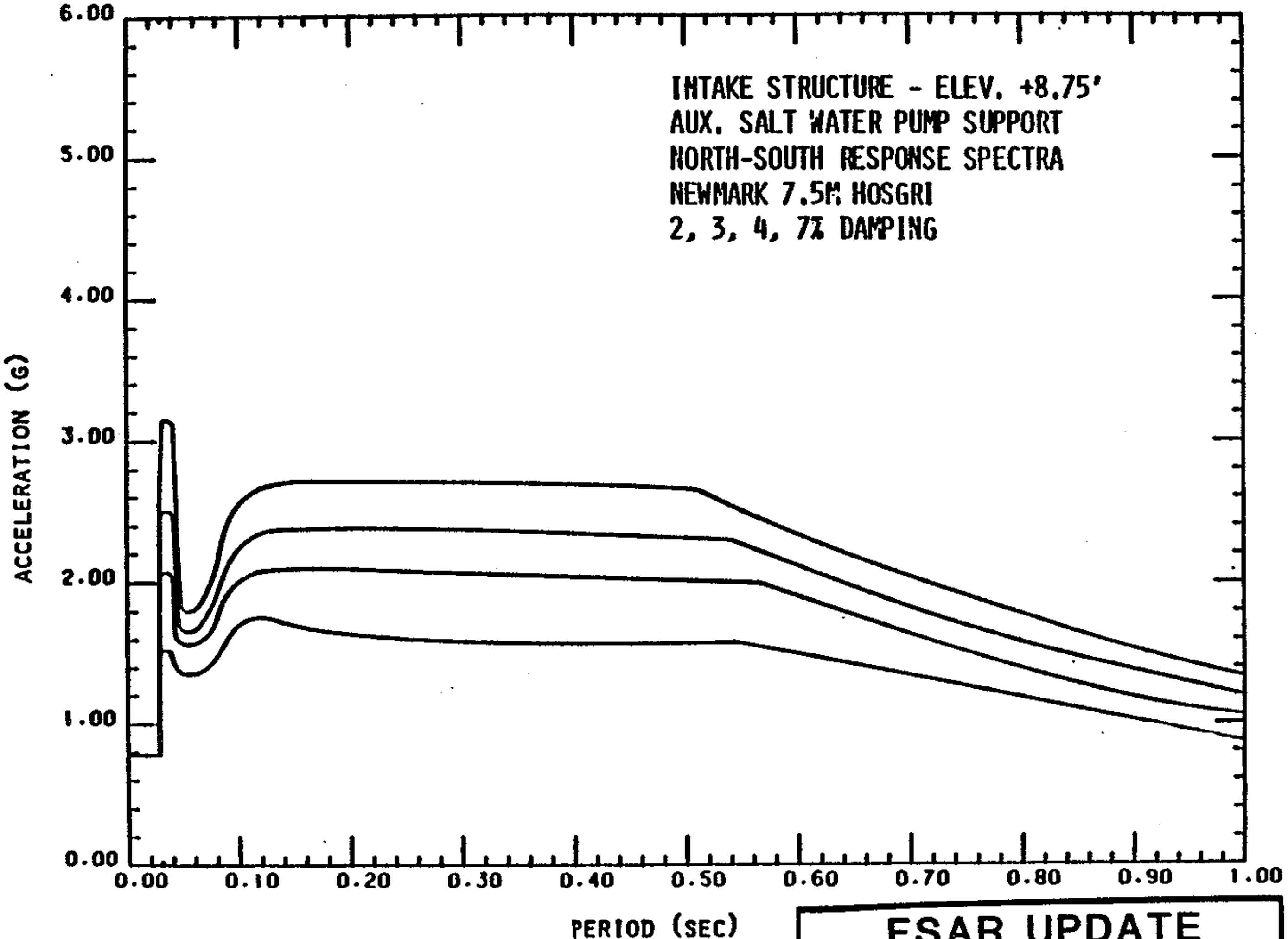
FIGURE 3.7 - 25 P
INTAKE STRUCTURE VERTICAL
RESPONSE SPECTRA 7.5M/HOSGRI
BLUME, NEWMARK ENVELOPE



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

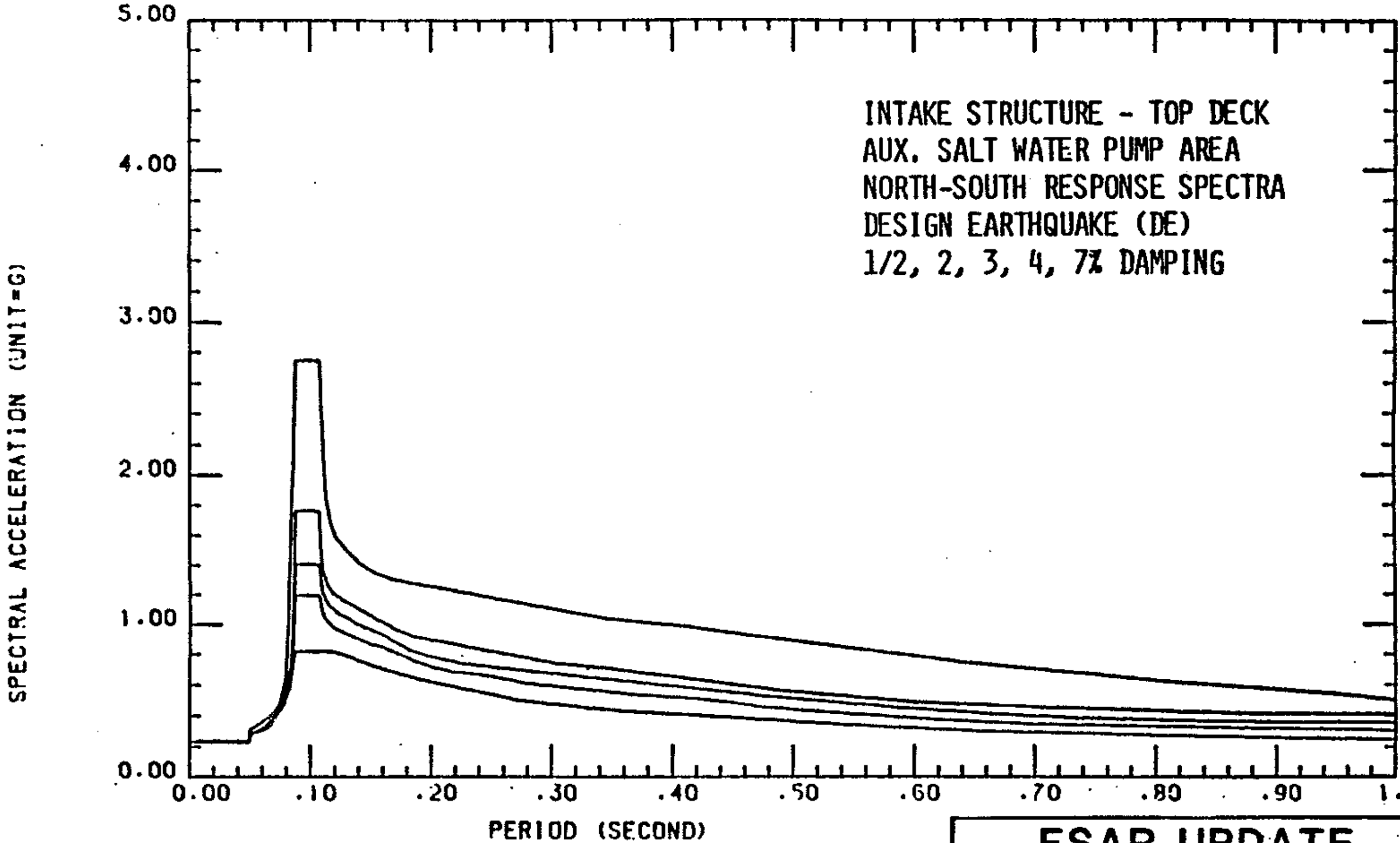
FIGURE 3.7 - 25 Q
INTAKE STRUCTURE
RESPONSE SPECTRA
NEWMARK 7.5 M HOSGRI



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

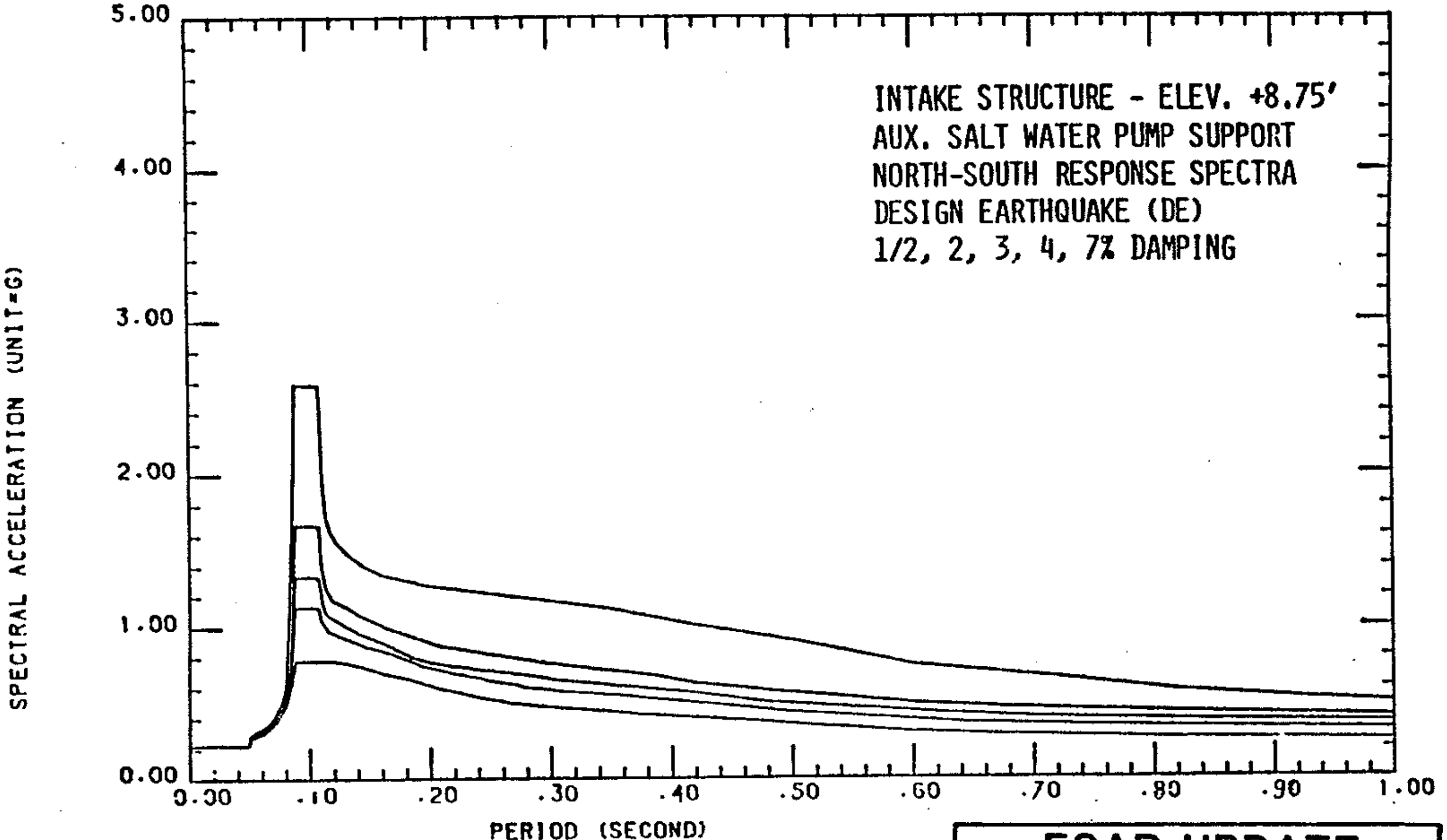
FIGURE 3.7 - 25 R
INTAKE STRUCTURE
RESPONSE SPECTRA
NEWMARK 7.5 M HOSGRI



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

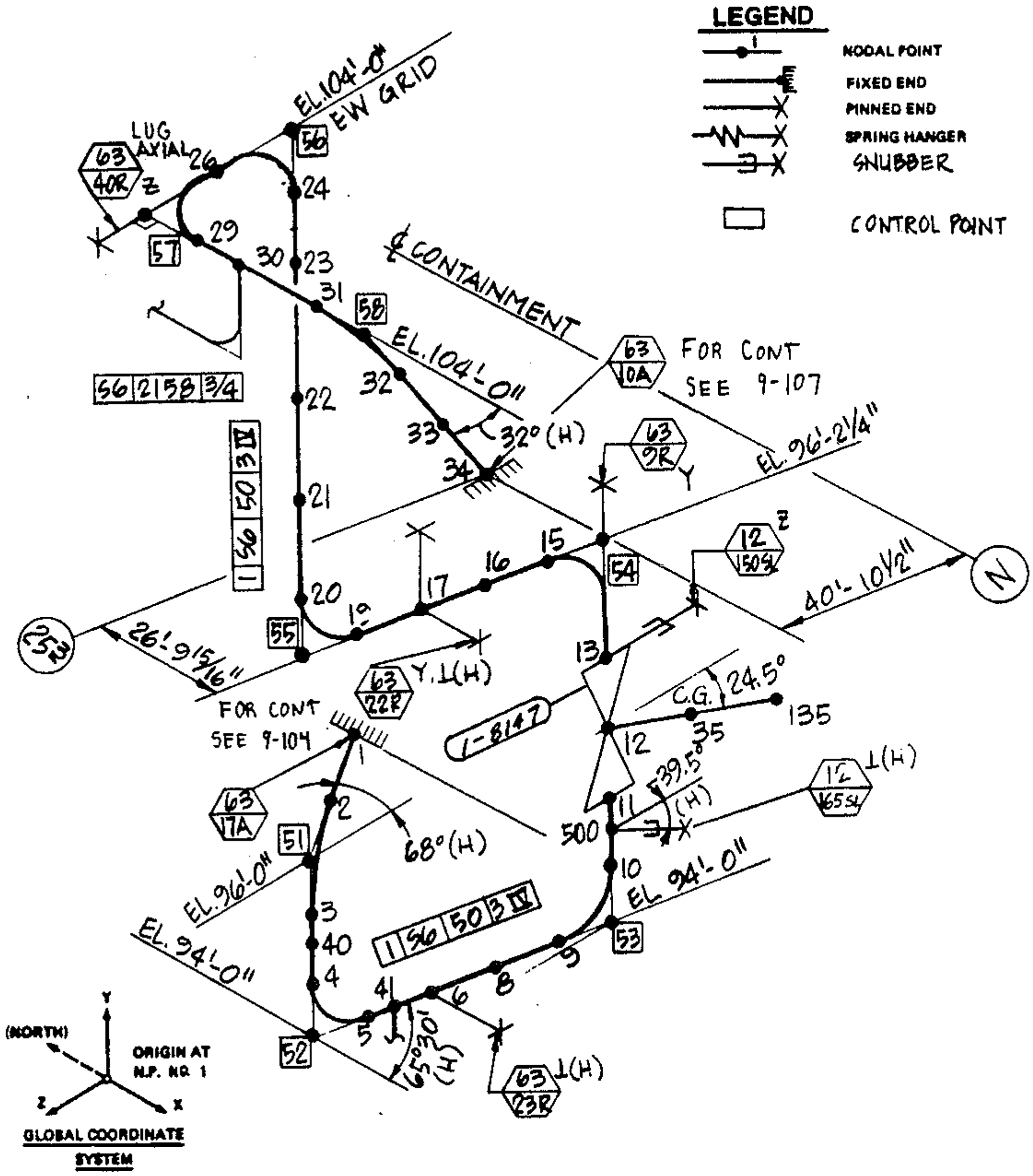
FIGURE 3.7 - 25 S
INTAKE STRUCTURE
RESPONSE SPECTRA
DESIGN EARTHQUAKE (DE)



FSAR UPDATE

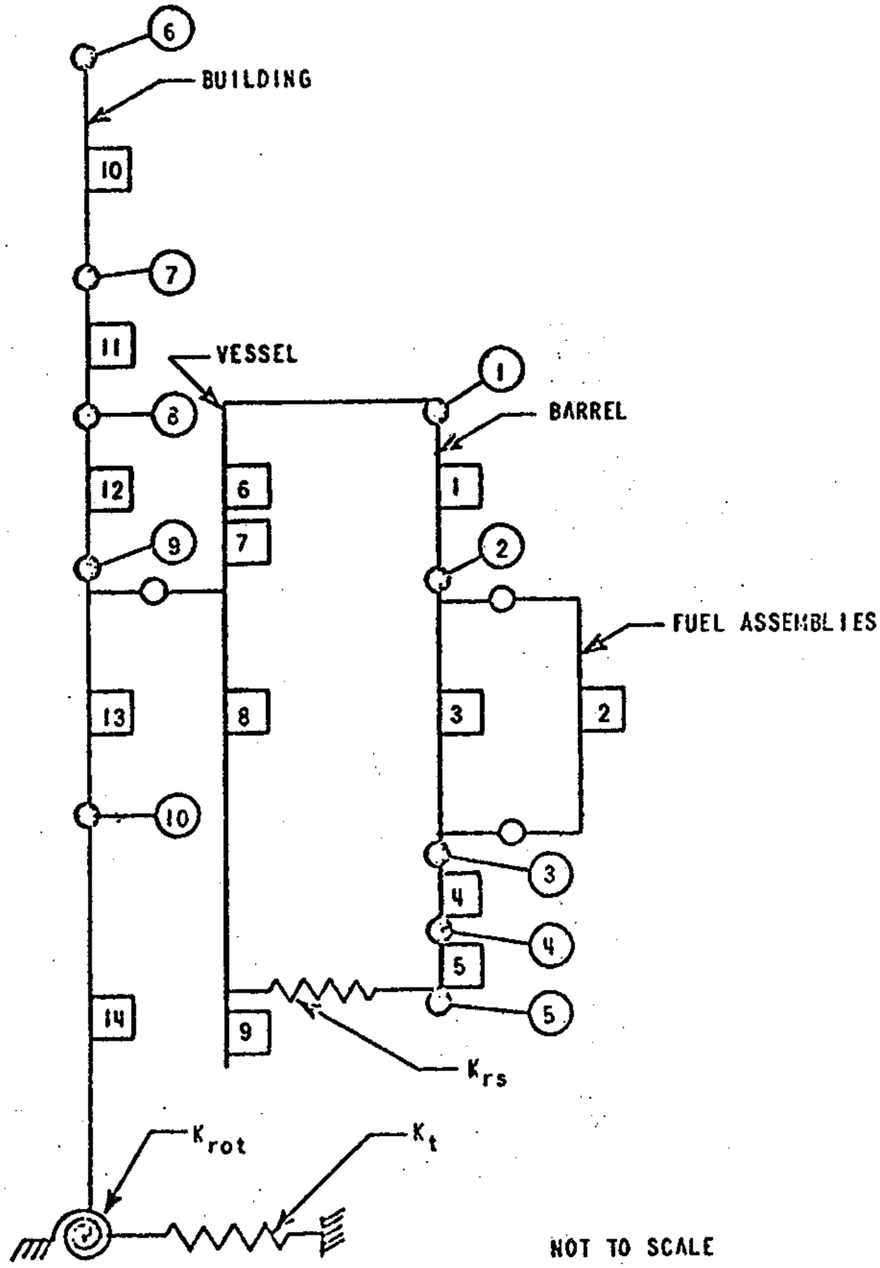
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7 - 25 T
INTAKE STRUCTURE
RESPONSE SPECTRA
DESIGN EARTHQUAKE (DE)



FSAR UPDATE
UNIT 1
DIABLO CANYON SITE
FIGURE 3.7-26
TYPICAL PIPING MATHEMATICAL MODEL

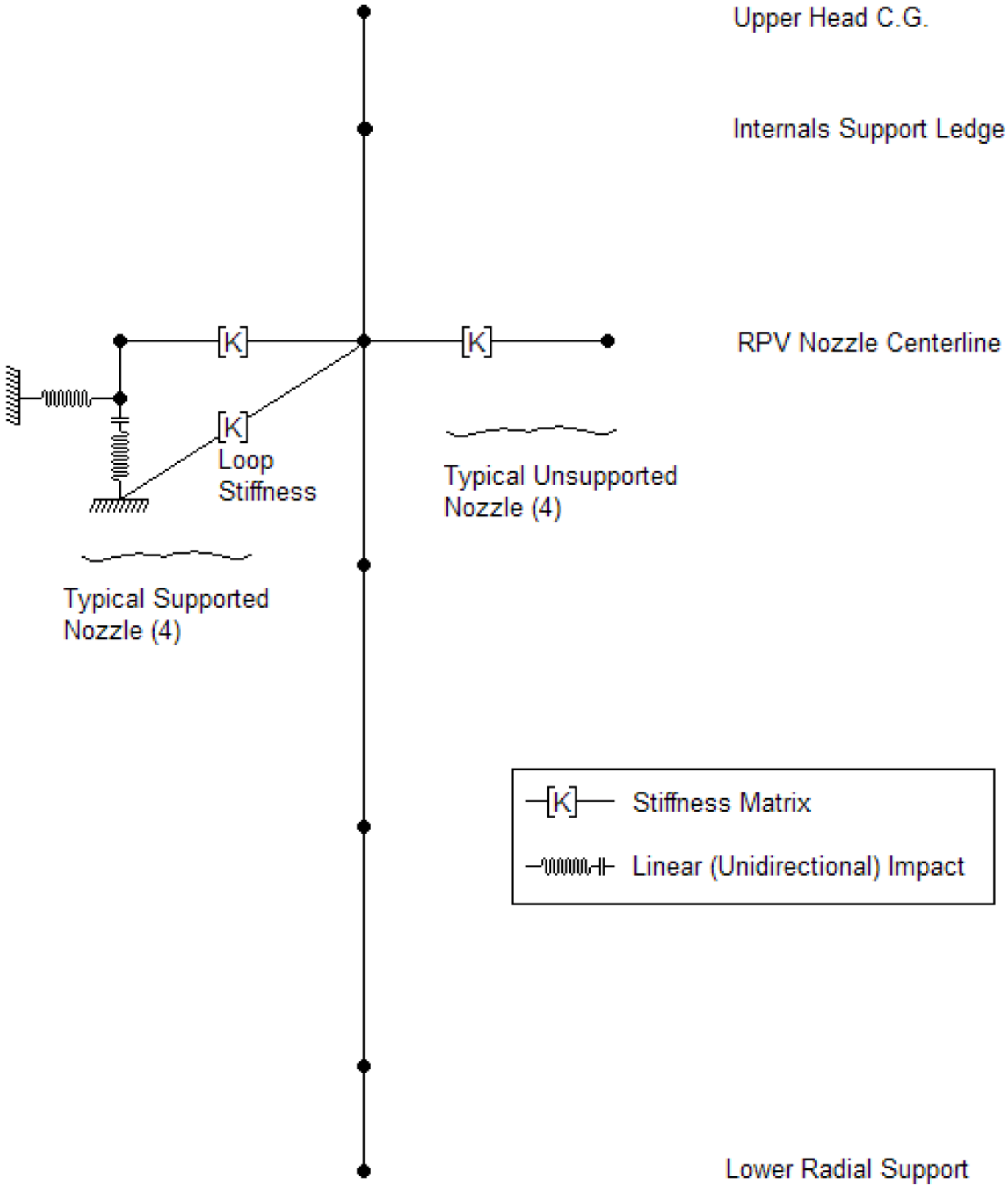
K_{rs} = RADIAL SUPPORT SPRING CONSTANT
K_{rot} = ROTATIONAL GROUND SPRING CONSTANT
K_t = TRANSLATIONAL GROUND SPRING CONSTANT



NOT TO SCALE

FSAR UPDATE
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7-27
REACTOR INTERNALS
MATHEMATICAL MODELS

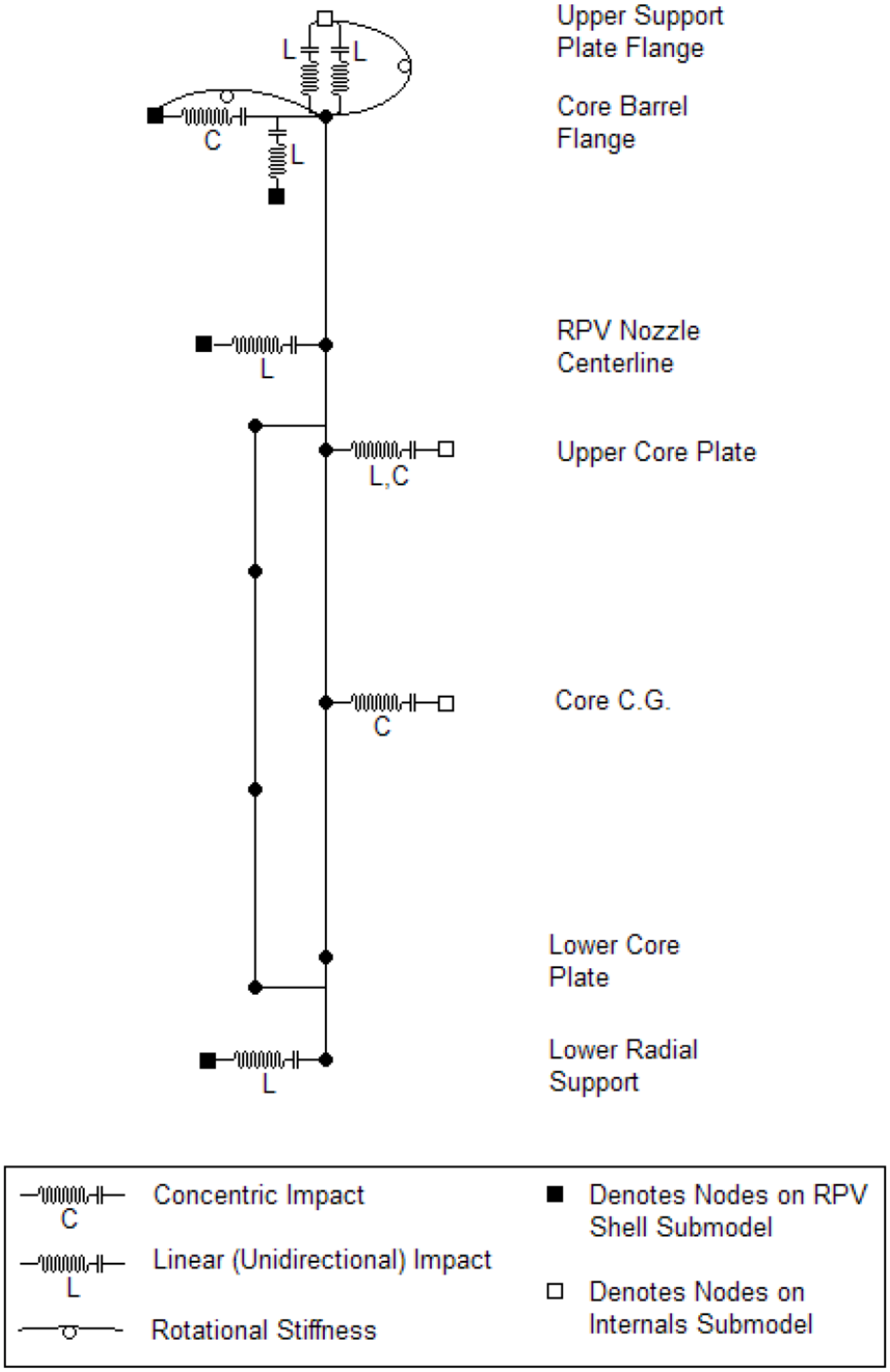


FSAR UPDATE

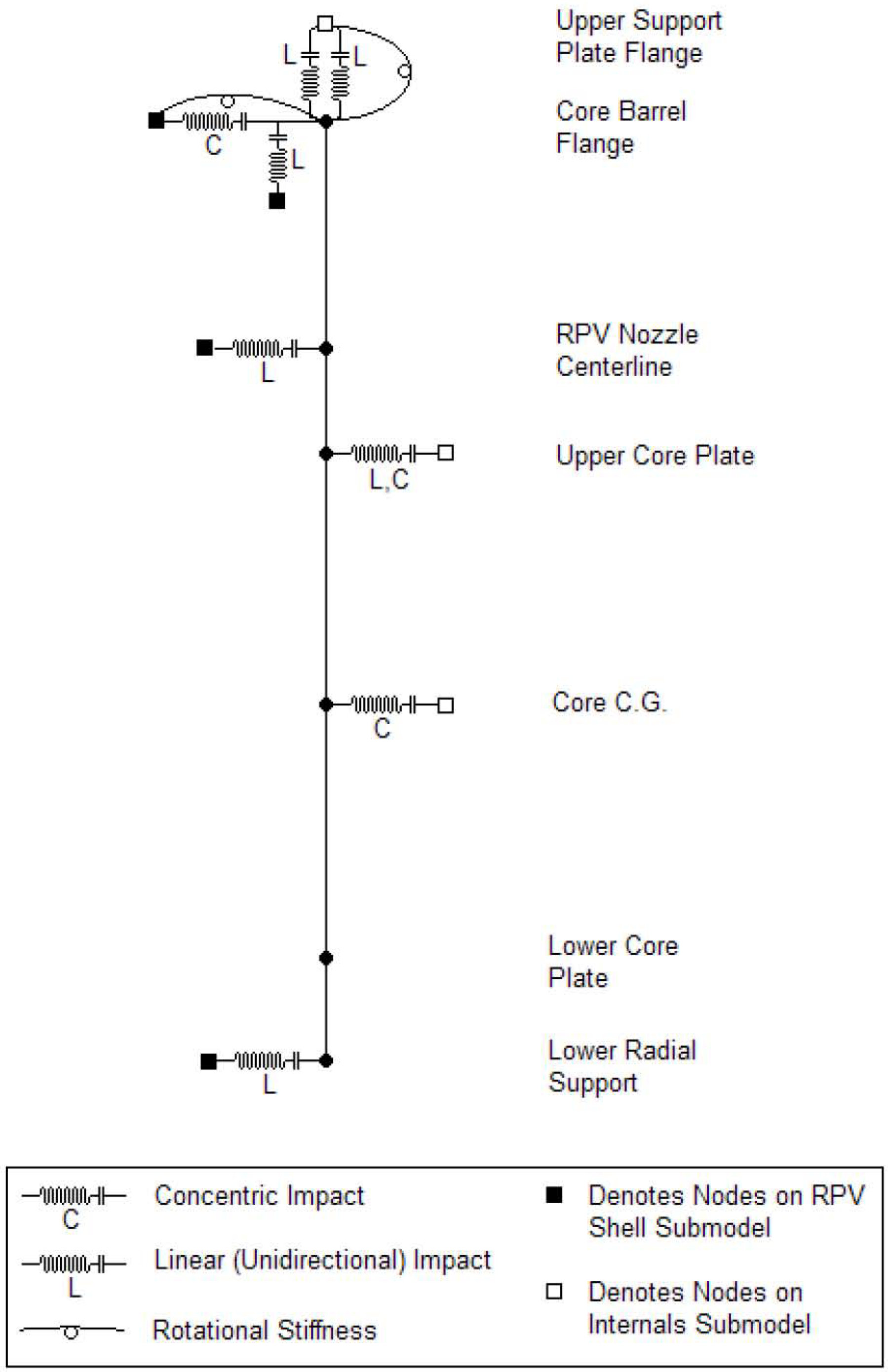
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7-27A

REACTOR PRESSURE VESSEL SHELL SUBMODEL



FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 3.7-27B CORE BARREL SUBMODEL

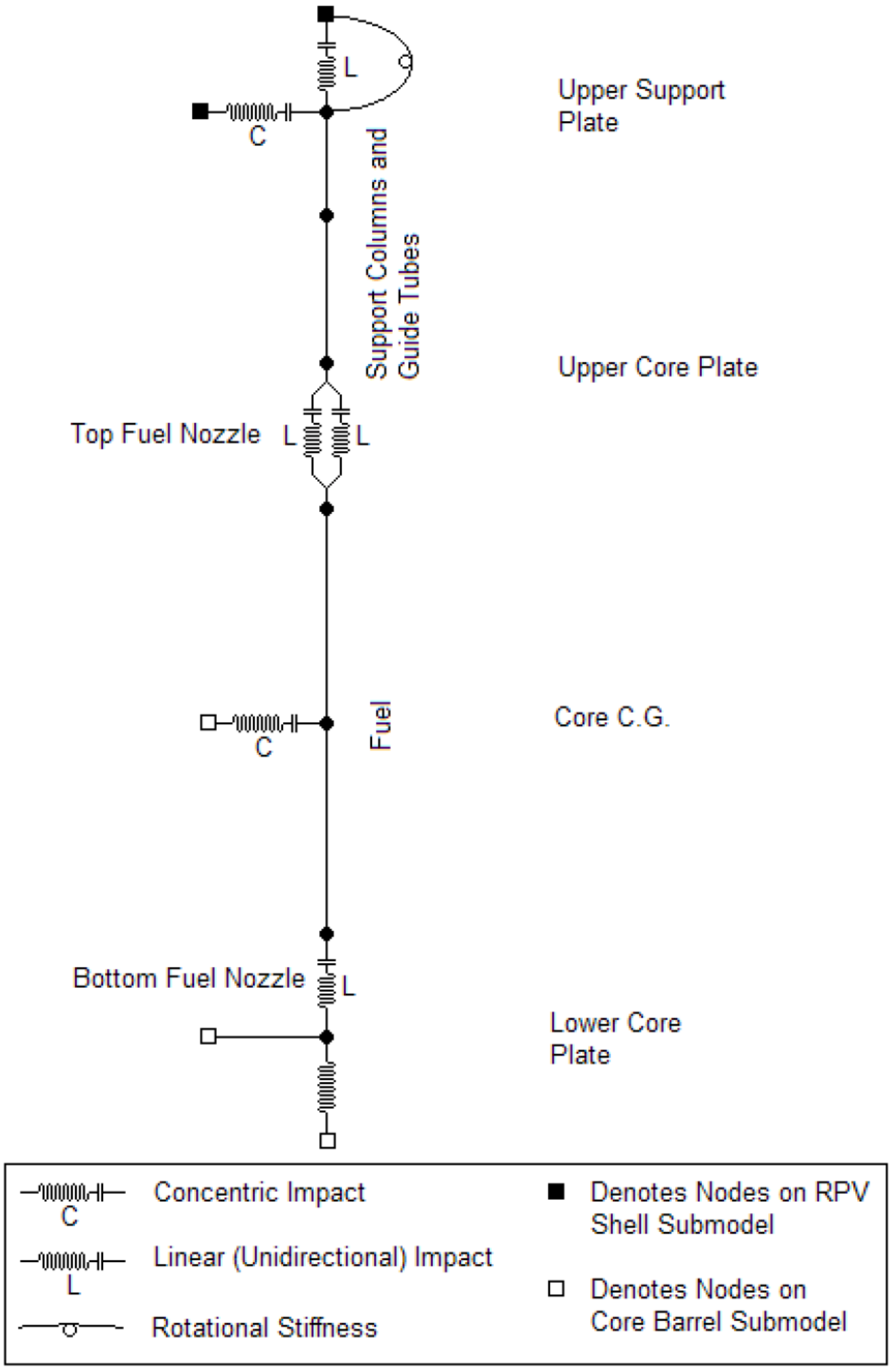


FSAR UPDATE

UNIT 2
DIABLO CANYON SITE

FIGURE 3.7-27C

CORE BARREL SUBMODEL

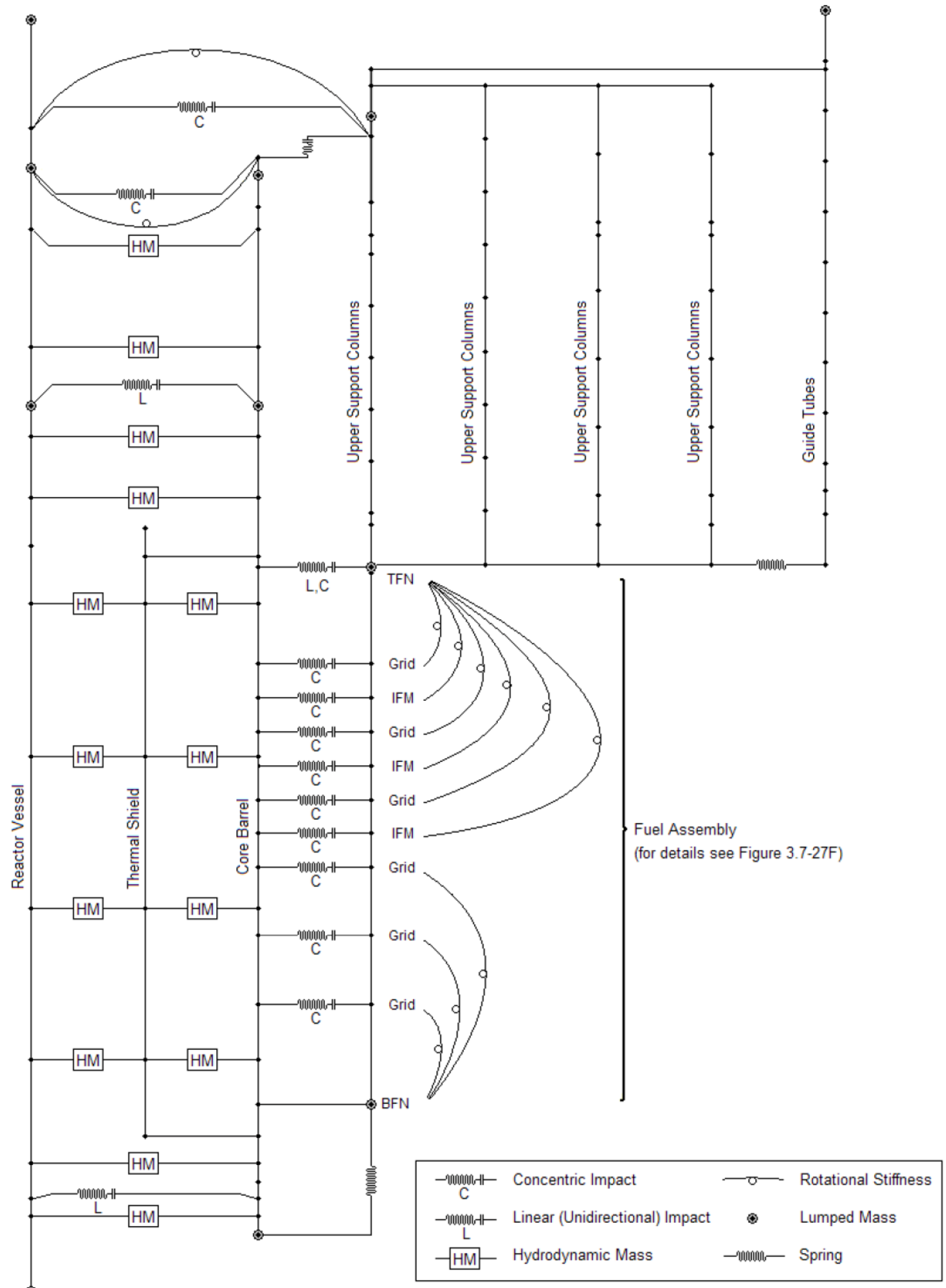


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7-27D

INTERNALS (INNERMOST)
SUBMODEL

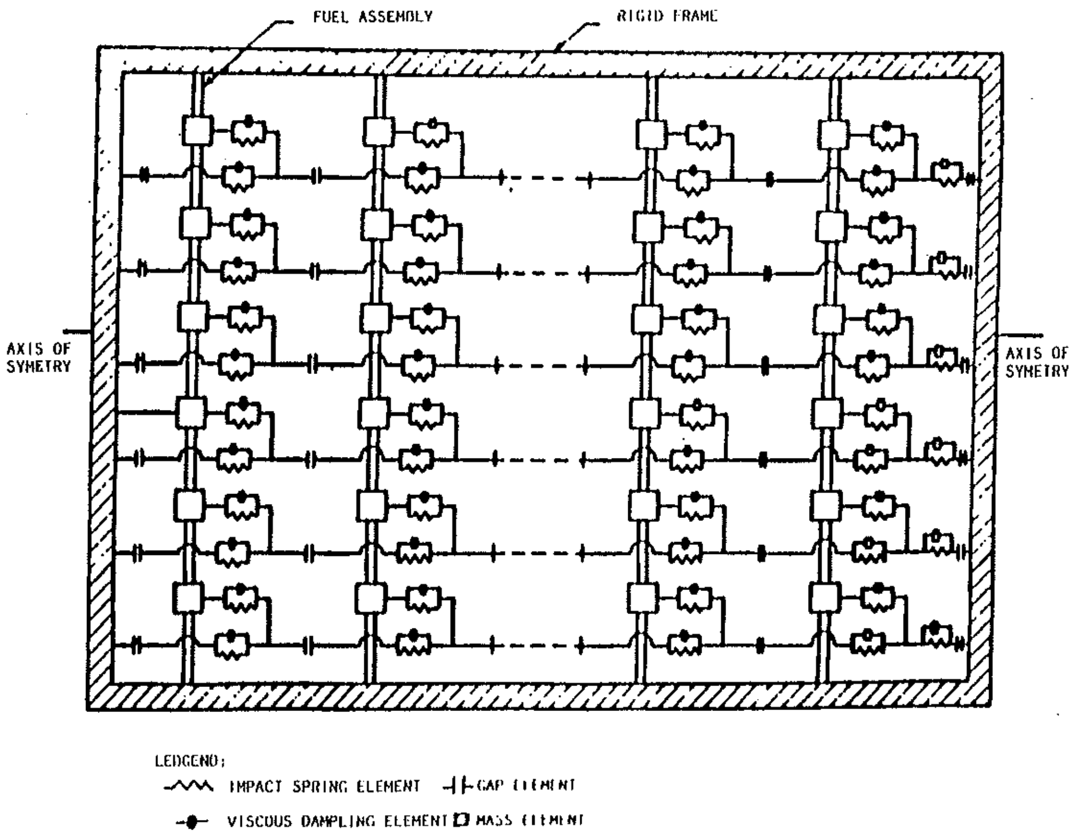


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7-27E

ASSEMBLED FINITE ELEMENT SYSTEM MODEL

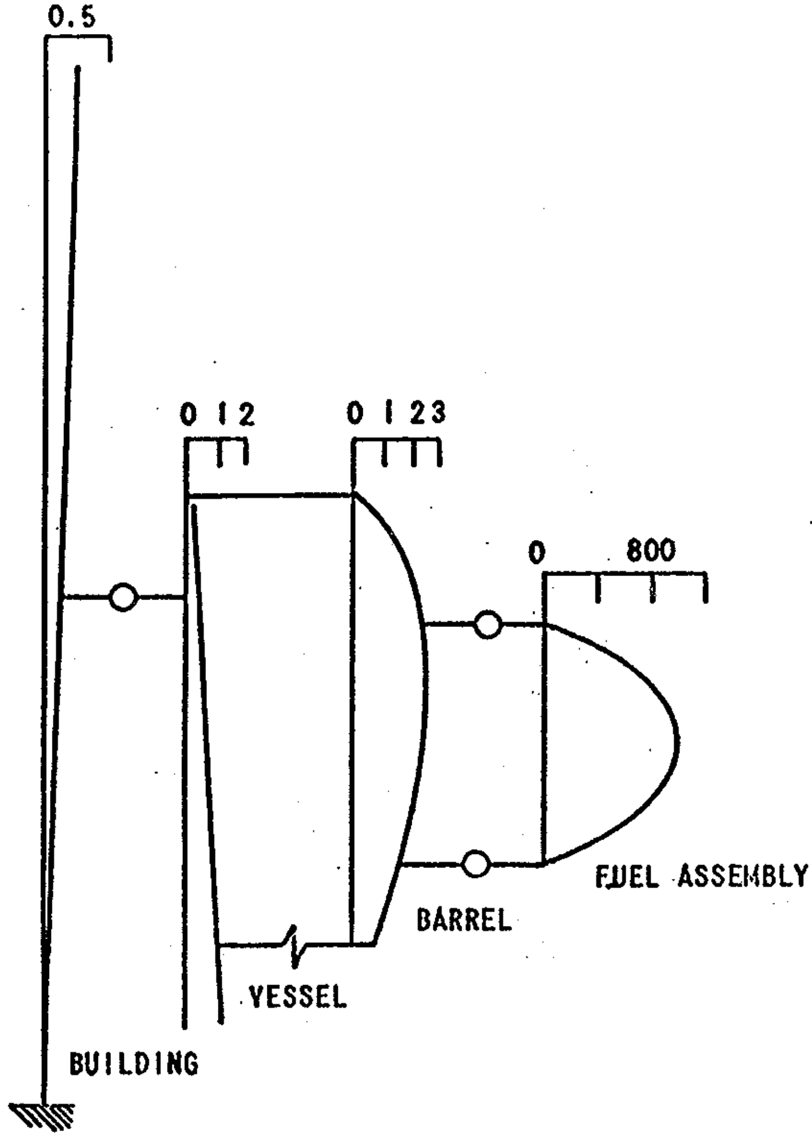


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7-27F
SCHEMATIC REPRESENTATION OF
COMPUTER MODEL USED TO
ANALYZE CORE DYNAMIC RESPONSE

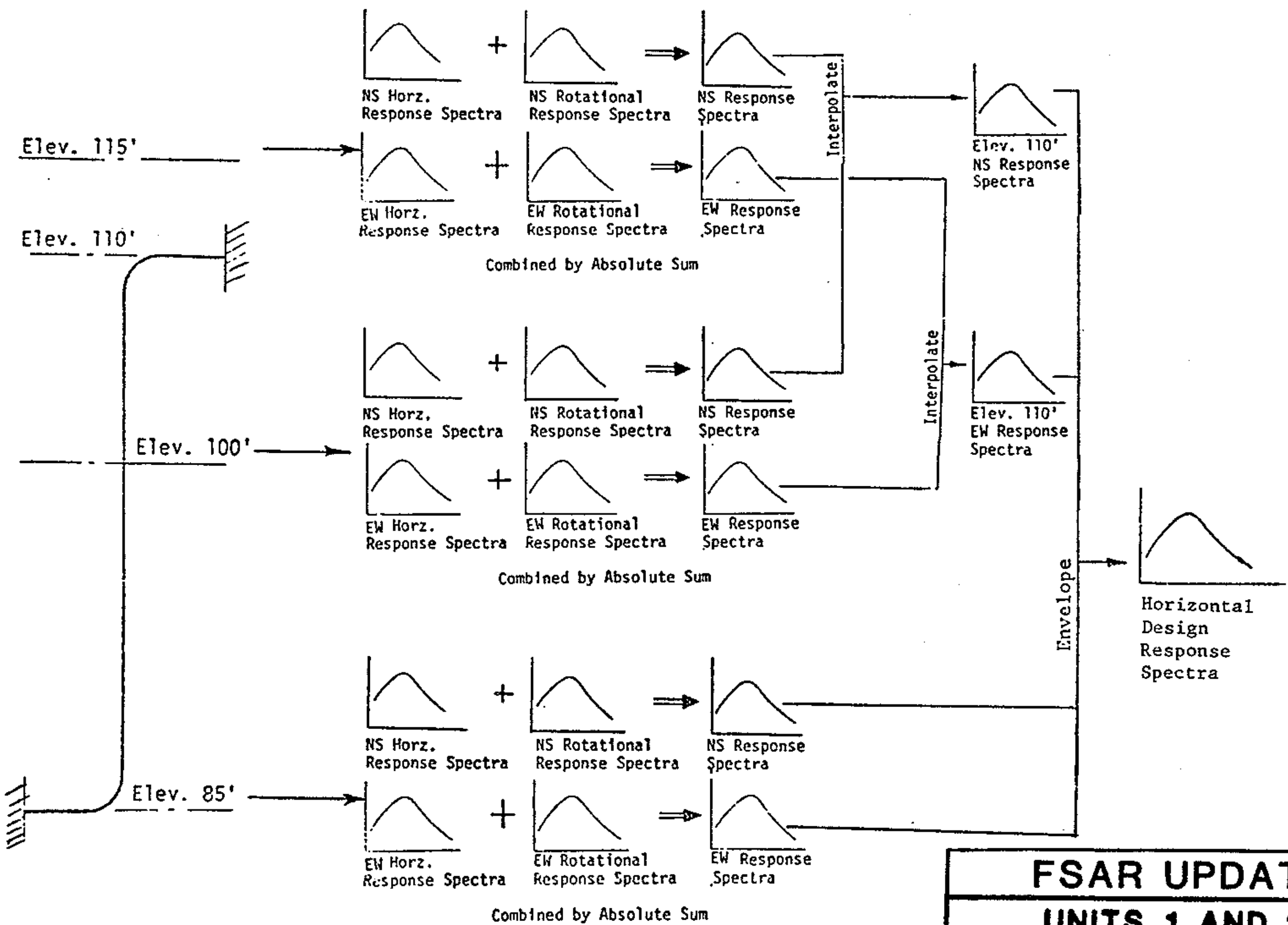
Revision 14 November 2001



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

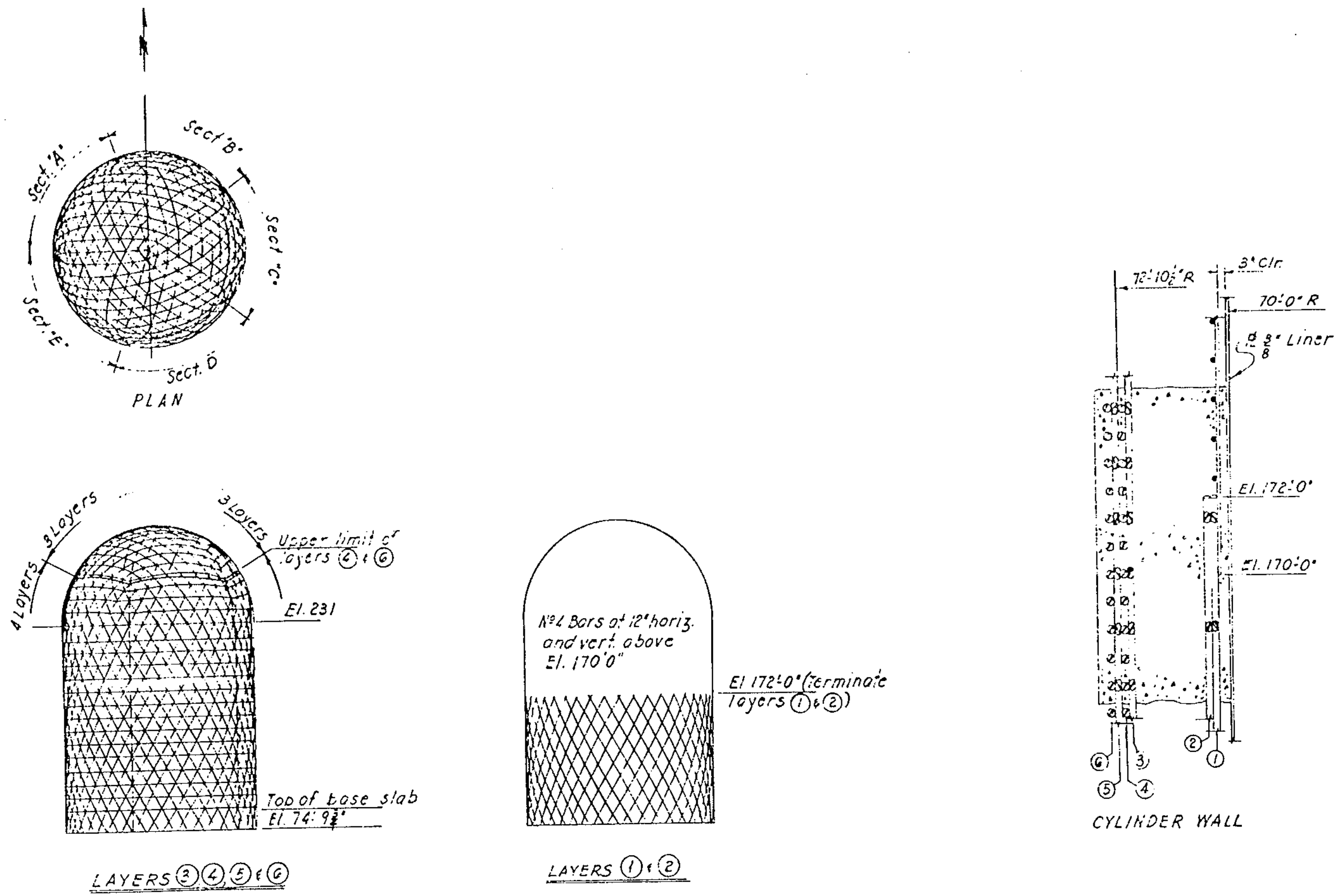
FIGURE 3.7-28
REACTOR INTERNALS
FIRST MODE OF VIBRATION



FSAR UPDATE

UNITS 1 AND 2 DIABLO CANYON SITE

FIGURE 3.7–29
DERIVATION OF
DESIGN RESPONSE SPECTRA
FOR A TYPICAL PIPING SYSTEM



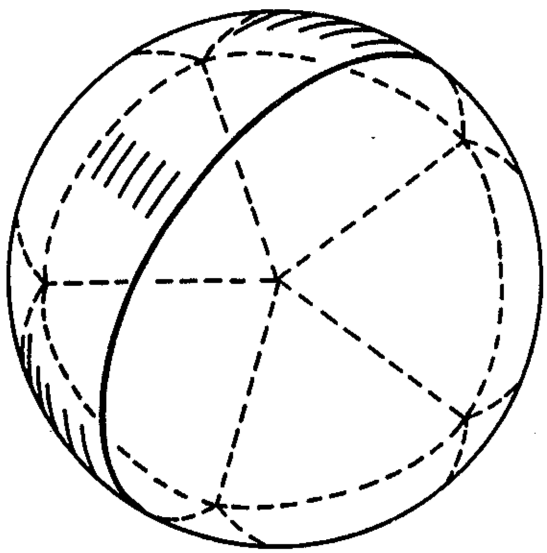
FSAR UPDATE

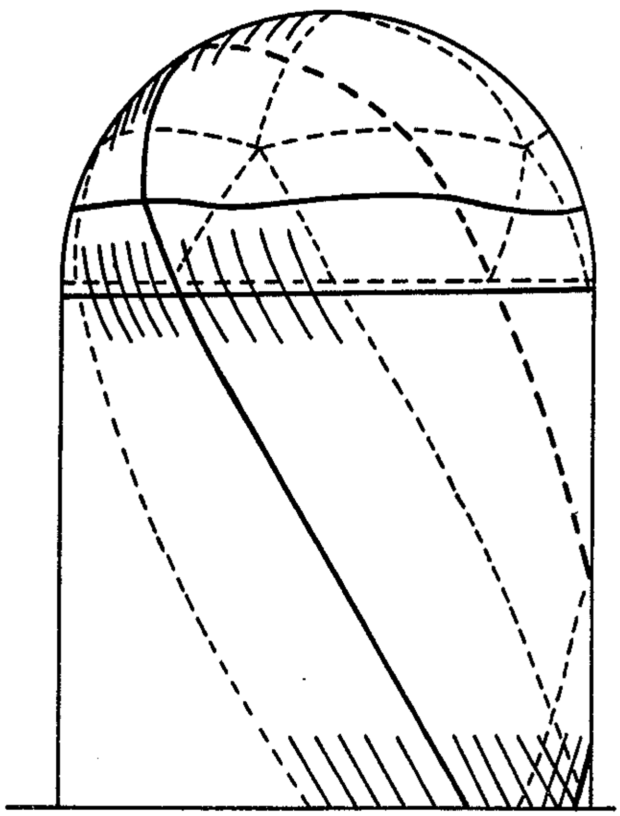
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-1

CONTAINMENT STRUCTURE

REINFORCING STEEL ARRANGEMENT





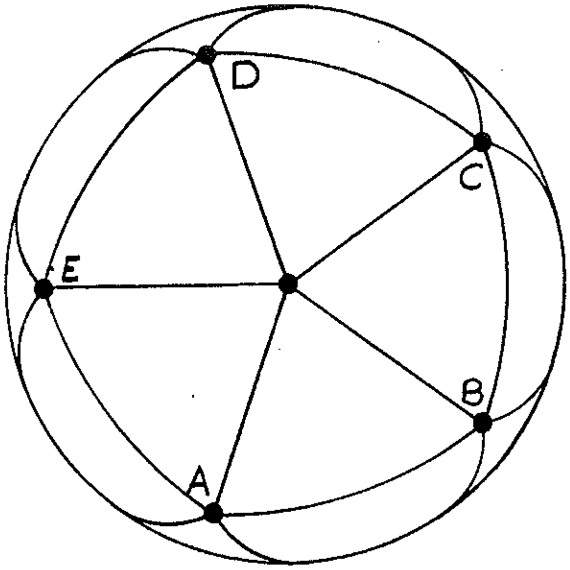
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

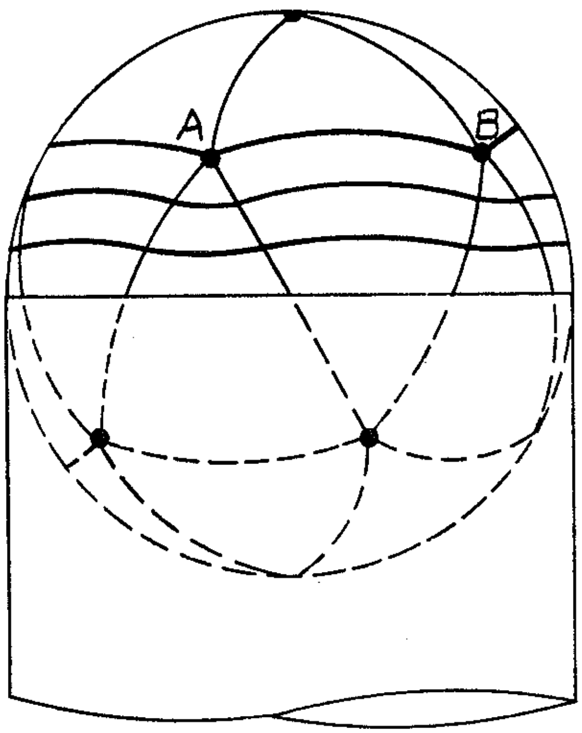
FIGURE 3.8-2

CONTAINMENT STRUCTURE

TYPICAL REINFORCING LOOP



SKETCH 1



SKETCH 2

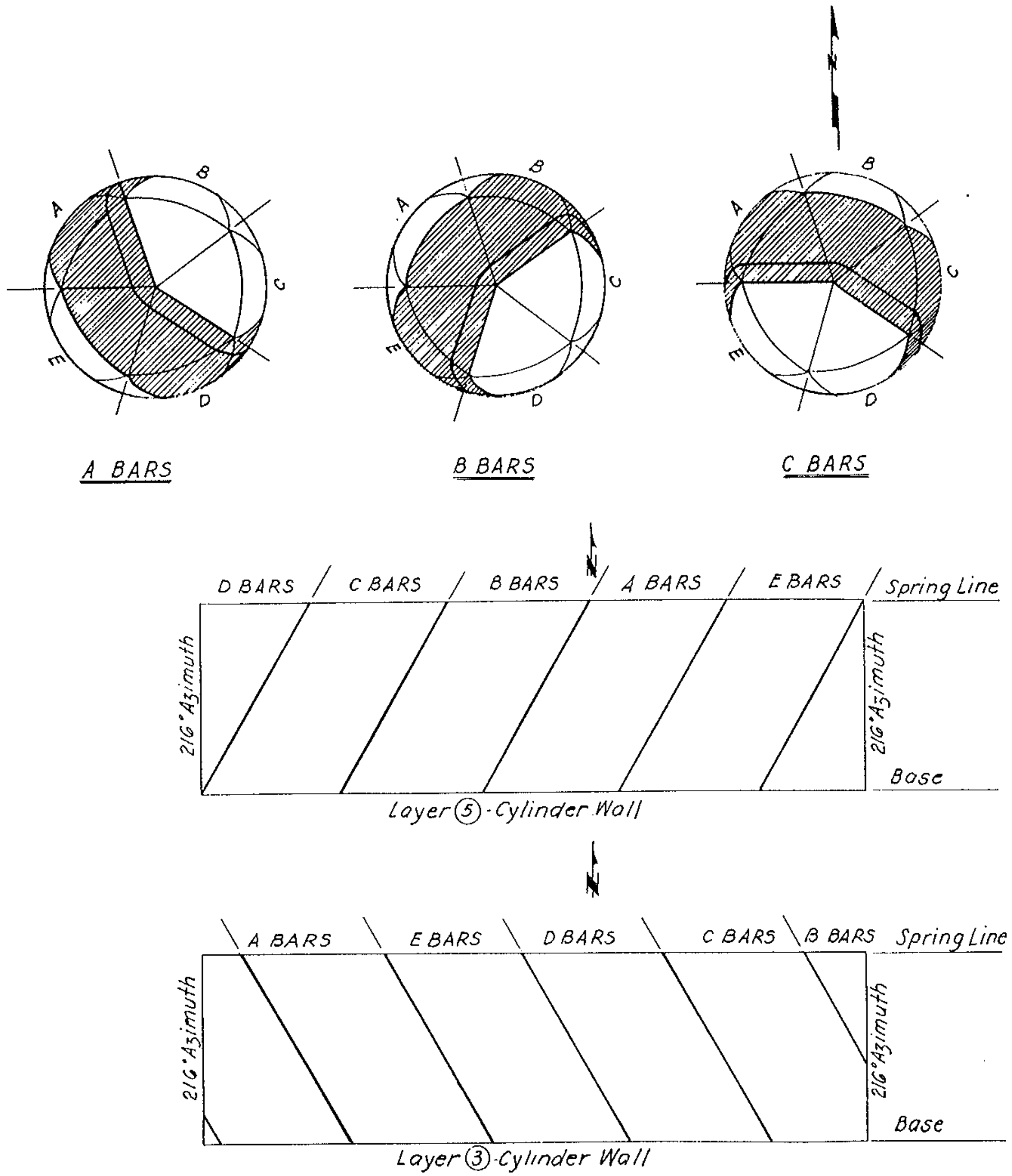
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-3

CONTAINMENT STRUCTURE

DOME SPHERICAL TRIANGLES



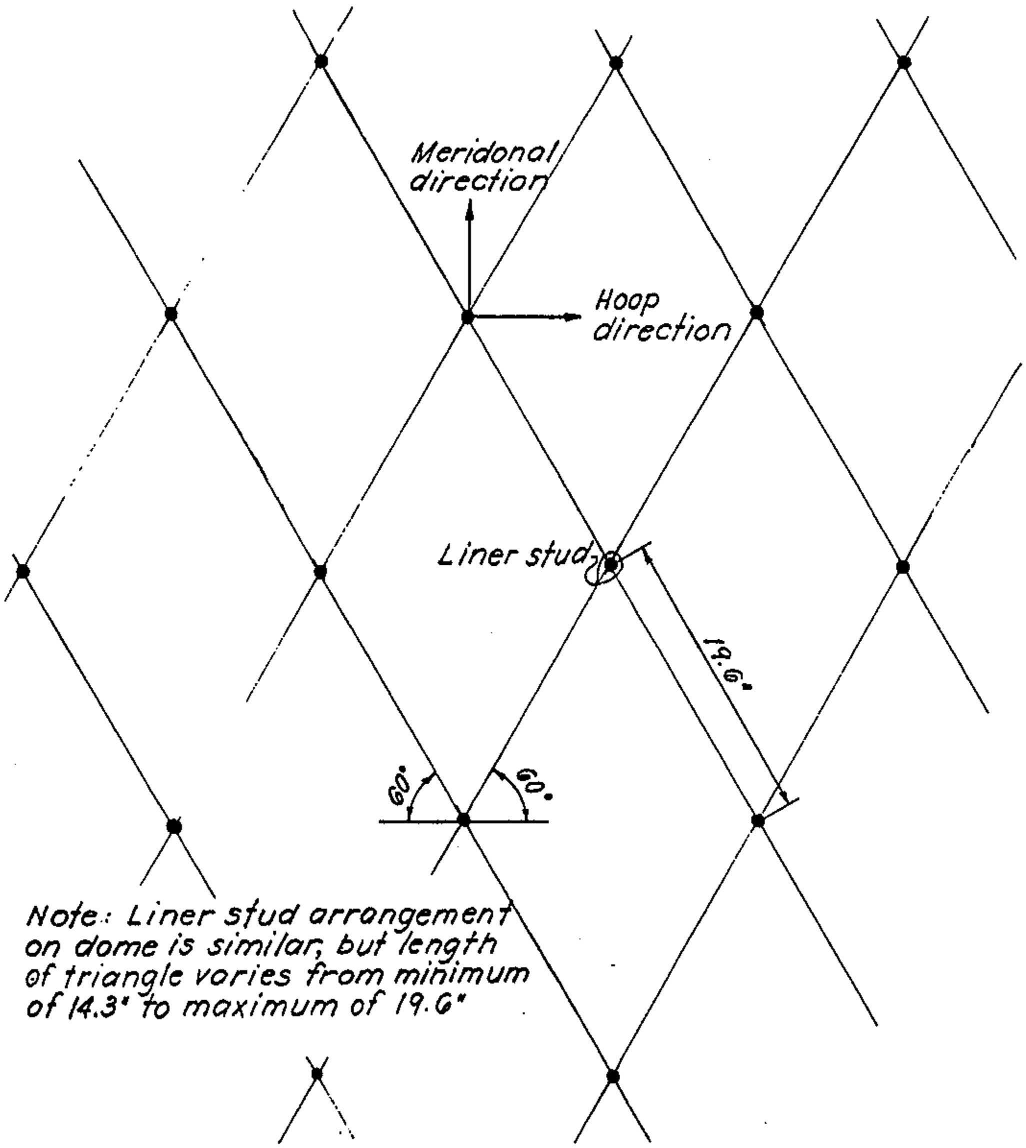
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-4

CONTAINMENT STRUCTURE
DOME AND CYLINDER BARS

Revision 11 November 1996



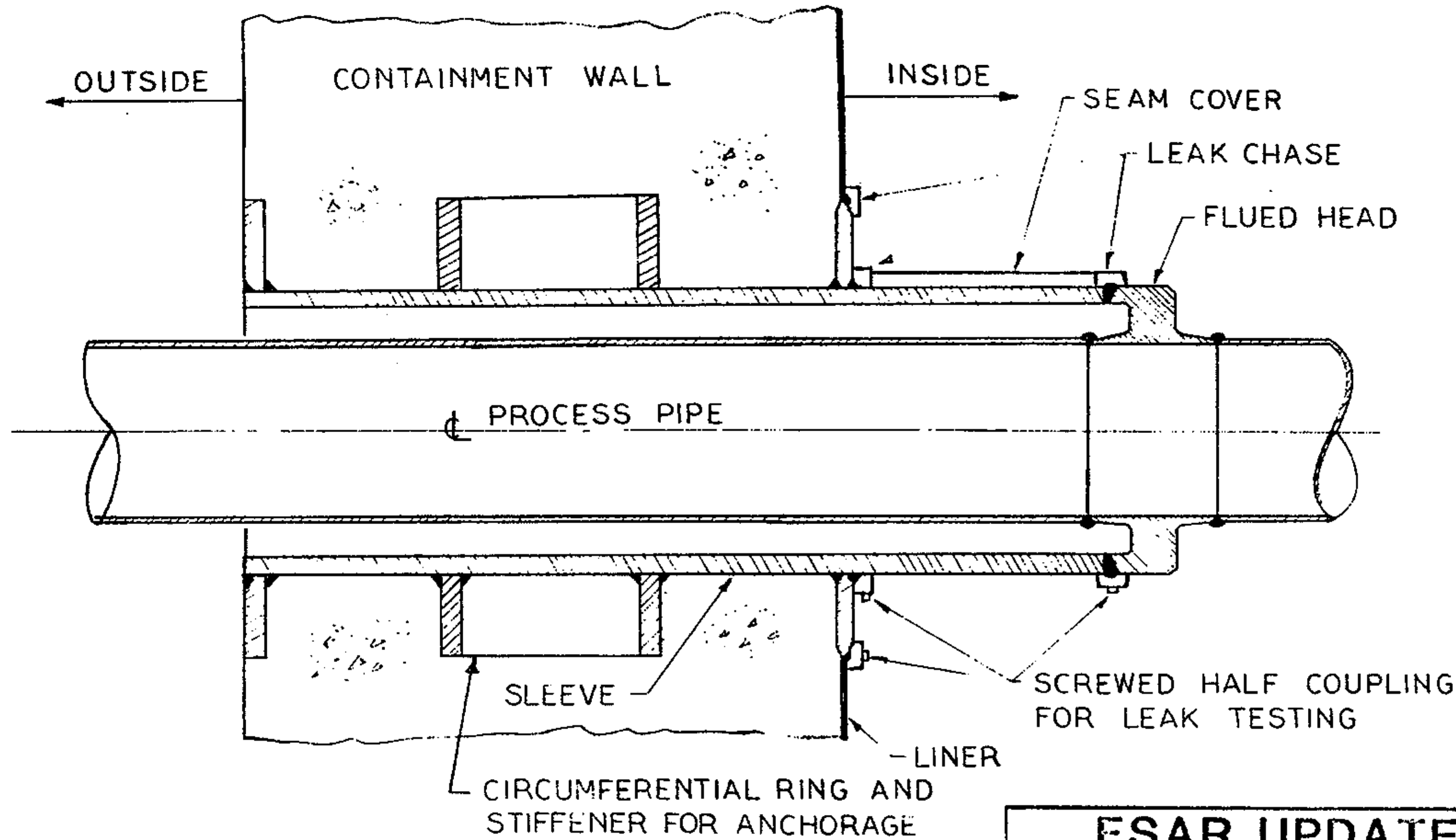
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-5

CONTAINMENT STRUCTURE

LINER STUD ARRANGEMENT



FSAR UPDATE

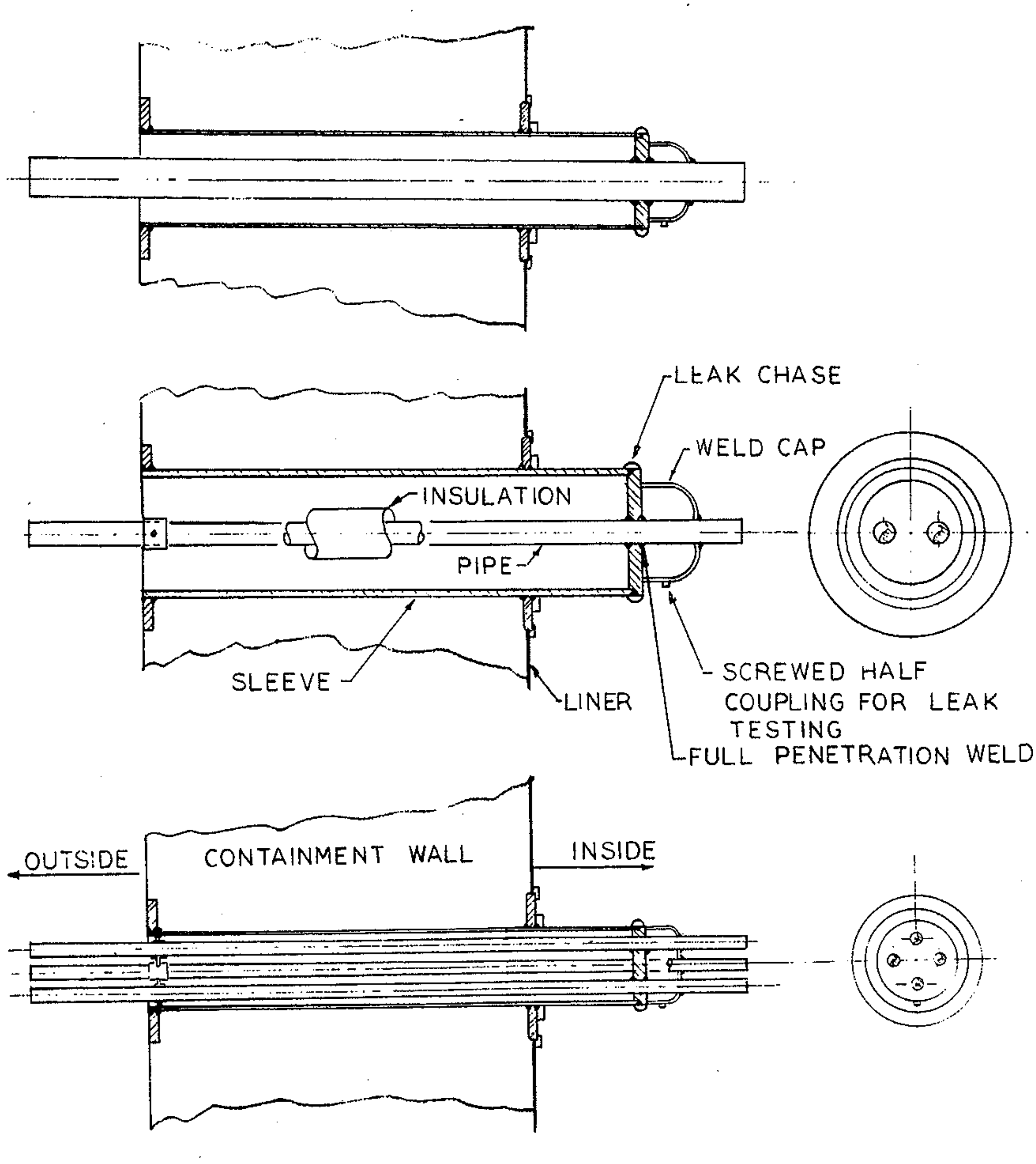
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-6

CONTAINMENT STRUCTURE

TYPICAL PIPING PENETRATION

Revision 11 November 1996



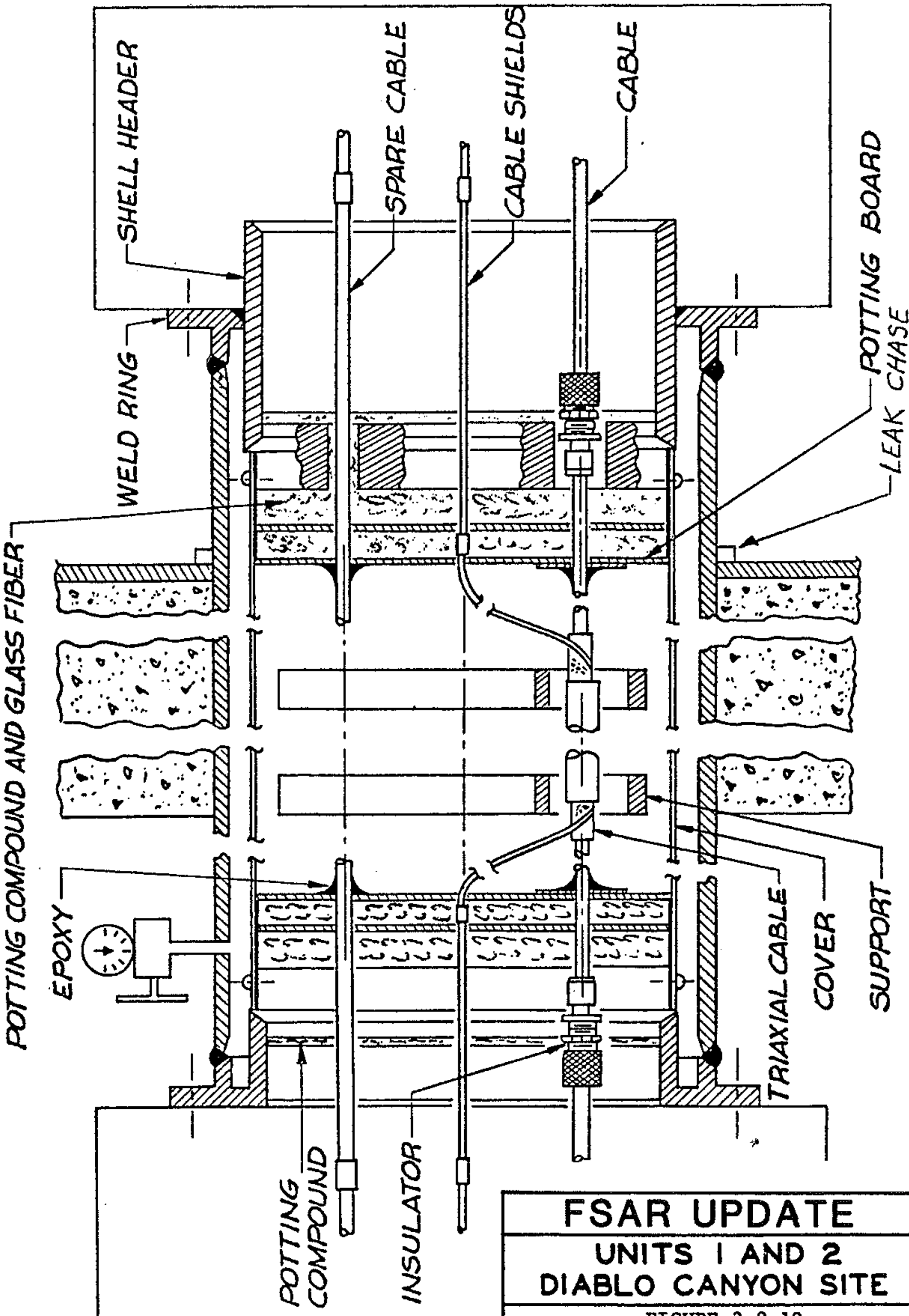
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-7

CONTAINMENT STRUCTURE

TYPICAL PIPING PENETRATION

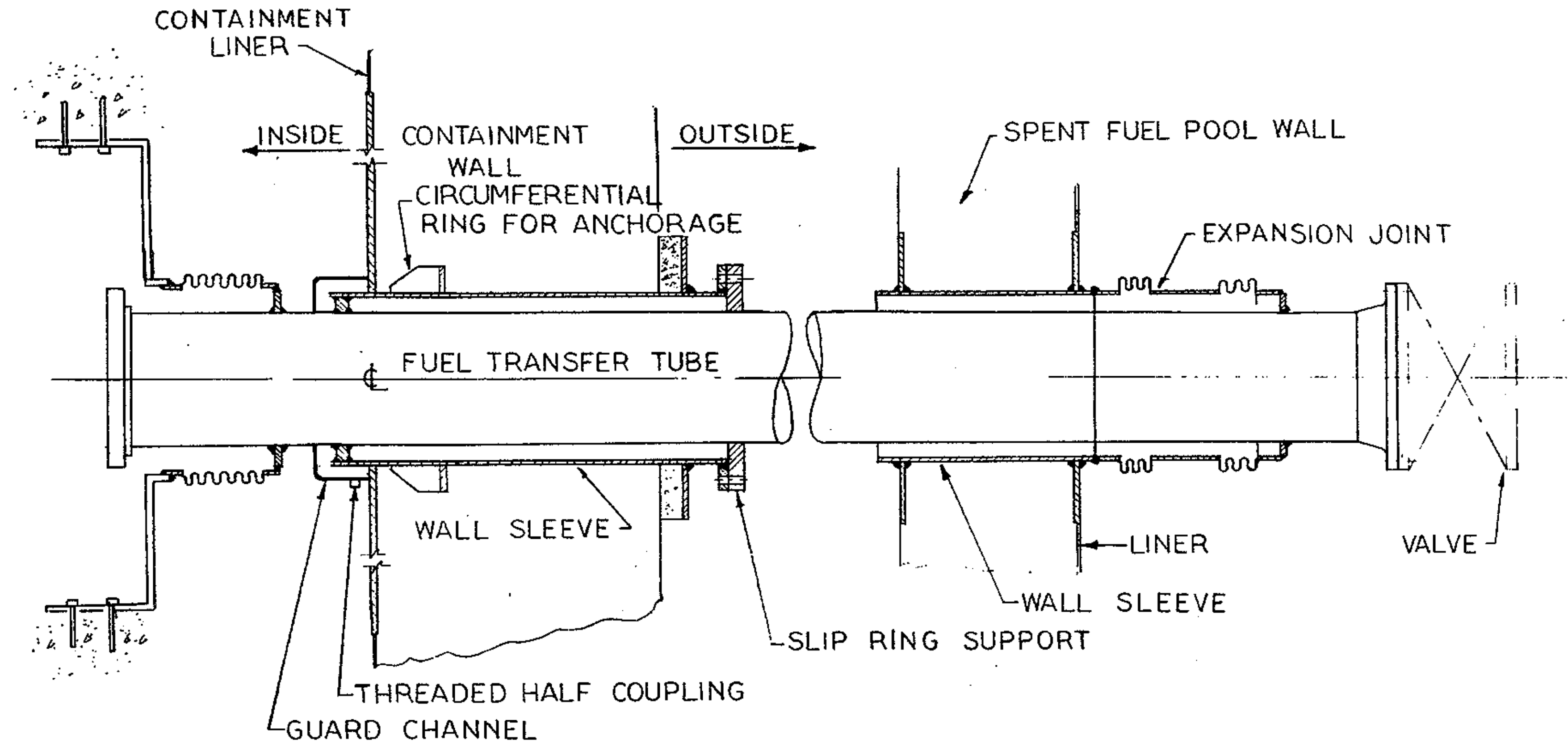


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-10

CONTAINMENT STRUCTURE
TYPICAL INSTRUMENTATION PENETRATION



FSAR UPDATE

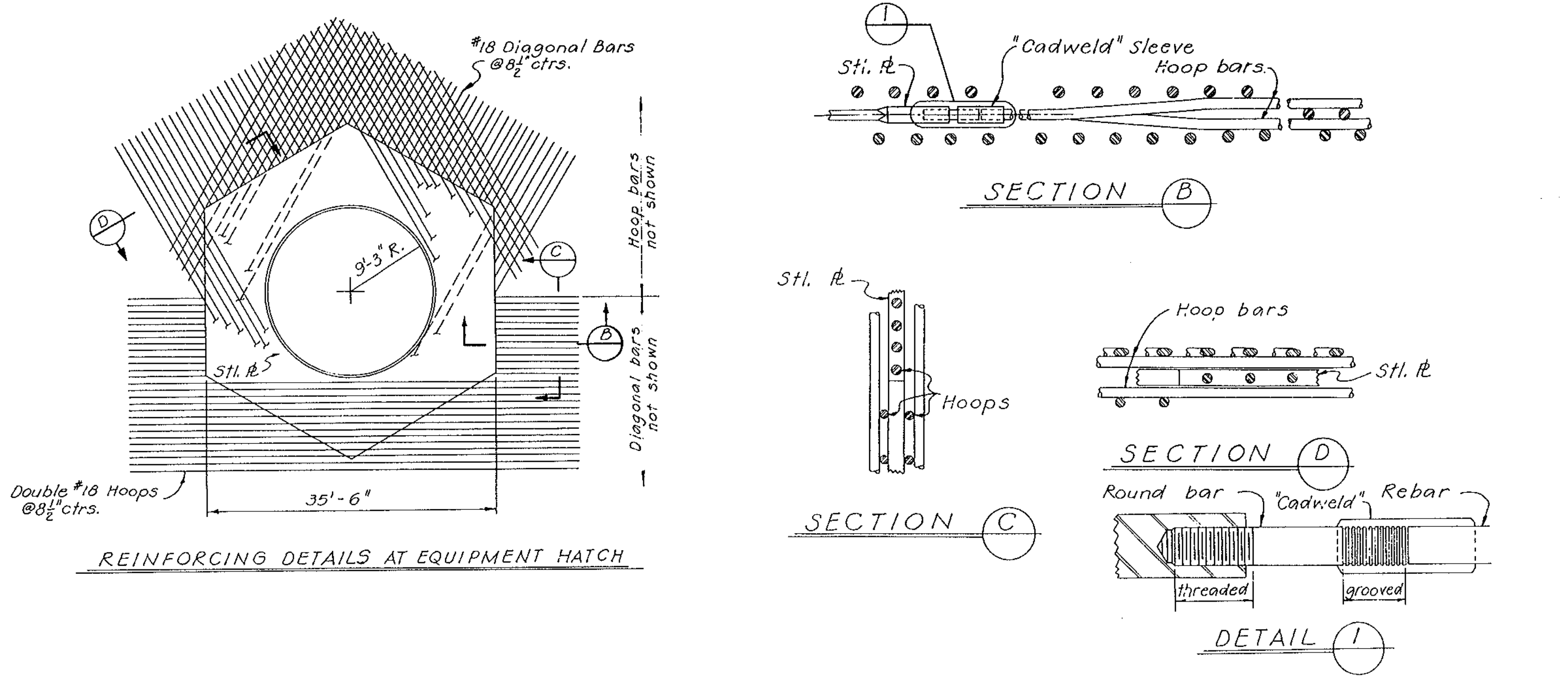
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-11

CONTAINMENT STRUCTURE

FUEL TRANSFER TUBE PENETRATION

Revision 11 November 1996



FSAR UPDATE

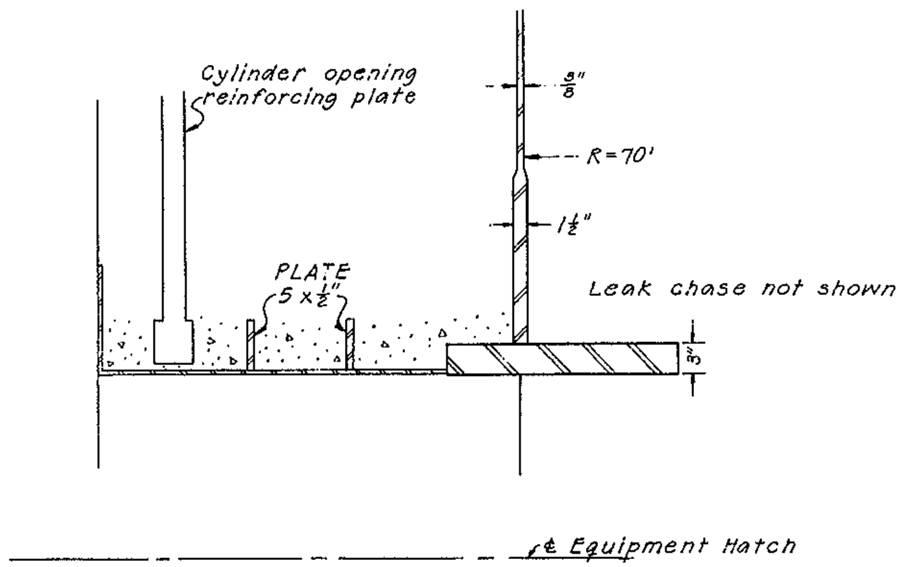
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-12

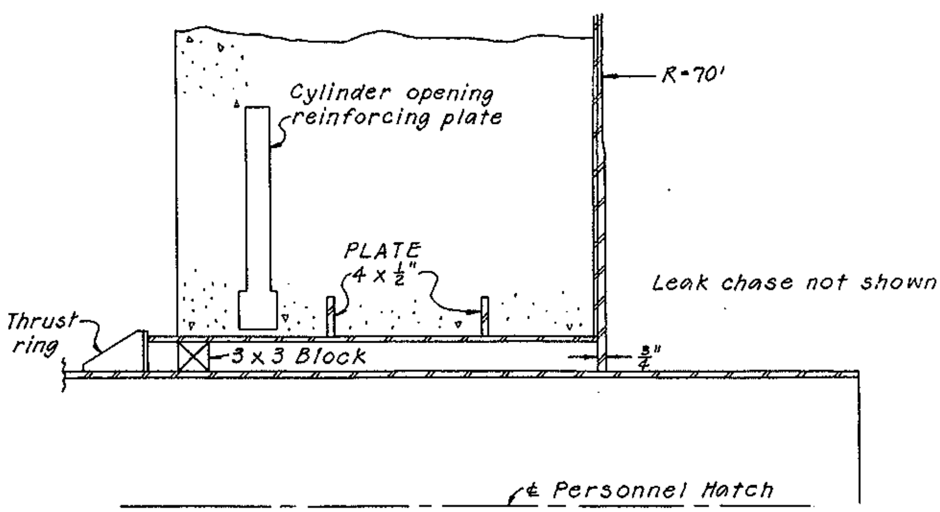
CONTAINMENT STRUCTURE

HEXAGONAL COLLARS

Revision 11 November 1996

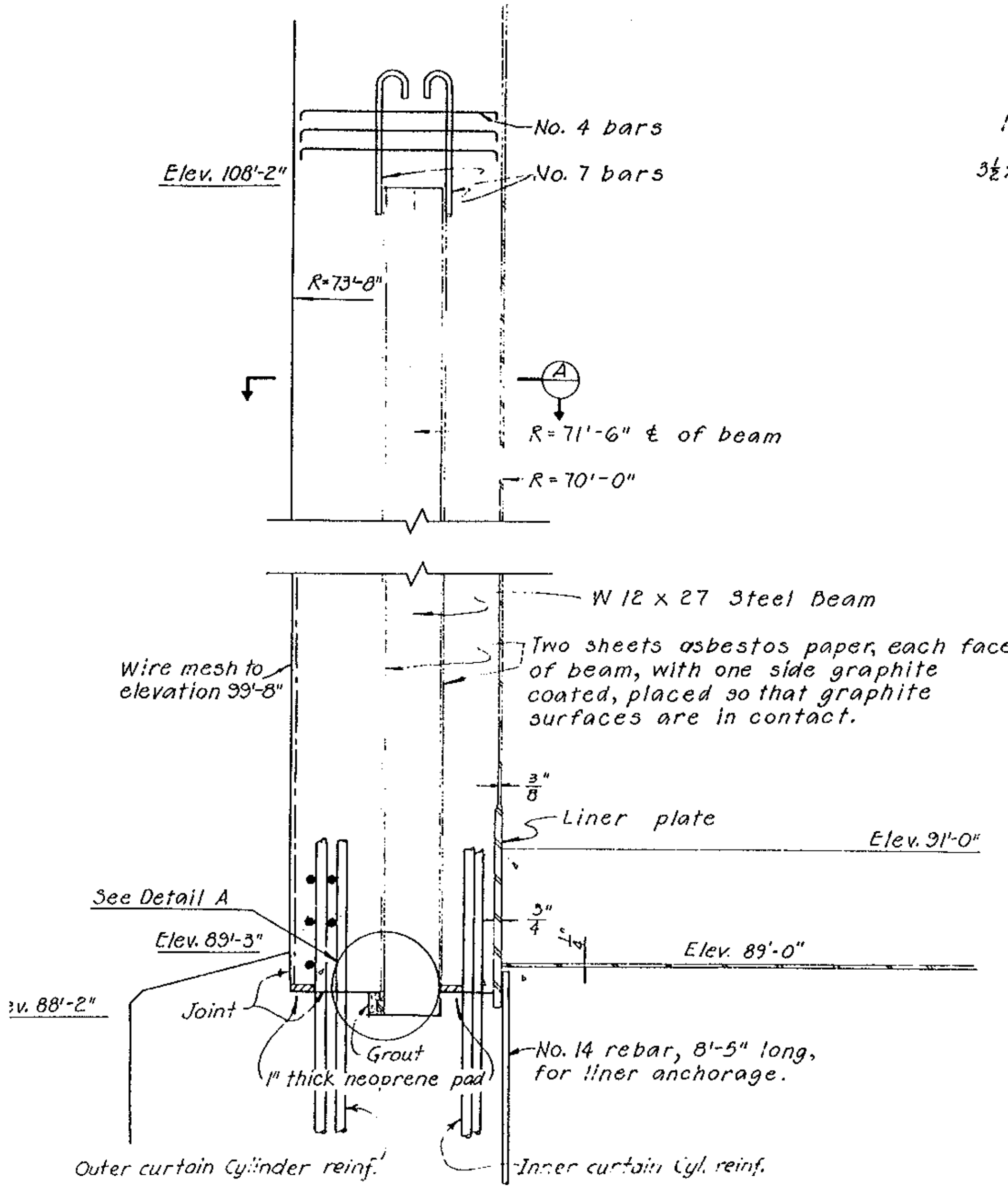


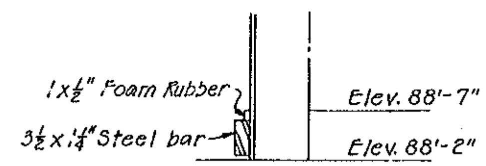
EQUIPMENT HATCH



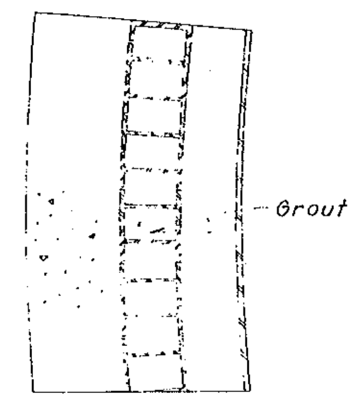
Unit I PERSONNEL HATCH

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.8-13 CONTAINMENT STRUCTURE ACCESS HATCH SLEEVES





DETAIL A



SECTION A

NOTES:

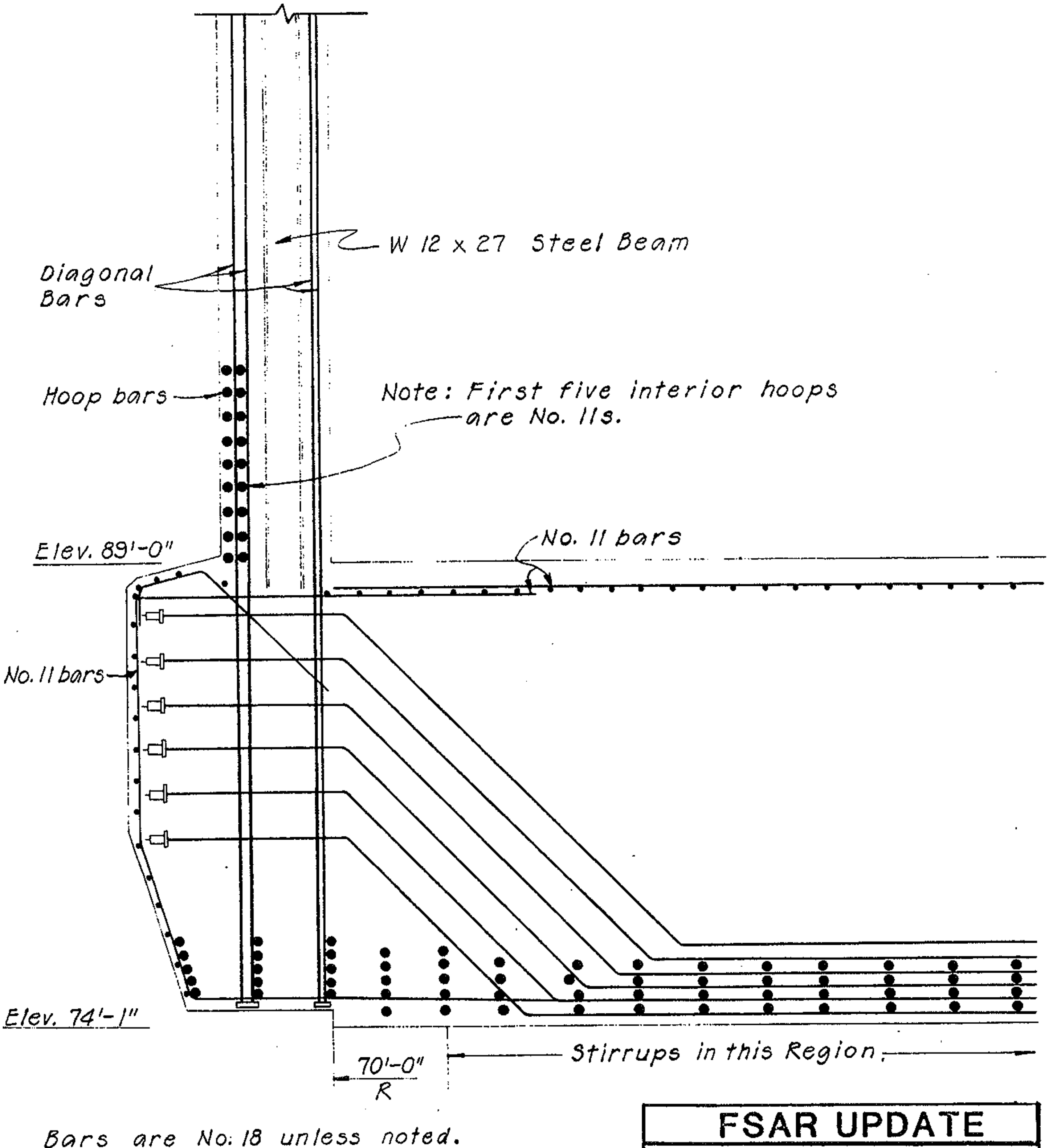
SEE FIGURE 3.8-15 FOR REINFORCING STEEL IN THIS REGION.

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-14
CONTAINMENT STRUCTURE
EMBEDDED BEAMS
CYLINDER-BASE SLAB JUNCTURE

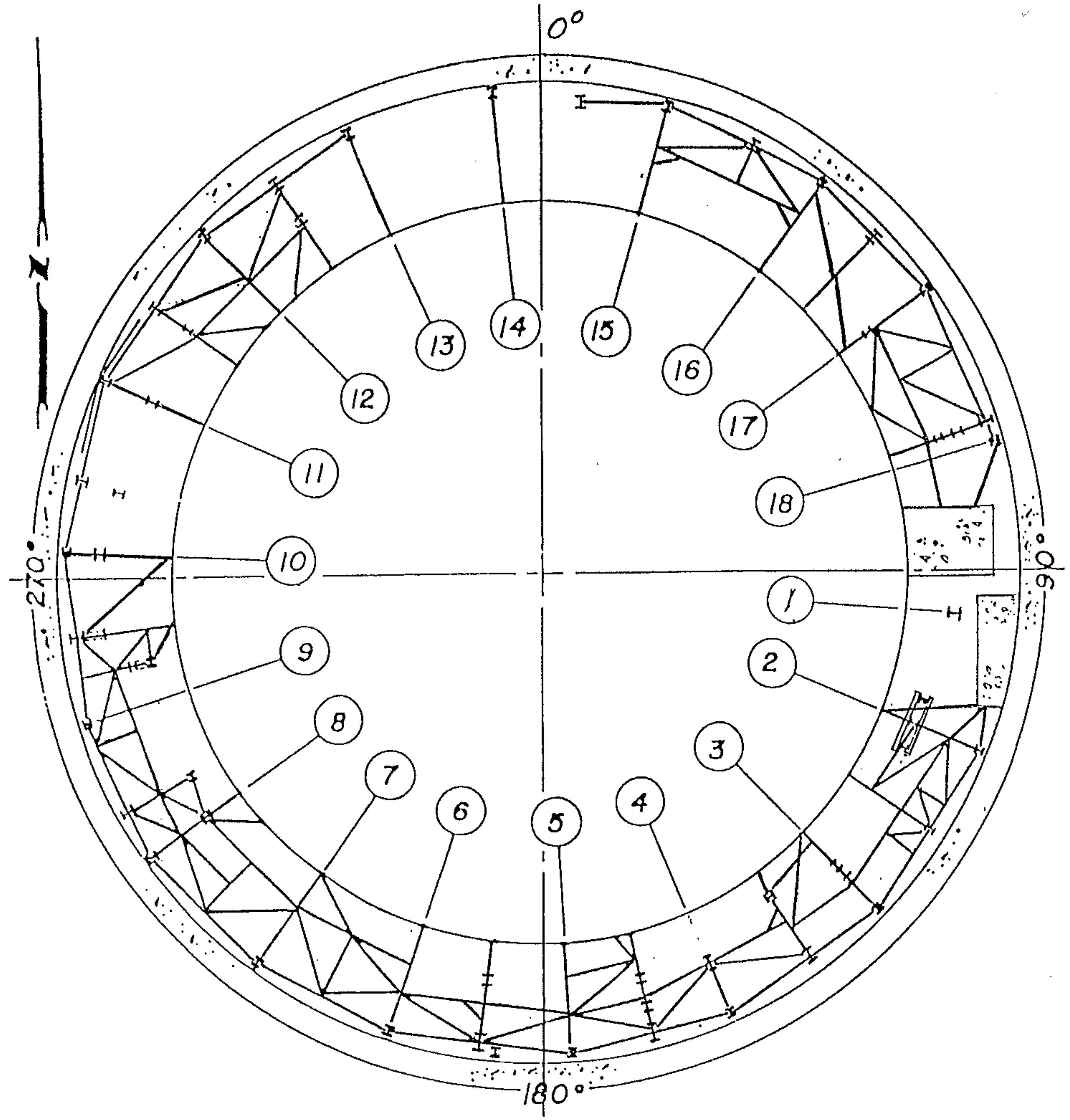
Revision 11 November 1996



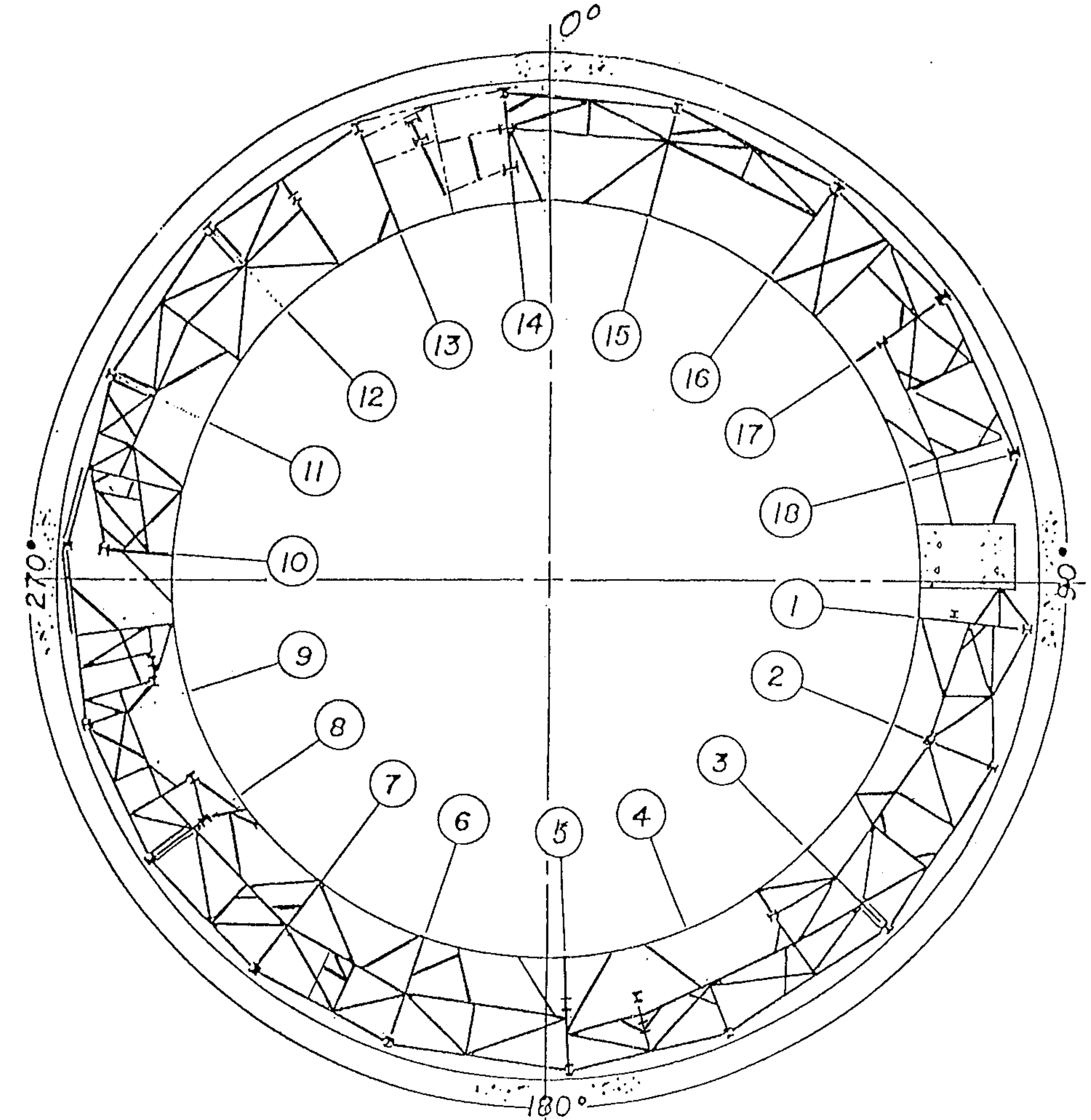
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-15
CONTAINMENT STRUCTURE
REINFORCING STEEL
BASE SLAB AND WALL

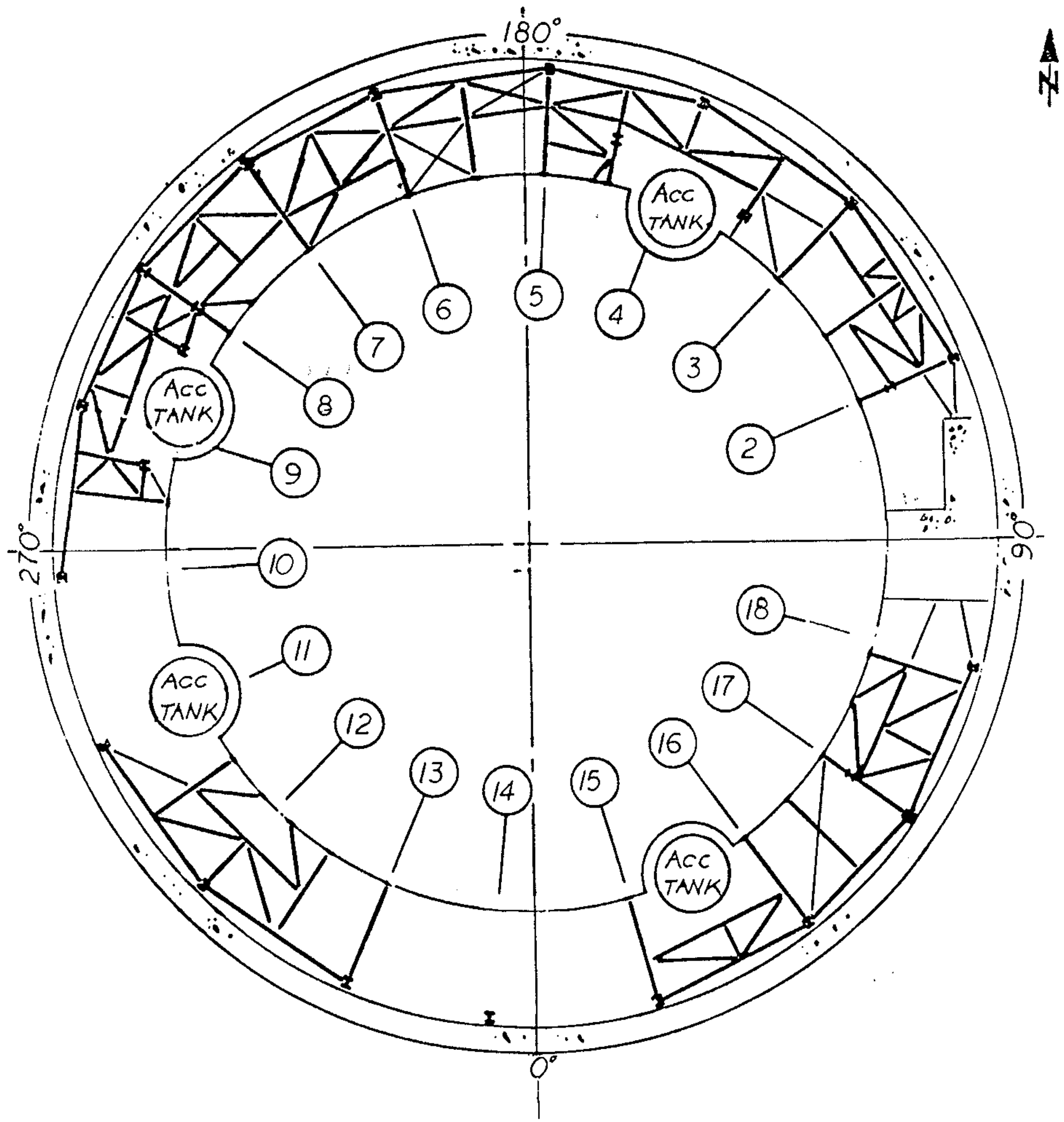


FRAMING PLAN T.O.S. EL 101'-4 1/2"

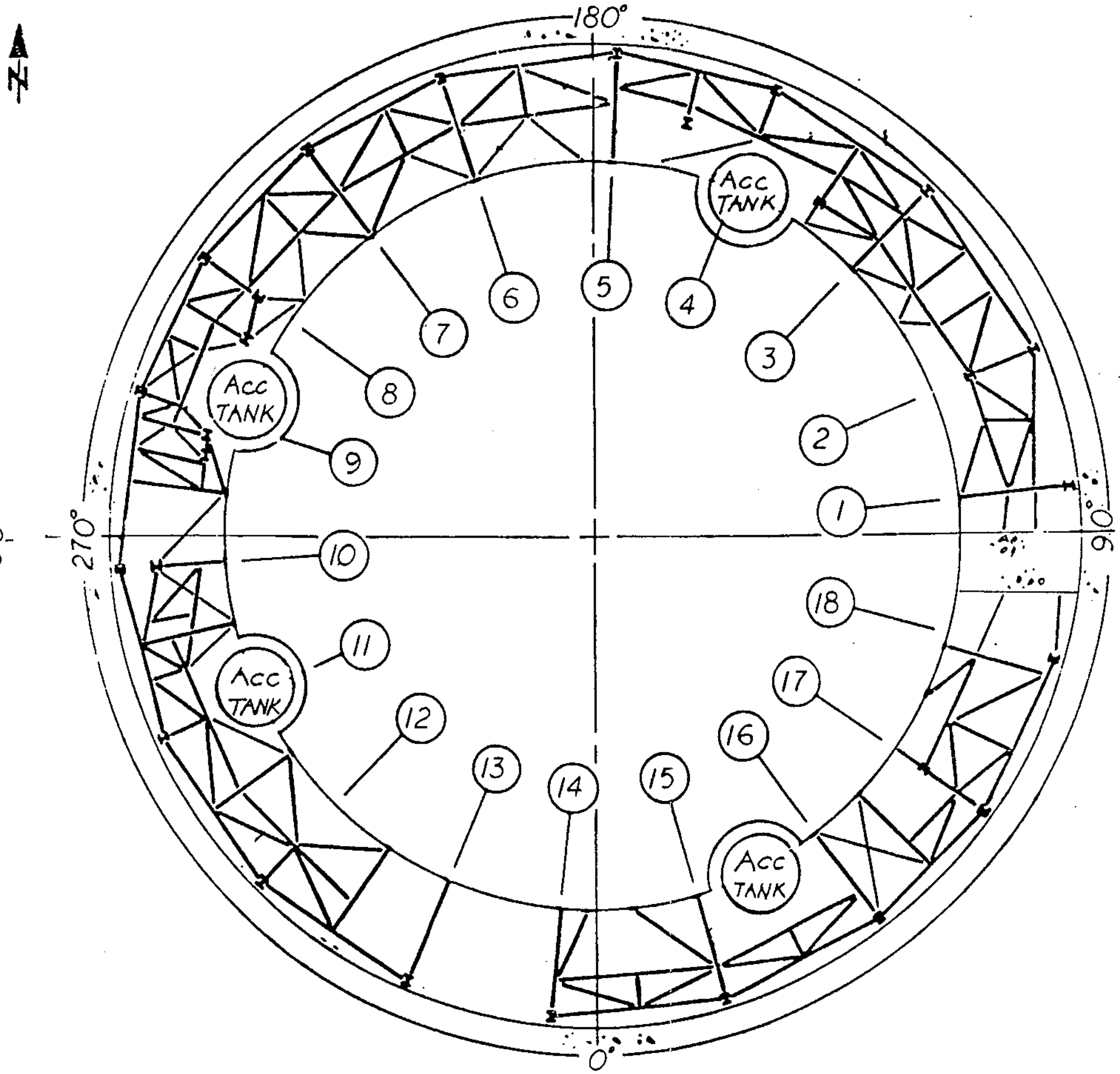


FRAMING PLAN T.O.S. EL 106'-8"

FSAR UPDATE
UNIT 1 **DIABLO CANYON SITE**
FIGURE 3.8-21, (Sheet 1 of 2) INTERNAL STRUCTURE ANNULUS PLATFORM ELEVATIONS 101 AND 106'



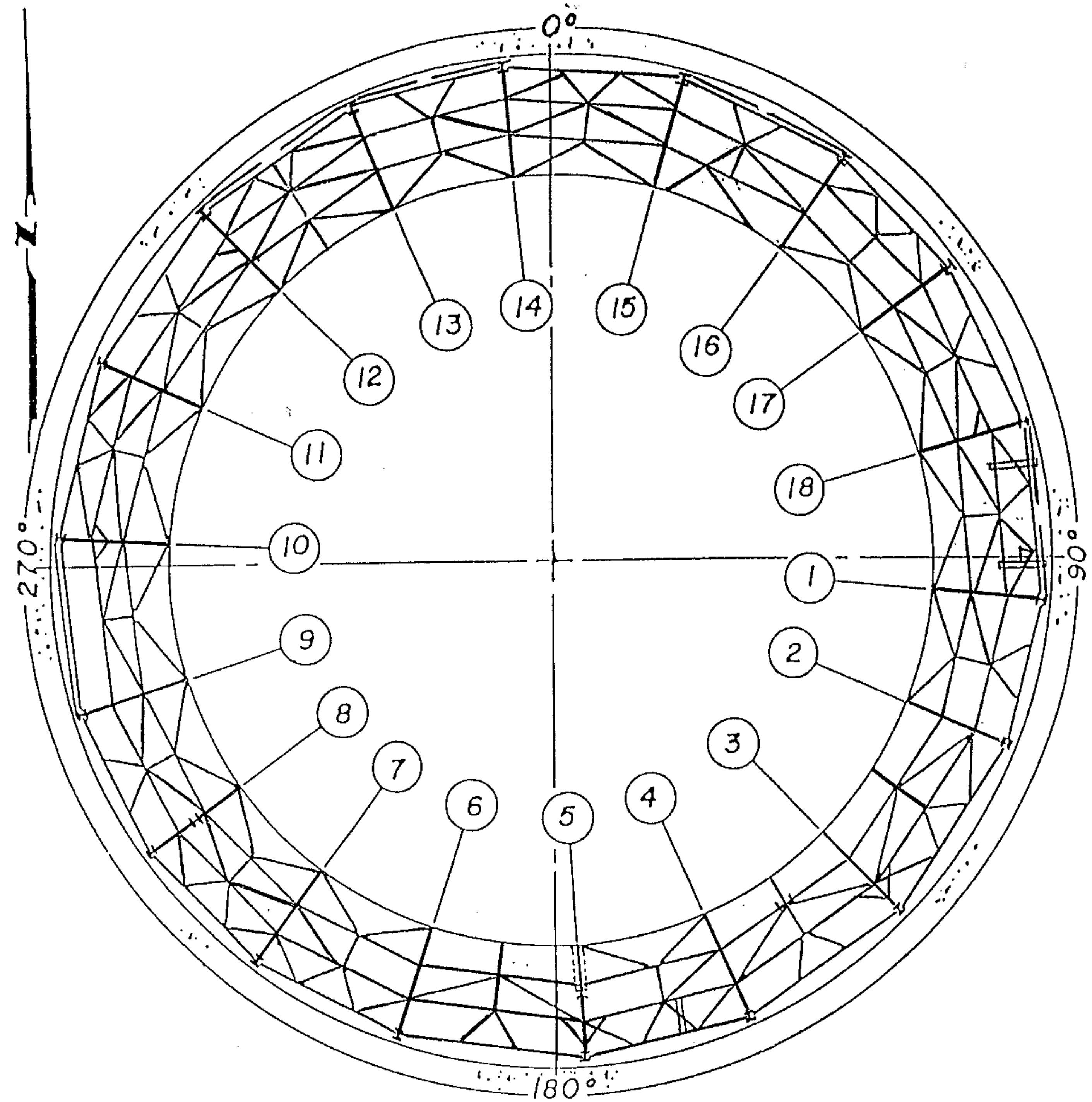
FRAMING PLAN T.O.S. EL. 101'-4½"



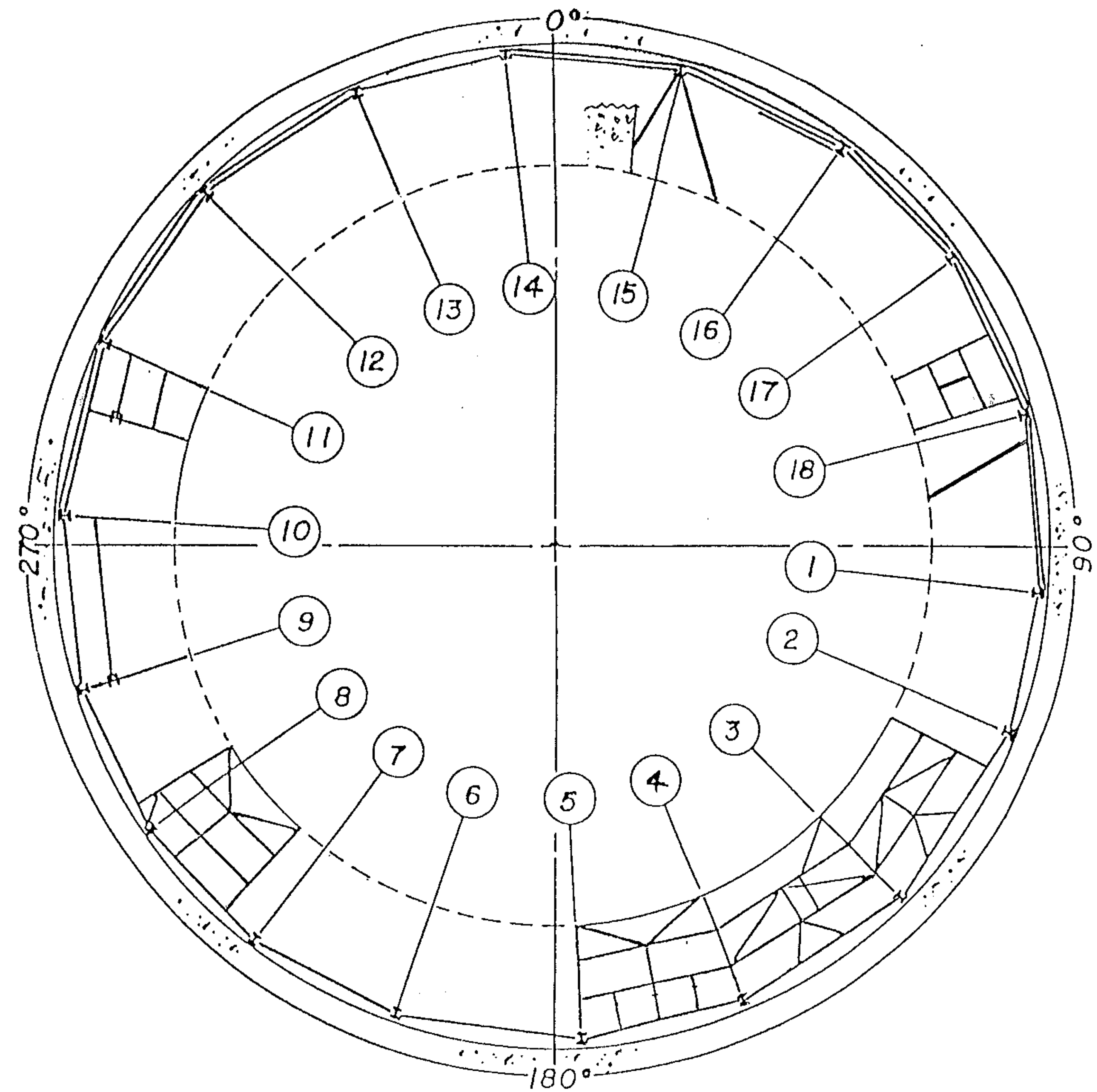
FRAMING PLAN T.O.S. EL. 106'-8"

FSAR UPDATE
UNIT 2
DIABLO CANYON SITE

FIGURE 3.8-21, (Sheet 2 of 2)
INTERNAL STRUCTURE
ANNULUS PLATFORM
ELEVATIONS 101 AND 106'

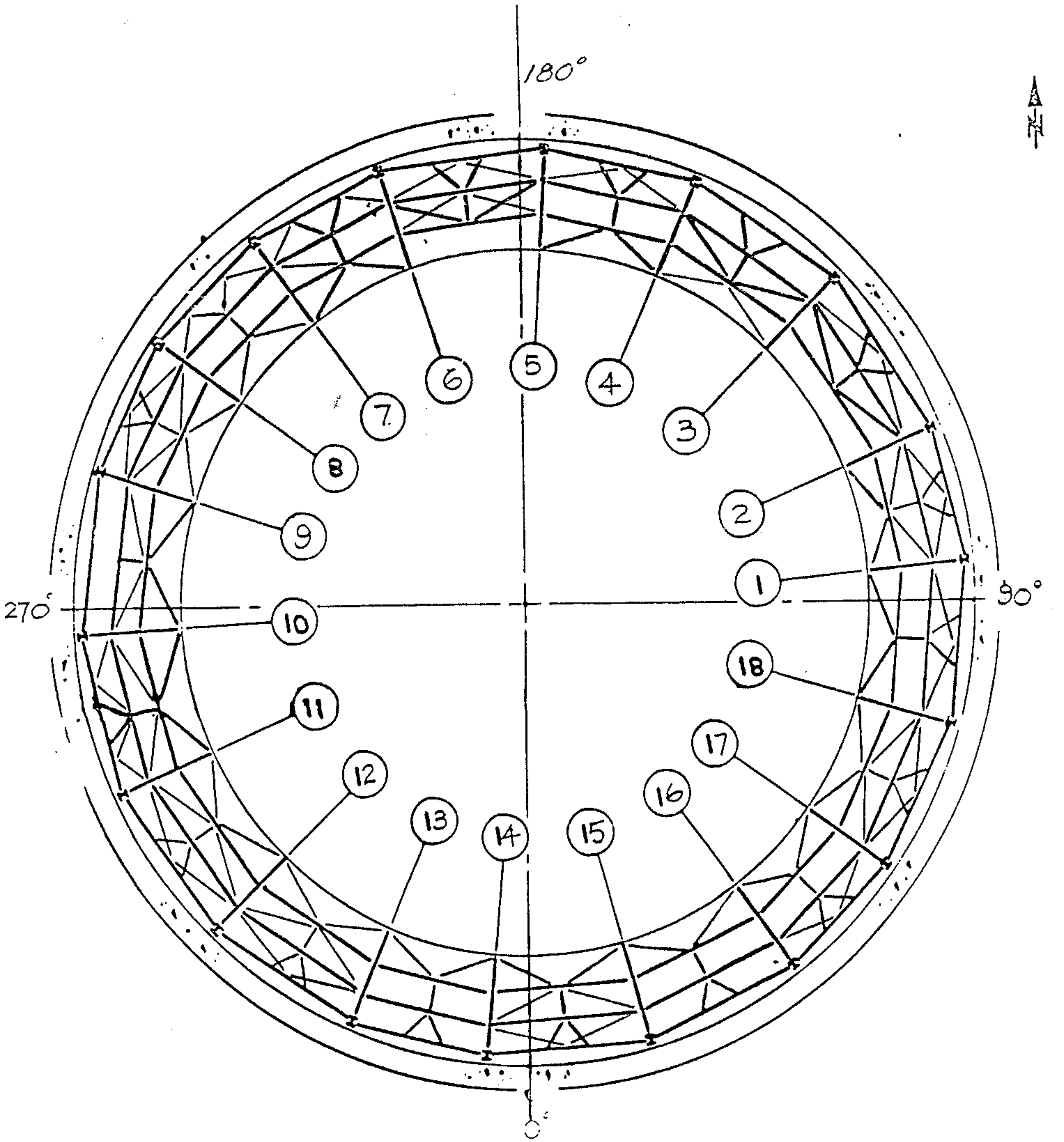


FRAMING PLAN T.O.S. EL 116'-10 3/4"

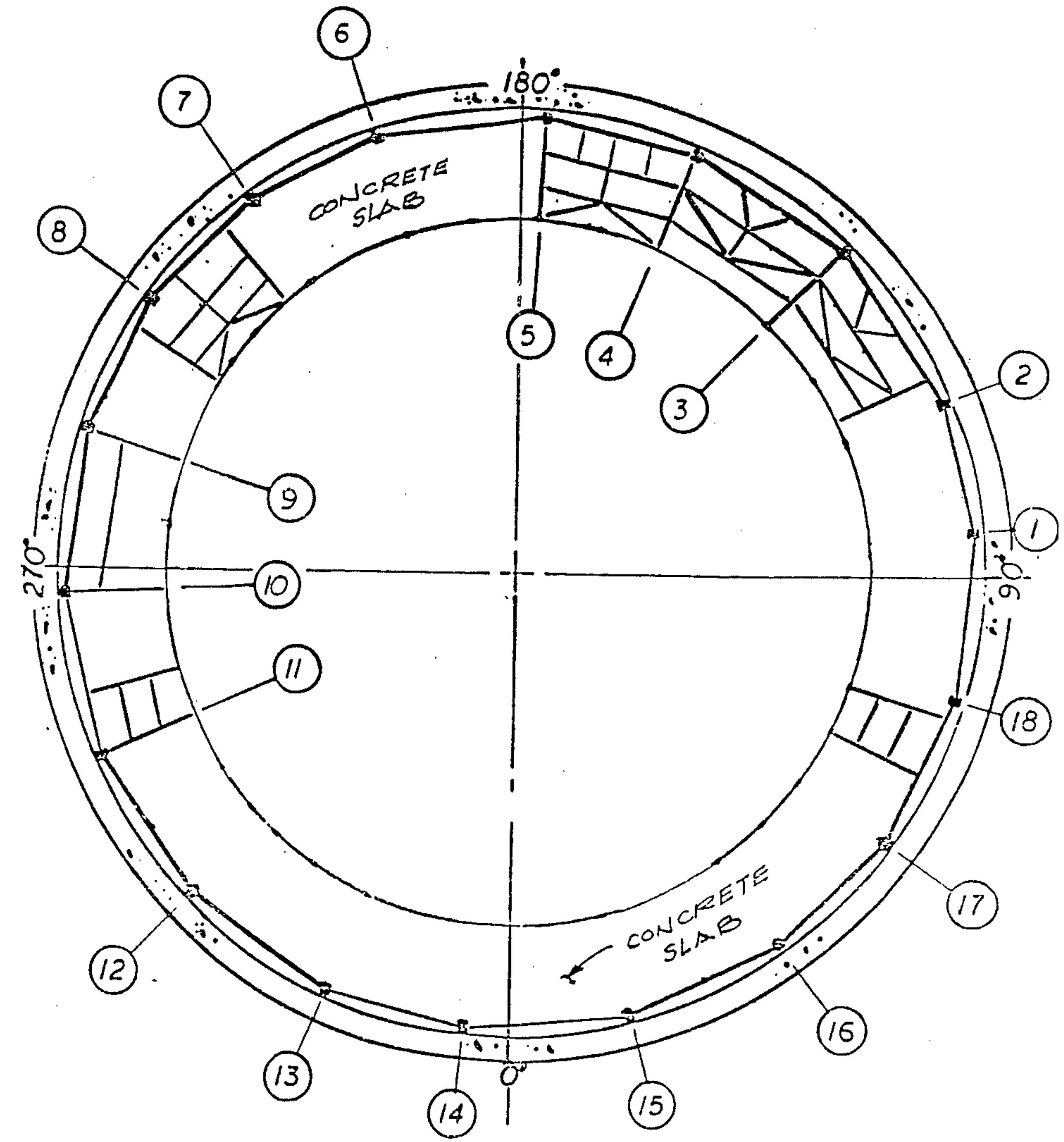


FRAMING PLAN T.O.S. EL 139'-10 3/4"

FSAR UPDATE
UNIT 1 **DIABLO CANYON SITE**
FIGURE 3.8-22 (Sheet 1 of 2) INTERNAL STRUCTURE ANNULUS PLATFORM ELEVATIONS 117 AND 140'



FRAMING PLAN T.O.S. EL. 116'-10¾"

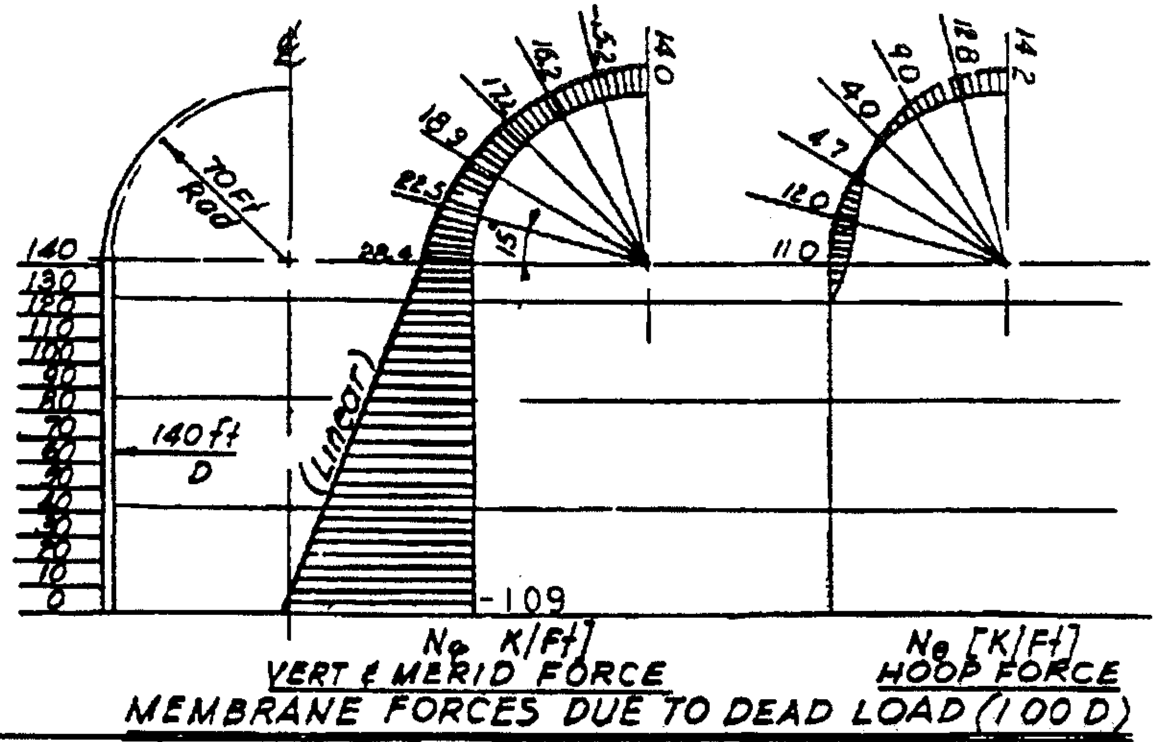


FRAMING PLAN AT EL. 140'-0"

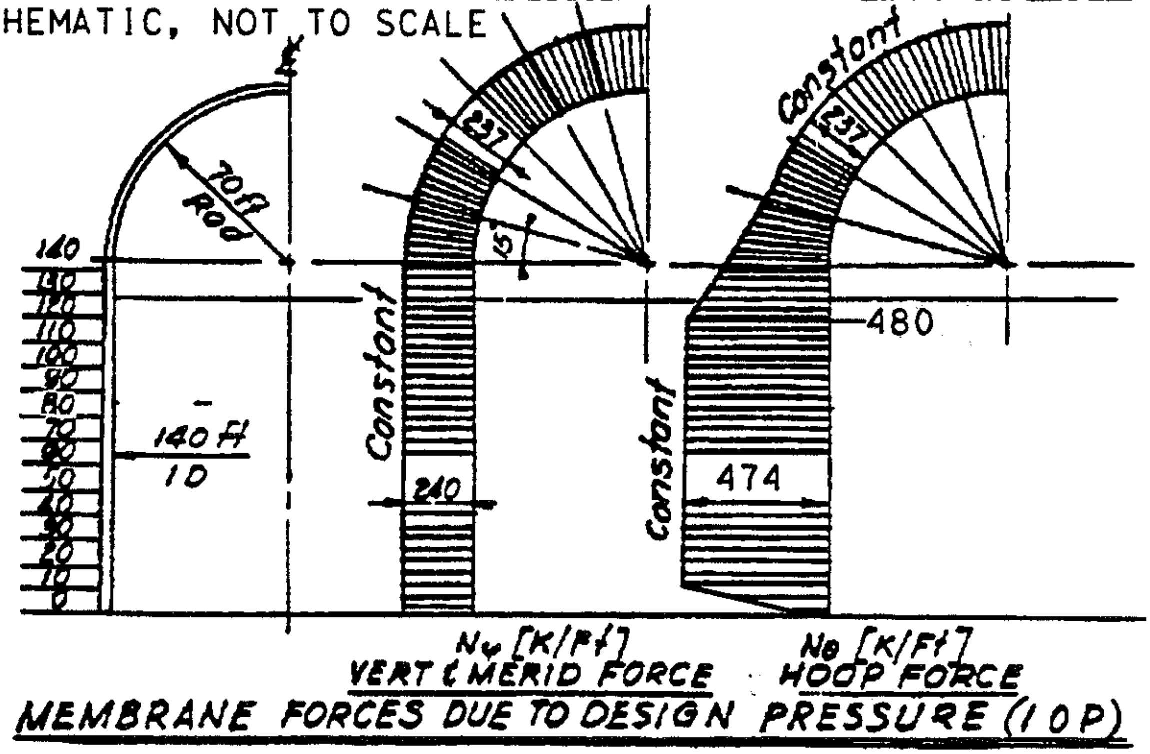
FSAR UPDATE

UNIT 2
DIABLO CANYON SITE

FIGURE 3.8-22 (Sheet 2 of 2)
INTERNAL STRUCTURE
ANNULUS PLATFORM
ELEVATIONS 117 AND 140'



SCHEMATIC, NOT TO SCALE

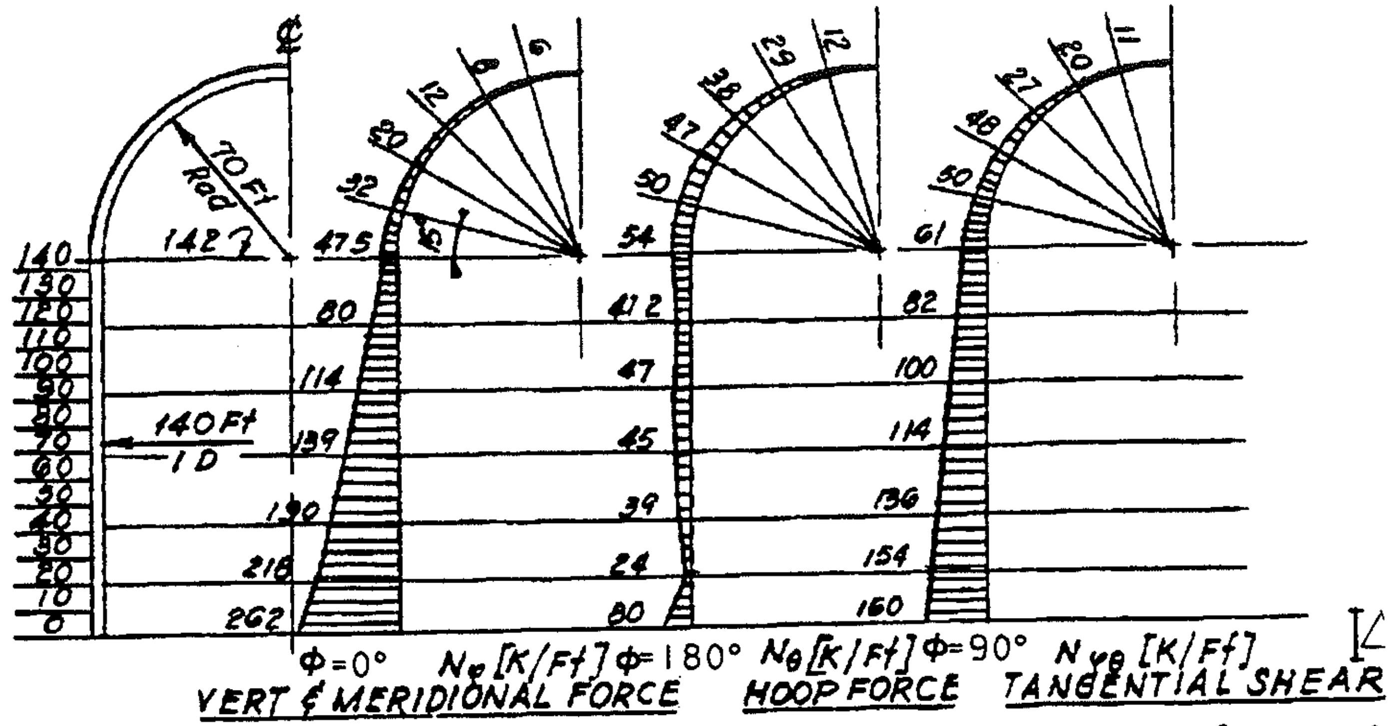


SCHEMATIC, NOT TO SCALE

FSAR UPDATE

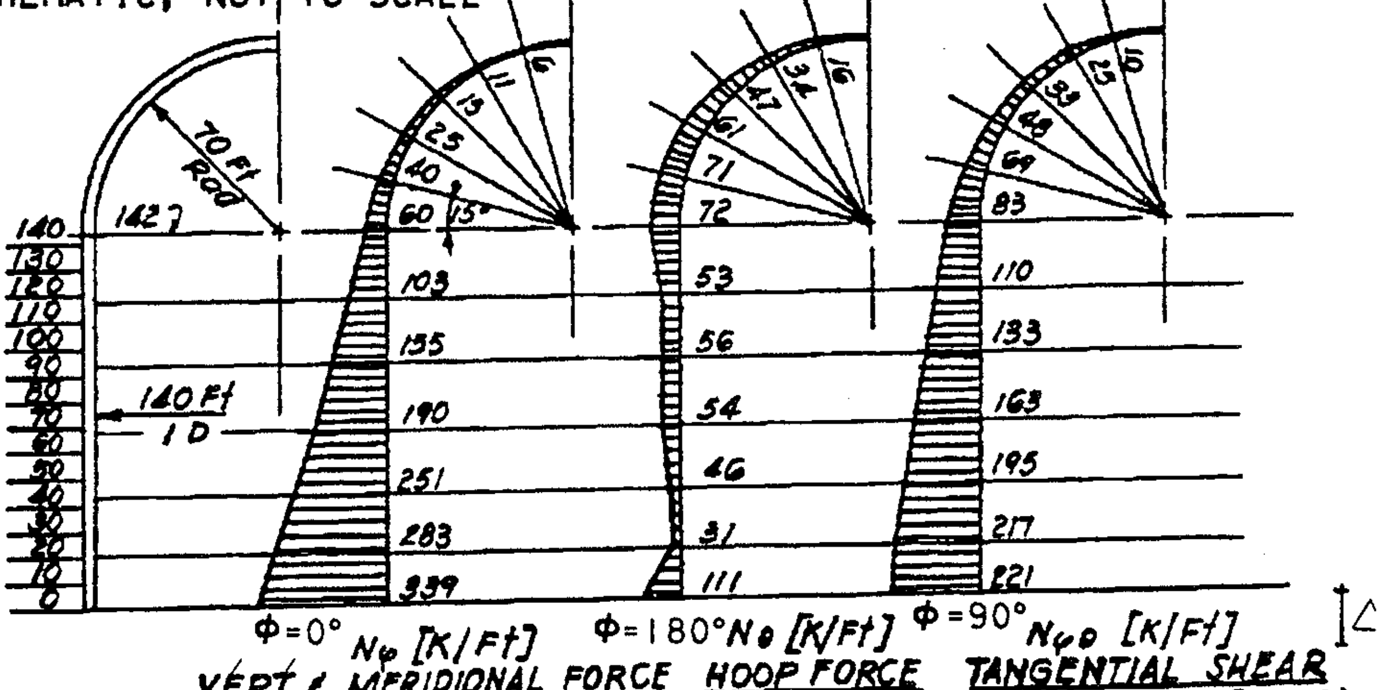
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-27
CONTAINMENT STRUCTURE
MEMBRANE FORCES
DEAD LOAD AND PRESSURE



MEMBRANE FORCES DUE TO 1.25x DESIGN EARTHQUAKE (1.25DE)

SCHEMATIC, NOT TO SCALE



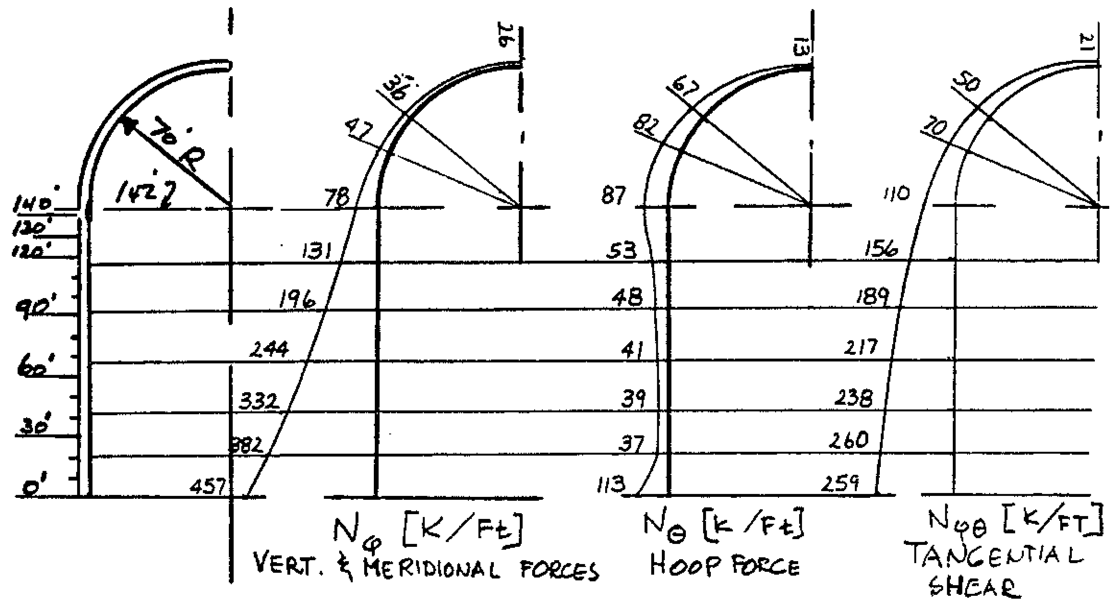
MEMBRANE FORCES DUE TO DOUBLE DESIGN EARTHQUAKE (DDE)

SCHEMATIC, NOT TO SCALE

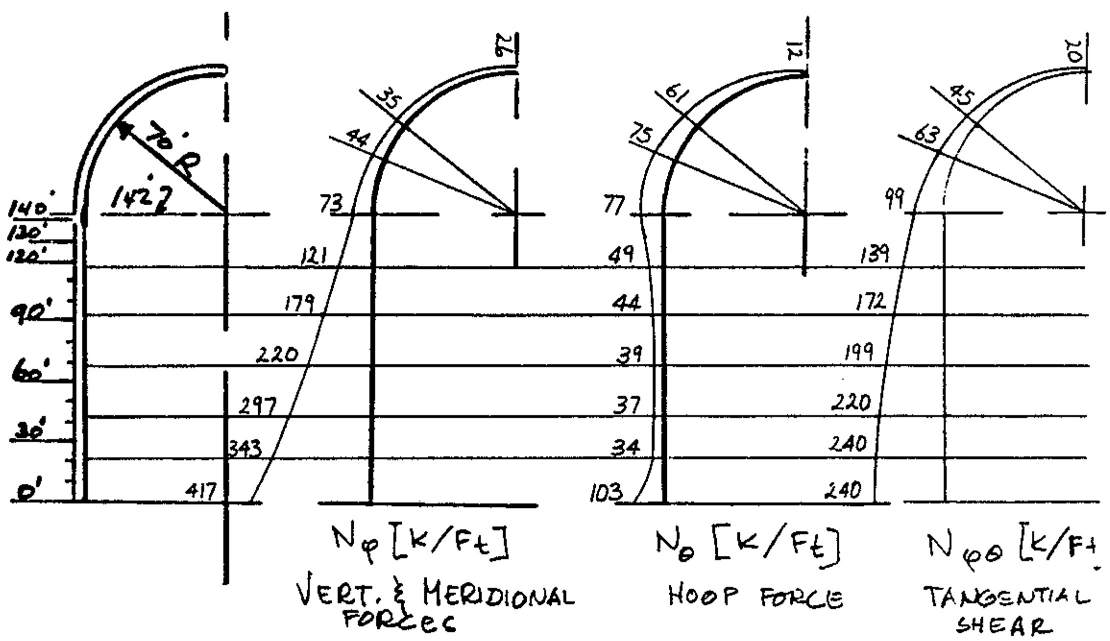
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-28
CONTAINMENT STRUCTURE
MEMBRANE FORCES
DE and DDE EARTHQUAKES-B



MEMBRANE FORCES DUE TO HOSGRI (BLUME) EARTHQUAKE

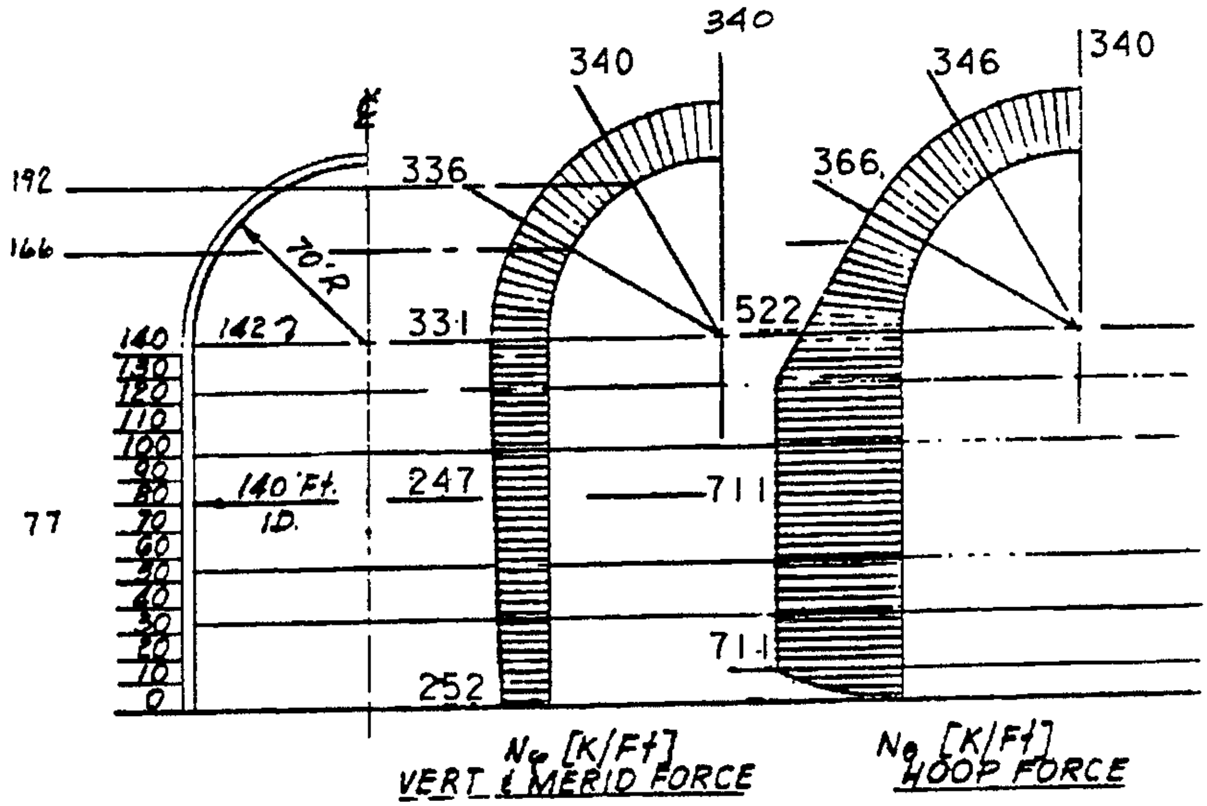


MEMBRANE FORCES DUE TO HOSGRI [NEWMARK] EARTHQUAKE

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-29
CONTAINMENT STRUCTURE
MEMBRANE FORCES
HOSGRI EARTHQUAKE



MAMBRANE FORCES

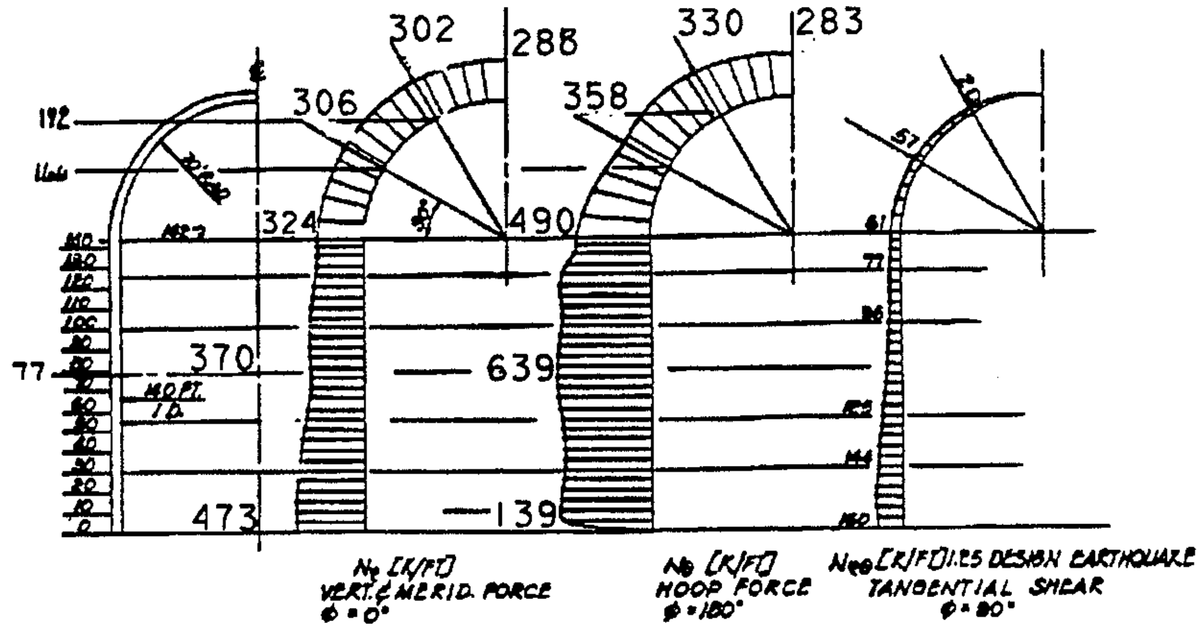
DUE TO LOAD CONDITION (I) U = 1.0D ± .05D + 1.5P +1.0T"

SCHEMATIC NOT TO SCALE

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-30
CONTAINMENT STRUCTURE
MEMBRANE FORCES
ACCIDENT CONDITION 1



MAMBRANE FORCES

DUE TO LOAD CONDITION (2) U = 1.0D ± .05D + 1.25P + 1.25DE

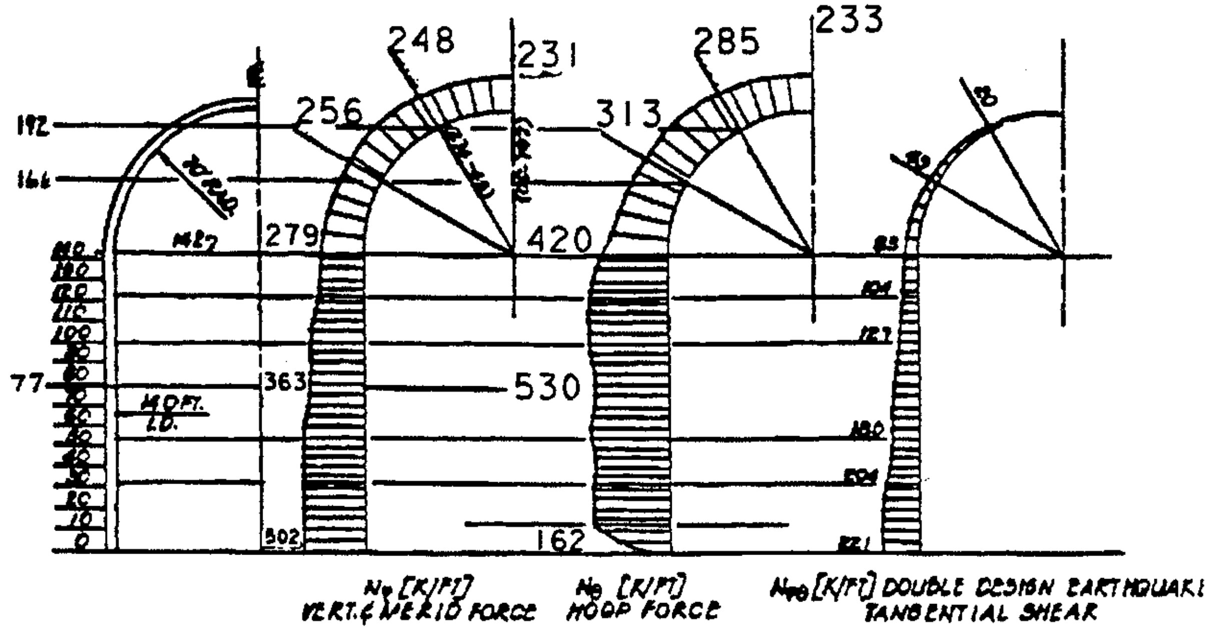
SCHEMATIC NOT TO SCALE

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-31
CONTAINMENT STRUCTURE
MEMBRANE FORCES
ACCIDENT CONDITION 2

Revision 11 November 1996



MAMBRANE FORCES

NOTE VALUES ARE FORCES IN REBAR

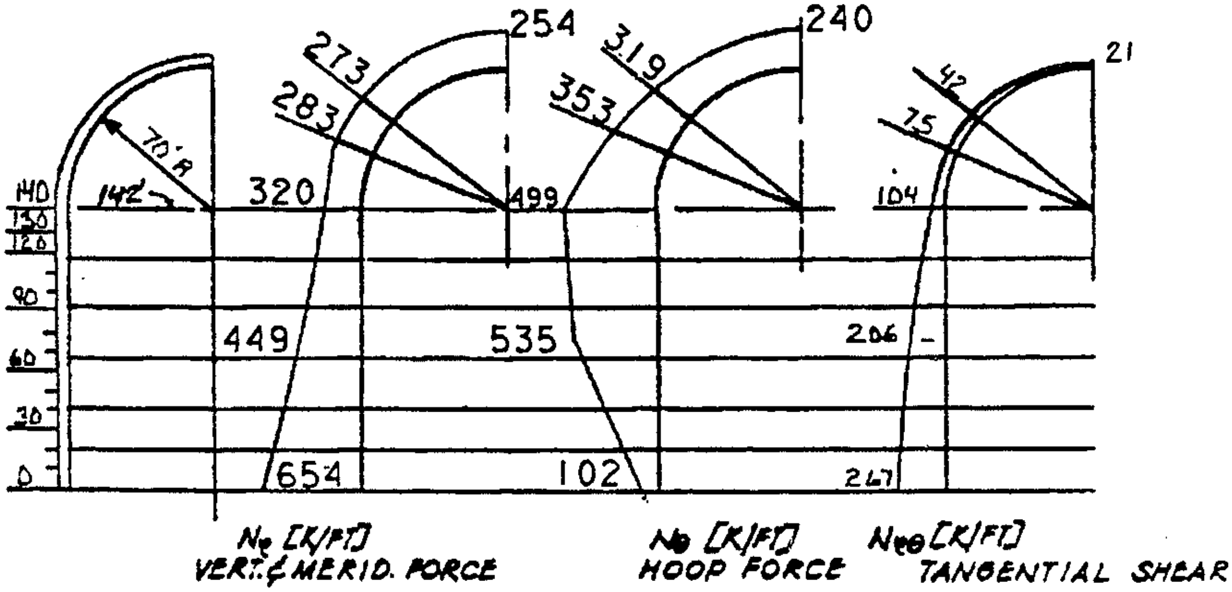
FORCES DUE TO LOAD CONDITION (3) U = 1.0D ± .05D + 1.0P + 1.0T + 1.0DDE

SCHEMATIC NOT TO SCALE

FSAR UPDATE

UNITS 1 AND 2 DIABLO CANYON SITE

FIGURE 3.8-32 CONTAINMENT STRUCTURE MEMBRANE FORCES ACCIDENT CONDITION 3

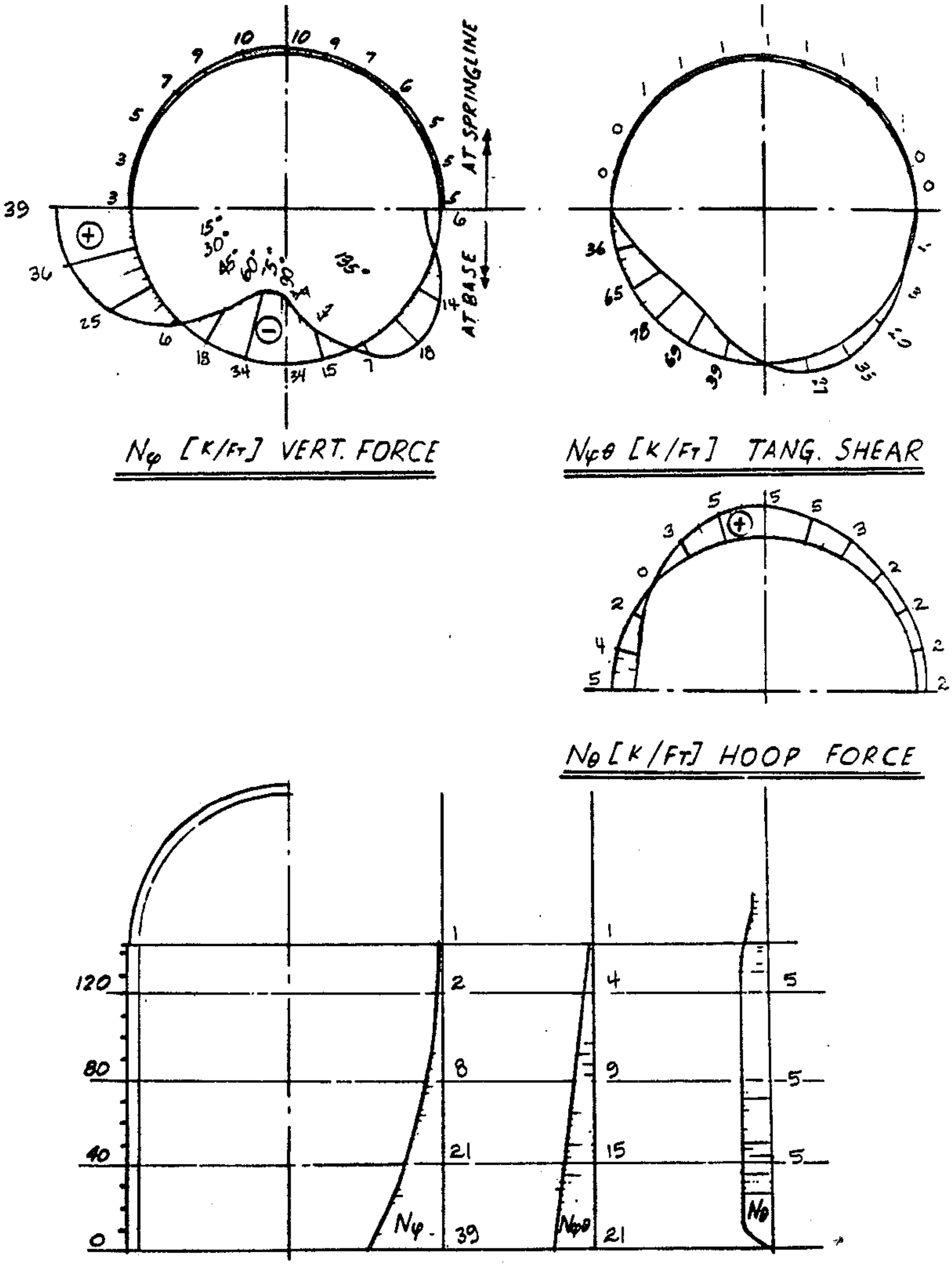


MEMBRANE FORCES

FORCES DUE TO LOAD CONDITION (4): $U = (1 \pm .05)\,D + P_A + T + HE$

SCHEMATIC NOT TO SCALE

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.8-33 CONTAINMENT STRUCTURE MEMBRANE FORCES ACCIDENT CONDITION 4

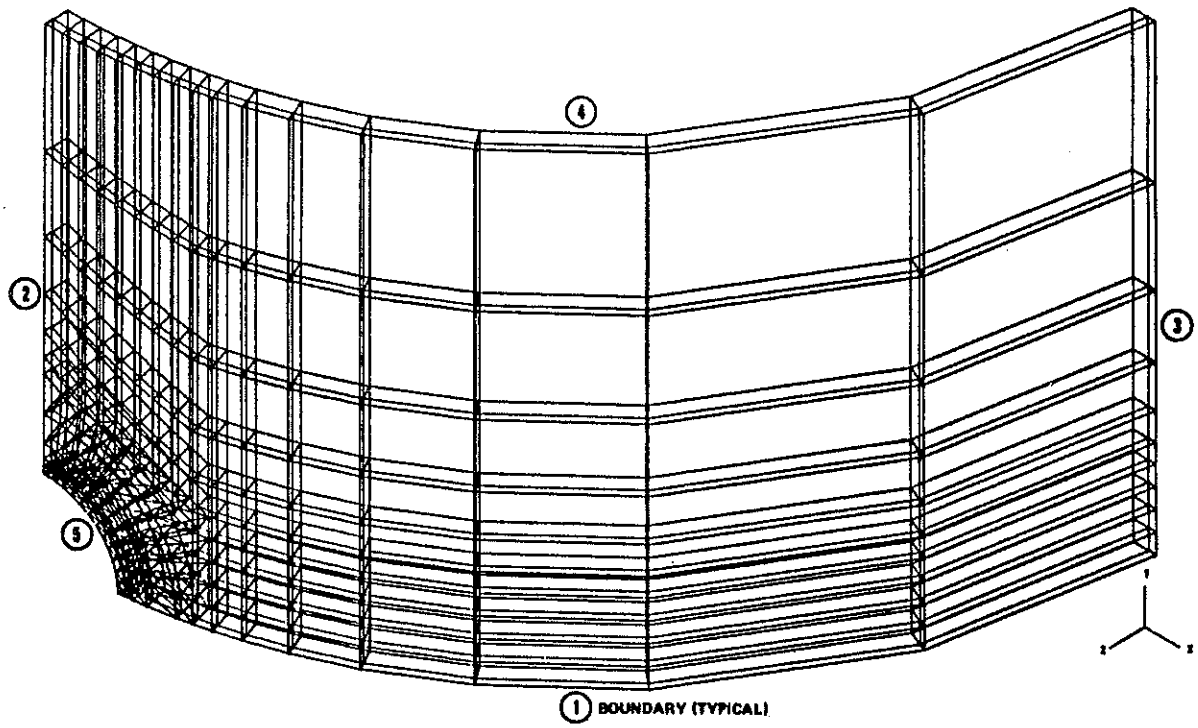


MEMBRANE FORCES DUE TO 80 MPH WIND

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-34
CONTAINMENT STRUCTURE
MEMBRANE FORCES
WIND LOAD



FSAR UPDATE

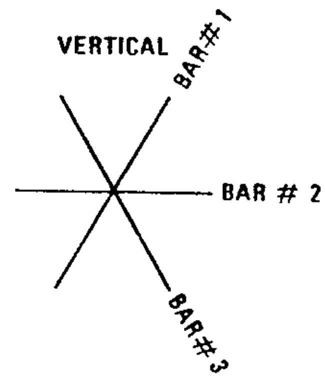
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-35
CONTAINMENT STRUCTURE
EQUIPMENT HATCH ANALYTICAL MODEL
ISOMETRIC VIEW

CRACKED SECTION

		CONDITION (a) C = 1.0D + 0.05D + 1.5P + 1.0T "							
		LINER NOT CONSIDERED			LINER CONSIDERED				
		REBAR STRESSES			REBAR STRESSES			LINER STRESS	
	ELEVATION (ABOVE BASE SLAB)	1	2	3	1	2	3	σ_{MAX}	σ_{MIN}
	ALLOWABLE STRESS	57.0	57.0	57.0	57.0	57.0	57.0		
DOME	212				42.8	42.8	42.8	-5.1	-5.1
DOME	185				42.8	44.5	42.8	-3.4	-5.2
DOME	169				42.3	41.0	42.3	-5.6	-7.0
CYLINDER	142	38.7	52.6	38.7	42.2	50.3	42.2	2.1	-6.5
CYLINDER	83	34.3	54.4	34.3	39.7	51.9	39.7	2.7	-10.2
CYLINDER	0	19.0	0	19.0	31.6	0	31.6	-23.8 (*)	-52.7 (*)

(*) Maximum strain levels for the liner plate are within acceptable limits.



ALL STRESSES .IN HIPS/SQUARE INCH

MINUS SIGN INDICATES COMPRESSION

FSAR UPDATE

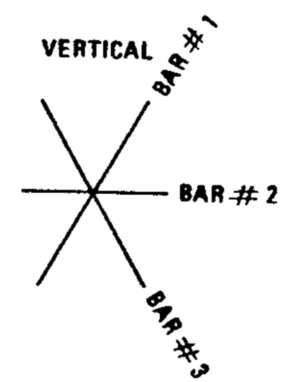
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-37
CONTAINMENT STRUCTURE
EXTERIOR SHELL STRESSES
ACCIDENT CONDITION 1

CRACKED SECTION — LINER CONSIDERED

CONDITION		$U = 1.0D \pm 0.05D + 1.25P + 1.0T' + 1.25DE$					$U = 1.0D \pm 0.05D + 1.0P + 1.0T' + 1.0 DDE$				
		REBAR STRESSES			LINER STRESS		REBAR STRESSES			LINER STRESS	
	ALLOWABLE STRESS ELEVATION (ABOVE BASE SLAB)	1	2	3	σ_{MAX}	σ_{MIN}	1	2	3	σ_{MAX}	σ_{MIN}
		57.0	57.0	57.0			57.0	57.0	57.0		
DOME	212	38.7	38.3	37.7	-8.4	-8.5	32.1	31.6	30.9	-8.6	-8.6
DOME	185	41.7	40.7	35.5	-5.9	-8.1	36.0	34.1	27.9	-6.0	-8.2
DOME	169	42.7	37.6	34.2	-9.0	-8.0	37.6	31.7	26.2	-8.1	-8.3
CYLINDER	142	45.2	44.9	32.9	-1.6	-7.8	41.0	37.5	24.2	-2.4	-7.4
CYLINDER	83	50.1	45.1	31.0	-.9	-5.7	48.9	36.7	22.7	-2.0	-2.9
CYLINDER	0	43.8	0	29.3	-10.4 (*)	-47.2 (*)	46.6	0	22.9	-4.8 (*)	-39.1 (*)

(*) Maximum strain levels for the liner plate are within acceptable limits.



ALL STRESSES IN KIPS/SQUARE INCH
MINUS SIGN INDICATES COMPRESSION

NOTE:
REBAR STRESSES FOR REBAR IN OUTER LAYER ONLY.

FSAR UPDATE

UNITS 1 AND 2 DIABLO CANYON SITE

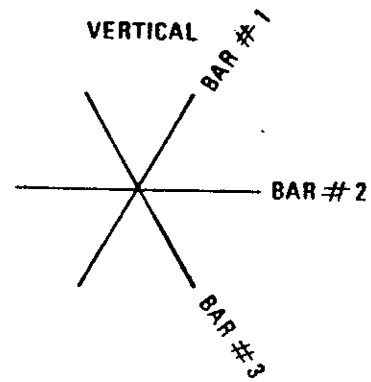
FIGURE 3.8-38

CONTAINMENT STRUCTURE EXTERIOR SHELL STRESSES ACCIDENT CONDITIONS 2 AND 3

CRACKED SECTION

ALLOWABLE STRESS ELEVATION (FT) (ABOVE BASE SLAB)		CONDITION (c) C = 1.0D ± 0.05D + 1.0P + 1.0T + 1.0 HE						
		REBAR STRESSES *				LINER PLATE * STRESS		
		1	2	3		MAX	MIN	
		63.5	63.5	63.5				
DOME	213	33.6	31.4	32.2		-6.4	-8.6	WITH LINER PLATE
	185	37.7	34.7	28.4		-4.9	-6.7	WITH LINER PLATE
	169	39.6	31.9	26.1		-6.7	-7.7	WITH LINER PLATE
CYLINDER	142	44.2	36.8	23.0		-2.6	-6.0	WITH LINER PLATE
	83	53.4	37.5	18.4		-1.2	-2.8	WITH LINER PLATE
	83	61.2	38.1	11.0				WITHOUT LINER PLATE
	0	49.5	0	24.8		-1.0 (*)	-38.1 (*)	WITH LINER PLATE

(*) Maximum strain levels for the liner plate are within acceptable limits.



ALL STRESSES IN KIPS/SQUARE INCH
MINUS SIGN INDICATES COMPRESSION

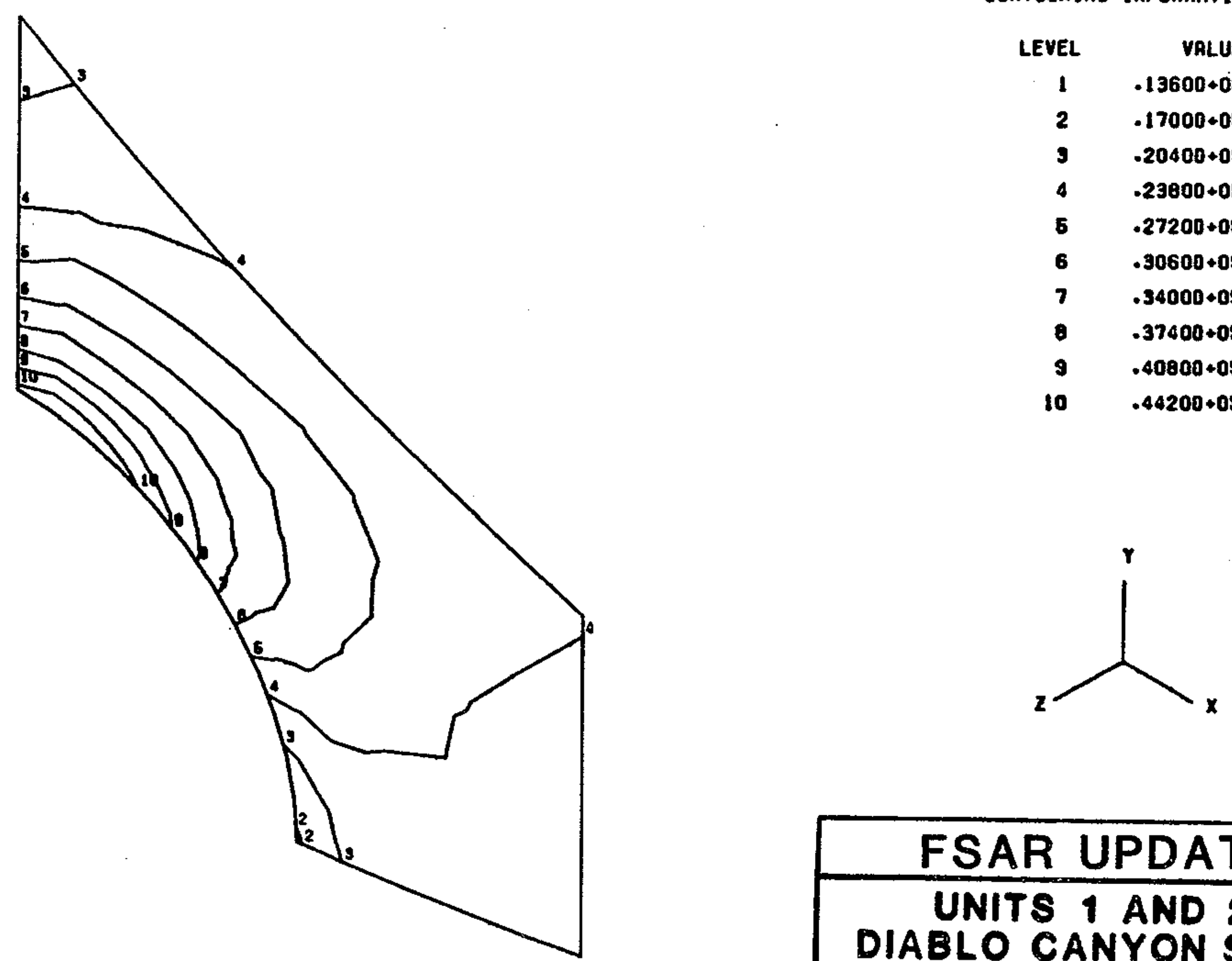
* STRESSES ARE MAXIMUM OR MINIMUM AT ANY SECTION:

FSAR UPDATE

**UNITS 1 AND 2
DIABLO CANYON SITE**

FIGURE 3.8-39

CONTAINMENT STRUCTURE, EXTERIOR SHELL STRESSES – ACCIDENT CONDITION 4



CONTOURING INFORMATION

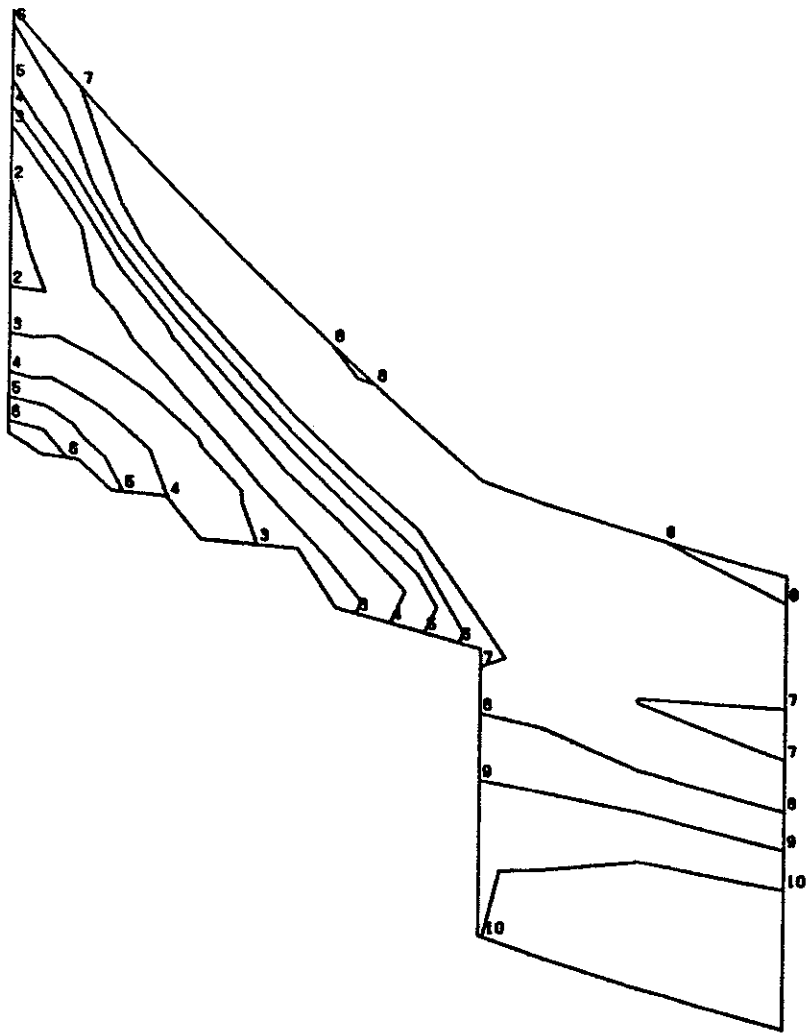
LEVEL	VALUE
1	.13600+05
2	.17000+05
3	.20400+05
4	.23800+05
5	.27200+05
6	.30600+05
7	.34000+05
8	.37400+05
9	.40800+05
10	.44200+05

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

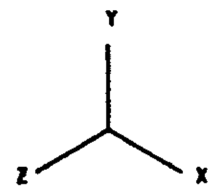
FIGURE 3.8-40

EQUIPMENT HATCH HEXAGONAL PLATE MAXIMUM STRESSES (1.05D + 1.5P + T")



CONTOURING INFORMATION

LEVEL	VALUE
1	.15200+05
2	.19000+05
3	.22800+05
4	.26600+05
5	.30400+05
6	.34200+05
7	.38000+05
8	.41800+05
9	.45600+05
10	.49400+05

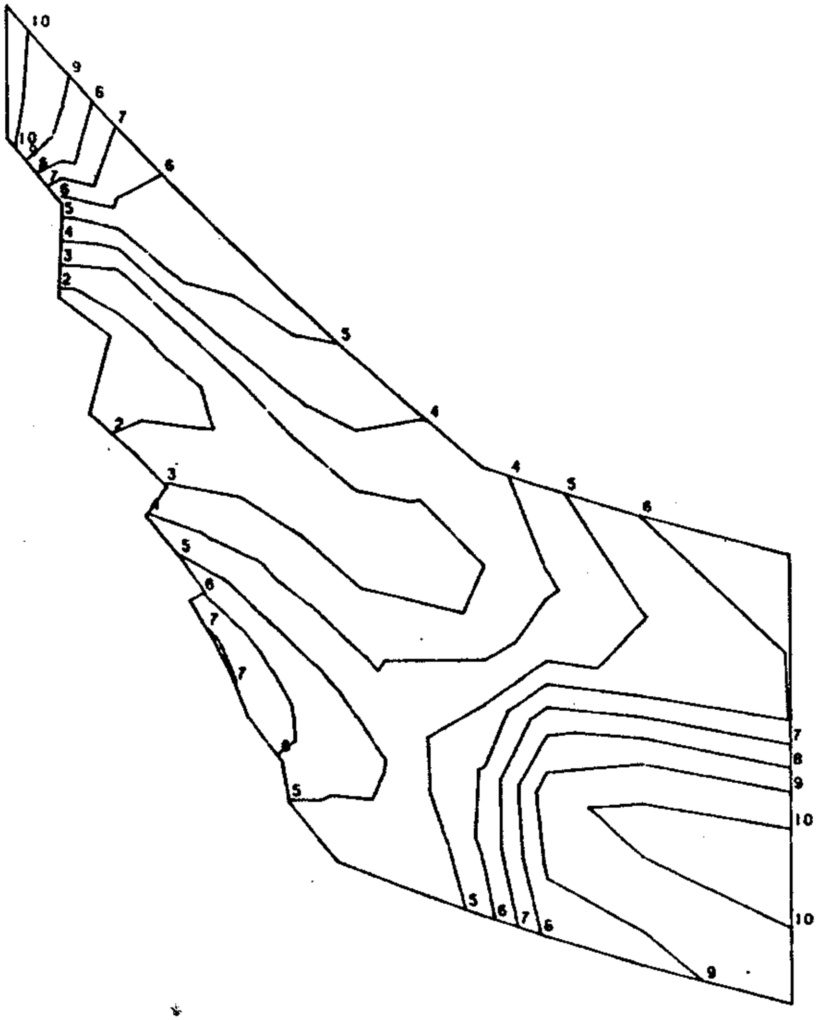


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

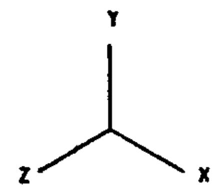
FIGURE 3.8-41

EQUIPMENT HATCH HOOP REINFORCEMENT STRESSES (1.05D + 1.5P + T'')



CONTOURING INFORMATION

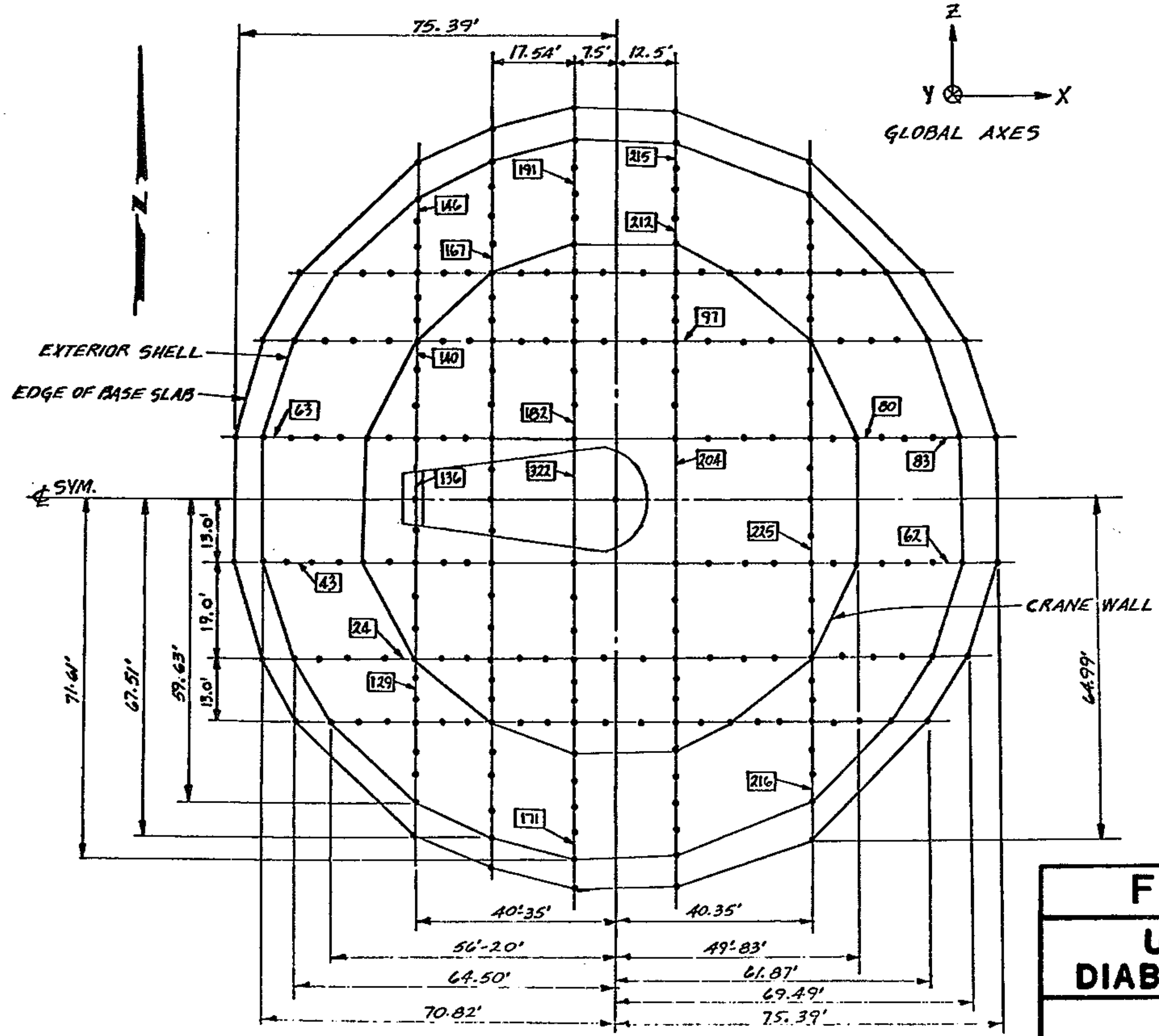
LEVEL	VALUE
1	.96000+04
2	.12000+05
3	.14400+05
4	.16800+05
5	.19200+05
6	.21600+05
7	.24000+05
8	.26400+05
9	.28800+05
10	.31200+05



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-42
EQUIPMENT HATCH DIAGONAL REINFORCEMENT STRESSES (1.05D + 1.5P + T'')

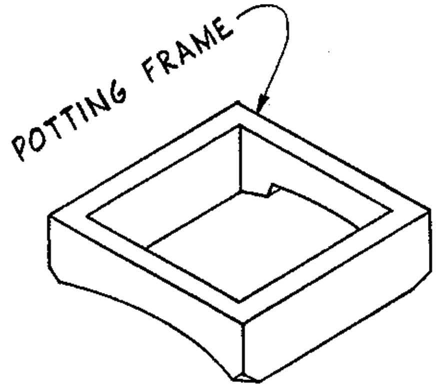


FSAR UPDATE

UNITS 1 AND 2 DIABLO CANYON SITE

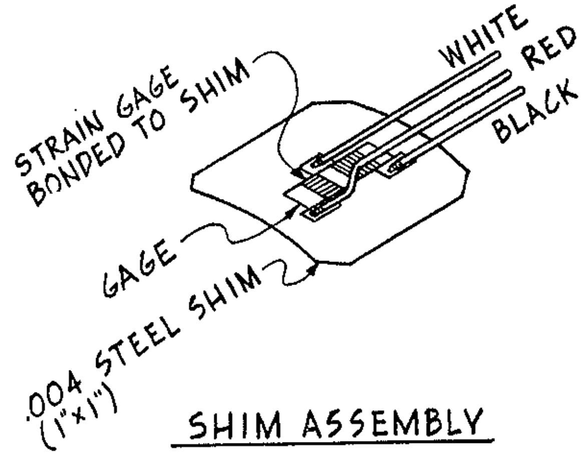
FIGURE 3.8-43

CONTAINMENT BASE SLAB MODEL

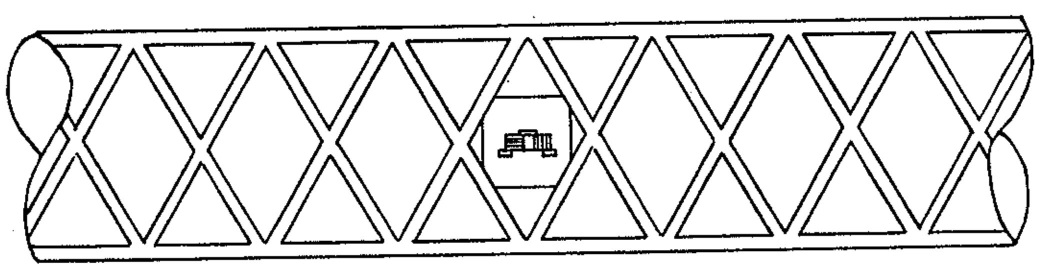


NOTES FOR FIELD INSTALLATION

1. REMOVE MILL SCALE AND POLISH REBAR SURFACE INSIDE OF DIAMOND AREA
2. BOND SHIM ASSEMBLY TO POLISHED REBAR
3. PLACE SEALANT AND PROTECTIVE COVER OVER SHIM ASSEMBLY.



SHIM ASSEMBLY

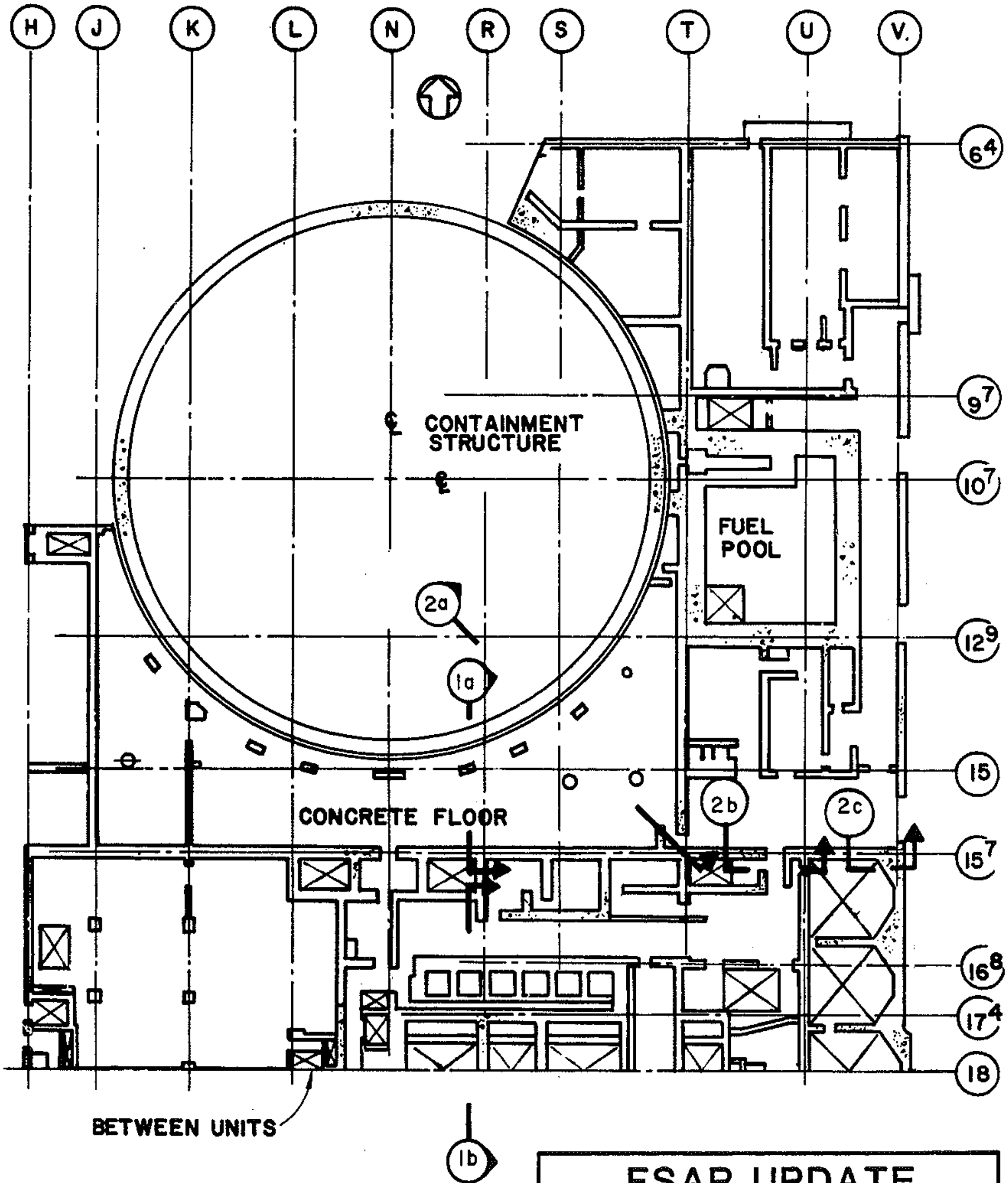


FSAR UPDATE

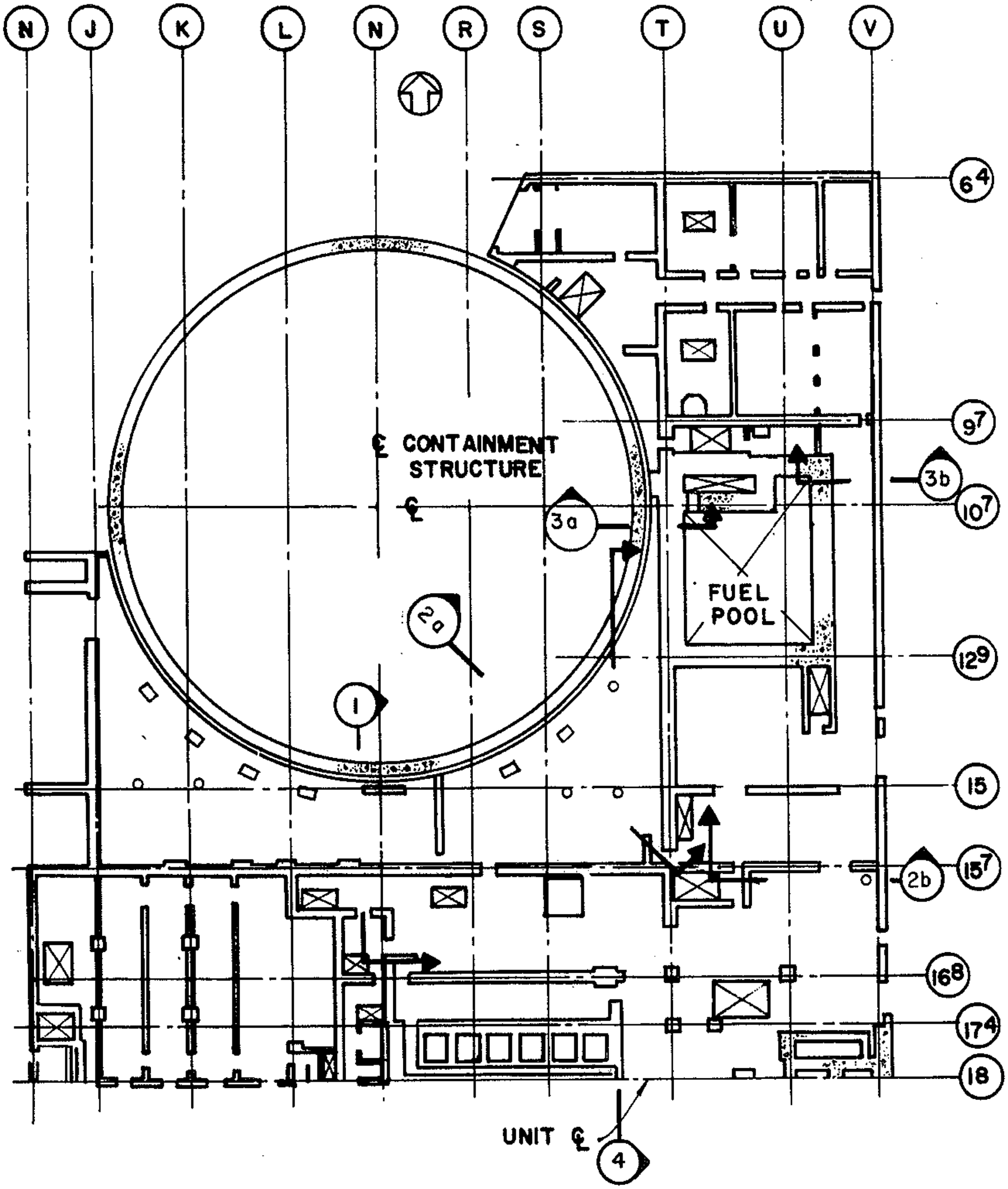
UNITS 1 AND 2 DIABLO CANYON SITE

FIGURE 3.8-44

CONTAINMENT STRUCTURE TYPICAL REBAR STRAIN GAUGE



FSAR UPDATE
UNIT 1 **DIABLO CANYON SITE**
FIGURE 3.8-60 AUXILIARY BUILDING FLOOR PLAN AT EL 100'-0"

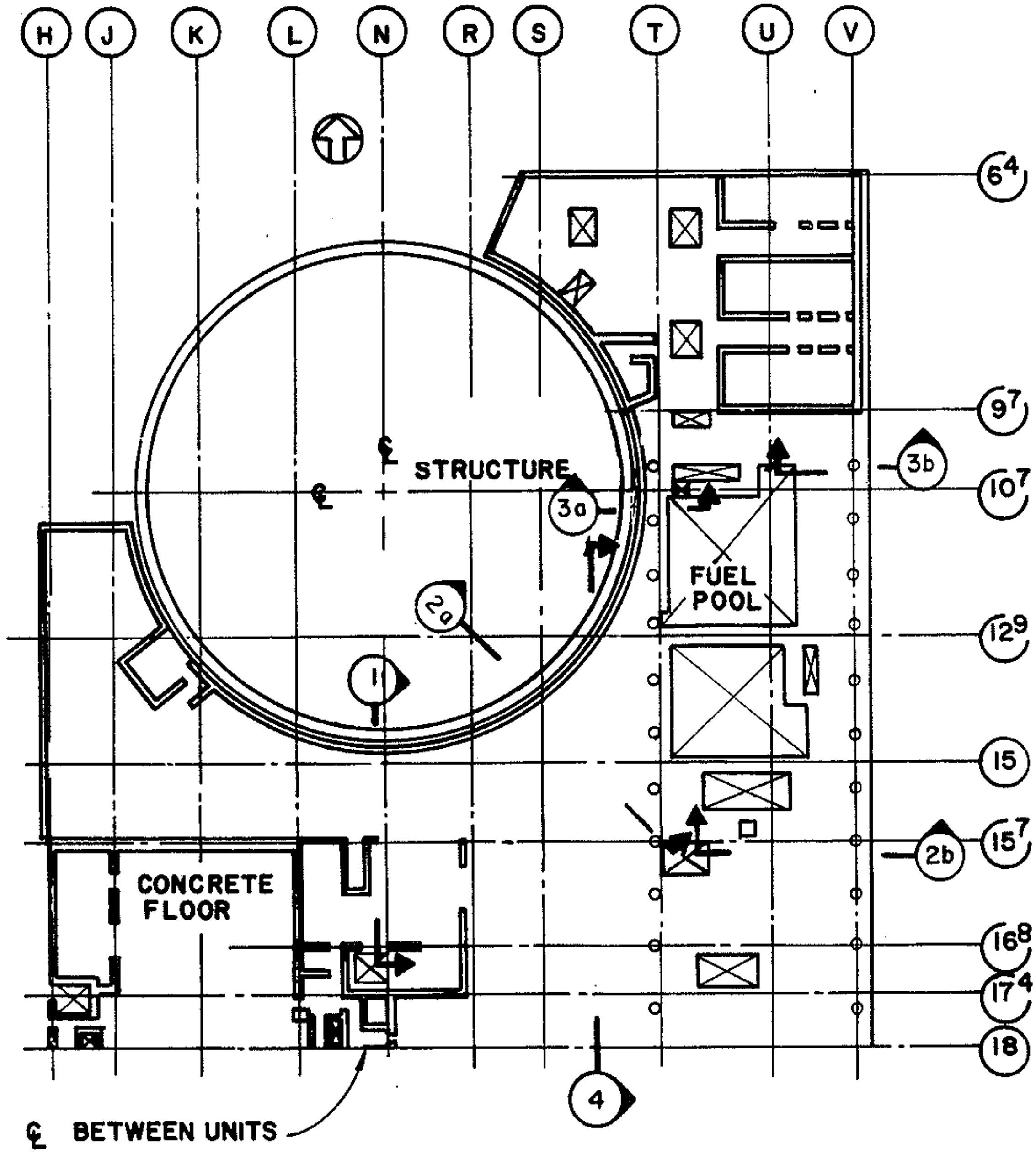


FSAR UPDATE

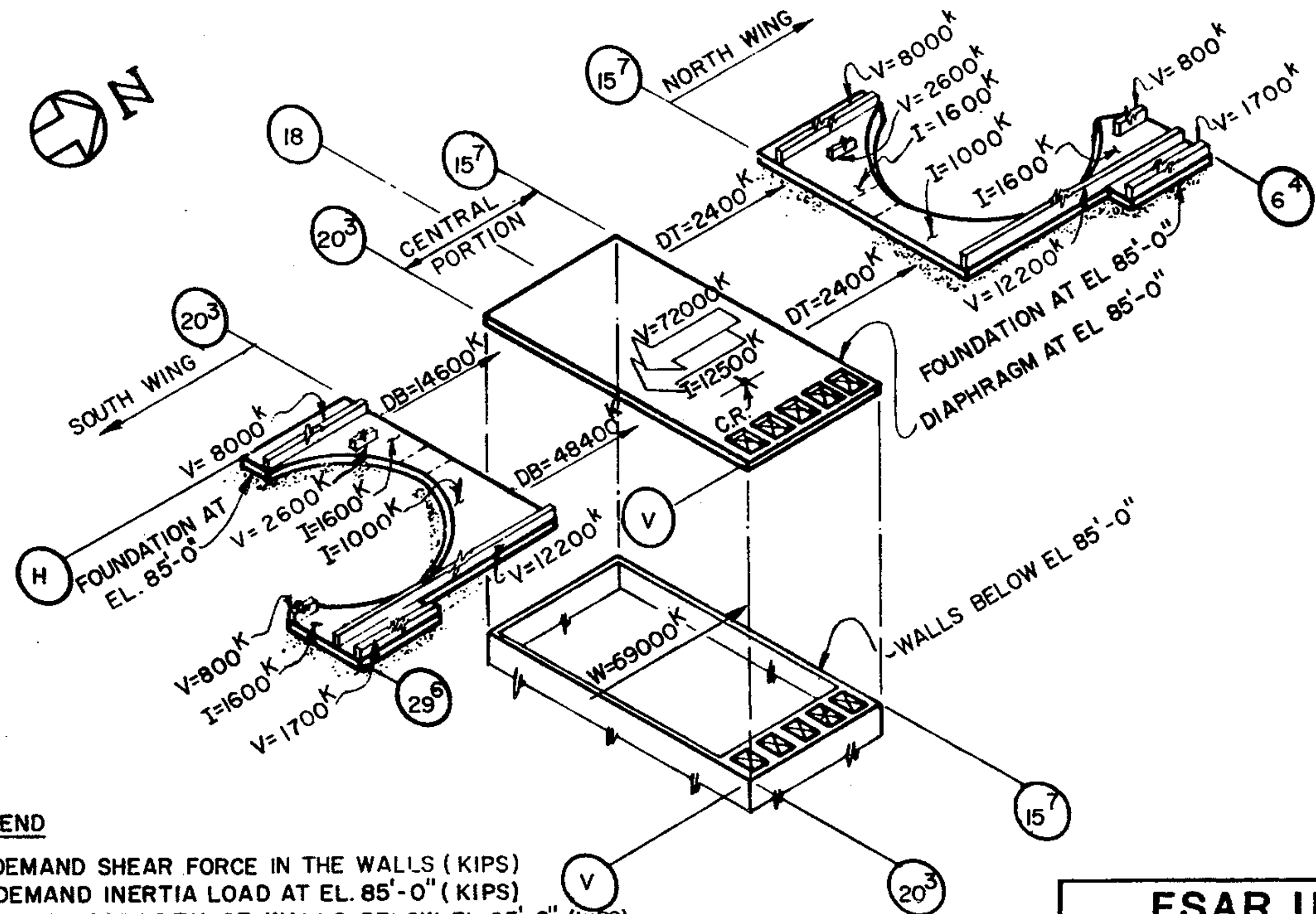
UNIT 1
DIABLO CANYON SITE

FIGURE 3.8-61

AUXILIARY BUILDING
FLOOR PLAN AT EL 115'-0"



FSAR UPDATE
UNIT 1 **DIABLO CANYON SITE**
FIGURE 3.8-62 AUXILIARY BUILDING FLOOR PLAN AT EL 140'-0"



LEGEND

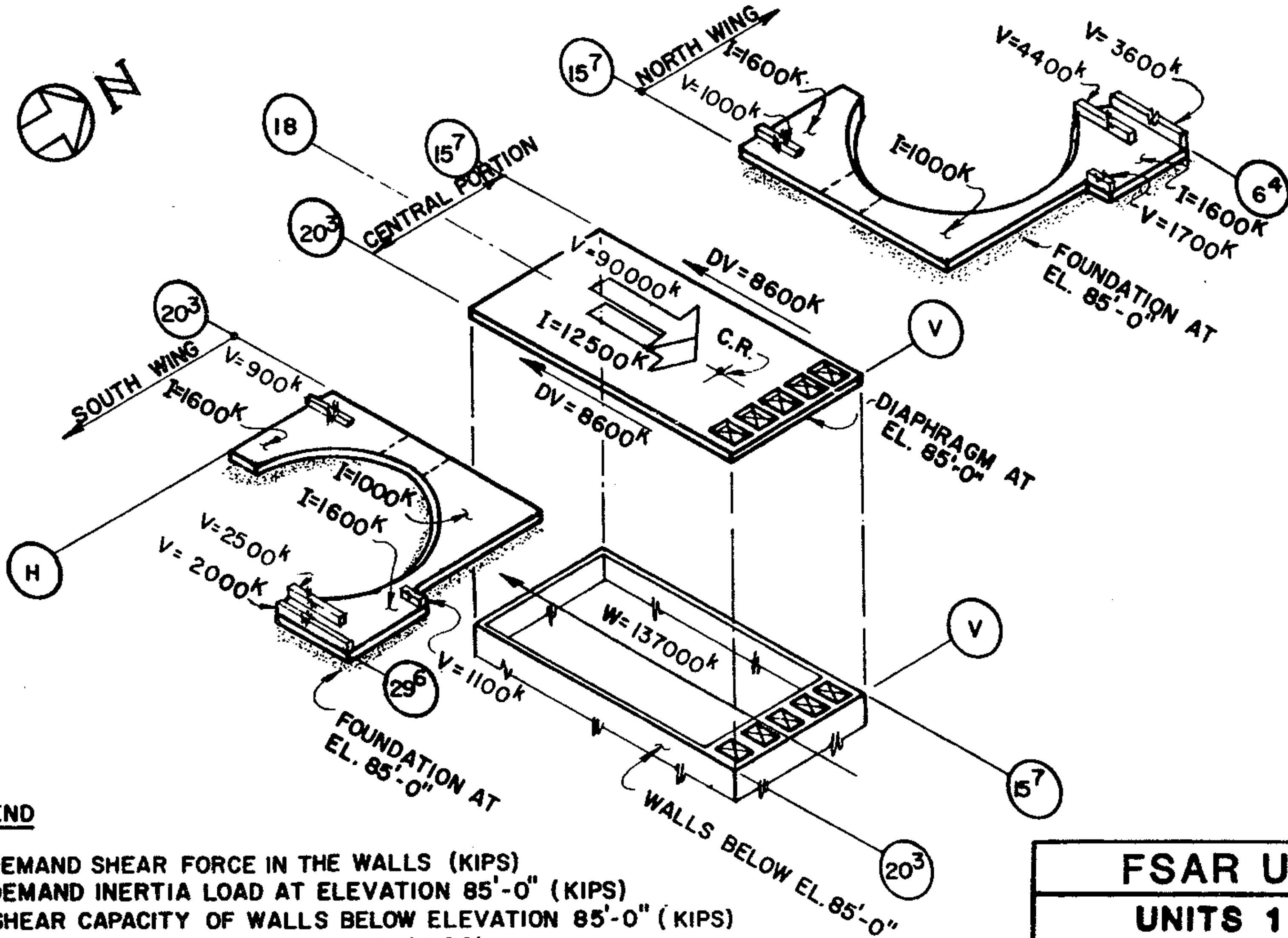
V = DEMAND SHEAR FORCE IN THE WALLS (KIPS)
I = DEMAND INERTIA LOAD AT EL. 85'-0" (KIPS)
W = SHEAR CAPACITY OF WALLS BELOW EL. 85'-0" (KIPS)
DT = CAPACITY THROUGH DIAPHRAGM REBAR TENSION (KIPS)
DB = CAPACITY THROUGH DIAPHRAGM BEARING (KIPS)

NOTE: DEMAND SHEARS IN WALLS WEST OF CENTER OF RIGIDITY CONSIDER DIRECT PLUS POSITIVE TORSIONAL SHEARS. THOSE IN WALLS EAST OF CENTER OF RIGIDITY CONSIDER ONLY DIRECT SHEARS.

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-63
AUXILIARY BUILDING
LOAD DISSIPATION TO FOUNDATION
HOSGRI N – S



LEGEND

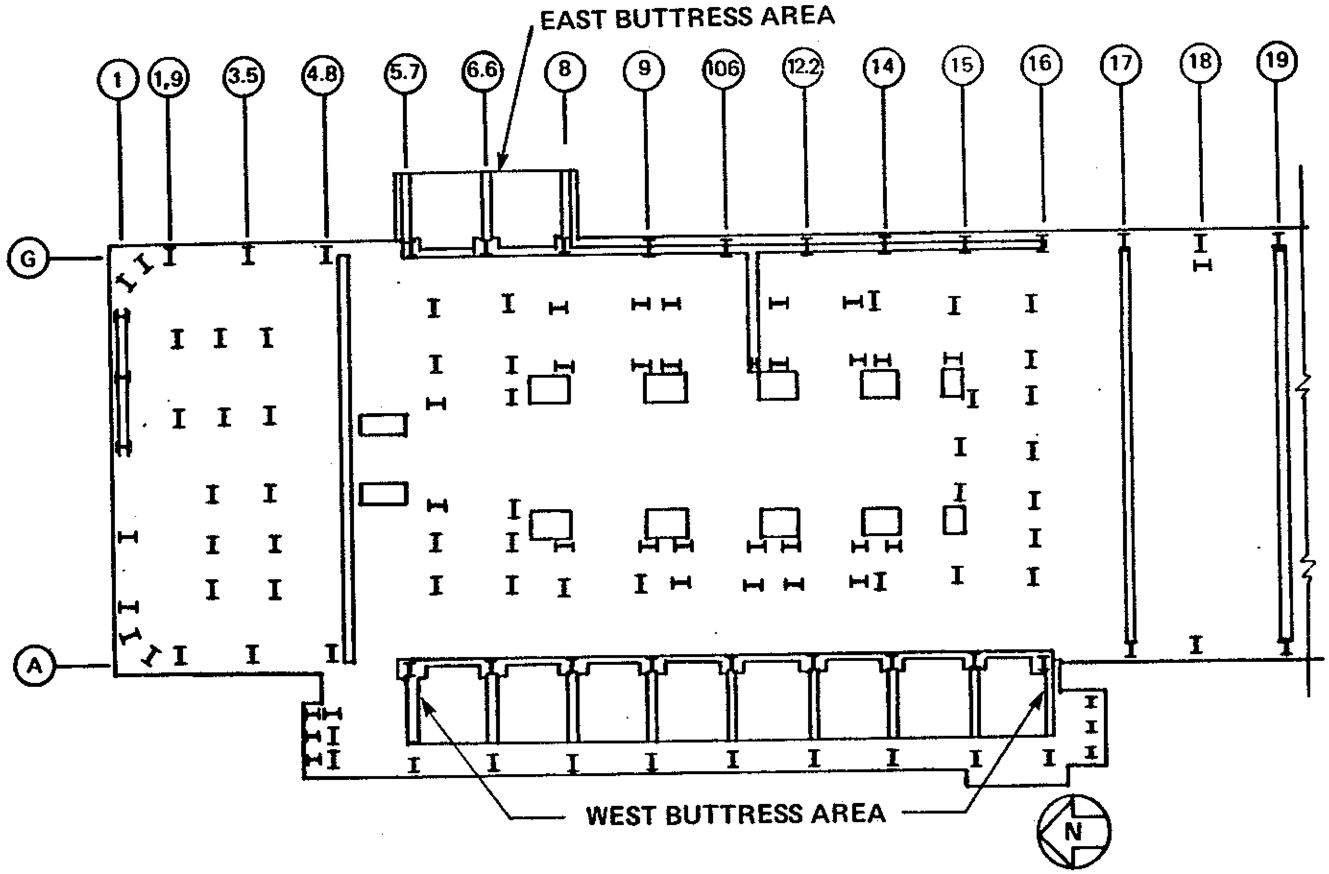
V= DEMAND SHEAR FORCE IN THE WALLS (KIPS)
I = DEMAND INERTIA LOAD AT ELEVATION 85'-0" (KIPS)
W= SHEAR CAPACITY OF WALLS BELOW ELEVATION 85'-0" (KIPS)
DV= SHEAR CAPACITY OF DIAPHRAGM (KIPS)

NOTE: WALLS NORTH OF LINE 18 CONSIDER DIRECT PLUS POSITIVE TORSIONAL EFFECT AND THOSE SOUTH OF LINE 18 CONSIDER ONLY DIRECT SHEARS.

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-64
AUXILIARY BUILDING
LOAD DISSIPATION TO FOUNDATION
HOSGRI E – W

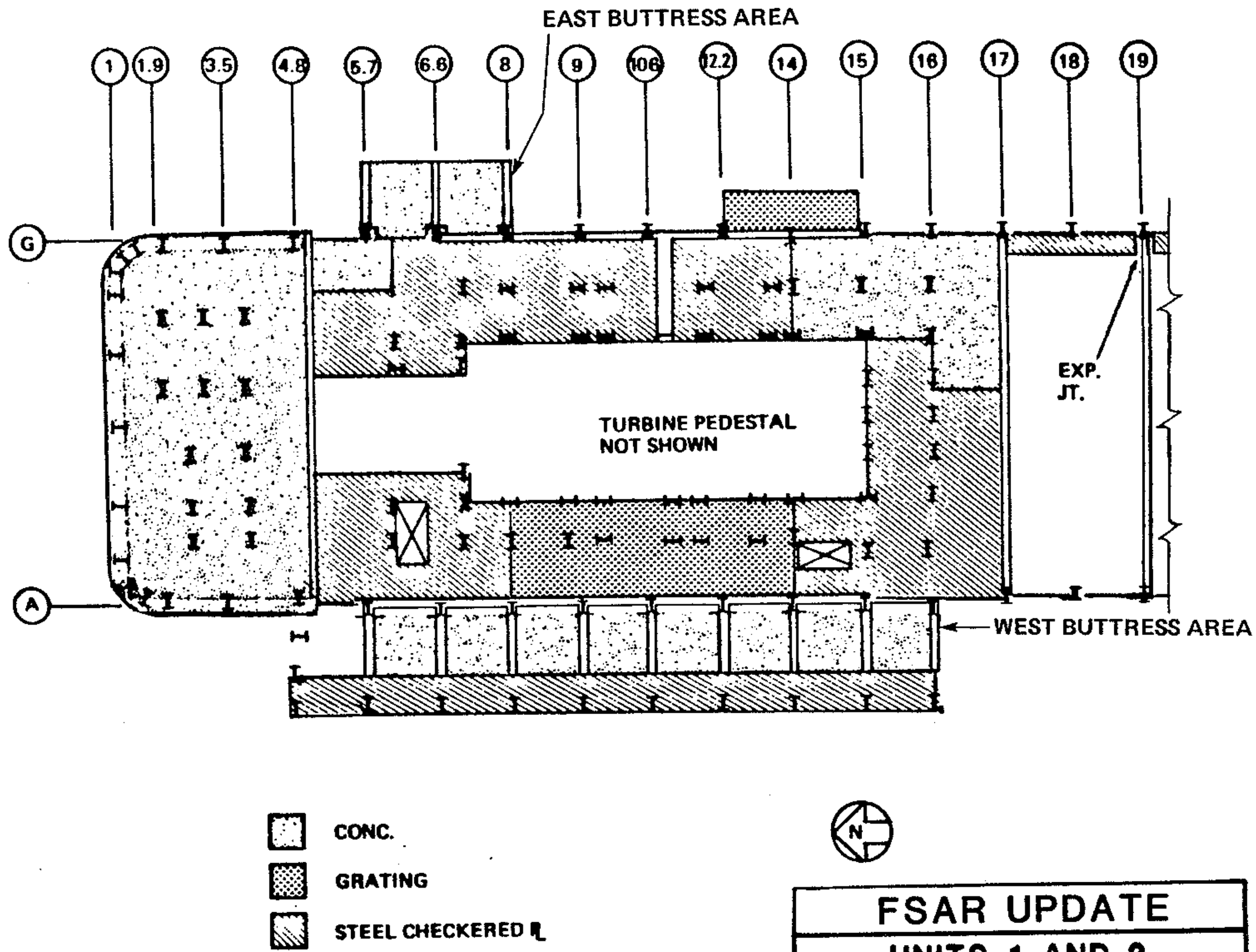


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8–66

TURBINE BUILDING
PLAN AT EL. 85'



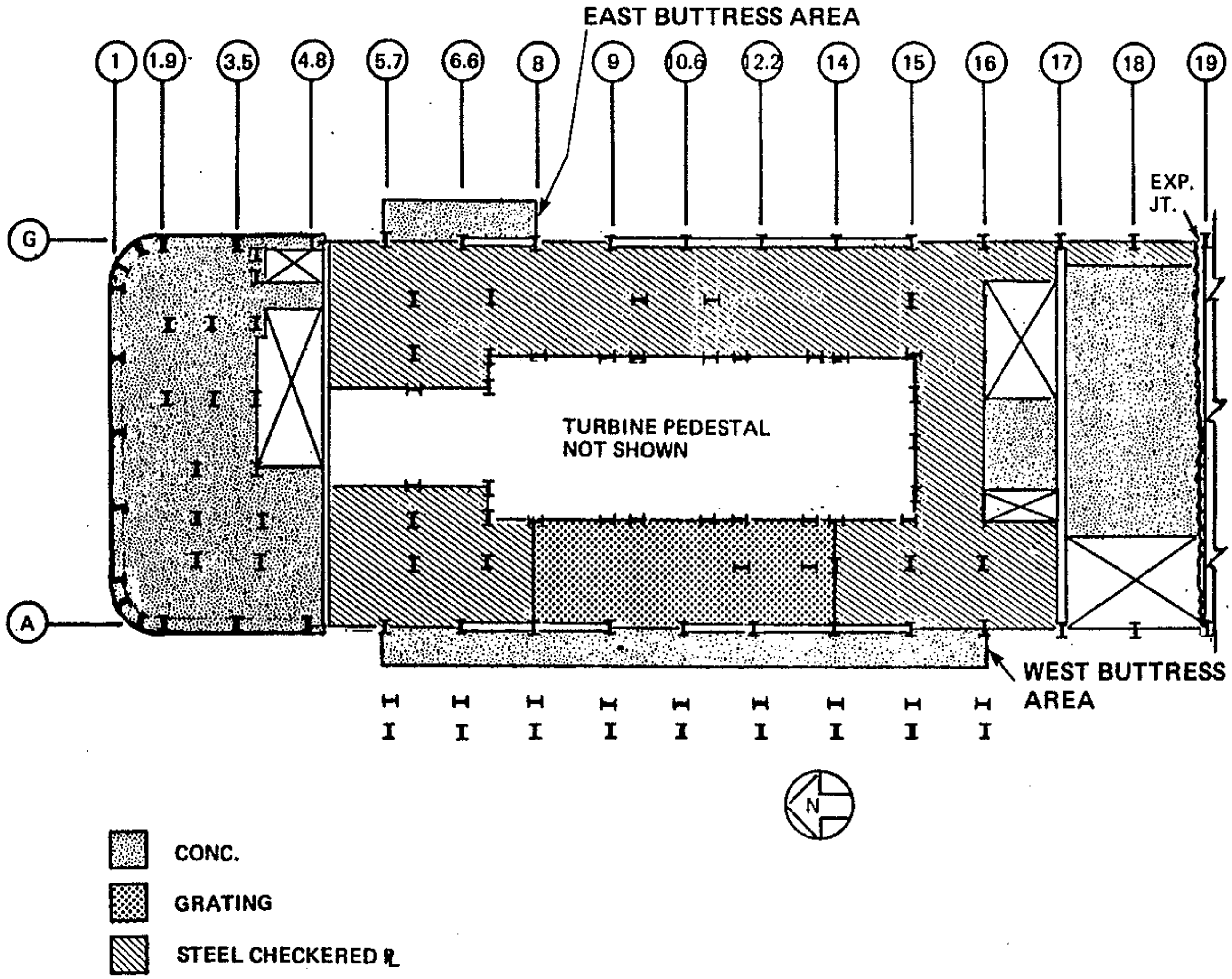
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8–67

TURBINE BUILDING
PLAN AT EL. 104'

Revision 11 November 1996

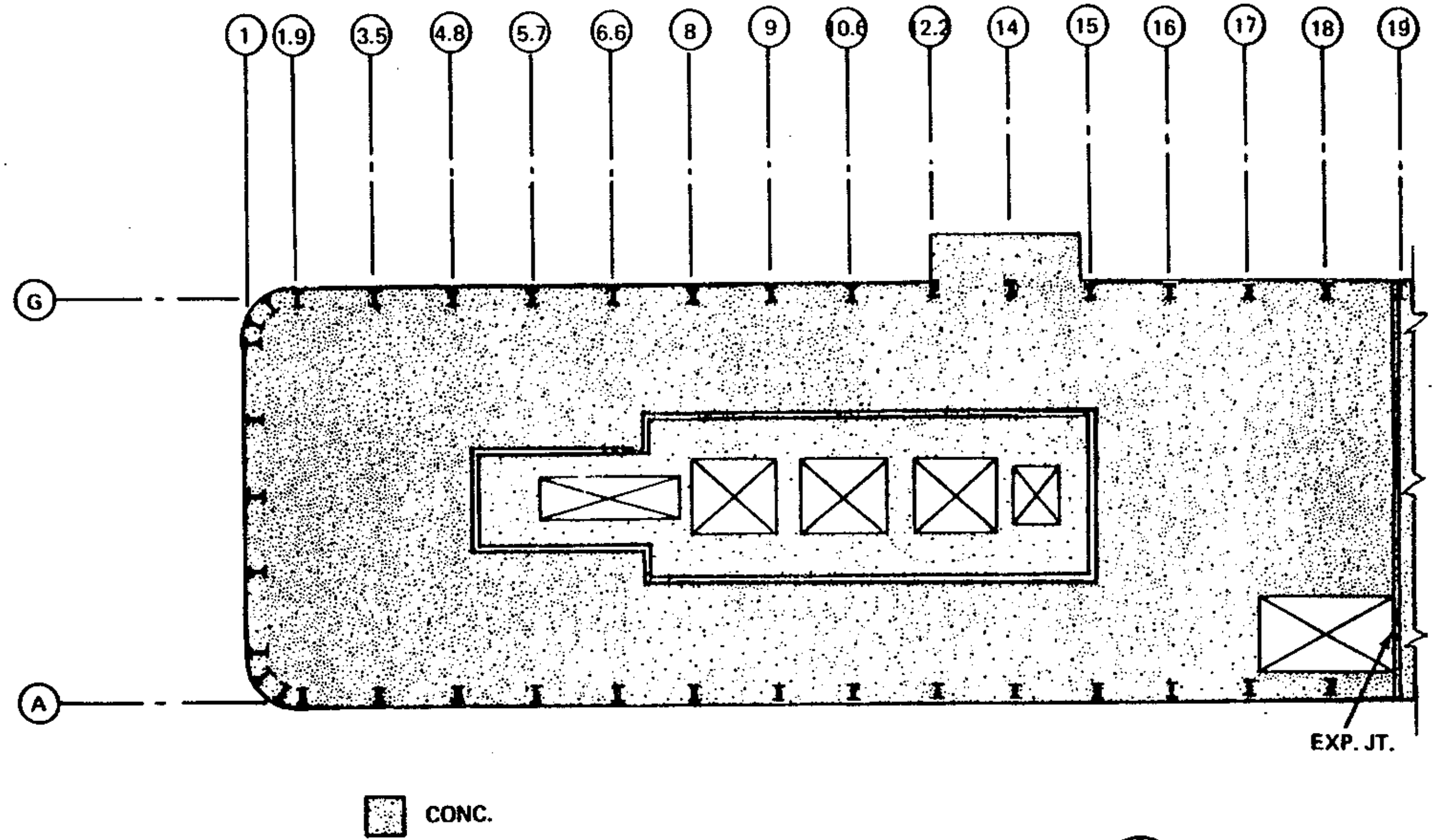


FSAR UPDATE

UNITS 1 AND 2 DIABLO CANYON SITE

FIGURE 3.8–68

TURBINE BUILDING PLAN AT EL. 119'



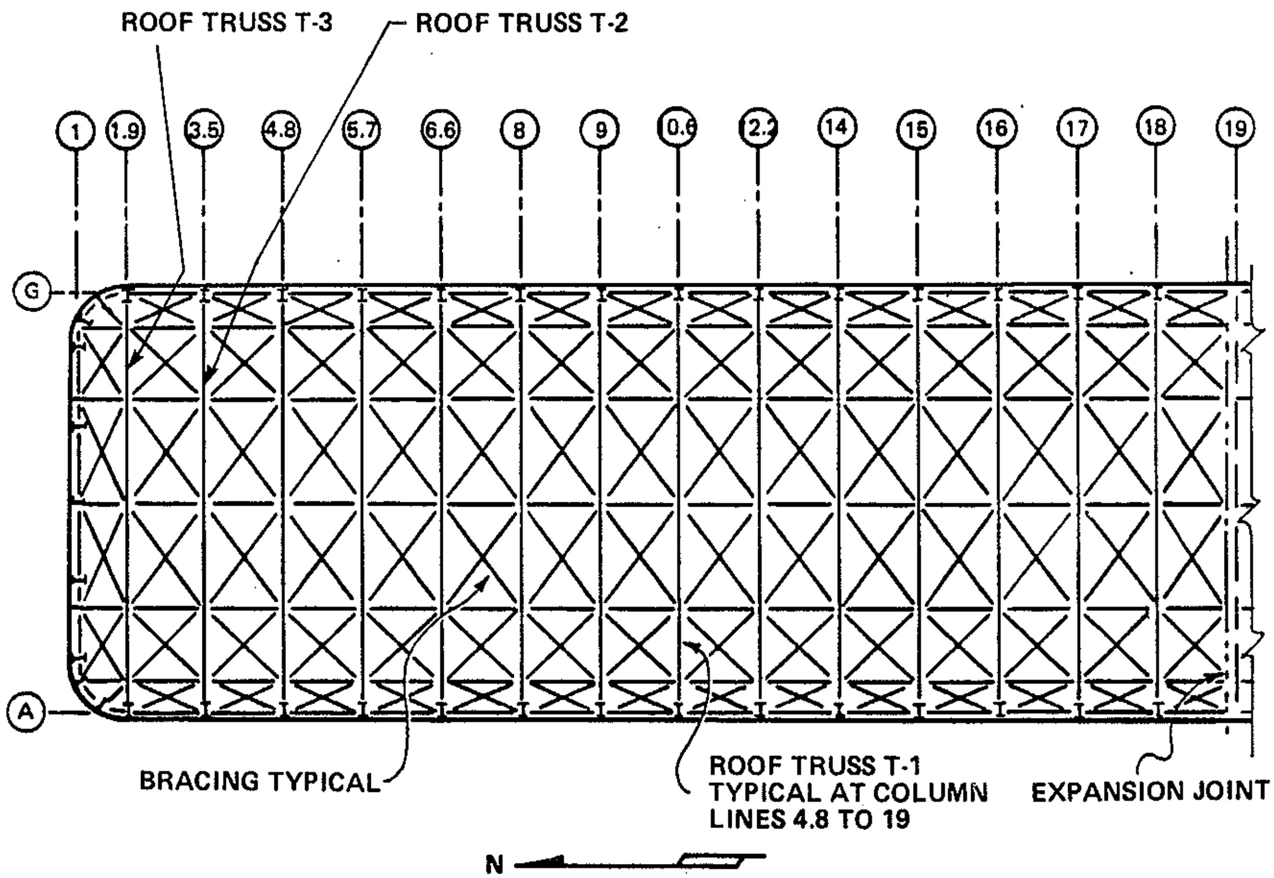
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8–69

TURBINE BUILDING
PLAN AT EL. 140'

Revision 11 November 1996

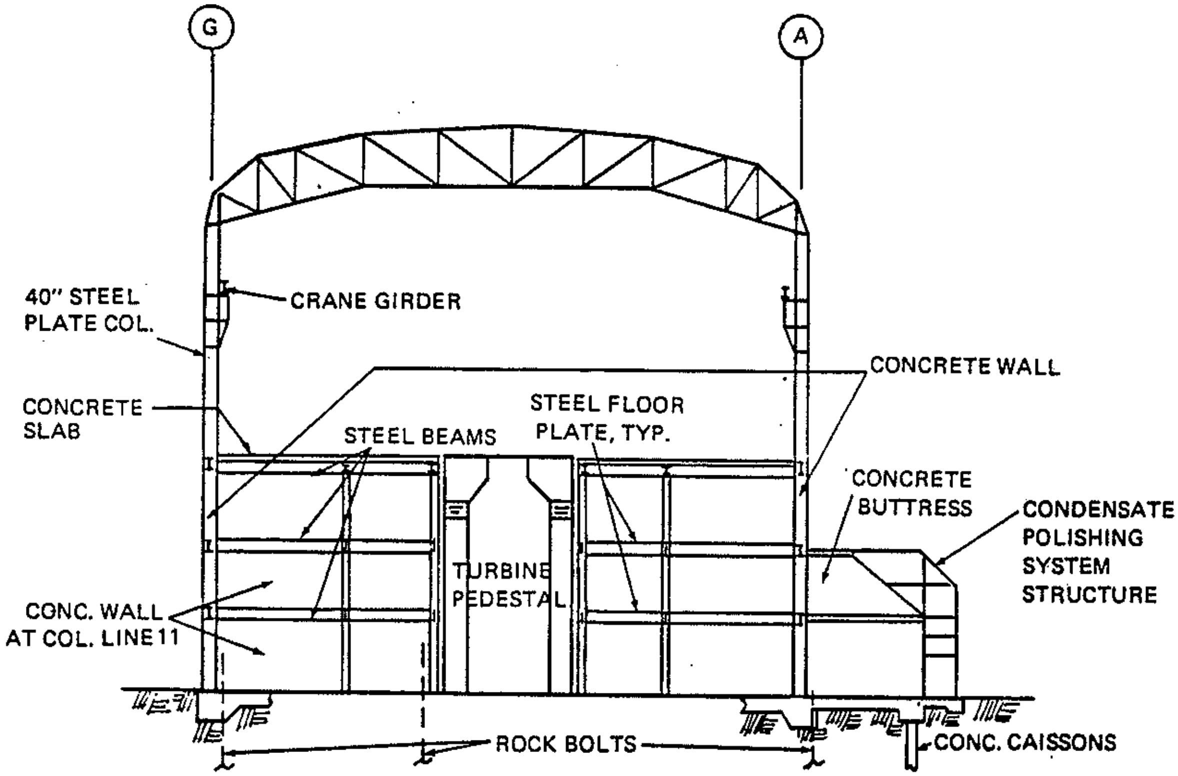


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

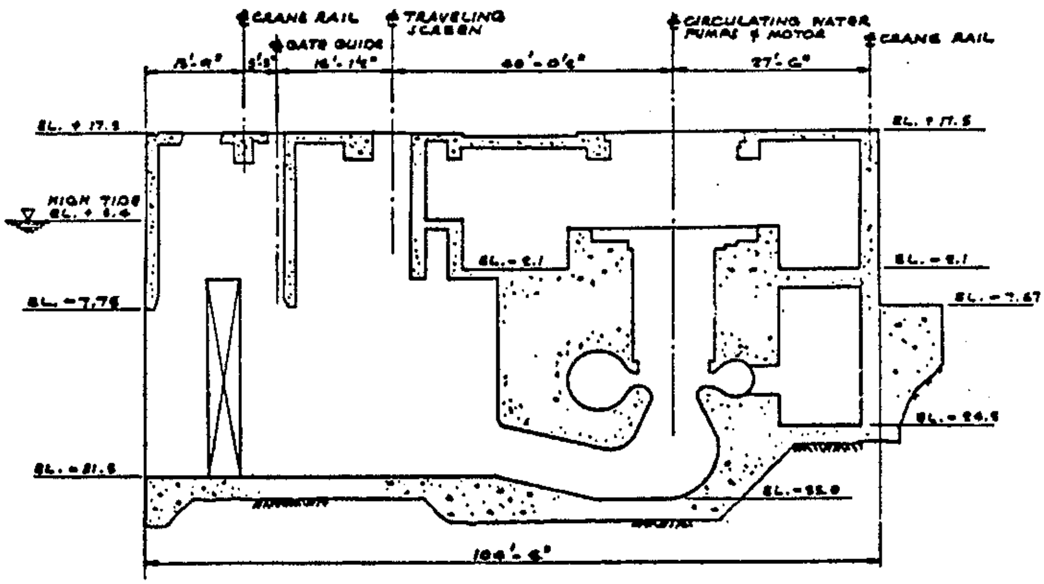
FIGURE 3.8–70

TURBINE BUILDING
PLAN AT LOWER CHORD OF
ROOF TRUSS



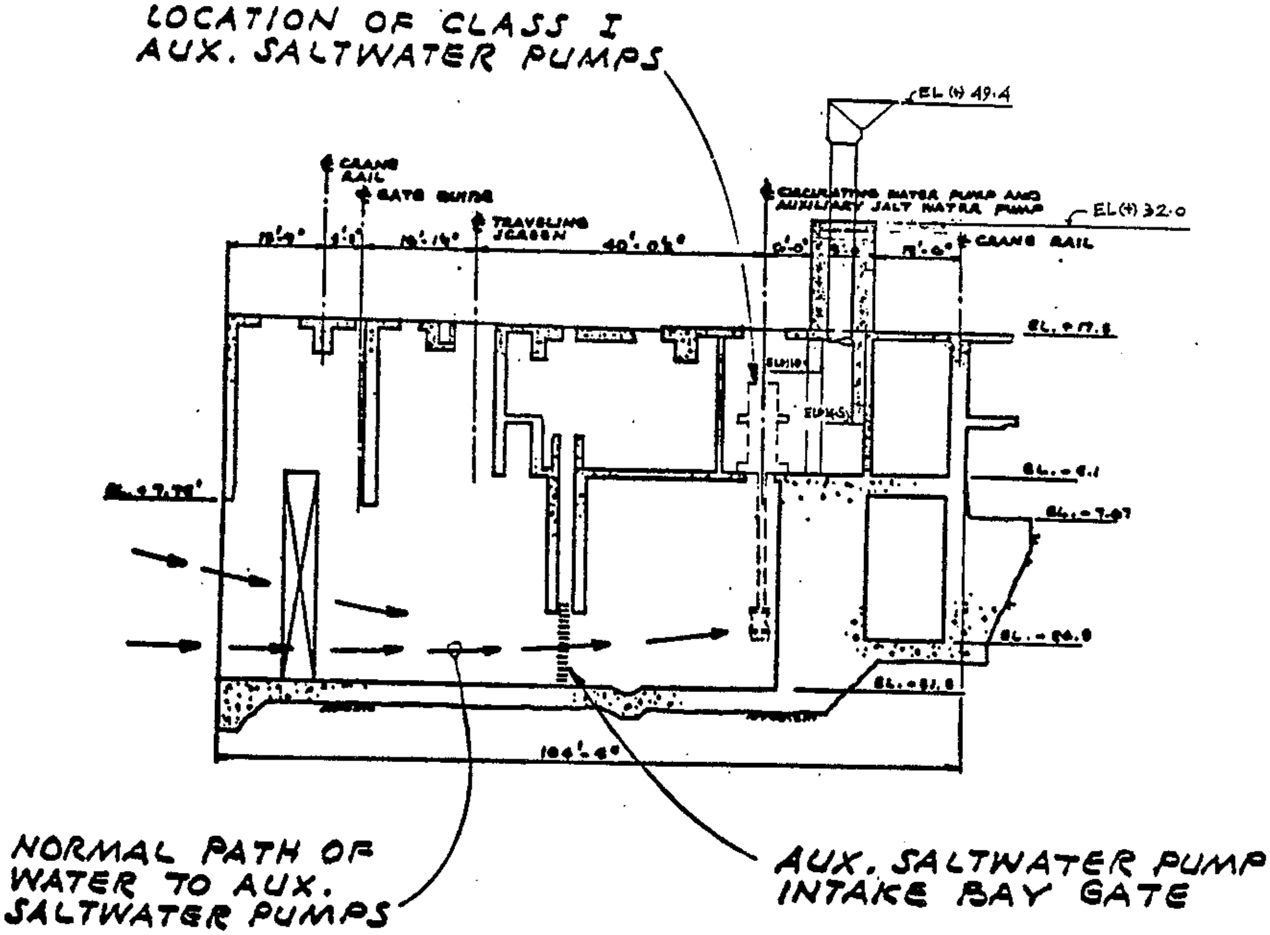
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.8–71 TURBINE BUILDING TYPICAL SECTION

Revision 11 November 1996

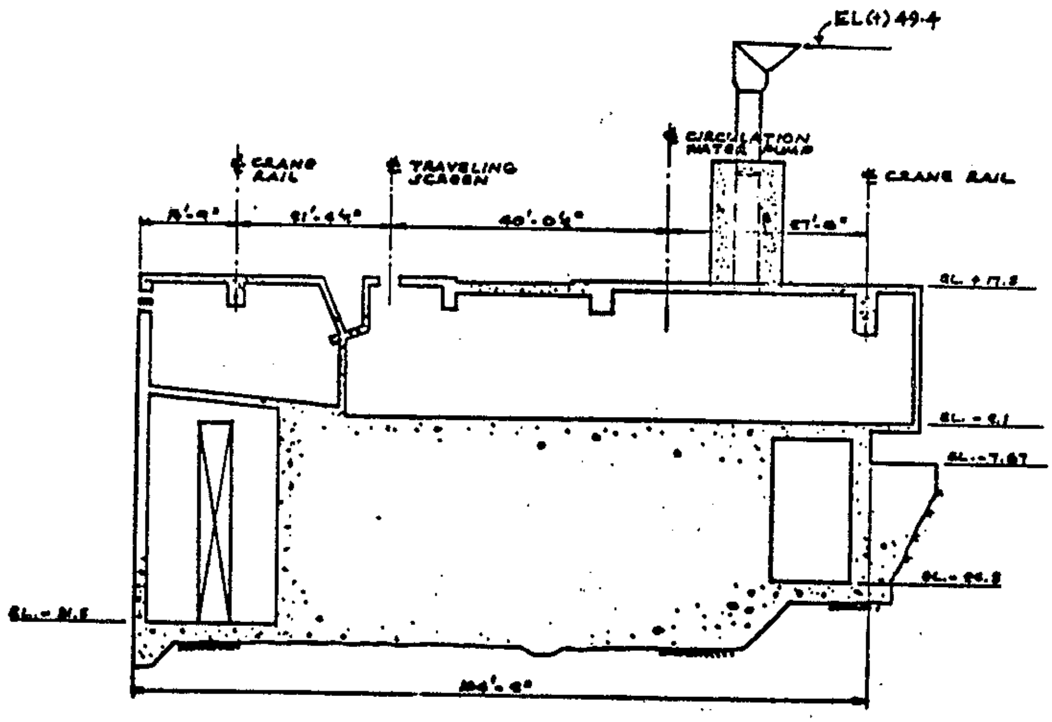


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.8–75 INTAKE STRUCTURE TRANSVERSE SECTION A

Revision 11 November 1996



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.8–76 INTAKE STRUCTURE TRANSVERSE SECTION B

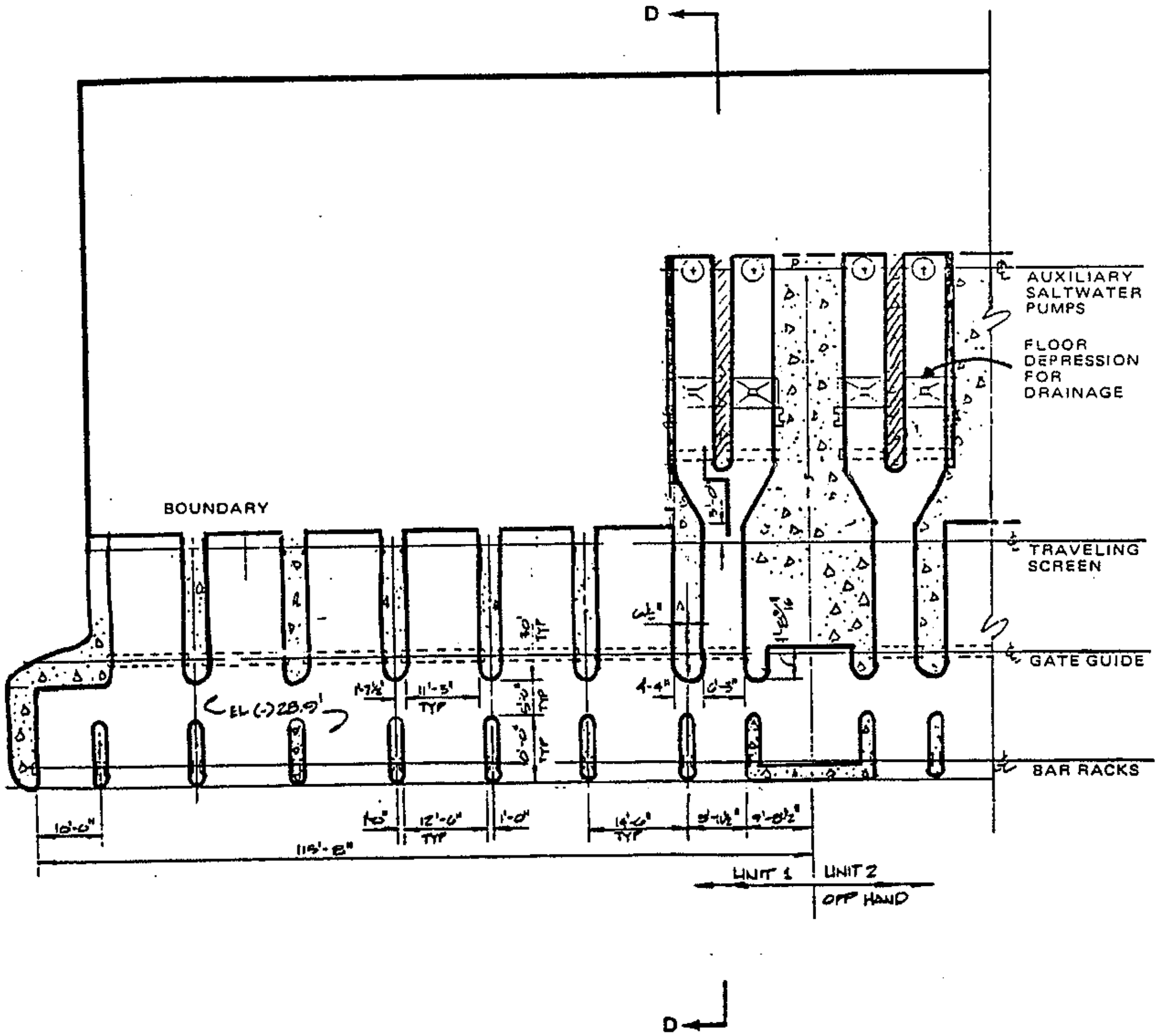


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-77

INTAKE STRUCTURE
TRANSVERSE SECTION C

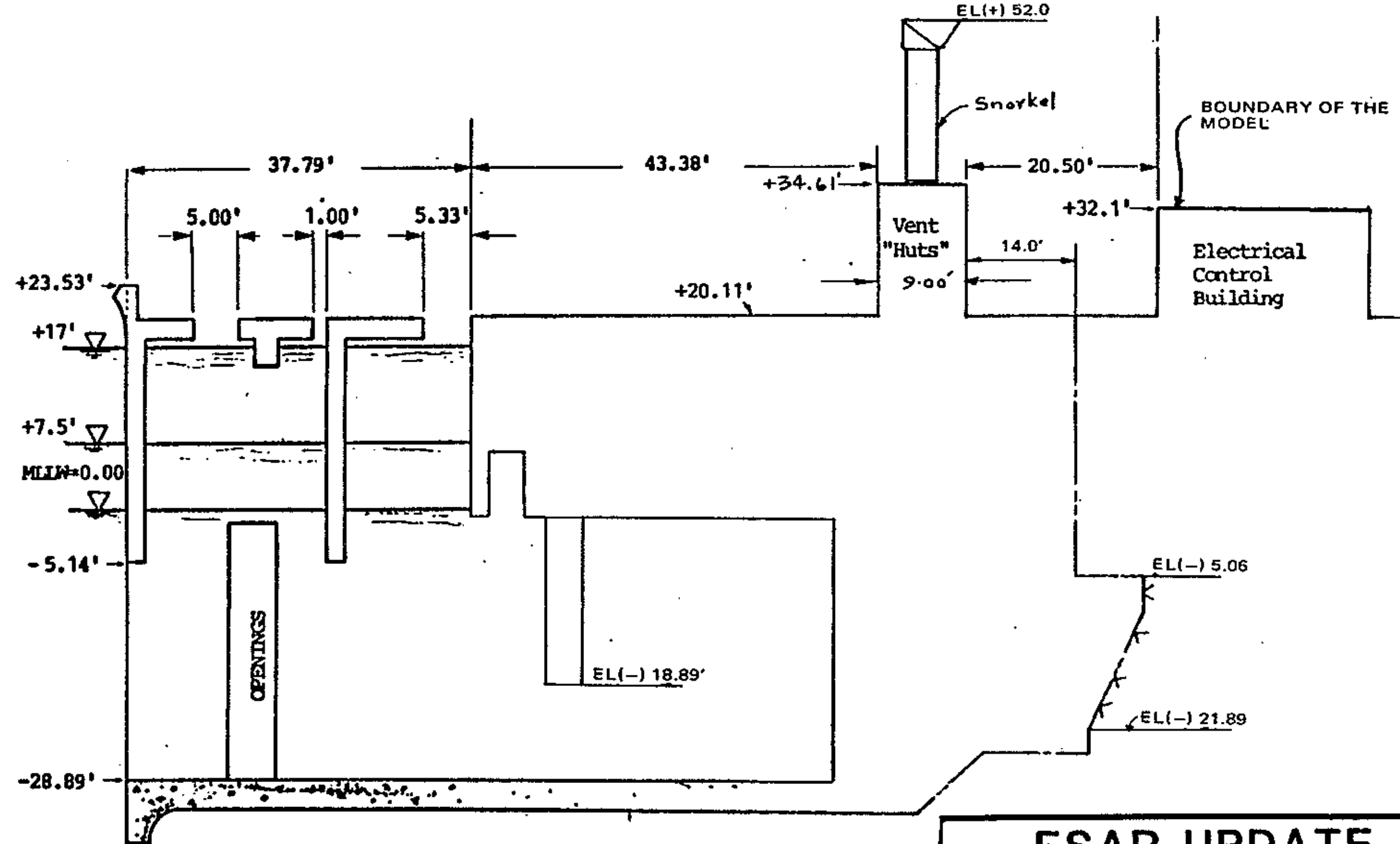


FSAR UPDATE

UNITS 1 AND 2 DIABLO CANYON SITE

FIGURE 3.8–78

INTAKE STRUCTURE
WAVE SCALE MODEL
PLAN-INVERT (UNIT 1)
NTS



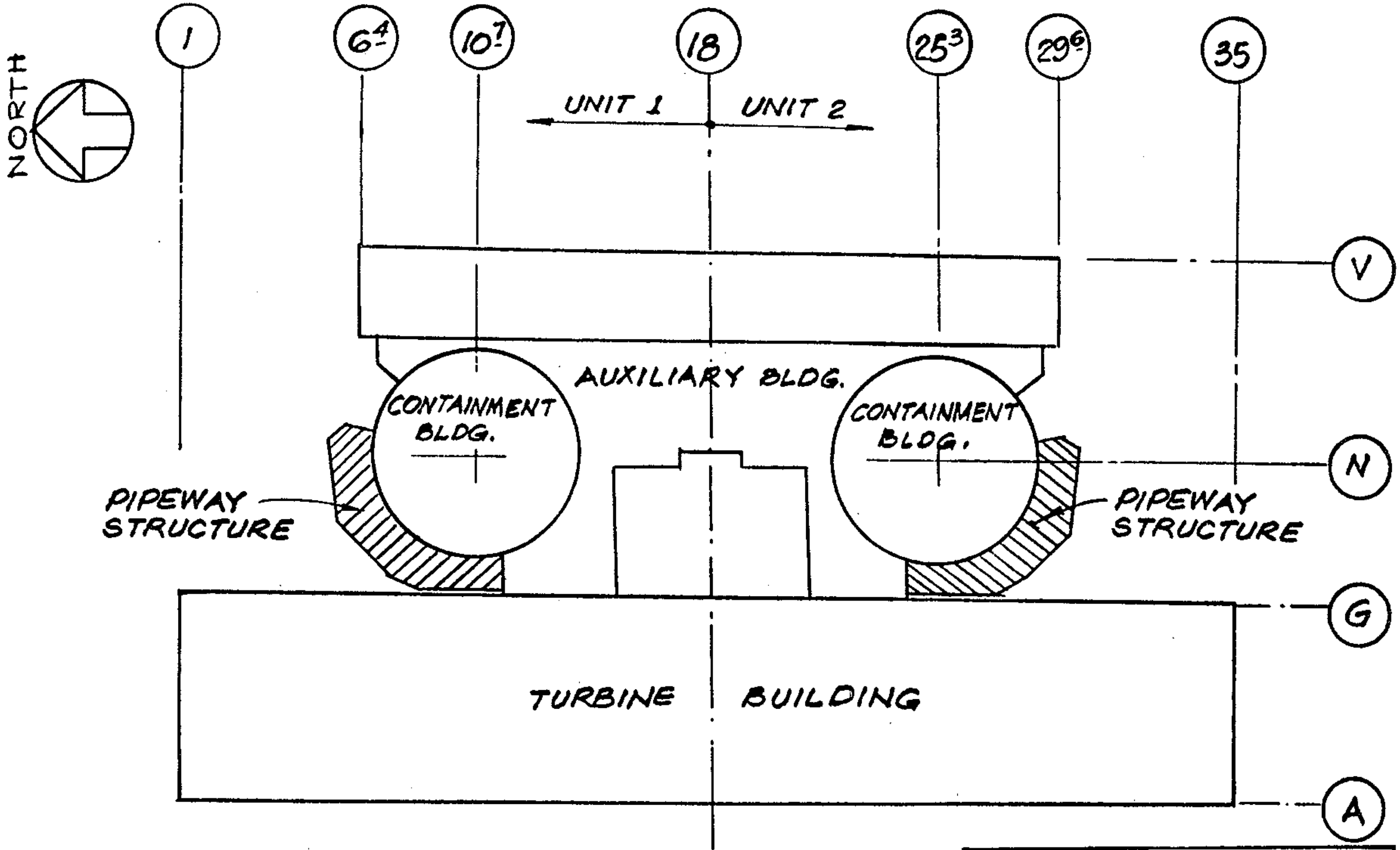
NOTE: (All Elevations Refer to Mean Lower Low Water Datum)

FSAR UPDATE

UNITS 1 AND 2 DIABLO CANYON SITE

FIGURE 3.8–79

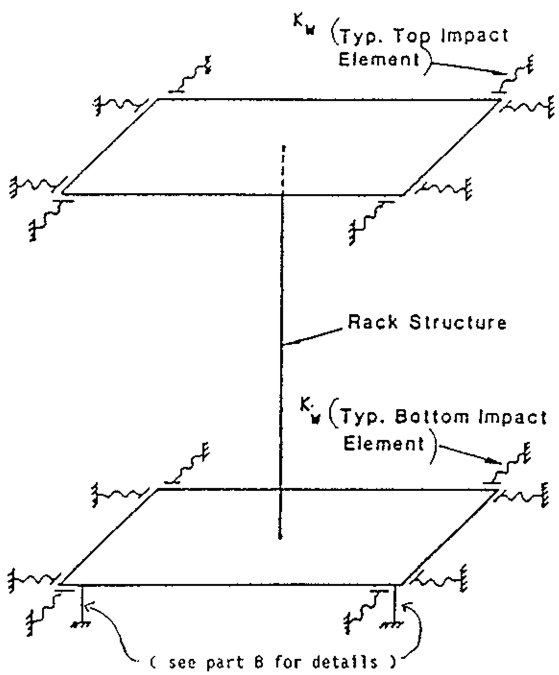
INTAKE STRUCTURE WAVE SCALE MODEL TRANSVERSE SECTION D



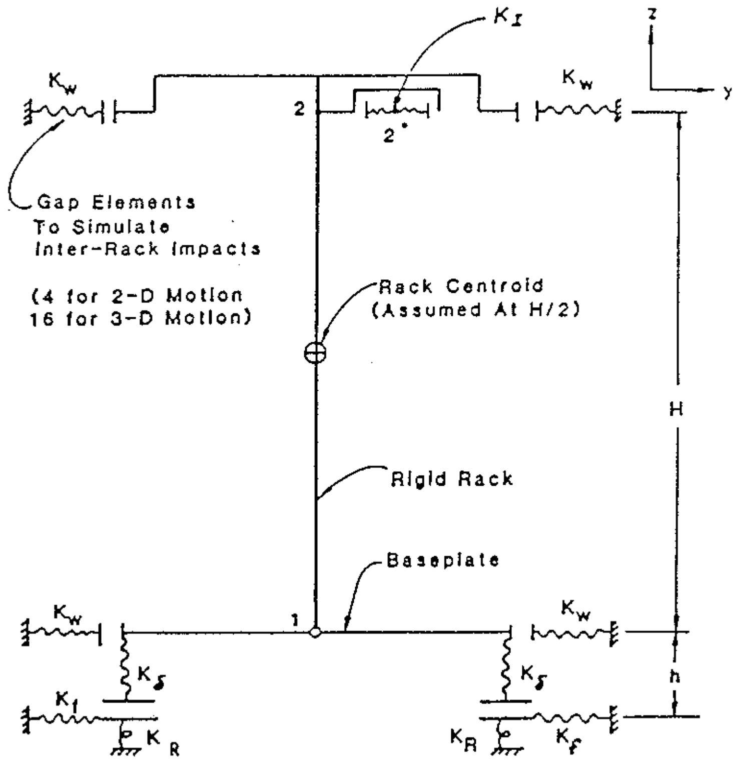
FSAR UPDATE

UNITS 1 AND 2 DIABLO CANYON SITE

FIGURE 3.8–80
PIPEWAY STRUCTURE LAYOUT

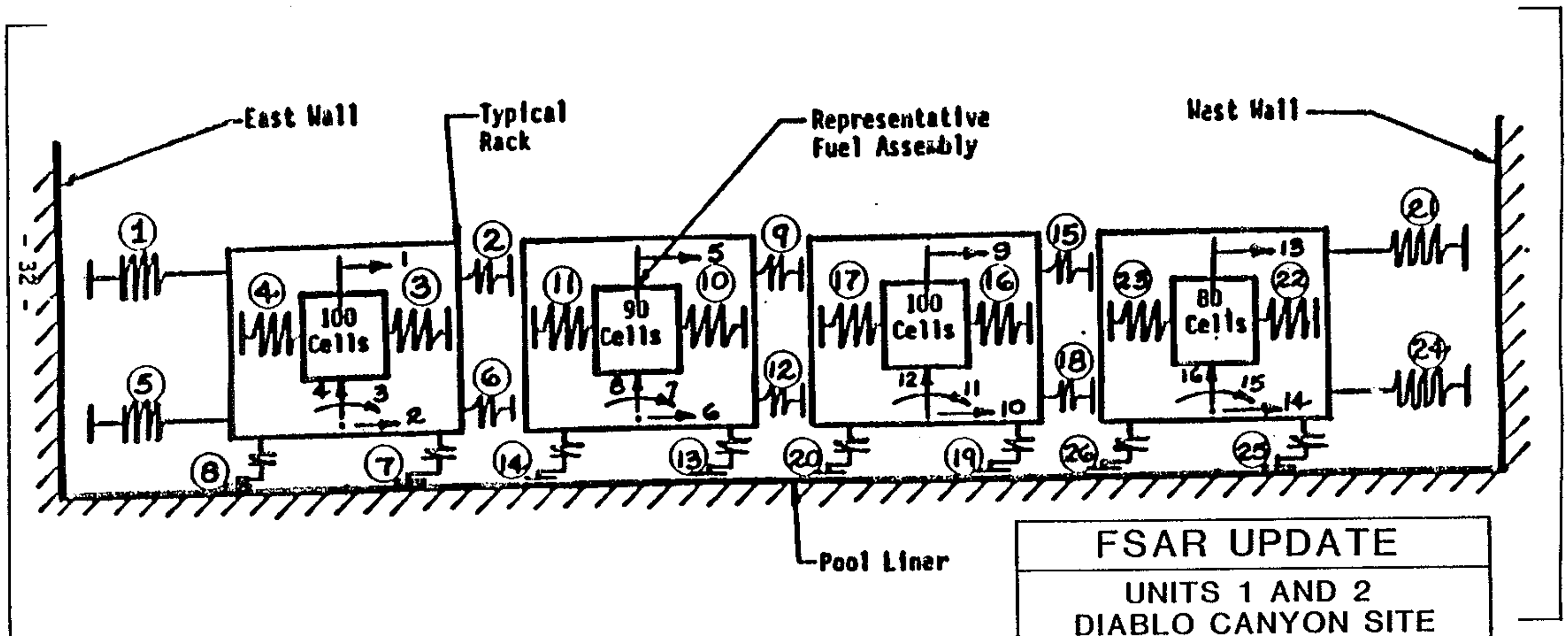


Part A. Three-Dimensional Representation of Rack Dynamic Model



Part B. Two-Dimensional Representation of Rack Dynamic Model

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
Figure 3.8-81. Rack Dynamic Model

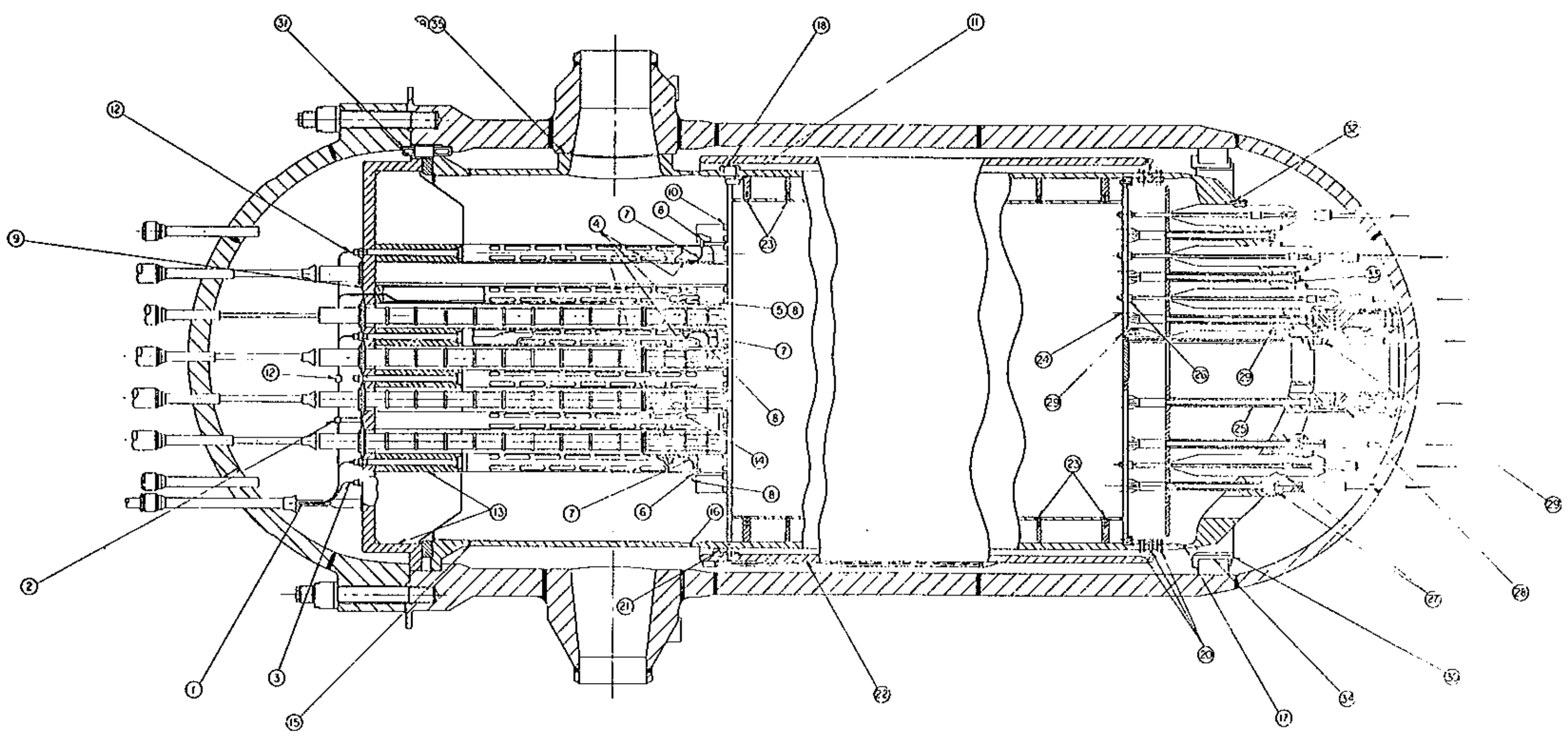


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

Figure 3.8-82.

MULTI-RACK MODEL

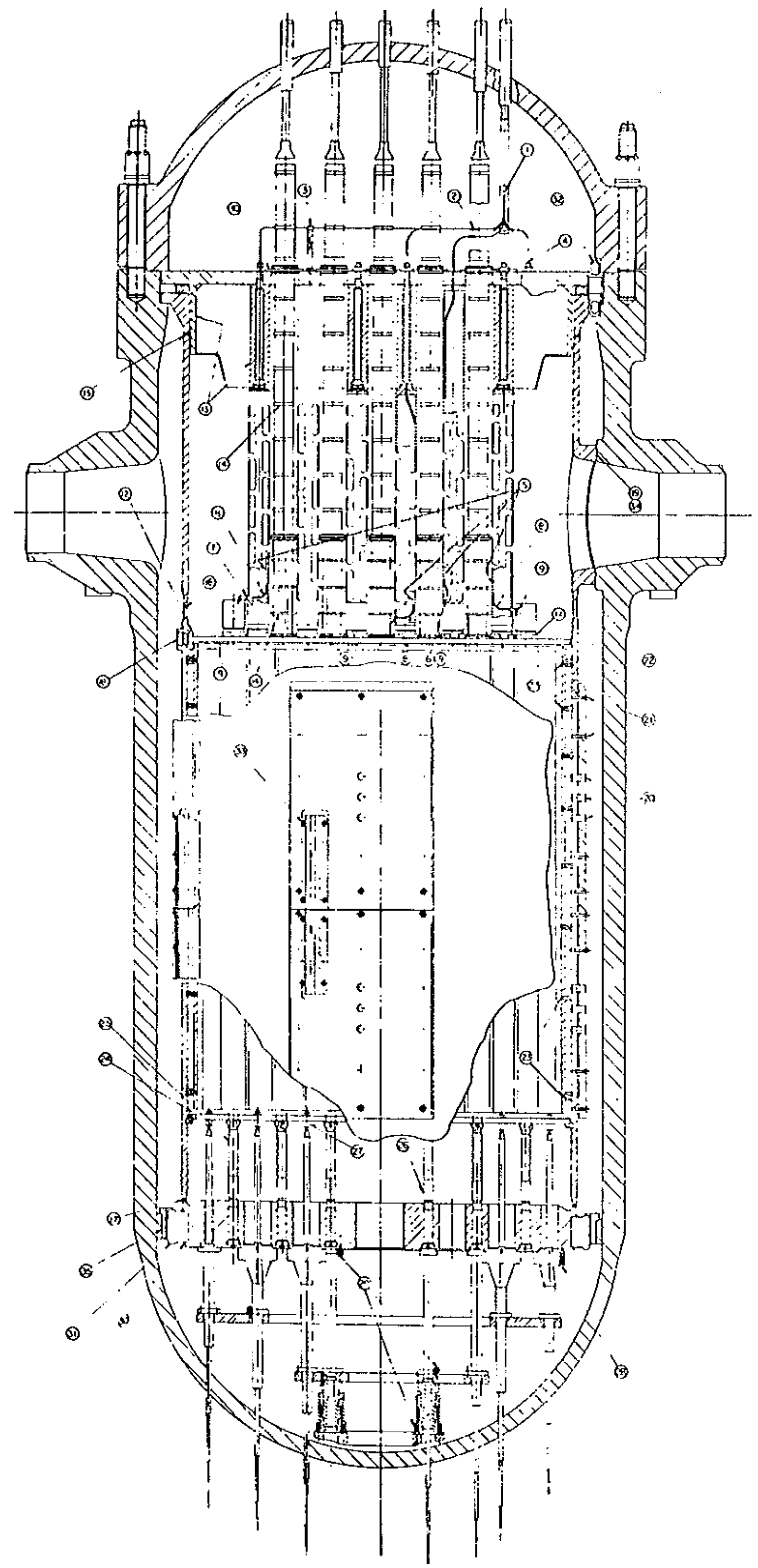


		FEATURES TO BE EXAMINED	COMMENTS AND OBSERVATIONS BEFORE FUNCTIONAL TEST
UPPER INTERNALS	1	THERMOCOUPLE CONDUIT CLAMPS INSIDE THE THERMOCOUPLE COLUMN.	
	2	CLAMP ARRANGEMENTS AT THE MOUNTING BRACKET LOCATIONS.	
	3	PLUG TO CONDUIT WELD AT THE FIVE SUPPORT COLUMNS ADJACENT TO THE THERMOCOUPLE COLUMNS.	
	4	ACCESSIBLE ANGLE CONDUIT CLAMPS INSIDE THE UPPER SUPPORT COLUMNS.	
	5	ACCESSIBLE WELD JOINTS AT THE THERMOCOUPLE STOP FOR THE SELF INSTRUMENTED COLUMNS.	
	6	WELD JOINTS ON ACCESSIBLE SUPPORT COLUMN AND MIXING DEVICE GUSSETS. (THERMOCOUPLE SUPPORT HARDWARE)	
	7	RIGIDITY OF EXPOSED PORTION OF THERMOCOUPLE CONDUIT RUNS, AT ACCESSIBLE LOCATIONS. (INSIDE SUPPORT COLUMNS - LOWER END)	
	8	RIGIDNESS OF THE ACCESSIBLE PROTRUDING THERMOCOUPLE TIPS	
	9	THERMOCOUPLE COLUMN AND GUIDE TUBE SCREW LOCKING DEVICES.	
	10	ACCESSIBLE SUPPORT COLUMN MIXING DEVICE, ORIFICE PLATE, AND CORE PLATE INSERT SCREW LOCKING DEVICES.	
	11	UPPER CORE PLATE INSERTS.	
	12	CONDUIT CONNECTOR FITTINGS AND CROSS RUN CLAMP ARRANGEMENTS.	
	13	DEEP BEAM WELDS AT THE SKIRT AND AT THE OUTER HOLLOW ROUNDS.	
	14	ACCESSIBLE GUIDE TUBE WELDS.	
LOWER INTERNALS	15	UPPER BARREL TO FLANGE GIRTH WELD.	
	16	UPPER BARREL TO LOWER BARREL GIRTH WELD.	
	17	LOWER BARREL TO CORE SUPPORT GIRTH WELD.	
	18	UPPER CORE PLATE ALIGNING PIN WELDS AND BEARING SURFACES.	
	19	OUTLET NOZZLE INTERFACE SURFACE CONDITION.	
	20	THERMAL SHIELD FLEXURE ARM, ATTACHMENTS TO BARREL, AND WELD TO THE THERMAL SHIELD. DYE PENETRANT INSPECT ALL SIX.	
	21	THERMAL SHIELD INTERFACE AT THE HANG OFF PADS.	
	22	IRRADIATION SPECIMEN BASKET WELDS.	
	23	BAFFLE ASSEMBLY SCREW LOCKING ARRANGEMENTS AT THE TWO TOP AND THE TWO BOTTOM FORMER ELEVATIONS.	
	24	CORE SUPPORT COLUMN TO LOWER CORE PLATE SCREW LOCKING DEVICES. (24 RANDOMLY CHOSEN)	
	25	CORE SUPPORT COLUMN ADJUSTING SLEEVES.	
	26	ACCESSIBLE (2) INSTRUMENTATION GUIDE COLUMN LOCKING COLLARS NEAREST THE MANWAY.	
	27	LOCKING DEVICES OF THE BOTTOM INSTRUMENTATION GUIDE COLUMNS.	
	28	LOCKING DEVICES OF THE SECONDARY CORE SUPPORT.	
	29	ACCESSIBLE LOCKING DEVICES OF THE OFF-SET INSTRUMENTATION COLUMN. (UPPER AND LOWER ENDS)	
	30	RADIAL SUPPORT KEY LOCKING ARRANGEMENTS AND BEARING SURFACES.	
	31	HEAD AND VESSEL ALIGNING PIN SCREW LOCKING DEVICES AND BEARING SURFACES.	
	32	CONTACT AT INTERFACE OF THE ACCESSIBLE INSTRUMENTATION GUIDE COLUMNS.	
	33	CONTACT AT INTERFACE OF THE ACCESSIBLE CORE SUPPORT COLUMN NUTS.	
VESSEL	34	VESSEL CLEVIS LOCKING ARRANGEMENTS AND BEARING SURFACES	
	35	VESSEL NOZZLE INTERFACE SURFACE CONDITION.	

FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

FIGURE 3.9-1
VIBRATION CHECKOUT - FUNCTIONAL TEST INSPECTION DATA

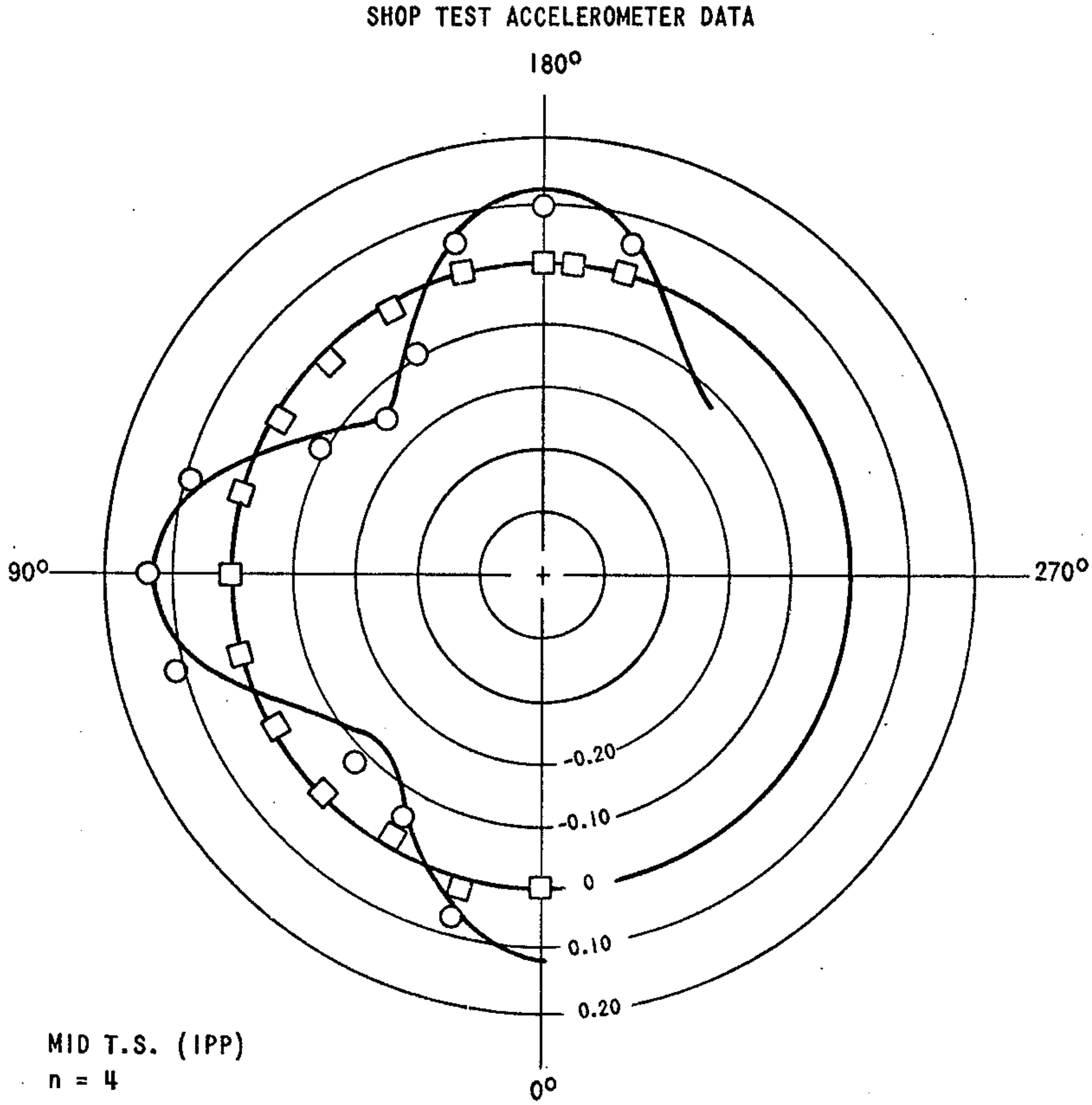


	FEATURES TO BE EXAMINED	COMMENTS AND OBSERVATIONS BEFORE FUNCTIONAL TEST	COMMENTS AND OBSERVATIONS AFTER FUNCTIONAL TEST
1	THERMOCOUPLE CONDUIT CLAMPS INSIDE THE THERMOCOUPLE COLUMN.		
2	CONDUIT SWAGELOK FITTINGS, THEIR BANDINGS, AND THE TAB TYPE LOCKS.		
3	CLAMP ARRANGEMENTS AT THE MOUNTING BRACKET LOCATIONS.		
4	PLUG TO CONDUIT WELD AT THE FOUR SUPPORT COLUMNS ADJACENT TO THE THERMOCOUPLE COLUMNS.		
5	ACCESSIBLE ANGLE CONDUIT CLAMPS INSIDE THE UPPER SUPPORT COLUMNS.		
6	ACCESSIBLE WELD JOINTS AT THE THERMOCOUPLE STOP FOR THE SELF INSTRUMENTED COLUMNS.		
7	WELD JOINTS ON ACCESSIBLE SUPPORT COLUMN AND MIXING DEVICE GUSSETS (THERMOCOUPLE SUPPORT HARDWARE.)		
8	RIGIDITY OF EXPOSED PORTION OF THERMOCOUPLE CONDUIT RUNS, AT ACCESSIBLE LOCATIONS. (INSIDE SUPPORT COLUMNS LOWER END.)		
9	RIGIDNESS OF THE ACCESSIBLE PROTRUDING THERMOCOUPLE TIPS.		
10	THERMOCOUPLE COLUMN AND GUIDE TUBE SCREW LOCKING DEVICES.		
11	ACCESSIBLE SUPPORT COLUMN, MIXING DEVICE, ORIFICE PLATE, AND CORE PLATE INSERT SCREW LOCKING DEVICES.		
12	UPPER CORE PLATE INSERTS.		
13	DEEP BEAM WELDS AT THE SKIRT AND AT THE OUTER HOLLOW ROUNDS.		
14	ACCESSIBLE GUIDE TUBE WELDS.		
15	UPPER BARREL TO FLANGE GIRTH WELD.		
16	UPPER BARREL TO LOWER BARREL GIRTH WELD.		
17	LOWER BARREL TO CORE SUPPORT GIRTH WELD.		
18	UPPER CORE PLATE ALIGNING PIN WELDS AND BEARING SURFACE'		
19	OUTLET NOZZLE INTERFACE SURFACE CONDITION.		
20	NEUTRON SHIELD PANEL DOWEL PIN COVER PLATE WELDS.		
21	NEUTRON SHIELD PANEL SCREW LOCKING DEVICES.		
22	INTERFACE SURFACES AT THE SPACER PADS ALONG THE TOP AND BOTTOM ENDS OF THE NEUTRON PANELS.		
23	BAFFLE ASSEMBLY SCREW LOCKING ARRANGEMENTS AT THE TWO TOP AND THE TWO BOTTOM FORMER ELEVATIONS.		
24	LOWER CORE PLATE TO CORE BARREL FLANGE SCREW LOCKING DEVICES ACCESSIBLE AT THE 0°, 90°, 180°, AND 270° AXES.		
25	CORE SUPPORT COLUMNS AND THEIR SCREW LOCKING DEVICES.		
26	CORE SUPPORT COLUMN ADJUSTING SLEEVES.		
27	ACCESSIBLE (2) INSTRUMENTATION GUIDE COLUMN LOCKING COLLARS NEAREST THE MANWAY.		
28	LOCKING DEVICES AND CONTACT OF THE CRUCIFORM SHAPED BOTTOM INSTRUMENTATION GUIDE COLUMNS WHERE ATTACHED TO THE CORE SUPPORT AND TIE PLATES.		
29	LOCKING DEVICES OF THE SECONDARY CORE SUPPORT BUTT COLUMNS AT THE CORE SUPPORT, TIE PLATE AND BASE PLATE.		
30	RADIAL SUPPORT KEY WELDS		
31	RADIAL SUPPORT KEY LOCKING ARRANGEMENTS AND BEARING SURFACES.		
32	HEAD AND VESSEL ALIGNING PIN SCREW LOCKING DEVICES AND BEARING SURFACES.		
33	IRRADIATION SPECIMEN GUIDE SCREW LOCKING DEVICES AND DOWEL PINS		
34	VESSEL NOZZLE INTERFACE SURFACE CONDITION.		
35	VESSEL CLEVIS LOCKING ARRANGEMENTS AND BEARING SURFACES.		

FSAR UPDATE

UNIT 2
DIABLO CANYON SITE

FIGURE 3.9-2
VIBRATION CHECKOUT - FUNCTIONAL
TEST INSPECTION DATA

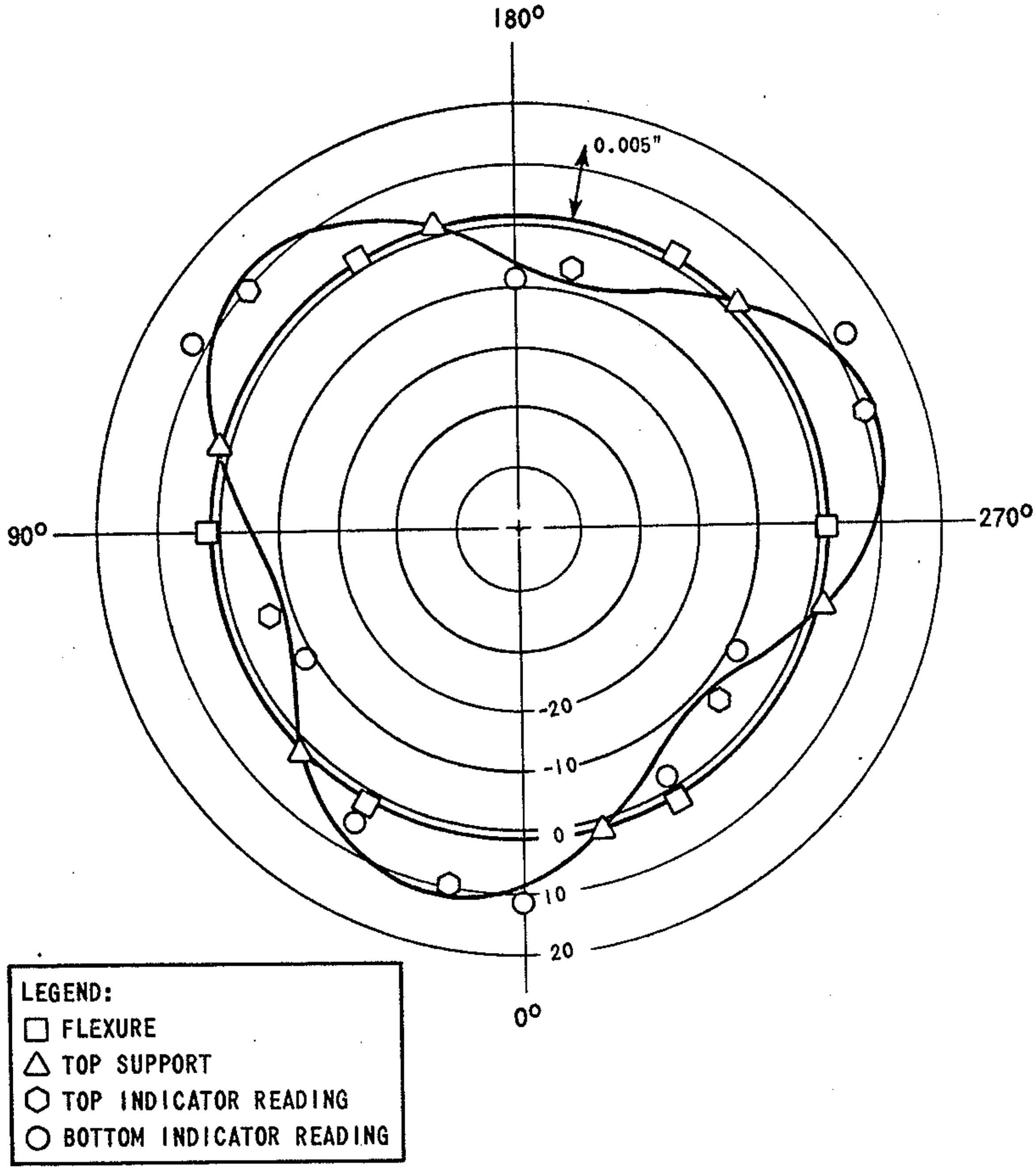


MID T.S. (IPP)
n = 4
f = 72 H_z FORCE = 6 LB
CURVE = 0.12 COS 4θ (LEAST SQUARE)
○ MIDDLE □ BOTTOM

FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

FIGURE 3.9-3
THERMAL SHIELD, MODEL SHAPE n=4
OBTAINED FROM SHAKER TEST



FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

FIGURE 3.9-4
THERMAL SHIELD, MAXIMUM AMPLITUDE OF VIBRATION DURING PREOPERATIONAL TEST

APPENDIX 3.1A

AEC
GENERAL DESIGN CRITERIA - 1971

Appendix 3.1A

AEC GENERAL DESIGN CRITERIA - 1971

As stated and described in Diablo Canyon Power Plant (DCPP) UFSAR Section 3.1, the DCPP units are designed to comply with the “General Design Criteria for Nuclear Power Plant Construction Permits,” published by the Atomic Energy Commission (AEC) in July, 1967. Appendix 3.1A briefly discusses the extent to which the original DCPP principal design features (the 1967 GDCs plus additional design features) for plant structures, systems and components (SSCs) conform to the intent of the AEC “General Design Criteria for Nuclear Power Plants” published in February 1971 as Appendix A to 10 CFR Part 50 (i.e., the 1971 GDCs). Submittal of the FSAR using RG 1.70, Rev 1 format and content was expected by the NRC as part of the initial DCPP licensing process, even though the NRC acknowledged in NUREG-0675 (SER-00) that the DCPP design basis was the 1967 GDCs.

Each 10 CFR Part 50, Appendix A 1971 GDC is addressed below including a summary of how the DCPP principal design features (the 1967 GDCs plus additional design features) demonstrates conformance to the intent of or exceptions to the criterion. The discussion of each GDC refers to sections of the FSAR presenting the details of the DCPP Units 1 and 2 designs. FSAR Table 3.1-2 provides a matrix listing of the 1971 GDC to the related 1967 GDC. Any exceptions to the 1971 GDCs that DCPP identified and the NRC approved in writing resulting from earlier DCPP design or construction commitments are identified in the discussion of the corresponding criterion in this Appendix.

The discussion of how the plant design conformed to the intent of the 1971 GDCs was included in the original FSAR in Appendix 3.1A, and was reviewed by the NRC to conclude that DCPP’s design conformed to the intent of the 1971 GDCs. The degree to which the DCPP design conforms to the intent of the 1971 GDCs, as summarized in this Appendix, establishes additional DCPP licensing basis which must be reviewed when evaluating facility changes.

Criterion 1, 1971 - Quality Standards and Records

Structures, systems, and components important to safety shall be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed. Where generally recognized codes and standards are used, they shall be identified and evaluated to determine their applicability, adequacy, and sufficiency and shall be supplemented or modified as necessary to assure a quality product in keeping with the required safety function. A quality assurance program shall be established and implemented in order to provide adequate assurance that these structures, systems, and components will satisfactorily perform their safety function. Appropriate records of the design, fabrication, erection and testing of structures, systems, and components important to safety shall be maintained by or under the control of the nuclear power unit licensee throughout the life of the unit.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 1. SSCs have been designed, fabricated, erected, and tested to quality levels commensurate with their relationship to safety. The appropriate codes employed for various items have been supplemented where required. A quality assurance program consistent with the 10 CFR 50, Appendix B, requirements has been employed and appropriate records have been made and are being maintained directly by PG&E or are under PG&E's control.

All systems and components of DCPP Units 1 and 2 are classified according to their importance in the prevention and mitigation of accidents. Those items vital to safe shutdown and isolation of the reactor, or whose failure might cause or increase the severity of a LOCA, or result in an uncontrolled release of excessive amounts of radioactivity, are designated PG&E Design Class I. Those items important to the reactor operation, but not essential to safe shutdown and isolation of the reactor or control of the release of substantial amounts of radioactivity, are designated PG&E Design Class II. Those items not related to reactor operation or safety are designated PG&E Design Class III.

PG&E Design Class I systems and components are essential to the protection of the health and safety of the public. Consequently, they are designed, fabricated, inspected, erected, and the materials selected to the applicable provisions of recognized codes, good nuclear practice, and to quality standards that reflect their importance. Discussions of applicable codes and standards as well as code classes are given in Section 3.2 for the major items and components. The quality assurance (QA) program conforms to the requirements of 10 CFR 50 Appendix B, Quality Assurance Criteria for Nuclear Power Plants. Details of the QA program are provided in Chapter 17.

Records of the design, fabrication, construction and testing of PG&E Design Class I components of the plant will be maintained by Pacific Gas and Electric Company or under its control throughout the life of the plant. Chapter 17 of the UFSAR describes the procedures for keeping these records. Operating records to be maintained throughout the life of the plant are described in Chapter 13 of the UFSAR.

This criterion is associated with 1967 GDCs 1 and 5.

Criterion 2, 1971 - Design Basis for Protection Against Natural Phenomena

Structures, systems, and components important to safety shall be designed to withstand the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, floods, tsunami, and seiches without loss of capability to perform their safety functions. The design bases for these structures, systems, and components shall reflect:

(1) Appropriate consideration of the most severe of the natural phenomena that have been historically reported for the site and surrounding area, with

sufficient margin for the limited accuracy, quantity, and period of time in which the historical data have been accumulated,

(2) Appropriate combinations of the effects of normal and accident conditions with the effects of the natural phenomena, and

(3) The importance of the safety functions to be performed.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 2. The components, structures and systems important to safety have been designed to accommodate without loss of capability the most severe natural phenomena recorded for the site and surrounding areas with appropriate combinations of postulated accidents and natural phenomena. The importance of the safety functions of the various items has been considered.

The site characteristics are discussed in Chapter 2. Wind design criteria and flood design criteria are found in Sections 3.3 and 3.4, respectively. Seismic design is discussed in Section 3.7.

This criterion is associated with 1967 GDC 2.

Criterion 3, 1971 - Fire Protection

Structures, systems, and components important to safety shall be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions. Noncombustible and heat-resistant materials shall be used wherever practical throughout the unit, particularly in locations such as the containment and control room. Fire detection and fighting systems of appropriate capacity and capability shall be provided and designed to minimize the adverse effects of fires on structures, systems, and components important to safety. Firefighting systems shall be designed to assure that their rupture or inadvertent operation does not significantly impair the safety capability of these structures, systems, and components.

Discussion

The DCPP Units 1 and 2 designs conform to the requirements of 10 CFR 50.48, which invokes the requirements Criterion 3, 1971.

GDC 3 (1971) is invoked by 10 CFR 50.48, Fire Protection. The fire protection program for DCPP satisfies the requirements of GDC 3 (1971) by complying with the guidelines of Appendix A to NRC Branch Technical Position (BTP) (APCSB) 9.5-1, and with the provisions of 10 CFR 50 Appendix R, Sections III.G, J, L, and O, as stipulated by Operating License Conditions 2.C(5) and 2.C(4) for Units 1 and 2, respectively. Approved deviations from Appendix A to BTP (APCSB) 9.5-1, and Appendix R sections

are identified in Supplement Numbers 8, 9, 13, 23, 27, and 31 to the Safety Evaluation Report (NUREG-0675).

The probability of fires and explosions is minimized by extensive use of noncombustible and fire resistant materials, by physical isolation and protection of flammable fluids, by providing both automatic and manual fire extinguishing systems, and by use of fire detection systems.

Electrical insulation is made of fire retardant, self-extinguishing materials. All exposed electrical raceways are metal and have fire stops liberally applied. Electrical conductors have adequate ratings and overcurrent protection to prevent breakdown or excessive heating.

Electrical equipment for safety systems is physically arranged to minimize the effect of a potential fire. Vital interconnecting circuits are located to avoid potential fire hazards as much as possible, with mutually redundant circuits placed in separate raceways. The facility is equipped with a fire protection system (FPS) for controlling any fire that might originate in plant equipment. This system is described in Section 9.5.1.

The containment and auxiliary building ventilation systems are operated from the control room. Critical areas of the plant have detectors and alarms to alert the control room operator of the possibility of fire, so that prompt action can be taken to prevent significant damage.

This criterion is associated with 1967 GDC 3.

Criterion 4, 1971 - Environmental and Missile Design Bases

Structures, systems, and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 4. The safety-related components, structures, and systems are designed to accommodate all normal or routine environmental conditions as well as those associated with postulated accidents. The designs include provisions to protect, where appropriate, those safety-related items from dynamic effects resulting from component failures and specific credible outside events and conditions.

Use of conservative design methods, segregated routing of piping, provision of missile shield walls, and use of engineered hangers and pipe restraints are incorporated in the design to accommodate dynamic effects of postulated accidents. The various sources of missiles that might affect ESFs have been identified, and protective measures have been devised to minimize these effects (see Section 3.5).

The basic approach for protection of Class 1E equipment and cables from missiles is to ensure design adequacy against generation of missiles. Where missiles cannot be contained within parent equipment, missile protection is attained by routing or placing Class 1E cables and equipment in non-missile prone areas or by shielding the equipment.

This criterion is associated with 1967 GDC 40.

<u>Criterion 5, 1971 - Sharing of Structures, Systems and Components</u>

Structures, systems, and components important to safety shall not be shared between nuclear power units unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions, including, in the event of an accident in one unit, an orderly shutdown and cooldown of the remaining units.

<u>Discussion</u>

The DCPP Units 1 and 2 designs conform to the intent of Criterion 5. Those SSCs that are shared are designed in such a manner that plant safety is not impaired by the sharing. A list of shared components and systems is given in Section 1.2.

This criterion is associated with 1967 GDC 4.

<u>Criterion 10, 1971 - Reactor Design</u>

The reactor core and associated coolant, control, and protection systems shall be designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

<u>Discussion</u>

The DCPP Units 1 and 2 designs conform to the intent of Criterion 10. Appropriate fuel margins are included in each design.

Each reactor core with its related control and protection systems is designed to function throughout its design lifetime without exceeding acceptable fuel damage limits. Core design, together with reliable process and decay heat removal systems, provides for this capability under all expected conditions of normal operation with appropriate margins for uncertainties and anticipated transient situations, including the effects of the

loss of reactor coolant flow, trip of the turbine generator, loss of normal feedwater and loss of offsite power.

The reactor control and protection instrumentation systems are designed to initiate a reactor shutdown for any anticipated combination of plant conditions when necessary to assure a minimum DNB ratio equal to or greater than the applicable limit value (see Sections 4.4.1.1 and 4.4.2.3) and fuel center temperatures below the melting point of UO_2.

Chapter 4 discusses the design bases and design evaluation of reactor components. The details of the control and protection instrumentation systems design and logic are discussed in Chapter 7. This information supports the accident analyses presented in Chapter 15.

This criterion is associated with 1967 GDC 6.

Criterion 11, 1971 - Reactor Inherent Protection

The reactor core and associated coolant systems shall be designed so that in the power operating range the net effect of the prompt inherent nuclear feedback characteristics tends to compensate for a rapid increase in reactivity.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 11. A negative reactivity coefficient is a basic feature of each design.

Prompt compensatory reactivity feedback effects are ensured when each reactor is critical by the negative fuel temperature effect (Doppler effect) and by the operational limit on moderator temperature coefficient of reactivity. The negative Doppler coefficient of reactivity is ensured by the inherent design using low-enrichment fuel. The limits on moderator temperature coefficient of reactivity are ensured by administratively controlling the dissolved neutron absorber concentration and control rod position. These reactivity coefficients are discussed in Section 4.3.

This criterion is associated with 1967 GDC 8.

Criterion 12, 1971 - Suppression of Reactor Power Oscillations

The reactor core and associated coolant, control and protection systems shall be designed to assure that power oscillations which can result in conditions exceeding specified acceptable fuel design limits are not possible or can be reliably and readily detected and suppressed.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 12. The designs include provisions to detect and control those power oscillations that might exceed acceptable fuel design limits during operation.

Oscillations due to xenon spatial effects, in the radial, diametral, and azimuthal overtone modes, are heavily damped due to the inherent design and due to the negative Doppler and non-positive moderator temperature coefficients of reactivity.

Oscillations due to xenon spatial effects, in the axial first overtone mode, may occur. Assurance that fuel design limits are not exceeded by xenon axial oscillations is provided as a result of reactor trip functions using the measured axial power imbalance as an input.

Oscillations due to xenon spatial effects, in axial modes higher than the first overtone, are heavily damped due to the inherent design and due to the negative Doppler coefficient of reactivity.

The stability of the cores against xenon-induced power oscillations and the functional requirements of instrumentation for monitoring and measuring core power distributions are discussed in Section 4.3. Details of the instrumentation design and logic are discussed in Chapter 7.

This criterion is associated with 1967 GDC 7.

Criterion 13, 1971 - Instrumentation and Control

Instrumentation shall be provided to monitor variables and systems over their anticipated range for normal operation, for anticipated operational occurrences, and for accident conditions as appropriate to assure adequate safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the reactor coolant pressure boundary, and the containment and its associated systems. Appropriate controls shall be provided to maintain these variables and systems within prescribed operating ranges.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 13. Appropriate instrumentation and control systems have been provided to monitor and control pertinent variables and systems over normal range of operation and postulated accident conditions.

Reactor, control rod, boron concentration, pressurizer pressure and level, feedwater, steam dump, and turbine instrumentation and controls are provided to monitor and maintain variables within prescribed operating ranges. Reactor protection systems that

receive plant instrumentation signals and automatically actuate alarms, inhibit control rod withdrawal, initiate load cutback, and/or trip the reactors as prescribed limits are approached or reached are also provided. These systems are discussed in Chapter 7. The reactivity control and nuclear instrumentation system are discussed in Chapters 4 and 7.

This criterion is associated with 1967 GDCs 12, 13, 14, and 15.

Criterion 14, 1971 - Reactor Coolant Pressure Boundary

The reactor coolant pressure boundary shall be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 14. The design, fabrication, erection, and testing employed on each reactor coolant pressure boundary and the extensive quality control measures employed during each of the above phases ensure that these pressure boundaries have extremely low probabilities of abnormal leakage, rapidly propagating failure, and gross rupture.

In addition to the loads imposed on the system under normal operating conditions, abnormal loading conditions, such as seismic loading and pipe rupture, are also considered, as discussed in Sections 3.6 and 3.7. The systems are protected from overpressure by means of pressure-relieving devices as required by applicable codes.

Means are provided to detect significant uncontrolled leakage from either reactor coolant pressure boundary with indication in the control room as discussed in Section 5.2. Each RCS boundary has provisions for inspection, testing, and surveillance of critical areas to assess the structural and leaktight integrity. The details of these provisions are given in Section 5.2. For each reactor vessel, a material surveillance program conforming to applicable codes is provided. Additional details are provided in Section 5.4.

The materials of construction of the pressure-retaining boundary of the RCS are protected by control of coolant chemistry from corrosion that might otherwise reduce the system structural integrity during its service lifetime.

This criterion is associated with 1967 GDC 9.

Criterion 15, 1971 - Reactor Coolant System Design

The reactor coolant system and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the

reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 15. Each reactor coolant system (RCS) design and associated pertinent systems include sufficient margin to assure that the appropriate design limits of the reactor coolant pressure boundary are not exceeded during normal operation, including transients as defined in Chapter 15. Reactor internals analysis and testing are described in Section 3.9. The reactor coolant system is discussed in Chapter 5.

No direct association exists with the 1967 GDC for this criterion.

Criterion 16, 1971 - Containment Design

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

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 16. The reactor containment is a reinforced concrete structure with a steel liner that provides an essentially leaktight barrier against the uncontrolled release of radioactivity to the environment under any postulated accident condition.

The reactor containment structure and penetrations, with the aid of containment heat removal systems, are designed to limit radiation doses resulting from leakage of radioactive fission products from the containment to below 10 CFR 100 values, assuming the largest credible energy release following a LOCA, including a margin to cover the effects of metal water or other undefined energy sources. The containment design is described in detail in Section 3.8.1.

This criterion is associated with 1967 GDCs 10 and 49.

Criterion 17, 1971 - Electric Power Systems

An onsite electric power system and an offsite electric power system shall be provided to permit functioning of structures, systems, and components important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences and (2) the core is cooled

and containment integrity and other vital functions are maintained in the event of postulated accidents.

The onsite electric power supplies, including the batteries, and the onsite electric distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure.

Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable. Each of these circuits shall be designed to be available in sufficient time following a loss of all onsite alternating current power supplies and the other offsite electric power circuit, to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. One of these circuits shall be designed to be available within a few seconds following a loss-of-coolant accident to assure that core cooling, containment integrity, and other vital safety functions are maintained.

Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies.

Discussion

The DCPP Units 1 and 2 designs conform to Criterion 17 instead of 1967 GDC 39. This is an exception to the commitments to 1967 GDCs.

The DCPP Offsite Power System is designed to supply offsite electrical power by two physically independent circuits. The 230-kV system provides startup and standby power, and is immediately available following a design basis accident to assure that core cooling, containment integrity, and other vital safety functions are maintained. The 500-kV system provides for transmission of the plant's electric power output. The 500-kV connection also provides a delayed access source of offsite power after the main generator is disconnected. A combination of the 230-kV circuits and the 500-kV circuits provides independent sources of offsite power as required by GDC 17, 1971.

The onsite emergency power source consists of three diesel generators for each unit.

Both offsite and onsite systems have sufficient independence, capacity, and testability to permit the operation of the ESFs assuming a failure of a single active component in each power system. The combination of two 230-kV lines plus the 500-kV system provides a high degree of assurance that offsite power will be available when required. The 230-kV and 500-kV systems meet the requirements of 1971 GDC 17. Further details are provided in Chapter 8.

This criterion supersedes 1967 GDC 39.

Criterion 18, 1971 - Inspection and Testing of Electric Power Systems

Electric power systems important to safety shall be designed to permit appropriate periodic inspection and testing of important areas and features, such as wiring, insulation, connections, and switchboards, to assess the continuity of the systems and the condition of their components. The systems shall be designed with a capability to test periodically (1) the operability and functional performance of the components of the systems, such as onsite power sources, relays, switches, and buses, and (2) the operability of the systems as a whole and, under conditions as close to design as practical, the full operational sequence that brings the systems into operation, including operation of applicable portions of the protection system, and the transfer of power among the nuclear power unit, the offsite power system, and the onsite power system.

Discussion

The DCPP Units 1 and 2 designs conform to Criterion 18.

The electric power system and its components have provisions for periodic inspection and testing. Electric power components have been provided with convenient and safe features for inspecting and testing to meet the requirements of GDC 18, 1971. Further details are provided in Chapter 8.

Criterion 19, 1971 - Control Room

A control room shall be provided from which actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain it in a safe condition under accident conditions including loss-of-coolant accidents. Adequate radiation protection shall be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 19. A centralized control room common to both units contains the controls and instrumentation necessary for operation of both units under normal and accident conditions, including loss of coolant accidents (LOCAs). Adequate radiation protection is provided to ensure that control room personnel are not subject to radiation exposures in excess of 10 CFR 20 limits. Provisions are made so that plant operators can readily maintain the plant at safe shutdown (MODE 3) condition from a location outside the control room.

The DCPP Units 1 and 2 designs conform to Criterion 19 for accident dose. Adequate radiation protection is provided to permit access and occupancy of the control room

under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident to meet the requirements of GDC 19, 1971. Refer to Section 6.4.

This criterion is associated with 1967 GDC 11.

Criterion 20, 1971 - Protection System Functions

The protection system shall be designed (1) to initiate automatically the operation of appropriate systems including the reactivity control systems, to assure that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences and (2) to sense accident conditions and to initiate the operation of systems and components important to safety.

Discussion

The DCPP Units 1 and 2 protection system designs comply with the intent of Criterion 20. The systems will automatically actuate alarms, inhibit control rod withdrawal, initiate load cutback, or trip the reactor as a result of anticipated operational occurrences. The systems will also sense accident conditions and initiate engineered safety features (ESF) operation if required. ESF and the protection systems are discussed in Chapters 6 and 7, respectively.

Operational limits for the core protection systems are defined by analyses of all plant operating and fault conditions requiring rapid rod insertion to prevent or limit core damage. The protection systems are discussed in UFSAR Section 7.2.

This criterion is associated with 1967 GDCs 14, 15, 20, 21, and 25.

Criterion 21, 1971 - Protection System Reliability and Testability

The protection system shall be designed for high functional reliability and inservice testability commensurate with the safety functions to be performed. Redundancy and independence designed into the protection system shall be sufficient to assure that (1) no single failure results in loss of protection function and (2) removal from service of any component or channel does not result in loss of the required minimum redundancy unless the acceptable reliability of operation of the protection system can be otherwise demonstrated. The protection system shall be designed to permit periodic testing of its functioning when the reactor is in operation, including a capability to test channels independently to determine failures and losses of redundancy that may have occurred.

Discussion

The DCPP Units 1 and 2 protection system designs comply with the intent of Criterion 21. Each protection system is comprised of redundant independent logic trains of high functional reliability capable of tolerating a single failure without loss of the

protection function, or removal from service of a single component or channel without loss of required minimum redundancy. Independent end-to-end channel tests can be performed with the reactor at power. The majority of system components can be tested very rapidly by use of built-in semiautomatic testers. Removal from service of any single channel or component does not result in loss of minimum required redundancy. For example, a two-of-three function becomes a one-of-two function when one channel is removed.

Semiautomatic testers are built into each of the two logic trains in a protection system. These testers have the capability of testing the major part of the protection system very rapidly while the reactor is at power. Between tests, the testers continuously monitor a number of internal protection system points including the associated power supplies and fuses. Outputs of the monitors are logically processed to provide alarms for failures in one train and automatic reactor trip for failures in both trains. Additional details can be found in Section 7.2.

This criterion is associated with 1967 GDC 19.

Criterion 22, 1971 - Protection System Independence

The protection system shall be designed to assure that the effects of natural phenomena, and of normal operating, maintenance, testing, and postulated accident conditions on redundant channels do not result in loss of the protection function, or shall be demonstrated to be acceptable on some other defined basis. Design techniques, such as functional diversity or diversity in component design and principles of operation, shall be used to the extent practical to prevent loss of the protection function.

Discussion

The DCPP Units 1 and 2 protection system designs comply with the intent of Criterion 22. Independent, redundant, and separate subsystems have been provided. Extensive measurement, equipment, and location diversity is employed in each design. These design techniques are defenses against loss of the protective function through the effects of natural phenomena, normal operation, maintenance, and testing.

Physical separation and electrical isolation of redundant channels and subsystems, functional diversity of subsystems, and safe failure modes are employed in design of the reactors as defenses against functional failure through exposure to common causative factors. The redundant logic trains, reactor trip breakers, and ESF actuation devices are physically separated and electrically isolated. Physically separate channel trays, conduits, and penetrations are maintained upstream from the logic elements of each train.

The protection system components have been qualified by testing under extremes of the normal environment. In addition, components are tested and qualified according to individual requirements for the adverse environment specific to their location that might

result from postulated accident conditions. The protection systems are discussed in Section 7.2.

This criterion is associated with 1967 GDCs 20, 21, 22, and 23.

Criterion 23, 1971 - Protective System Failure Modes

The protection system shall be designed to fail into a safe state or into a state demonstrated to be acceptable on some other defined basis if conditions such as disconnection of the system, loss of energy (e.g., electric power, instrument air), or postulated adverse environments (e.g., extreme heat or cold, fire, pressure, steam, water, and radiation) are experienced.

Discussion

The DCPP Units 1 and 2 protection system designs comply with the intent of Criterion 23. Each system is designed with due consideration of the most probable failure modes of the components under various perturbations of energy sources and environment. Each trip channel is designed to trip on de-energization. Loss of power, disconnection, open channel faults, and the majority of internal channel short circuit faults cause a channel to go into its tripped mode. Components of each system are qualified by testing for the environments that might result from postulated accident conditions. The protection system details can be found in Section 7.2.

This criterion is associated with 1967 GDC 26

Criterion 24, 1971 - Separation of Protection and Control Systems

The protection system shall be separated from control systems to the extent that failure of any single control system component or channel, or failure or removal from service of any single protection system component or channel which is common to the control and protection systems leaves intact a system satisfying all reliability, redundancy, and independence requirements of the protection system. Interconnection of the protection and control systems shall be limited so as to assure that safety is not significantly impaired.

Discussion

The DCPP Units 1 and 2 protection and control system designs comply with the intent of Criterion 24. Failure of or removal from service of any single component or channel of either the protection system or the control system leaves intact a system satisfying the reliability, redundancy, and independence requirements of the protection system. The protection system is separate and distinct from the control system.

The control system is dependent on the protection system in that control system signals are derived from protection system measurements where applicable. Interconnection is

through isolation amplifiers that are classified as protection system components. The adequacy of systems isolation has been verified by testing under the conditions of maximum credible faults.

The protection systems comply with the requirements of IEEE Standard 279-1971 "Criteria for Protection Systems for Nuclear Power Generation Stations" although construction permits for the Diablo Canyon units were issued prior to issuance of the 1971 version of the standard. The protection systems and control systems are discussed in Chapter 7.

This criterion is associated with 1967 GDC 22.

Criterion 25, 1971 - Protection System Requirements for Reactivity Control Malfunctions

The protection system shall be designed to assure that specified acceptable fuel design limits are not exceeded for any single malfunction of the reactivity control systems, such as accidental withdrawal (not ejection or dropout) of control rods.

Discussion

The DCPP Units 1 and 2 designs comply with the intent of Criterion 25. Reactor shutdown with control shutdown rods is completely independent of control functions. The reactor trip breakers interrupt power to all rod drive mechanisms regardless of the status of existing control signals. The design is such that the systems can withstand accidental withdrawal of control groups or unplanned dilution of soluble boron without exceeding acceptable fuel design limits.

The facility reactivity control systems are discussed further in Chapter 7, and analyses of the effects of the other possible malfunctions are discussed in Chapter 15. The analyses show that acceptable fuel damage limits are not exceeded in the event of a single malfunction of either system.

This criterion is associated with 1967 GDC 31.

Criterion 26, 1971 - Reactivity Control System Redundancy and Capability

Two independent reactivity control systems of different design principles shall be provided. One of the systems shall use control rods, preferably including a positive means for inserting the rods, and shall be capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including anticipated operational occurrences, and with appropriate margins for malfunctions such as stuck rods, specified acceptable fuel design limits are not exceeded. The second reactivity control system shall be capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes (including xenon burnout) to assure acceptable fuel design limits are not exceeded. One of the systems shall be capable of holding the reactor core subcritical under cold conditions.

Discussion

The DCPP Units 1 and 2 designs comply, with the possible exception of the preferred rod insertion means, with the intent of Criterion 26. Two independent reactivity control systems of different design principles are provided for each reactor design. One of the systems uses control rods; the other system uses dissolved boron. The boron system is capable of maintaining the reactor in a subcritical status under cold shutdown conditions. The rod control system maintains a programmed average reactor temperature with scheduled and transient load changes; the boron system is capable of controlling the rate of reactivity change resulting from planned normal power changes including xenon burnout. The control rods are inserted by gravity.

The rod cluster control assembly system is capable of making and holding the core subcritical from all operating and hot shutdown conditions sufficiently fast to prevent exceeding acceptable fuel damage limits. The chemical shim control is also capable of making and holding the core subcritical, but at a slower rate, and is not employed as a means of compensating for rapid reactivity transients. The rod cluster control assembly system is, therefore, used in protecting each core from fast transients. Details of the construction of the rod cluster control assembly are included in Section 4.2, with the operation discussed in Chapter 7. The means of controlling the boric acid concentration is described in Section 9.3.4.

This criterion is associated with 1967 GDCs 27, 28, and 29.

Criterion 27, 1971 - Combined Reactivity Control Systems Capability

The reactivity control systems shall be designed to have a combined capability, in conjunction with poison addition by the emergency core cooling system, of reliably controlling reactivity changes to assure that under postulated accident conditions and with appropriate margin for stuck rods the capability to cool the core is maintained.

Discussion

The DCPP Units 1 and 2 designs comply with the intent of Criterion 27. Appropriate reactivity margin is available for each unit under postulated accident conditions to ensure that the capability to cool the core is maintained. Such margin includes an allowance for the most reactive rod control cluster being stuck out of the core.

The boron reactivity (chemical shim) control systems are capable of making and holding the core subcritical under any anticipated conditions and with appropriate margin for contingencies. These means are discussed in detail in Chapters 4 and 9. Normal reactivity shutdown capability is provided by rapid control rod insertion. The chemical shim control system permits the necessary shutdown margin to be maintained during long-term xenon decay and plant cooldown.

This criterion is associated with 1967 GDC 30.

Criterion 28, 1971 - Reactivity Limits

The reactivity control systems shall be designed with appropriate limits on the potential amount and rate of reactivity increase to assure that the effects of postulated reactivity accidents can neither (1) result in damage to the reactor coolant pressure boundary greater than limited local yielding nor (2) sufficiently disturb the core, its support structures or other reactor pressure vessel internals to impair significantly the capability to cool the core. These postulated reactivity accidents shall include consideration of rod ejection (unless prevented by positive means), rod dropout, steam line rupture, changes in reactor coolant temperature and pressure, and cold water addition.

Discussion

The DCPP Units 1 and 2 designs comply with the intent of Criterion 28. For each unit, the maximum reactivity worth of control rods and the maximum rates of reactivity insertion employing both control rods and boron removal are limited to values that prevent rupture of the coolant pressure boundary or disruption of the core or internals to a degree that could impair the effectiveness of the emergency core cooling system (ECCS). The appropriate reactivity insertion rate for withdrawal of rods and the dilution of boron in the coolant system are discussed in Chapter 15.

The boron reactivity (chemical shim) control systems are capable of making and holding the core subcritical under any anticipated condition and with appropriate margin for contingencies. These means are discussed in detail in Chapters 4 and 9.

This criterion is associated with 1967 GDC 30.

Criterion 29, 1971 - Protection Against Anticipated Operational Occurrences

The protection and reactivity control systems shall be designed to assure an extremely high probability of accomplishing their safety functions in the event of anticipated operational occurrences.

Discussion

The DCPP Units 1 and 2 designs comply with the intent of Criterion 29. The protection and reactivity control systems for each plant are designed to ensure an extremely high probability of fulfilling their intended functions. The design principles of diversity and redundancy coupled with a rigorous quality assurance program support this probability as does operating experience in plants using the same basic design. The protection systems are described in Section 7.2.

This criterion is associated with 1967 GDCs 19 and 20.

Criterion 30, 1971 - Quality of Reactor Coolant Pressure Boundary

Components which are part of the reactor coolant pressure boundary shall be designed, fabricated, erected, and tested to the highest quality standards practical. Means shall be provided for detecting and, to the extent practical, identifying the location of the source of reactor coolant leakage.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 30. The quality levels employed in the design, fabrication, erection and testing for each reactor coolant pressure boundary are extremely comprehensive. Systems are included in the plant to detect and, to the extent practical, to locate leakage.

All RCS components are designed, fabricated, inspected, and tested in conformance with the ASME Boiler and Pressure Vessel Code.

Leakage is detected by an increase in the amount of makeup water required to maintain a normal level in the pressurizer. The reactor vessel closure joint is provided with a temperature monitored leakoff between double gaskets.

Leakage into the reactor containment is drained to the reactor building sump where the level is monitored.

Leakage is also detected by measuring the airborne activity and quantity of the condensate drained from each reactor containment fan cooler unit. These leakage detection methods are described in detail in Section 5.2.

This criterion is associated with 1967 GDCs 9 and 16.

Criterion 31, 1971 - Fracture Prevention of Reactor Coolant Pressure Boundary

The reactor coolant pressure boundary shall be designed with sufficient margin to assure that when stressed under operating, maintenance, testing, and postulated accident conditions (1) the boundary behaves in a nonbrittle manner and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the boundary material under operating, maintenance, testing, and postulated accident conditions and the uncertainties in determining (1) material properties, (2) the effects of irradiation on material properties, (3) residual, steady-state and transient stresses, and (4) size of flaws.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 31. Each reactor coolant boundary is designed so that, for all normal operating and postulated accident

modes, the boundary behaves in a nonbrittle manner and so that the probability of rapidly propagating failure is minimized. Service temperature and pressure, irradiation, cyclic loading, seismic, blowdown and thermal forces from postulated accidents, residual stresses, and code allowable material discontinuities have all been considered in the design, with appropriate margins for each.

Sufficient testing and analysis of materials employed in RCS components have been performed to ensure that the required NDTT limits specified in the criterion are met. Removable test capsules installed in the reactor vessel are removed and tested at various times in the plant lifetime to determine the effects of operation on system materials. Details of the testing and analysis programs are included in Chapter 5.

Close control is maintained over material selection and fabrication for the RCS. Materials exposed to the coolant are corrosion-resistant stainless steel or Inconel. Materials testing consistent with 10 CFR 50 ensures that only materials with adequate toughness properties are used.

The fabrication and quality control techniques used in the fabrication of the RCS are equivalent to those used for the reactor vessel. The inspections of reactor vessel, steam generators, pressurizer, pumps, and piping are governed by ASME code requirements.

This criterion is associated with 1967 GDCs 34 and 35.

Criterion 32, 1971 - Inspection of Reactor Coolant Pressure Boundary

Components which are part of the reactor coolant pressure boundary shall be designed to permit (1) periodic inspection and testing of important areas and features to assess their structural and leaktight integrity, and (2) an appropriate material surveillance program for the reactor pressure vessel.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 32. Each reactor coolant pressure boundary is periodically inspected under the provisions of ASME Section XI. The DCPP Inservice Inspection (ISI) and Testing Program plans for the first ten-year interval conformed to the extent practicable with the 1977 Edition of Section XI with Addenda through Summer 1978. The Inservice Inspection Program plan for the second ten-year interval conformed to the extent practicable with the 1989 Edition of Section XI without Addenda. The Inservice Inspection Program plan for the third ten-year interval will conform to the extent practicable with the 2001 Edition of Section XI with 2002 and 2003 Addenda. A reactor vessel metal surveillance program will be employed in accordance with ASTM 185, Recommended Practice for Surveillance Tests on Structural Materials in Nuclear Reactors.

Monitoring of the NDT temperature properties of each core region plate, forging, weldment, and associated heat-treated zones are performed in accordance with ASTM E 185, Recommended Practice for Surveillance Tests on Structural Materials in Nuclear Reactors. Samples of reactor vessel plate materials are retained and cataloged in case future engineering development shows the need for further testing.

The material properties surveillance program includes not only the conventional tensile and impact tests, but also fracture mechanics specimens. The observed shifts in NDTT of the core region materials with irradiation are used to confirm the calculated limits to startup and shutdown transients.

To define permissible operating conditions below NDTT, a pressure range is established that is bounded by a lower limit for pump operation and an upper limit that satisfies reactor vessel stress criteria. To allow for thermal stresses during heatup or cooldown of the reactor vessel, an equivalent pressure limit is defined to compensate for thermal stress as a function of rate of change of coolant temperature. Because the normal operating temperature of the reactor vessel is well above the maximum expected NDTT brittle fracture during normal operation, it is not considered to be a credible mode of failure. Additional details can be found in Section 5.2.

This criterion is associated with 1967 GDC 36.

Criterion 33, 1971 - Reactor Coolant Makeup

A system to supply reactor coolant makeup for protection against small breaks in the reactor coolant pressure boundary shall be provided. The system safety function shall be to assure that specified acceptable fuel design limits are not exceeded as a result of reactor coolant loss due to leakage from the reactor coolant pressure boundary and rupture of small piping or other small components which are part of the boundary. The system shall be designed to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished using the piping, pumps, and valves used to maintain coolant inventory during normal reactor operation.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 33. The normal flowpath for each RCS charging system can be used to ensure appropriate makeup protection against small breaks. The RCS charging system is discussed in Section 9.3.

No direct association exists with the 1967 GDC.

Criterion 34, 1971 - Residual Heat Removal

A system to remove residual heat shall be provided. The system safety function shall be to transfer fission product decay heat and other residual heat from the reactor core at a rate such that specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded.

Suitable redundancy in components and features, and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 34. Each residual heat removal (RHR) system, consisting of two redundant trains of pumps and heat exchangers, has appropriate heat removal capacity to ensure fuel protection. This system supplements the normal steam and power conversion system (SPCS) which is used for the first cooldown. The auxiliary feedwater system (AFS) complements the SPCS in this function. The systems together accommodate the single failure criteria.

The RHR system is discussed in Section 5.5.

No direct association exists with the 1967 GDC.

Criterion 35, 1971 - Emergency Core Cooling

A system to provide abundant emergency core cooling shall be provided. The system safety function shall be to transfer heat from the reactor core following any loss of reactor coolant at a rate such that (1) fuel and clad damage that could interfere with continued effective core cooling is prevented and (2) clad metal-water reaction is limited to negligible amounts.

Suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 35. Appropriate core cooling systems have been designed for each plant so as to provide for the removal of core thermal loads and for the limiting of metal-water reactions to an insignificant level. Suitable redundancy is provided in core cooling systems. The charging accumulator

and safety injection systems will accommodate a single active failure and still fulfill their intended safety function. The RHR system will accommodate a single passive or active failure and still fulfill its intended safety function.

By combining the use of passive accumulators with two centrifugal charging pumps (CCP1 and CCP2), two safety injection pumps, and two RHR pumps, emergency core cooling is provided even if there should be a failure of any single component in any system. The ECCS employs a passive system of accumulators that do not require any external signals or source of power for their operation to cope with the short-term cooling requirements of large reactor coolant pipe breaks. Two independent and redundant high-pressure flow and pumping systems, each capable of the required emergency cooling, are provided for small break protection and to keep the core submerged after the accumulators have discharged following a large break. These systems are arranged so that the single failure of any active component does not interfere with meeting the short-term cooling requirements.

Borated water is injected into the RCS by accumulators, safety injection pumps, RHR pumps, and charging pumps. Pump design includes consideration of fluid temperature and containment pressure in accordance with AEC Safety Guide (SG) 1, November 1970. The failure of any single active component or the development of excessive leakage during the long term cooling period does not interfere with the ability to meet necessary long-term cooling objectives with one of the systems.

The primary function of the ECCS is to deliver borated cooling water to the reactor core in the event of a LOCA. This limits the fuel cladding temperature and thereby ensures that the core will remain intact and in place, with its essential heat transfer geometry preserved. This protection is afforded for:

(1) All pipe break sizes up to and including the hypothetical circumferential rupture of a reactor coolant loop

(2) A loss of coolant associated with a rod ejection accident

The basic criteria for LOCA evaluations are (a) no cladding melting will occur, (b) zirconium-water reactions will be limited to an insignificant amount, and (c) the core geometry will remain essentially in place and intact so that effective cooling of the core will not be impaired. The zirconium-water reactions will be limited to an insignificant amount so that the accident:

(1) Does not interfere with the emergency core cooling function to limit cladding temperatures

(2) Does not produce hydrogen in an amount that, when burned, would cause the containment pressure to exceed the design value

For any rupture of a steam pipe and the associated uncontrolled heat removal from the core, the ECCS adds shutdown reactivity so that with a stuck rod, no offsite power, and minimum ESF, there is no consequential damage to the primary system and the core remains in place and intact. With no stuck rod, offsite power, and all equipment operating at design capacity, there is insignificant cladding rupture. The ECCS is described in Section 6.3. Chapter 15 provides the analysis for the LOCA.

This criterion is associated with 1967 GDCs 37 and 44.

Criterion 36, 1971 - Inspection of Emergency Core Cooling System

The emergency core cooling system shall be designed to permit appropriate periodic inspection of important components, such as spray rings in the reactor pressure vessel, water injection nozzles, and piping, to assure the integrity and capability of the system.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 36. They provide for inspection of the emergency core cooling branch line connections to the RCS for each plant in accordance with the provision of ASME Section XI. These are the areas of principal stress in the system due to temperature gradients. The remainder of the systems are verified as to integrity and functioning by means of periodic testing as described in the Technical Specifications.

Design provisions facilitate access to the critical parts of the reactor vessel internals, injection nozzles, pipes, and valves for visual or nondestructive inspection. The components outside containment are accessible for leaktightness inspection during operation of the reactor.

Details of the inspection program for the reactor vessel internals are included in Section 5.4. Information on inspection for the ECCS is provided in Section 6.3.

This criterion is associated with 1967 GDC 45.

Criterion 37, 1971 - Testing of Emergency Core Cooling System

The emergency core cooling system shall be designed to permit appropriate periodic pressure and functional testing to assure (1) the structural and leaktight integrity of its components, (2) the operability and performance of the active components of the system, and (3) the operability of the system as a whole and, under conditions as close to design as practical, the performance of the full operational sequence that brings the system into operation, including operation of applicable portions of the protection system, the transfer between normal and emergency power sources, and the operation of the associated cooling water system.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 37. Periodic tests demonstrate the integrity, operability, and performance of each active component. Each system as a whole, and the entire operational sequence of actuation, power transfer, and cooling water operation are tested in several phases rather than in one phase during periodic testing.

The design provides for periodic testing of both active and passive components of the ECCS for operability and functional performance. Preoperational performance tests of the components were performed in the manufacturer's shop. Initial system flow tests demonstrate proper functioning of the system. Thereafter, periodic tests demonstrate that components are functioning properly.

Each active component of the ECCS may be individually actuated on the normal power source at any time during plant operation to demonstrate operability. The centrifugal charging pumps are part of the charging system, and this system is in continuous operation during plant operation. The test of the safety injection pumps employs the minimum flow recirculation test line that connects back to the refueling water storage tank (RWST). Remotely operated valves are exercised and actuation circuits tested. The automatic actuation circuitry, valves, and pump breakers also may be checked during integrated system tests performed during a planned cooldown of the RCS. Details of the ECCS are found in Section 6.3. Performance under accident conditions is evaluated in Chapter 15.

Design provisions include special instrumentation, testing, and sampling lines to perform tests during plant shutdown to demonstrate proper operation of the ECCS. A test signal is applied to initiate automatic action. The test demonstrates the operation of the valves, pump circuit breakers, and automatic circuitry. In addition, the periodic recirculation to the RWST can verify that the safety injection pumps attain required discharge heads. During a refueling outage the full flow capability of each injection pump can be verified.

This criterion is associated with 1967 GDCs 38, 46, 47, and 48.

Criterion 38, 1971 - Containment Heat Removal

A system to remove heat from the reactor containment shall be provided. The system safety function shall be to reduce rapidly, consistent with the functioning of other associated systems, the containment pressure and temperature following any loss-of-coolant accident and maintain them at acceptably low levels.

Suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for

offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 38. Two diverse heat removal systems, each composed of redundant components, are provided. These are the containment spray system (100 percent capacity pumping systems) and the containment fan cooler system (five units provided, two required for accident heat removal).

The reactor containment structure and penetrations, with the aid of containment heat removal systems, are designed to limit radiation doses resulting from leakage of radioactive fission products from the containment to below 10 CFR 100 values, assuming the largest credible energy release following a LOCA, including a margin to cover the effects of metal water or other undefined energy sources. The containment design is described in detail in Section 3.8.1.

Two separate heat removal systems, the containment spray system (CSS) and the containment fan coolers, are provided to remove heat from the containment following an accident. The design cooling rates of the two systems at the containment design pressure and temperature conditions are the same. The heat removal capability of either system is sufficient to rapidly reduce the containment pressure following an accident. The containment heat removal systems are described in Section 6.2.

This criterion is associated with 1967 GDCs 49 and 52.

Criterion 39, 1971 - Inspection of Containment Heat Removal System

The containment heat removal system shall be designed to permit appropriate periodic inspection of important components, such as the torus, pumps, spray nozzles, and piping to assure the integrity and capability of the system.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 39 except for limited areas. Four or fewer fan cooler units are continually operating and are rotated in service to provide continuous verification of operability and integrity. Access for routine maintenance and inspection has been provided.

The containment spray system integrity will be verified by means of periodic testing as described in the Technical Specifications. Access has been provided for routine maintenance and inspection except for the spray ring headers and nozzles for which no inspection provision was made, except that provisions were made to smoke or air test these headers and nozzles periodically.

Where practicable, all active components and passive components of the containment cooling system are inspected periodically to demonstrate system readiness. The pressure containing systems are inspected for leaks from pump seals, valve packing, flanged joints, and safety valves. During operational testing of the containment spray pumps, the portions of the system subjected to pump pressure are inspected for leaks. The containment fan coolers are normally in use, which provides an additional check on the readiness of the system. Additional details are found in Section 6.2.

This criterion is associated with 1967 GDC 58.

Criterion 40, 1971 - Testing of Containment Heat Removal System

The containment heat removal system shall be designed to permit appropriate periodic pressure and functional testing to assure (1) the structural and leaktight integrity of its components, (2) the operability and performance of the active components of the system, and (3) the operability of the system as a whole, and, under conditions as close to the design as practical, the performance of the full operational sequence that brings the system into operation, including operation of applicable portions of the protection system, the transfer between normal and emergency power sources, and the operation of the associated cooling water system.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 40. Periodic tests demonstrate the integrity, operability, and performance of the containment heat removal systems.

To the extent practicable, active components of the containment fan coolers are given preoperational performance tests after installation. Since these coolers are in use during normal operation, they are continually subjected to operational tests. The same is true of the component cooling water system that supplies the cooling water for the fan coolers. Each unit can be isolated during plant operation and subjected to a leak test to determine that the leaktight integrity of the unit has not been lost.

Similarly, active components in the containment spray system are given preoperational performance tests after installation. Periodic tests demonstrate that components are functioning properly. Tests are performed after any component maintenance affecting operability. Permanent test lines for all the containment spray loops are located so that all components up to the isolation valves at the containment can be tested.

The air test lines for checking that spray nozzles are not obstructed are connected upstream of the spray ring isolation valves. Airflow through the nozzles is monitored by positive means.

The containment systems are described in detail in Section 6.2.

This criterion is associated with 1967 GDCs 59, 60, and 61.

Criterion 41, 1971 - Containment Atmosphere Cleanup

Systems to control fission products, hydrogen, oxygen, and other substances which may be released into the reactor containment shall be provided as necessary to reduce, consistent with the functioning of other associated systems, the concentration and quality of fission products released to the environment following postulated accidents, and to control the concentration of hydrogen or oxygen and other substances in the containment atmosphere following postulated accidents to assure that containment integrity is maintained.

Each system shall have suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) its safety function can be accomplished, assuming a single failure.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 41. The containment spray system and containment fan coolers, provide controls on, and means for, reduction of fission products and other substances.

The containment spray system removes radioactive iodine isotopes from the containment atmosphere should these fission products be released in the event of an accident. The system is designed to deliver enough sodium hydroxide mixed with the borated spray water from the refueling water storage tank to provide pH control for iodine removal when mixed with the other sources of water in the containment recirculation sump.

The containment spray system, including required auxiliary systems, is designed to tolerate a single active failure during the injection phase following a LOCA or steam line break without loss of protective function. The containment spray pumps are of the horizontal centrifugal type and are driven by electric motors. The motors are powered from separate vital buses.

The containment fan cooler system consists of five identical fan coolers, each including cooling coils, fan and drive motor, locked open air flow dampers and pressure relief dampers, duct distribution system, instrumentation, and control.

The containment fan cooler system and the containment spray system operate during the injection phase following a LOCA to reduce the containment ambient temperature and pressure. While performing this cooling function, the containment heat removal system also helps limit offsite radiation levels by reducing the pressure differential

between containment and outside atmosphere, thus reducing the driving force for leakage of fission products from the containment atmosphere.

The fan cooler units are powered from vital buses and have a standby unit. Used in conjunction with one another during the injection phase, one containment spray pump and two containment fan cooler units will provide the heat removal capability to maintain the postaccident containment pressure below the design value of 47 psig.

The containment systems are described in Section 6.2. Diversity of electric power supplies is discussed in Chapter 8.

This criterion is associated with 1967 GDC 37.

Criterion 42, 1971 - Inspection of Containment Atmosphere Cleanup Systems

The containment atmosphere cleanup systems shall be designed to permit appropriate periodic inspection of important components, such as filter frames, ducts, and piping to assure the integrity and capability of the systems.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 42.

Nondestructive examination is performed on the components of the systems in accordance with the requirements of the applicable codes as described in Section 3.2.

The containment spray system is designed so that component surveillance can be performed periodically to demonstrate system readiness. The pressure-containing portions of the system are tested periodically to check for leakage. This testing includes the portions of the system that would circulate radioactive water from the containment sump, if recirculation spray was required.

Access is available for visual inspection of the fan cooler components, including fans, cooling coils, enclosure dampers, and ductwork. Because these units are in use during power operation, continuous checks of their status are available. Additional details are found in Section 6.2.

This criterion is associated with 1967 GDC 62.

Criterion 43, 1971 - Testing of Containment Atmosphere Cleanup Systems

The containment atmosphere cleanup systems shall be designed to permit appropriate periodic pressure and functional testing to assure (1) the structural and leaktight integrity of its components, (2) the operability and performance of the active components of the systems such as fans, filters, dampers, pumps, and valves and (3) the operability of the systems as a whole and, under conditions as close to design as

practical, the performance of the full operational sequence that brings the systems into operation, including operation of applicable portions of the protection system, the transfer between normal and emergency power sources, and the operation of associated systems.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 43. Periodic tests demonstrate the integrity, operability, and performance of the containment atmosphere cleanup systems.

The containment spray system, utilizing sodium hydroxide, serves as the air cleanup system. The active components in the containment spray system are given preoperational performance tests after installation. Permanent test lines for all containment spray loops are located so that all components up to the isolation valves at the containment may be tested. The nozzles are tested by airflow that is monitored by positive means. The fan coolers are normally in use, which provides a check on the operability of the system. Additional details are found in Section 6.2.

Design provisions have been made, to the extent practicable, to facilitate access for periodic visual inspection of all important components of the containment fan cooler system. Testing of any components, after maintenance or as a part of a periodic inspection program, may be performed at any time, since the containment fan cooler system units are in operation on an essentially continuous schedule during normal plant operation.

This criterion is associated with 1967 GDCs 63, 64, and 65.

Criterion 44, 1971 - Cooling Water

A system to transfer heat from structures, systems, and components important to safety, to an ultimate heat sink shall be provided. The system safety function shall be to transfer the combined heat load of these structures, systems, and components under normal operating and accident conditions.

Suitable redundancy in components and features, and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 44. A PG&E Design Class I component cooling water (CCW) system is provided to transfer heat from reactor coolant, engineered safety features, and the containment to the PG&E Design

Class I auxiliary saltwater (ASW) system. The latter system discharges to the Pacific Ocean, which is the ultimate heat sink.

The CCW system is designed to provide cooling water to vital and nonvital components and to operate in all plant operating modes, including normal power operation, plant cooldown, and emergencies, including a LOCA or MSLB. Safety analyses for containment peak pressure demonstrate that only one ASW pump and one CCW heat exchanger is required to provide sufficient heat removal from containment to mitigate a MSLB or LOCA.

The CCW system is designed to continue to perform its safety function following an accident assuming a single active failure during the short-term recovery period and either a single active or passive failure during the long-term recovery period. Refer to Section 3.1.1 for a description of DCPP single failure criteria and definition of terms. During normal operation and up to 24 hours after an accident (the short-term recovery period), the CCW headers are crosstied. This configuration will withstand a single active failure without the loss of safety function. For a passive failure (up to a 200 gpm leak for 20 minutes), operator mitigation action (consisting of valve manipulations) is credited to stop leaks. The CCW piping design includes valving for isolating cooling water flow associated with individual components and for complete isolation of a header. The CCW system components that are considered vital are redundant. The three CCW pump motors are on separate vital 4.16 kV buses that have diesel generator standby power sources. A radiation monitor associated with each of the two CCW pump discharge headers monitors the CCW system for radioactive in-leakage.

Additional details are found in Section 9.2.

No direct correlation exists with the 1967 GDC.

Criterion 45, 1971 - Inspection of Cooling Water System

The cooling water system shall be designed to permit appropriate periodic inspection of important components, such as heat exchangers and piping, to assure the integrity and capability of the system.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 45. The component cooling water pumps, heat exchangers, associated valves, large piping, and instrumentation are located outside the containment and are therefore accessible for maintenance and inspection during power operation. Cooling water systems are discussed in Section 9.2.

No direct association exists with the 1967 GDC.

Criterion 46, 1971 - Testing of Cooling Water System

The cooling water system shall be designed to permit appropriate periodic pressure and functional testing to assure (1) the structural and leaktight integrity of its components, (2) the operability and the performance of the active components of the system, and (3) the operability of the system as a whole and under conditions as close to design as practical, the performance of the full operational sequence that brings the system into operation for reactor shutdown and for loss-of-coolant accidents, including operation of applicable portions of the protection system and the transfer between normal and emergency power sources.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 46. System design permits periodic hydrostatic testing of the cooling water system during plant shutdown. The system is pressurized during power operation. The emergency control functions can be tested out to the final actuated device as described in Chapter 7.

No direct association exists with the 1967 GDC.

Criterion 50, 1971 - Containment Design Basis

The reactor containment structure, including access openings, penetrations, and the containment heat removal system shall be designed so that the containment structure and its internal compartments can accommodate, without exceeding the design leakage rate and, with sufficient margin, the calculated pressure and temperature conditions resulting from any loss-of-coolant accident. This margin shall reflect consideration of (1) the effects of potential energy sources which have not been included in the determination of the peak conditions, such as energy in steam generators and energy from metal-water and other chemical reactions that may result from degraded emergency core cooling functioning, (2) the limited experience and experimental data available for defining accident phenomena and containment responses, and (3) the conservatism of the calculational model and input parameters.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 50. The containment structure has been designed with sufficient margins to accommodate the calculated pressure and temperature conditions resulting from any LOCA.

The containment, including access openings and penetrations, has a design pressure of 47 psig. The greatest transient peak pressure associated with a postulated rupture of the piping in the RCS and the calculated effects of metal-water reaction do not exceed this value. The containment is strength tested at 54 psig.

The reactor containment structure and penetrations, with the aid of containment heat removal systems, are designed to limit radiation doses resulting from leakage of radioactive fission products from the containment to below 10 CFR 100 values, assuming the largest credible energy release following a LOCA, including a margin to cover the effects of metal water or other undefined energy sources. The containment design is described in detail in Section 3.8.1.

This criterion is associated with 1967 GDC 49.

Criterion 51, 1971 - Fracture Prevention of Containment Pressure Boundary

The reactor containment boundary shall be designed with sufficient margin to assure that under operating, maintenance, testing, and postulated accident conditions (1) its ferritic materials behave in a nonbrittle manner and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the containment boundary material during operation, maintenance, testing, and postulated accident conditions, and the uncertainties in determining (1) material properties, (2) residual, steady-state, and transient stresses, and (3) size of flaws.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 51. The concrete containment structure is not susceptible to low-temperature brittle fracture. The independence of the reinforcing steel minimizes the possibility of rapidly propagating fracture. The steel liner is not directly exposed to the temperature of the environs.

The selection and use of containment structure materials comply with the applicable codes and standards.

The containment liner is enclosed within the containment structure and thus not directly exposed to the temperature of the external environment and not subject to Criterion 50, 1967. Nevertheless, the design specification required Charpy V notch tests at 20°F for the containment liner. This corresponds to a lowest service temperature of 50°F during operation. Further information on containment structure materials appears in Section 3.8.

This criterion is associated with 1967 GDC 50.

Criterion 52, 1971 - Capability for Containment Leakage Rate Testing

The reactor containment and other equipment which may be subjected to containment test conditions shall be designed so that periodic integrated leakage rate testing can be conducted at containment design pressure.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 52. The containment design will accommodate both initial strength testing at 1.15 times design pressure and periodic leakage rate testing. The containment is provided with testable weld channels and penetrations so that sensitive leakage rate tests can be made of these areas where leakage could occur. Periodic leakage rate testing will be performed over the life of the units in accordance with the requirements of Appendix J to 10 CFR 50, Option B, as modified by approved exemptions.

The leakage rate tests and the sensitive leakage rate test demonstrate the integrity of the double leakage barriers provided by the penetrations and the overall integrity of the containment structure. The criterion for acceptance is that the measured leakage rate be less than 0.10 percent of the containment free volume per day. Further details of the integrated leakage rate test and the sensitive leakage rate test provisions appear in Section 3.8.

This criterion is associated with 1967 GDCs 54 and 55.

Criterion 53, 1971 - Provisions for Containment Testing and Inspection

The reactor containment shall be designed to permit (1) appropriate periodic inspection of all important areas, such as penetrations, (2) an appropriate surveillance program, and (3) periodic testing at containment design pressure of the leaktightness of penetrations which have resilient seals and expansion bellows.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 53. The containment design includes provision for testing and inspecting penetrations, liner plate areas, and areas of seals and expansion bellows.

All penetrations are provided with a volume that can be pressurized to test for leaktightness. There are three configurations used: (a) weld channels over the penetration welds, (b) an annular space between the penetration insert and the sleeve, which is sealed at both ends, and (c) double resilient seals with a gap between the seals. Further details appear in Section 3.8.

Periodic leakage rate testing is performed in accordance with the requirements of Appendix J of 10 CFR 50. Applicable surveillance requirements for such testing are included in the Technical Specifications.

This criterion is associated with 1967 GDC 56.

Criteria 54, 1971 - Piping Systems Penetrating Containment

Piping systems penetrating primary reactor containment shall be provided with leak detection, isolation, and containment capabilities having redundance, reliability, and performance capabilities which reflect the importance to safety of isolating these piping systems. Such piping systems shall be designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to Criterion 54 except where specifically indicated in Section 6.2.4. The containment isolation design provides for a double barrier at the containment penetration in those fluid systems that are not required to function following a design basis event. Piping systems penetrating the containment are provided with test vents and test connections or have other provisions to allow periodic leakage testing. Those automatic isolation valves that do not restrict normal plant operation are periodically tested to ensure operability. Section 6.2.4 describes in detail the testing of isolation valves.

This criterion is associated with 1967 GDC 57.

Criterion 55, 1971 - Reactor Coolant Pressure Boundary Penetrating Containment

Each line that is part of the reactor coolant pressure boundary and that penetrates primary reactor containment shall be provided with containment isolation valves as follows, unless it can be demonstrated that the containment isolation provisions for a specific class of lines, such as instrument lines, are acceptable on some other defined basis:

(1) One locked closed isolation valve inside and one locked closed isolation valve outside containment; or

(2) One automatic isolation valve inside and one locked closed isolation valve outside containment; or

(3) One locked closed isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment; or

(4) One automatic isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment.

Isolation valves outside containment shall be located as close to containment as practical and upon loss of actuating power, automatic isolation valves shall be designed to take the position that provides greater safety.

Other appropriate requirements to minimize the probability or consequences of an accidental rupture of these lines or of lines connected to them shall be provided as necessary to assure adequate safety. Determination of the appropriateness of these requirements, such as higher quality in design, fabrication, and testing, additional provisions for inservice inspection, protection against more severe natural phenomena, and additional isolation valves and containment, shall include consideration of the population density, use characteristics, and physical characteristics of the site environs.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to Criterion 55 except where specifically indicated in Section 6.2.4. The reactor coolant pressure boundary is defined as those piping systems and components that contain reactor coolant at design pressure and temperature. With the exception of the reactor coolant sampling lines, the entire reactor coolant pressure boundary, as defined above, is located entirely within the containment structure. All sampling lines are provided with remotely operated valves for isolation in the event of a failure. These valves also close automatically on a containment isolation signal. Sampling lines are only used during infrequent sampling and can readily be isolated. Refer to Section 6.2.4 for details on conformance.

This criterion is associated with 1967 GDCs 51 and 57.

Criterion 56, 1971 - Primary Containment Isolation

Each line that connects directly to the containment atmosphere and penetrates primary reactor containment shall be provided with containment isolation valves as follows, unless it can be demonstrated that the containment isolation provisions for a specific class of lines, such as instrument lines, are acceptable on some other defined basis:

(1) One locked closed isolation valve inside and one locked closed isolation valve outside containment; or

(2) One automatic isolation valve inside and one locked closed isolation valve outside containment; or

(3) One locked closed isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment; or

(4) One automatic isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment.

Isolation valves outside containment shall be located as close to containment as practical and upon loss of actuating power, automatic isolation valves shall be designed to take the position that provides greater safety.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to Criterion 56 except where specifically indicated in Section 6.2.4. Each line that connects directly to the containment atmosphere and penetrates the primary reactor containment is provided with containment isolation valves as required. Refer to Section 6.2.4 for further discussion. This criterion is associated with 1967 GDC 53.

Criterion 57, 1971 - Closed System Isolation Valves

Each line that penetrates primary reactor containment and is neither part of the reactor coolant pressure boundary nor connected directly to the containment atmosphere shall have at least one containment isolation valve which shall be either automatic, or locked closed, or capable of remote manual operation. This valve shall be outside containment and located as close to the containment as practical. A simple check valve may not be used as the automatic isolation valve.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to Criterion 57 except where specifically indicated in Section 6.2.4. Each line that penetrates the reactor containment in each unit, and is neither part of the reactor coolant pressure boundary nor connected directly to the containment atmosphere, has at least one containment isolation valve located outside the containment as close to the containment as practicable. The component cooling water penetration to the excess letdown heat exchanger is an exception that does not meet the 1971 GDC because of commitments to design and construction made prior to the issuance of the 1971 GDC; this penetration does comply with the 1967 GDC 53. Refer to Section 6.2.4 for details on conformance.

This criterion is associated with 1967 GDC 53.

Criterion 60, 1971 - Control of Releases of Radioactive Materials to the Environment

The nuclear power unit design shall include means to control suitably the release of radioactive materials in gaseous and liquid effluents and to handle radioactive solid wastes produced during normal reactor operation, including anticipated operational occurrences. Sufficient holdup capacity shall be provided for retention of gaseous and liquid effluents containing radioactive materials, particularly where unfavorable site environmental conditions can be expected to impose unusual operational limitations upon the release of such effluents to the environment.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 60. An extensive treatment system has been incorporated in the design for processing liquid wastes. Gaseous wastes are processed by appropriate holdup. Solid wastes are solidified in concrete (except for clothing, paper, etc.) for eventual disposition in licensed burial grounds.

The containment atmosphere, the plant vents, and the liquid and gaseous waste systems effluent discharge paths are monitored for radioactivity concentrations during all modes of operations. The monitoring systems are described in Section 11.4. The offsite radiological monitoring program is described in Section 11.6.

Waste handling systems are incorporated in each facility design for processing and/or retention of normal operation radioactive wastes with appropriate controls and monitors to ensure that releases do not exceed the limits of 10 CFR 20. The facilities are also designed with provisions to monitor radioactivity release during accidents and to prevent releases from causing exposures in excess of the guideline levels specified in 10 CFR 100.

The containment system, which forms a barrier to the escape of fission products should a loss of coolant occur, is described in Section 6.2. Postulated accidents that could release radioactivity to the environment are analyzed in Chapter 15.

This criterion is associated with 1967 GDCs 17 and 70.

Criterion 61, 1971 - Fuel Storage and Handling and Radioactivity Control

The fuel storage and handling, radioactive waste, and other systems which may contain radioactivity shall be designed to assure adequate safety under normal and postulated accident conditions. These systems shall be designed (1) with a capability to permit appropriate periodic inspection and testing of components important to safety, (2) with suitable shielding for radiation protection, (3) with appropriate containment, confinement, and filtering systems, (4) with a residual heat removal capability having reliability and testability that reflects the importance to safety of decay heat and other residual heat removal, and (5) to prevent significant reduction in fuel storage coolant inventory under accident conditions.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 61. The fuel storage facility meets the requirements of Safety Guide 13, March 1971. Radioactive waste treatment systems that contain or confine leakage under normal and accident conditions are located in the auxiliary building. Adequate shielding is provided. The associated ventilation equipment includes charcoal filtration that minimizes radioactive material release associated with a postulated fuel handling accident.

The spent fuel area is enclosed and maintained under negative pressure. All ventilation air is passed through HEPA filters prior to being released to the plant vent. In the event of an accident, high activity would be detected by the radiation monitor (see Section 11.4), and the exhaust air would be diverted through charcoal filters. For radioactive waste storage, refer to the detailed discussion in Chapter 11. Failure of a gas decay tank has been postulated and analyzed in Chapter 15.

Waste handling systems are incorporated in the facility design for processing and/or retention of radioactive wastes from normal operation, with appropriate controls and monitors to ensure that releases do not exceed the limits of 10 CFR 20. The radioactive waste processing system, the design criteria, and amounts of estimated releases of radioactive effluents to the environment are described in Chapter 11. Details of the monitoring system are found in Section 11.4.

Refueling water provides a reliable and adequate cooling medium for spent fuel transfer, and heat removal is provided by an auxiliary cooling system. Natural radiation and convection is adequate for cooling the holdup tanks.

Active components of the spent fuel pool cooling and cleanup system are either in continuous or intermittent use during normal system operation. Periodic visual inspection and preventive maintenance are conducted using normal industry practice.

System piping is arranged so that failure of any pipeline cannot inadvertently drain the spent fuel pool below the water level required for radiation shielding. Demineralized makeup water can be added directly to the spent fuel pool by a PG&E Design Class I source.

This criterion is associated with 1967 GDCs 68 and 69.

Criterion 62, 1971 - Prevention of Criticality in Fuel Storage and Handling

Criticality in the fuel storage and handling system shall be prevented by physical systems or processes, preferably by use of geometrically safe configurations.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 62. Fuel storage and transfer systems are configured to preclude criticality.

During reactor vessel head removal and while loading and unloading fuel from the reactor, the boron concentration in the refueling water and the spent fuel pool is maintained at not less than that required to shut down the core to a k_{eff} = 0.95.

Borated water is used to fill the spent fuel storage pools at a concentration comparable to that used in the reactor cavity and refueling canal during refueling operations. The

fuel is stored vertically in an array with sufficient center-to-center distance between assemblies to ensure that, including uncertainties, a k_{eff} of less than or equal to 0.95 if the fuel racks are flooded with borated water, and a k_{eff} < 1.0, even if unborated water is used to fill the pool. The fuel storage and handling details are found in Section 9.1.

This criterion is associated with 1967 GDC 66.

Criterion 63, 1971 - Monitoring Fuel and Waste Storage

Appropriate systems shall be provided in fuel storage and radioactive waste systems and associated handling area (1) to detect conditions that may result in loss of residual heat removal capability and excessive radiation levels and (2) to initiate appropriate safety actions.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 63. Failure in the spent fuel pool cooling system and high radiation level in the spent fuel pool or radioactive waste areas are alarmed locally and in the control room.

The fuel and waste storage and handling areas are provided with monitoring and alarm systems for radioactivity, and the plant vents are monitored for radioactivity during all operations. The monitoring systems are described in Section 11.4.

The spent fuel pool cooling system is equipped with adequate instrumentation for normal operation. Water temperatures in the pool and at the outlet of the heat exchanger are indicated locally, and high pool temperature is alarmed in the control room. The spent fuel pool cooling system is described in Section 9.1.

This criterion is associated with 1967 GDC 18.

Criterion 64, 1971 - Monitoring Radioactivity Releases

Means shall be provided for monitoring the reactor containment atmosphere, spaces containing components for recirculation of loss-of-coolant accident fluids, effluent discharge paths, and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences, and from postulated accidents.

Discussion

The DCPP Units 1 and 2 designs conform to the intent of Criterion 64. The containment atmospheres, the plant vents, and the waste effluents are monitored for radioactivity concentration during all operations.

Radiation detection instruments are located in areas of the plant that house equipment containing or processing radioactive materials. These instruments continually detect, compute, and record operating radiation levels.

The data from the offsite monitoring program are reported annually. The reports include the basic data on sampling locations, organism collected, counting data, gross activity levels, identification of gamma emitting isotopes, and the associated counting errors. The monitoring systems are described in Section 11.4. The offsite radiological monitoring program is described in Section 11.6.

This criterion is associated with 1967 GDC 17.

Chapter 4

REACTOR

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FIGURES (Continued)

FIGURES (Continued)

Chapter 4

REACTOR

This chapter describes the design for the reactors at Diablo Canyon Power Plant (DCPP) Units 1 and 2, and evaluates their capability to function safely under all operating modes expected during their lifetimes.

4.1 SUMMARY DESCRIPTION

This chapter describes the following subjects: (a) the mechanical components of the reactor and reactor core, including the fuel rods and fuel assemblies, reactor internals, and the control rod drive mechanisms, (b) the nuclear design, and (c) the thermal-hydraulic design.

The reactor core of each unit typically consists of VANTAGE 5 fuel assemblies, instead of the low parasitic (LOPAR) fuel previously used. Some of the current Chapter 15 accident analyses, including the large break and small break loss of coolant accidents, assume an all Vantage 5 core. Therefore, it is not expected that LOPAR fuel will be used without further analysis. Nevertheless, this section addresses both LOPAR fuel assemblies and Vantage 5 arranged in a low leakage core-loading pattern.

The significant mechanical design features of the VANTAGE 5 design, as defined in Reference 1, relative to the LOPAR fuel design may include the following:

- Integral Fuel Burnable Absorber (IFBA)
- Intermediate Flow Mixer (IFM) Grids
- Protective Grid Assemblies (P-Grid)
- Reconstitutable Top Nozzle (RTN)
- Slightly longer fuel rods and thinner top and bottom nozzle end plates to accommodate extended burnup
- Axial Blanket (typically six inches of natural or slightly enriched UO_2 at both ends of fuel stack)
- Replacement of six intermediate Inconel grids with zirconium alloy grids
- Reduction in fuel rod, guide thimble and instrumentation tube diameter
- Redesigned fuel rod bottom end plug to facilitate reconstitution capability.
- Debris filter bottom nozzle (DFBN)

Commencing with Unit 2 Region 20 (Cycle 18 feed) and Unit 1 Region 21 (Cycle 19 feed), the Westinghouse fuel assemblies will utilize the Standardized Debris Filter Bottom Nozzle (SDFBN). This feature is discussed in detail in Section 4.2.1.2.2.

The core is cooled and moderated by light water at a nominal pressure of 2250 psia in the reactor coolant system (RCS). The moderator coolant uses boron as a neutron absorber. Boron concentration in the coolant is varied as required to control relatively slow reactivity changes, such as fuel burnup. Additional boron, in the form of Integral Fuel Burnable Absorbers (IFBA) or burnable absorber rods may be employed to limit the moderator temperature coefficient (MTC) and the local power peaking that can be achieved.

A fuel assembly consists of up to 264 mechanically joined fuel rods in a 17 x 17 square array. The fuel rods are supported at intervals along their length by grid assemblies that maintain the lateral spacing between the rods throughout the design life of the assembly. The grid assembly consists of an "egg-crate" arrangement of interlocked straps. The straps contain spring fingers and dimples for maintaining fuel rod lateral and axial support, as well as for providing coolant mixing vanes. The fuel rods consist of enriched UO_2 cylindrical pellets contained in zirconium alloy tubing that is plugged and seal-welded at the ends. To increase fatigue life, all fuel rods are pressurized with helium during fabrication to reduce stress and strain.

The center position in the assembly is reserved for incore instrumentation; the remaining 24 positions in the array are equipped with guide thimbles joined to the grids and the top and bottom nozzles. Depending on assembly position in the core, the guide thimbles are used as core locations for rod cluster control assemblies (RCCAs), neutron source assemblies, and burnable absorber rods (if used).

The bottom nozzle is a box-like structure that serves as a bottom structural element of the fuel assembly and directs the coolant flow to the assembly.

The top nozzle assembly functions as the upper structural element of the fuel assembly in addition to providing a partial protective housing for the RCCA or other components.

Each RCCA consists of a group of individual absorber rods fastened at the top end to a common hub or spider assembly.

The control rod drive mechanisms (CRDMs) for the RCCA are of the magnetic latch type. The latches are controlled by three magnetic coils. Upon a loss of power to the coils, the RCCA is released and falls by gravity to shut down the reactor.

Components of the reactor internals are divided into three parts: (a) the lower core support structure (including the entire core barrel, the Unit 1 thermal shield, and the Unit 2 neutron shield pad assembly), (b) the upper core support structure, and (c) the incore instrumentation support structure. Reactor internals support the core, maintain fuel alignment, limit fuel assembly movement, maintain alignment between fuel

assemblies and CRDMs, direct coolant flow past the fuel elements to the pressure vessel head, provide gamma and neutron shielding, and provide guides for incore instrumentation.

The nuclear design analyses and evaluation establish physical locations for control rods, burnable absorber, and physical parameters such as fuel enrichments and boron concentration in the coolant. These characteristics, together with corrective actions by the reactor control and the protection and the emergency core cooling systems, provide adequate reactivity control even if the RCCA with the highest reactivity worth is stuck in the fully withdrawn position. They meet the reactor performance and safety criteria specified in Section 4.2.

The thermal-hydraulic design analyses and evaluation establish coolant flow parameters that ensure adequate heat transfer between fuel cladding and reactor coolant. The thermal design takes into account local variations in dimensions, power generation, flow distribution, mixing and the IFM grids in the VANTAGE 5 fuel assembly. The mixing vanes incorporated in the fuel assembly spacer grid design induce additional flow mixing between the various flow channels within a fuel assembly as well as between adjacent assemblies.

The fuel assembly design, starting at Cycle 9, consisted of VANTAGE 5+ assemblies with fully enriched annular fuel pellets in the axial blanket region of the fuel rods (see Section 4.2.1.2.1) in order to provide additional internal rod pressure design margin.

The Cycle 9 core design also revised the design Departure From Nucleate Boiling Ratio (DNBR) (see Section 4.4) to incorporate uncertainties and biases for reactor power, flow, temperature, and pressure. The original Improved Thermal Design Procedure (ITDP) (see Section 4.2.4, Reference 86) is updated with these new uncertainties and evaluated for each fuel reload cycle. The reload design documents for each fuel cycle contain the updated ITDP reference and the new design DNBR, if required, to be incorporated into the Technical Specification Bases.

Starting at Cycle 12, the VANTAGE 5+ design had evolved to incorporate a protective grid assembly (P-Grid) at the bottom of the fuel rods that spans the gap between the bottom nozzle and grid and the fuel rods and provides an additional debris barrier to improve fuel reliability.

Instrumentation is provided in and out of the core to monitor the nuclear, thermal-hydraulic, and mechanical performance of the reactor, and to provide input signals to control functions automatically.

Table 4.1-1 presents a comparison between the reactor design parameters for the DCPP Units 1 and 2 reactor cores fueled with LOPAR fuel assemblies and VANTAGE 5 fuel assemblies. The analysis techniques employed in the core design are tabulated in Table 4.1-2. Design loading conditions for reactor core components are tabulated in Table 4.1-3.

4.1.1 REFERENCES

1. S. L. Davidson, (Ed.), Reference Core Report - VANTAGE 5 Fuel Assembly, WCAP-10444-P-A, September 1985.

4.2 MECHANICAL DESIGN

For design purposes, the Diablo Canyon Power Plant (DCPP) conditions are divided into four categories, in accordance with their anticipated frequency of occurrence and risk to the public, as follows:

(1) Condition I - Normal Operation

(2) Condition II - Incidents of Moderate Frequency

(3) Condition III - Infrequent Faults

(4) Condition IV - Limiting Faults

In general, Condition I occurrences are accommodated with margin between any plant parameter and the value of that parameter which would require either automatic or manual protective action. Condition II incidents are accommodated with, at most, a shutdown of the reactor with the plant capable of returning to operation after corrective action.

The release of radioactive material due to Condition III incidents should not be sufficient to interrupt or restrict public use of areas outside the exclusion area. Furthermore, a Condition III incident shall not, by itself, generate a Condition IV fault or result in a consequential loss of function of the reactor coolant system (RCS) or reactor containment barriers.

Condition IV occurrences are faults that are not expected to occur, but are defined as limiting faults that must be considered in design. Condition IV faults shall not cause a release of radioactive material that results in an undue risk to public health and safety.

The reactor is designed so that its components meet the following performance and safety criteria:

(1) The mechanical design of the reactor core components and their physical arrangement, together with corrective actions by the reactor control, protection, and emergency cooling systems (when applicable) ensure that:

(a) Fuel damage[a] is not expected during Conditions I and II events, although a very small number of fuel rod failures is anticipated. This number of failures is within the capability of the plant cleanup system and is consistent with the plant design bases.

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[a] Fuel damage as used here is defined as penetration of the fission product barrier (i.e., the fuel rod cladding).

(b) The reactor can be brought to a safe state following a Condition III event with only a small number of fuel rods damaged, although sufficient fuel damage may occur to preclude resumption of operation without considerable outage time.

(c) The reactor can be brought to a safe state and the core can be kept subcritical with acceptable heat transfer geometry, following transients arising from Condition IV events.

(2) The fuel assemblies are designed to accommodate conditions expected to exist as a result of handling during assembly, inspection, and refueling operations, as well as shipping loads.

(3) The fuel assemblies are designed to accept control rod insertions to provide the reactivity control required for power operations and shutdown conditions.

(4) All fuel assemblies have provisions for the insertion of the incore instrumentation necessary for plant operation.

(5) The reactor internals, in conjunction with the fuel assemblies, direct reactor coolant through the core to achieve acceptable flow distribution and to restrict bypass flow so that the heat transfer performance requirements can be met for all modes of operation. In addition, internals provide core support and distribute coolant flow to the pressure vessel head. The distribution of flow into the vessel head minimizes axial and circumferential temperature gradients, thus precluding excessive rotation or warpage that could result in leakage past the O-ring gaskets during Conditions I and II operations. Required inservice inspections can be carried out since the internals are removable and provide access to the inside of the pressure vessel.

4.2.1 FUEL

4.2.1.1 Design Bases

For both the low parasitic (LOPAR) and the VANTAGE 5 fuel assemblies, the fuel rod and fuel assembly design bases are established to satisfy the general performance and safety criteria presented in Section 4.2 and the specific criteria noted below.

4.2.1.1.1 Fuel Rods

To ensure their integrity, fuel rods are designed to prevent excessive fuel temperatures, excessive internal gas pressures due to fission gas buildup, and excessive cladding stresses and strains. To this end, the following conservative design bases are adopted for Condition I and Condition II operations:

(1) Fuel Pellet Temperatures - The center temperature of the hottest pellet is to be below the melting temperature of the UO2 (melting point of 5080°F (Reference 1)) unirradiated and reducing by 58°F per 10,000 megawatt days/metric ton of uranium (MWD/MTU). While a limited amount of center melting can be tolerated, the design conservatively precludes center melting. A calculated centerline fuel temperature of 4700°F has been selected as the overpower limit. This provides sufficient margin for uncertainties.

(2) Internal Gas Pressure - The fuel rod internal gas pressure remains below the value that can cause the fuel-cladding diametral gap to increase due to outward cladding creep during steady state operation. Rod pressure is also limited so that extensive departure from nucleate boiling (DNB) propagation does not occur during normal operation and accident events (Reference 14). Also, cladding flattening (Reference 15) will not occur during the fuel rod incore life.

(3) Cladding Stress - The effective cladding stresses are less than those that would cause general cladding yield. While the cladding has some capability to accommodate plastic strain, the yield strength has been accepted as a conservative design basis.

(4) Cladding Tensile Strain - The cladding tangential strain is less than 1 percent. The cladding strain design basis addresses slow transient strain rate mechanisms where the cladding effective stress never reaches the yield strength due to stress relaxation. The 1 percent strain limit is based on tensile and burst test data from irradiated cladding. Irradiated cladding properties are appropriately used since irradiation effects on cladding ductility occur before strain-limiting fuel cladding interaction during a transient event can occur.

(5) Strain Fatigue - The cumulative strain fatigue cycles are less than the design strain fatigue life.

Radial, tangential, and axial stress components due to pressure differential and fuel cladding contact pressure are combined into an effective stress using the maximum-distortion-energy theory. The von Mises criterion (Reference 22) is used to evaluate whether or not the yield strength has been exceeded. The criterion states that an isotropic material under multiaxial stress will begin to yield plastically when the effective stress (i.e., combined stress using maximum-distortion-energy theory) becomes equal to the material yield stress in simple tension, as determined by a uniaxial tensile test. Since general yielding is prohibited, the volume average effective stress determined by integrating across the cladding thickness is increased by an allowance for local nonuniformity effects before the stress is compared to the yield strength. The yield strength correlation is that appropriate for irradiated cladding since the irradiated properties are attained at low exposure, whereas the fuel/cladding

interaction conditions, which can lead to minimum margin to the design basis limit, always occur at much higher exposures.

The preceding fuel rod design bases and other supplementary fuel design criteria/limits are given in Section 2 of Reference 25. Reference 25 provides the methodology for peak rod burnups in excess of 50,000 MWD/MTU. The above requirements impact design parameters such as pellet size and density, cladding-pellet diametral gap, gas plenum size, and helium pre-pressure. The design also considers effects such as fuel density changes, fission gas release, cladding creep, and other physical properties that vary with burnup.

An extensive irradiation testing and fuel surveillance operational experience program has been conducted to verify the adequacy of the fuel performance and design bases. This program is discussed in Section 4.2.1.3.3.

4.2.1.1.2 Fuel Assembly Structure

Structural integrity of fuel assemblies is ensured by setting limits on stresses and deformations due to various loads, and by determining that the assemblies do not interfere with other components' operability. Three types of loads are considered:

(1) Nonoperational loads, such as those due to shipping and handling

(2) Normal and abnormal loads defined for Conditions I and II

(3) Abnormal loads defined for Conditions III and IV

These stress and deformation limits are applied to the design and evaluation of the top and bottom nozzles, the guide thimbles, the grids, and the thimble joints.

The design bases for evaluating the structural integrity of the fuel assemblies are:

(1) Nonoperational - 4g axial and 6g lateral loading with dimensional stability in both lateral and axial directions.

(2) Normal Operation (Condition I) and Incidents of Moderate Frequency (Condition II). The fuel assembly component structural design criteria are classified into two material categories: austenitic steels and zirconium alloys. Although not strictly fuel assembly components, reactor core elements that are made of stainless steel and are closely related to the fuel assembly design include the top and bottom nozzle, the RCCA cladding, and some burnable absorber rod's cladding.

    The stress categories and strength theory presented in the ASME Boiler and Pressure Vessel Code (ASME B&PV), Section III, are used as a general guide.

Zirconium alloy structural components, which consist of guide thimbles and fuel tubes, are in turn subdivided into two categories because of material differences and functional requirements. The fuel tube design criteria are covered separately in Section 4.2.1.3.1. To evaluate the guide thimble design, the maximum stress theory, which assumes that yielding due to combined stresses occurs when one of the principal stresses is equal to the simple tensile or compressive yield stress, is used. Unirradiated zirconium alloy properties are used to define the stress limits.

The maximum shear stress theory (Tresca criterion (Reference 22) for combined stresses is used to determine the stress intensities for the austenitic steel components. The stress intensity is defined as the numerically largest difference between the various principal stresses in a three-dimensional field. The allowable stress intensity value for austenitic stainless steel, such as nickel-chromium-iron alloys, is given by the lowest of the following:

(a) One-third of the specified minimum tensile strength, or two-thirds of the minimum yield strength, at room temperature.

(b) One-third of the tensile strength or 90 percent of the yield strength, at temperature, but not to exceed two-thirds of the specified minimum yield strength at room temperature.

The stress intensity limits for the austenitic steel components are:

Stress Intensity Limits

Categories	Limit
General Primary Membrane Stress Intensity	1.0 S_m
Local Primary Membrane Stress Intensity	1.5 S_m
Primary Membrane plus Bending Stress Intensity	1.5 S_m
Total Primary plus Secondary Stress Intensity	3.0 S_m

where S_m is the membrane stress.

(3) Abnormal Loads During Conditions III or IV - Worst cases are represented by combined seismic and blowdown loads; however, with acceptance of the DCPP leak-before-break analysis by the NRC (Reference 30), the blowdown loads resulting from pipe rupture events in the main reactor coolant loop piping no longer have to be considered in the design basis analysis. Only the much smaller blowdown loads from RCS branch line breaks have to be considered (see Section 3.6.2.1.1.1.).

(a) Deflections of components cannot interfere with reactor shutdown or emergency cooling of fuel rods.

(b) The fuel assembly structural component stress under faulted conditions are evaluated using primarily the methods outlined in Appendix F of the ASME Boiler and Pressure Vessel Code, Section III. Since the current analytical methods utilize elastic analysis, the stress allowables are defined as the smaller value of 2.4 S_m or 0.70 Su (ultimate stress) for primary membrane and 3.6 S_m or 1.05 Su for primary membrane plus primary bending. For the austenitic steel fuel assembly components, the stress intensity is defined in accordance with the rules described in the previous section for normal operating conditions. For the Zircaloy components the stress intensity limits are set at two-thirds of the material yield strength, Sy, at reactor operating temperature. This results in Zircaloy stress limits being the smaller of 1.6 Sy or 0.70 Su for primary membrane and 2.4 Sy or 1.05 Su for primary membrane plus bending. For conservative purposes, the Zircaloy unirradiated properties are used to define the stress limits. The grid component strength criteria are based on experimental tests. For both Zircaloy and Inconel grids, the limit is the 95 percent confidence level on the true mean as taken from the distribution of measurements at operating temperature.

4.2.1.2 Description and Design Drawings

The fuel assembly and fuel rod design data are listed in Table 4.1-1. NRC approval of the VANTAGE 5 design is given in Reference 26. Figure 4.2-1 shows a cross section of the fuel assembly array, and Figures 4.2-2 and 4.2-2a show fuel assembly full-length outlines. The fuel rods are loaded into the fuel assembly structure so that there is clearance between the fuel rod ends and the top and bottom nozzles. A slightly modified rod end plug, an improved bottom nozzle reconstitution feature, and modified grid straps to improve resistance to hangup during refueling were introduced with Region 4 of both units.

Shown in Figure 4.2-2a is a comparison of the different assembly designs noting respective overall height and grid elevation dimensions. The changes from the LOPAR design to the VANTAGE 5 design include a reduction in fuel rod, guide thimble and instrumentation tube diameters, and replacement of the six intermediate (mixing vane) Inconel grids with zirconium alloy grids. The VANTAGE 5 design also incorporates three zirconium alloy intermediate flow mixing (IFM) grids. The debris filter bottom nozzle (DFBN) has been incorporated into the VANTAGE 5 fuel assembly. The DFBN is similar to the LOPAR bottom nozzle design used in Region 5 (Cycle 3 feed) of the Diablo Canyon cores, except it is lower in height and has a new pattern of smaller flow holes. The DFBN minimizes passage of debris particles which could cause fretting damage to fuel rod cladding. Starting with Unit 2 Region 20 (Cycle 18 feed) and Unit 1 Region 21 (Cycle 19 feed), the SDFBN will be utilized. This SDFBN is discussed further in Section 4.2.1.2.2.

The VANTAGE 5 assembly has the same cross-sectional envelope as the LOPAR assembly. The grid centerline elevations of the VANTAGE 5 are identical to those of the LOPAR assembly, except for the top and bottom grids. The grid centerline elevations of the VANTAGE 5 assemblies with P-Grids are identical to those of the VANTAGE 5, except for the bottom and first intermediate grid. However, for mixed cores, an integral grid-to-grid contact between different fuel assemblies is maintained. By matching grid elevation, any crossflow maldistribution between the fuel assemblies is minimized. The effect of any grid composition differences on the hydraulic compatibility is addressed in References 26 and 29.

Each fuel assembly is installed vertically in the reactor vessel and stands upright on the lower core plate, which is fitted with alignment pins to locate and orient the assembly. After all fuel assemblies are set in place, the upper support structure is installed. Alignment pins, built into the upper core plate, engage and locate the upper ends of the fuel assemblies. The upper core plate then bears downward against the fuel assemblies' top nozzles, via the holddown springs, to hold the fuel assemblies in place.

4.2.1.2.1 Fuel Rods

The fuel rods consist of UO_2 pellets encapsulated in zirconium alloy tubing that is plugged and seal-welded at the ends. Fuel rod schematics are shown in Figures 4.2-3 and 4.2-3a. The fuel pellets are right circular cylinders consisting of uranium dioxide powder that has been compacted by cold pressing and then sintered to the required density. The ends of each pellet are dished slightly to allow greater axial expansion at the center of the pellets. Beginning with Region 4, fuel pellets have chamfered ends to reduce pellet cracking during fuel manufacturing and handling.

The VANTAGE 5 fuel rod has the same cladding wall thickness as the LOPAR fuel rod, but the VANTAGE 5 fuel rod diameter is reduced to optimize the water-to-uranium ratio. The VANTAGE 5 fuel rod length is larger by 0.695 inches to provide a longer plenum and bottom end plug. The bottom end plug has an internal grip feature to facilitate rod loading on both designs and is longer to provide a longer lead-in for the removable top nozzle reconstitution feature. The Diablo Canyon fuel may include axial blankets of natural or enriched uranium and Integral Fuel Burnable Absorbers (IFBA).

The VANTAGE 5 fuel uses a standardized pellet design, which is a refinement to the previous chamfered pellet design, with the objective of improving manufacturability while maintaining or improving performance (e.g., improved pellet chip resistance during manufacturing/ handling). This design (and the previous Region 5 design) incorporates a reduced pellet length (see Table 4.1-1) and modifications to the Region 4 pellet chamfer and dish size.

The axial blankets typically are a nominal 6 inches of natural or enriched fuel pellets at each end of the fuel rod pellet stack. However, the option exists to increase the top axial blanket length to a nominal 7 inches. Certain fuel assemblies utilize annular fuel pellets in the axial blanket region of the fuel rods. The use of this feature provides

additional margin to the fuel rod internal pressure design limits. Axial blankets reduce neutron leakage and improve fuel utilization. The axial blankets utilize pellets, which are physically different from the non-axial blanket pellets to prevent accidental mixing during manufacturing.

Beginning with Cycle 9, the new fuel regions incorporated the Westinghouse VANTAGE + design, which is capable of achieving extended burnup operation. The VANTAGE + fuel system design includes many of the Westinghouse VANTAGE 5 design features and incorporates additional features necessary for extended operation/fuel cycles. One of these features incorporated is the use of fully enriched axial annular fuel pellets in the blanket region of the fuel rods.

Beginning with Cycle 12, the new fuel regions incorporated Westinghouse VANTAGE 5 with P-Grid design, which incorporates a new protective grid. This design includes many of the VANTAGE + system design features and adds a P-Grid above the bottom nozzle for an additional debris barrier for the fuel assembly, and extends the fuel rod bottom plug for interface with the P-Grid.

The IFBA coated fuel pellets are identical to the enriched uranium dioxide pellets except for the addition of a thin boride coating on the pellet cylindrical surface. Coated pellets occupy the central portion of the fuel column. The number and pattern of IFBA rods within an assembly may vary depending on specific application. The ends of the non-annular pellets are dished to allow for greater axial expansion at the pellet centerline and void volume for fission gas release. An evaluation and test program for the IFBA design features is given in Section 2.5 in Reference 26.

Beginning with Cycle 11, the new fuel regions incorporate assemblies whose non-IFBA rods contain fully enriched solid fuel pellets in the blanket region.

To avoid overstressing of the cladding or seal welds, void volume and clearances are provided within the rods to accommodate fission gases released from the fuel, differential thermal expansion between the cladding and the fuel, and fuel density changes during burnup. Shifting of the fuel within the cladding during handling or shipping prior to core loading is prevented by a helical spring that bears on top of the fuel. All fuel rods are internally pressurized with helium during the welding process to minimize compressive cladding stresses and creep due to coolant operating pressures. Fuel rod pressurization depends on the planned fuel burnup, as well as other fuel design parameters and fuel characteristics (particularly densification potential).

4.2.1.2.2 Fuel Assembly Structure

The fuel assembly structure consists of a bottom nozzle, top nozzle, guide thimbles, and grids, as shown in Figures 4.2-2 and 4.2-2a.

4.2.1.2.2.1 Bottom Nozzle

The bottom nozzle is a box-like structure that serves as a bottom structural element of the fuel assembly and directs the coolant flow distribution to the assembly. The square nozzle is fabricated from Type 304 stainless steel. The legs form a plenum for the inlet coolant flow. The plate prevents a downward ejection of the fuel rods. The bottom nozzle is fastened to the fuel assembly guide tubes by locked screws that penetrate through the nozzle and mate with an inside fitting in each guide thimble tube. In Region 4 assemblies, the bottom nozzle design has a reconstitution feature that permits remote unlocking, removing, and relocking of the thimble screws. Coolant flow through the fuel assembly is directed from the plenum in the bottom nozzle upward through the penetrations in the plate to the channels between the fuel rods.

The debris filter bottom nozzle (DFBN) has been introduced into the Diablo Canyon Region 6 fuel assemblies to reduce the possibility of fuel rod damage due to debris-induced fretting. The relatively large flow holes in a conventional bottom nozzle are replaced with a new pattern of smaller flow holes for the DFBN. The holes are sized to minimize passage of debris particles large enough to cause damage while providing sufficient flow area, comparable pressure drop, and continued structural integrity of the nozzle. Tests to measure pressure drop and demonstrate structural integrity have been performed to verify that the debris filter bottom nozzle is totally compatible with the current design.

The 304 stainless steel DFBN is similar to the LOPAR design used for the Diablo Canyon Region 5 fuel assemblies. Significant changes compared to the LOPAR design involve: (a) a modified flow hole size and pattern as described above; and (b) a decreased nozzle height and thinner top plate (identical to the existing VANTAGE 5 bottom nozzle described in Reference 26) to accommodate the high burnup fuel rods. The DFBN retains the design reconstitution feature, which facilitates easy removal of the nozzle from the fuel assembly in the same manner as the bottom nozzle used for the Region 5 LOPAR fuel assemblies.

The weight and axial loads (holddown) imposed on the fuel assembly are transmitted through the bottom nozzle to the lower core plate. Indexing and positioning of the fuel assembly is controlled by alignment holes in two diagonally opposite bearing plates that mate with locating pins in the lower core plate. Any lateral loads on the fuel assembly are transmitted to the lower core plate through the locating pins.

Westinghouse has developed the Standardized Debris Filter Bottom Nozzle (SDFBN) for use on its 17x17 fuel designs, including the 17x17 VANTAGE+ fuel design. The SDFBN was specifically designed to have a loss coefficient that is the same, independent of supplier. The SDFBN has eliminated the side skirt communication flow holes as a means of improving the debris mitigation performance of the bottom nozzle. This nozzle has been evaluated and meets all of the applicable mechanical design criteria. In addition, there is no adverse effect on the thermal hydraulic performance of the SDFBN either with respect to the pressure drop or with respect to DNB. The SDFBN

was implemented at Diablo Canyon beginning with Unit 2 Region 20 (Cycle 18 feed) and Unit 1 Region 21 (Cycle 19 feed).

4.2.1.2.2.2 Top Nozzle

The top nozzle assembly functions as the upper structural element of the fuel assembly in addition to providing a partial protective housing for the RCCA. It consists of an adapter plate, enclosure, top plate, and pads. The integral welded assembly has holddown springs mounted on the assembly, as shown in Figure 4.2-2. The springs are made of Inconel 718. The bolts are made of Inconel 718 or Inconel 600. The other components are made of Type 304 stainless steel.

The reconstitutable top nozzle for the VANTAGE 5 assembly differs from the LOPAR design in two ways: (a) a groove is provided in each thimble thru-hole in the nozzle plate to facilitate attachment and removal; and (b) the nozzle plate thickness is reduced to provide additional axial space for fuel rod growth.

The square adapter plate penetrations permit the flow of coolant upward through the top nozzle. Other holes accept sleeves that are welded to the adapter plate and mechanically attached to the thimble tubes. The ligaments in the plate cover the tops of the fuel rods and prevent their upward ejection from the fuel assembly. The sheet metal shroud enclosure sets the distance between the adapter and the top plates. A large square hole in the top plate permits access for the control rods and the control rod spiders. Holddown springs are mounted on the top plate and fastened by bolts and clamps located at two diagonally opposite corners. On the other two corners, integral pads contain alignment holes to locate the upper end of the fuel assembly.

The Westinghouse Integral Nozzle (WIN) top nozzle design, first introduced in Unit 1 cycle 14 and Unit 2 cycle 13, is a direct replacement for the previous RTN design. The WIN design incorporates design and manufacturing improvements to eliminate the Alloy 718 spring screw for attachment of the hold-down springs. The springs are assembled into the nozzle pad and pinned in place. The WIN design provides a wedged rather than a clamped (bolted) joint for transfer of the fuel assembly hold-down forces into the top nozzle structure. The flow plate, thermal characteristics, and method of attachment of the nozzle are all unchanged from the RTN top nozzle design.

4.2.1.2.2.3 Guide and Instrument Thimbles

Guide thimbles are structural members that also provide channels for the neutron absorber rods, burnable poison rods, or neutron source assemblies. Each guide thimble is fabricated from zirconium alloy tubing having two different diameters. The larger diameter at the top permits rapid insertion of the control rods during a reactor trip and accommodates coolant flow during normal operation. Four holes are provided on the thimble tube above the dashpot to reduce the rod drop time. The lower portion of the guide thimble has a reduced diameter to produce a dashpot action near the end of the control rod travel during normal operation, and to accommodate the outflow of water

from the dashpot during a reactor trip. The dashpot is closed at the bottom by an end plug that is provided with a small flow port to avoid fluid stagnation in the dashpot volume during normal operation. The top end of the guide thimble is fastened to a tubular sleeve by three expansion swages. The sleeve fits into, and is welded to, the top nozzle adapter plate. The lower end of the guide thimble is fitted with an end plug that is then fastened into the bottom nozzle by a weld-locked screw.

The central instrumentation thimble of each fuel assembly is not attached to either the top or bottom nozzles, but is constrained by its seating in counterbores of each nozzle. Incore neutron detectors pass through the bottom nozzle's large counterbore into the center thimble.

With the exception of a reduction in the guide thimble diameter and increased length above the dashpot, the VANTAGE 5 guide thimbles are identical to those in the LOPAR design. A 0.008 inch reduction to the guide thimble OD and ID (Table 4.1-1) is required due to the thicker zirconium alloy grid straps and reduced cell size. The VANTAGE 5 thimble tube is 0.170 inches longer due to the reconstitutable top nozzle feature.

The VANTAGE 5 guide thimble tube ID provides an adequate nominal diametral clearance of 0.061 inches for the control rods. The reduced VANTAGE 5 thimble tube ID also provides sufficient diametral clearance for burnable absorber rods, source rods, and dually compatible thimble plugs. The thimble plugs used in previous cycles are not the dually compatible type and cannot be inserted into the VANTAGE 5 guide thimbles.

The VANTAGE 5 instrumentation tube also has an 0.008 inch diametral decrease compared to the LOPAR assembly instrumentation tube. This decrease still allows sufficient diametral clearance for the flux thimble (max. OD = 0.397 inch) to traverse the tube without binding.

The top Inconel grid sleeve, insert, and thimble tube of the VANTAGE 5 design are joined together using three bulge joint mechanical attachments similar to that used in the LOPAR design. This bulge joint connection was mechanically tested and found to meet all applicable design criteria.

The intermediate and IFM zirconium alloy grids employ a single bulge connection to the sleeve and thimble as compared to a double bulge connection used in the Inconel grids. Mechanical testing of this bulge joint connection was also found to be acceptable.

4.2.1.2.2.4 Grid Assemblies

The fuel rods, as shown in Figure 4.2-2, are supported laterally at eight intervals along their length by grid assemblies that maintain the lateral spacing between the rods by the combination of support dimples and springs. The grid assembly consists of individual slotted straps interlocked and brazed in an "egg-crate" arrangement to join the straps permanently at their points of intersection. The straps contain spring fingers, support dimples, and mixing vanes.

Inconel 718 and zirconium alloys were chosen as the grid materials because of corrosion resistance, neutron economy, and high strength properties. The magnitude of the grid restraining force on the fuel rod is set high enough to minimize possible fretting, without overstressing the cladding at the points of contact. The grid assemblies also allow axial thermal expansion of the fuel rods to prevent their buckling or distortion.

A second type of grid assembly, with mixing vanes projecting from the edges of the straps into the coolant stream, is used in the high heat flux region of the fuel assemblies to promote coolant mixing. The outside straps on all grids contain mixing vanes which, in addition to their mixing function, help guide the grids and fuel assemblies past projecting surfaces during fuel handling or core loading and unloading.

A third type of grid assembly, configured with the same “egg crate” support matrix and other internal structures as the normal grid, is added to the bottom of the fuel assembly to provide an additional debris barrier thereby improving fuel reliability. This protective or “P” grid is thinner (i.e., shorter) than the normal grid to accommodate the gap between the bottom nozzle and the fuel rods. It has no mixing vanes and has shorter inner straps comprising the support matrix compared to the normal grid. The P-Grid is composed of Inconel 718 material.

4.2.1.3 Design Evaluation

4.2.1.3.1 Fuel Rods

The fuel rods are designed to ensure that the design bases are satisfied for Conditions I and II events.

4.2.1.3.1.1 Materials - Fuel Cladding

The zirconium alloys used as fuel rod cladding have a superior combination of neutron economy (low absorption cross section), high strength (to resist deformation due to differential pressures and mechanical interaction between fuel and cladding), high corrosion resistance (to coolant, fuel, and fission products), and high reliability. Reference 8 summarizes the extensive pressurized-water reactor (PWR) operating experience with Zircaloy as a cladding material. The differences between ZIRLO and Zircaloy are stated in Reference 29.

Metallographic examination of irradiated commercial fuel rods has shown occurrences of fuel/cladding chemical interaction. Reaction layers of 1 mil in thickness have been observed between fuel and cladding at limited points around the circumference. These data give no indication of propagation of the layer and eventual cladding penetration.

Stress corrosion cracking is another postulated phenomenon related to fuel/cladding chemical interaction. Out-of-reactor tests have shown that in the presence of high cladding tensile stresses, large concentrations of iodine can chemically attack the fuel

cladding and lead to eventual cladding cracking. Westinghouse has no evidence that this mechanism is operative in commercial fuel.

4.2.1.3.1.2 Materials - Fuel Pellets

Sintered, high-density UO_2 reacts only slightly with the cladding at core operating temperatures and pressures. In the event of cladding defects, the high resistance of uranium dioxide to attack by water protects against fuel deterioration, although limited fuel erosion can occur. Operating experience and extensive experimental work reveal that the thermal design parameters conservatively account for changes in the thermal performance of the fuel elements due to pellet fracture that may occur during power operation. The consequences of defects in the cladding are greatly reduced by the ability of uranium dioxide to retain fission products, including those that are gaseous or highly volatile.

Improvements in fuel fabrication techniques, based on extensive analytical and experimental work (Reference 9), have eliminated or minimized the fuel pellet densification effect that had been observed in fuel irradiated in operating Westinghouse PWRs (References 5 and 8).

Fuel densification is considered in the nuclear and thermal-hydraulic design of the reactor, as described in Sections 4.3 and 4.4, respectively.

Some fuel pellets are fabricated with a thin boride coating on the pellet outside surface for reactivity control.

4.2.1.3.1.3 Materials - Strength Considerations

One of the most important limiting factors in fuel element duty is the mechanical interaction of fuel and cladding. This fuel-cladding interaction produces cyclic stresses and strains in the cladding, and these in turn consume cladding fatigue life. To reduce fuel-cladding interaction, which is a principal goal of design, and enhance the cyclic operational capability of the fuel rod, prepressurized fuel rods are used.

Prepressurized fuel rods partially offset the effect of the coolant external pressure and reduce the rate of cladding creep toward the surface of the fuel. Fuel rod prepressurization delays the time at which substantial fuel-cladding interaction and hard contact occur and, hence, significantly reduces the number and extent of cyclic stresses and strains experienced by the cladding, both before and after fuel-cladding contact. These factors increase the fatigue life margin of the cladding and lead to greater cladding reliability. If gaps should form in the fuel stacks, cladding flattening will be prevented by the rod prepressurization so that the flattening time will be greater than the fuel core life.

To minimize fuel-cladding interaction during startup, following handling of irradiated fuel assemblies during a refueling, or a cold shutdown, limitations in power increase rates are instituted.

4.2.1.3.1.4 Steady State Performance Evaluation

In the calculation of the steady state performance of a nuclear fuel rod, the following interacting factors must be considered:

(1) Cladding creep and elastic deflection

(2) Pellet density changes, thermal expansion, gas release, and thermal properties as a function of temperature and fuel burnup

(3) Internal pressure as a function of fission gas release, rod geometry, and temperature distribution

These effects are evaluated using the fuel rod design model of Reference 3, modified as described in Reference 9, to account for time-dependent fuel densification. The model determines fuel rod performance characteristics for a given rod geometry, power history, and axial power shape. In particular, internal gas pressure, fuel and cladding temperatures, and cladding deflections are calculated. The fuel rod is divided lengthwise into several sections and radially into a number of annular zones. Fuel density changes, cladding stresses, strains and deformations, and fission gas releases are calculated separately for each segment. These effects are then integrated to obtain the total internal pressure.

Subject to the design criteria of Section 4.2.1.1.1, the initial rod internal pressure is selected to delay fuel-cladding mechanical interaction and to avoid the potential for flattened rod formation.

The gap conductance between the pellet surface and the cladding inner diameter is calculated as a function of the composition, temperature, and pressure of the gas mixture, and the gap size or contact pressure between cladding and pellet. After computing the fuel temperature for each pellet's annular zone, the fractional fission gas release is assessed using an empirical model derived from experimental data (Reference 3). Finally, the gas released is summed over all zones and the pressure is calculated.

The code shows good agreement in fit for a variety of published and proprietary data on fission gas release, fuel temperatures, and cladding deflection (Reference 3). Included in this spectrum are variations in power, time, fuel density, and geometry.

Typical fuel cladding inner diameter and the fuel pellet outer diameter as a function of exposure are presented in Figure 4.2-4. The cycle-to-cycle changes in the pellet outer diameter represent the effects of power changes as the fuel is moved into different

positions during refueling. The gap size at any time is given by the difference between cladding inner radius and pellet outer radius. Total cladding-pellet surface contact occurs between 600 and 800 EFPD. Figure 4.2-4 represents hot fuel dimensions for a fuel rod operating at the power level shown in Figure 4.2-5. Figure 4.2-5 also illustrates representative fuel rod internal gas pressure and linear power for the lead burnup rod versus irradiation time. In addition, it outlines the typical operating range of internal gas pressures that is applicable to the total fuel rod population within a region. The plenum height of the fuel rod is designed to ensure that the maximum internal pressure of the fuel rod remains below the value that causes the fuel-cladding diametral gap to increase due to outward cladding creep.

Cladding stresses during steady state operation are low. Compressive stresses are created by the pressure differential between the coolant pressure and the rod internal gas pressure.

Because of helium prepressurization, the volume average effective stresses are always less than the yield stress at the pressurization level used in this fuel rod design. Stresses due to the temperature gradient are not included because their contribution to the cladding volume average stress is small and decreases with time during steady state operation due to stress relaxation. The stress due to pressure differential is highest in the minimum power rod at the beginning of life (BOL) (due to low internal gas pressure), and the thermal stress is highest in the maximum power rod (due to the steep radial temperature gradient).

Tensile stresses could be created once the cladding comes in contact with the pellet. These stresses would be induced by the fuel pellet swelling during irradiation. As shown in Figure 4.2-4, there is very limited cladding pushout after pellet-cladding contact. Reactor experiments (Reference 10) have shown that Zircaloy tubing exhibits "super-plasticity" at slow strain rates during neutron irradiation. Uniform cladding strains of 10 percent have been achieved under these conditions with no sign of plastic instability.

Reference 16 presents the NRC-approved model used for evaluation of fuel rod bowing. The effects of bowing on departure from nucleate boiling ratio (DNBR) are described in Section 4.4.2.3.5.

4.2.1.3.1.5 Transient Evaluation Method

A "modified CYGRO," which retains the basic design approach of the referenced CYGRO (Reference 4), was used by Westinghouse to investigate fuel rod mechanical integrity during power transients.

Comparisons between the modified CYGRO and the fuel rod design model of Section 4.2.1.3.1.4 show that in all cases conformity is satisfactory. Power escalations or spikes early in life do not lead to hard cladding-pellet interaction because the pellet merely expands into the gap. Power increases that occur after considerable gap

closure result in hard cladding-pellet interaction. The extent of the interaction determines the cladding stress level.

Pellet thermal expansion due to power increases in a fuel rod is considered the only mechanism by which significant stresses and strains can be imposed on the cladding. Such power increases in commercial reactors can result from fuel shuffling, reactor power escalation following extended reduced power operation, and control rod movement. In the mechanical design model, depletion of lead rods is calculated using best estimate power histories as determined from core physics calculations. During the depletion, the diametral gap closure is evaluated using the pellet expansion-cracking model, cladding creep model, and fuel swelling model. At various times during the depletion, the power is increased locally on the rod to the burnup-dependent attainable power density, as determined by core physics calculation. The radial, tangential, and axial cladding stresses resulting from the power increase are combined into a volume average effective cladding stress.

The von Mises' criterion, described in Section 4.2.1.1.1, is used to determine if the cladding yield stress has been exceeded. The yield stress correlation is that for irradiated cladding, since fuel-cladding interaction occurs at high burnup. Furthermore, the effective stress is increased by an allowance that accounts for stress concentrations in the cladding adjacent to radial cracks in the pellet, prior to the comparison with the yield stress. This allowance was evaluated using a two-dimensional (r, θ) finite element model.

Since slow transient power increases can result in large cladding strains without exceeding the cladding yield stress due to cladding creep and stress relaxation, a criterion on allowable cladding positive strain is necessary. Based on high strain rate burst and tensile test data for irradiated tubing, 1 percent strain was adopted as the lower limit on irradiated cladding ductility.

In addition to the mechanical design models and design criteria, Westinghouse relies on performance data accumulated from transient power test programs in experimental and commercial reactors, and normal operation in commercial reactors.

It is recognized that a possible limitation to the satisfactory behavior of the fuel rods in a reactor that is subjected to daily load follow is the failure of the cladding by low cycle strain fatigue. During their normal residence time in a reactor, the fuel rods may be subjected to 1000 cycles with typical changes in power level from 50 to 100 percent of their steady state values. Fatigue life determination of fuel rod cladding is uncertain due to strain range evaluation difficulties that result from the cyclic interaction of fuel pellets and cladding, and from such highly unpredictable phenomena as pellet cracking, *fragmentation, and relocation. Strain fatigue tests by Westinghouse since 1968 on irradiated and nonirradiated hydrided Zircaloy-4 cladding have permitted a definition of a conservative fatigue life limit and a methodology to treat the strain fatigue evaluation.

Westinghouse-accumulated experience in load follow operation, that dates back to early 1970, shows that no significant coolant activity increase can be associated with the load follow mode of operation.

The Westinghouse analytical approach to strain fatigue results from evaluating several strain-fatigue models and the results of the Westinghouse experimental programs. In conclusion, the approach defined by Langer-O'Donnell (Reference 12) was retained, and the empirical factors of their correlation were modified to conservatively bound the results of the Westinghouse testing program.

The Langer-O'Donnell empirical correlation has the following form:

$$S_a = \frac{E}{\sqrt[4]{\left(N_f\right)}} \ln\left(\frac{100}{100-RA}\right) + S_e \tag{4.2-1}$$

where:

S_a = 1/2 $E\Delta\varepsilon_\tau$
$\Delta\varepsilon_\tau$ = pseudo-stress amplitude that causes failure in N_f cycles, lb/in^2
ε_τ = total strain range, in./in
E = Young's Modulus, lb/in^2
N_f = number of cycles to failure
RA = reduction in area at fracture in a uniaxial tensile test, %
S_e = endurance limit, lb/in^2

Both RA and S_e are empirical constants that depend on the type of material, the temperature, and the irradiation.

The results of the Westinghouse test programs provided information on different cladding conditions, including the effect of irradiation, hydrogen level, and temperature.

The Westinghouse design equations followed the concept for the fatigue design criterion according to Section III of the ASME B&PV Code, namely:

(1) The calculated pseudo-stress amplitude (Sa) includes a safety factor of 2.

(2) The allowable cycles for a given Sa are 5 percent of Nf or a safety factor of 20 on cycles.

The lesser of the two allowable numbers of cycles is selected. The cumulative fatigue life fraction is then computed as:

$$\frac{n_k}{\sum_{1}^{k} N_{fk}} \leq 1 \qquad (4.2\text{-}2)$$

where:

n_k = number of diurnal cycles of mode k

4.2.1.3.2 Fuel Assembly Structure

4.2.1.3.2.1 Stresses and Deflections

Stresses in the fuel rod due to thermal expansion and fuel cladding irradiation growth are limited by the relative motion of the rod as it slips over the grid spring and dimple surfaces. Clearances between the fuel rod ends and nozzles are provided so that fuel cladding irradiation growth does not produce interferences. Stresses due to hold-down springs opposing the hydraulic lift force are limited by the deflection characteristic of the springs. Stresses in the fuel assembly caused by tripping of the RCCA have little influence on fatigue because of the small number of events during the life of an assembly. Welded joints in the fuel assembly structure are considered in the structural analysis of the assembly. Appropriate material properties of welds ensure that the design bases are met. Assembly components and prototype fuel assemblies made from production parts were subjected to structural tests to verify that the design bases requirements were met.

Precautions are taken during fuel handling operations to minimize fuel assembly grid strap damage. These precautions include proper training of operators, confirmation of proper functioning and alignment of the fuel handling and transfer equipment, implementation of appropriate handling precautions, and the Westinghouse recommendations. In addition, starting with Cycle 4, the grid straps are modified to prevent assembly hangup from grid strap interference during fuel handling.

The fuel assembly design loads for shipping have been established at 6g laterally and 4g axially. Probes, permanently placed in the shipping cask, monitor and detect fuel assembly displacements that would result from loads in excess of the criteria. Experience indicates that loads which exceed the allowable limits rarely occur. Exceeding the limits requires reinspection of the fuel assembly. Tests on various fuel assembly components such as the grid assembly, sleeves, inserts, and structure joints have been performed to ensure that the shipping design limits do not result in impairment of fuel assembly function.

The evaluation of the fuel assembly for the postulated Hosgri earthquake is discussed in Section 3.7.3.15.2.

Seismic analysis of the fuel assembly is presented in Reference 11 and updated in Reference 32.

4.2.1.3.2.2 Dimensional Stability

A prototype LOPAR fuel assembly has been subjected to column loads in excess of those expected in normal service and faulted conditions. The VANTAGE 5 Mechanical Test Program description and results are given in Appendix A of Reference 26. With the acceptance of the DCPP leak-before-break analysis by the NRC (Reference 30), dynamic loading conditions resulting from pipe rupture events in the main reactor coolant loop piping no longer have to be considered in the design basis analyses. Only the much smaller loads from RCS branch line breaks have to be considered (see Section 3.6.2.1.1.1).

The dimensional stability of coolant flow channels is maintained by the grids and guide thimbles structure. The lateral spacing between fuel rods is controlled by the support dimples of adjacent grid cells plus the spring force and the internal moments generated between the spring and the support dimples.

Tests and analyses have been performed to evaluate the effects of small cracks in the grid strap dimples. While burr cracks up to 2 mils in length are acceptable for dimples, cracks greater than 2 mils in length may exist in installed grids despite stringent inspections. Testing and analysis results indicate that dimples with cracks exceeding the acceptance criteria will survive in-pile fatigue, and crack propagation is not expected.

No interference with control rod insertion into thimble tubes will occur during a postulated loss-of-coolant accident (LOCA) transient due to fuel rod swelling, thermal expansion, or bowing. In the early phase of the event, the high axial loads, which could be potentially generated by the difference in thermal expansion between fuel cladding and thimbles, are relieved by slippage of the fuel rods through the grids. The relatively low drag force restraint on the fuel rods will induce only minor thermal bowing, not enough to close the fuel rod-to-thimble tube gap. This rod-to-grid slip mechanism occurs simultaneously with control rod drop. Subsequent to the control rod insertion, the transient temperature increase of the fuel rod cladding can result in sufficient swelling to contact the thimbles.

4.2.1.3.2.3 Vibration and Wear

The effect of a flow-induced vibration on the fuel assembly and individual fuel rods is minimal. Both fretting and vibration have been experimentally investigated. The cyclic stress range associated with deflections of such small magnitude is insignificant and has no effect on the structural integrity of the fuel rod.

The conclusion that the effect of flow-induced vibrations on the fuel assembly and fuel rod is minimal is based on test results and analysis documented in WCAP-8279 (Reference 13), which consider conditions normally encountered in reactor operation.

The reaction on the grid support due to vibration motions is correspondingly small and much less than the spring preload. Firm contact is therefore maintained. No significant cladding or grid support wear is expected during the life of the fuel assembly, as described in Section 4.2.1.3.3.

During the mid-1970s, unexpected degradation of guide thimble tube walls was observed during examination of irradiated fuel assemblies taken from several operating pressurized water reactors. It was later determined that coolant up-flow through the guide thimble tubes and turbulent cross-flow above the fuel assemblies were responsible for inducing vibratory motion in normally fully withdrawn ("parked") control rods. When these vibrating rods were in contact with the inner surface of the thimble wall, a fretting wear of the thimble wall occurred. The extent of the observed wear is both time and nuclear steam supply system (NSSS) design-dependent and has been observed, in some non-Westinghouse cases, to extend through the guide tube walls, resulting in the formation of holes.

Guide thimble tubes function as the main structural members of the fuel assembly and as channels to guide and decelerate tripped control rods. Significant loss of mechanical integrity due to wear or hole formation could: (a) result in the inability of the guide thimble tubes to withstand their anticipated loadings for fuel handling accidents and transients, and (b) hinder RCCA trip.

The susceptibility and impact of guide thimble tube wear in Westinghouse plants of the DCPP design have been assessed in References 17 through 20. Included is a mechanistic wear model and the impact of the model's wear predictions on plant designs such as for DCPP.

Accordingly, the DCPP fuel design will experience less wear than that reported for other NSSS designs because that design uses thinner, more flexible control rods that have relatively more lateral support in the guide tube assembly of the upper core structure. Such construction provides the housing and guide path for the RCCA above the core, and thus restricts control rod vibration due to lateral exit flow. The wear model is also believed to conservatively predict guide thimble tube wear and even with the worst anticipated wear conditions (both in the degree of wear and the location of wear), the guide thimble tubes will be able to fulfill their design functions.

PG&E participated in a surveillance program to obtain data related to guide tube thimble wear (References 20 and 21). Data obtained from surveillance program examinations confirmed that guide thimble tubes used in DCPP meet design requirements.

4.2.1.3.3 Operational Experience

The operational experience of Westinghouse cores is presented in WCAP-8183 (Reference 8), which is revised annually.

4.2.1.4 Testing and Inspection Plan

4.2.1.4.1 Quality Assurance Program

The Quality Assurance Program for Westinghouse nuclear fuel is summarized in the latest edition of the Westinghouse Nuclear Fuel Division Quality Assurance Program Plan, as listed in the PG&E Qualified Suppliers List.

4.2.1.4.2 Manufacturing

The Westinghouse quality control philosophy during manufacturing is described in the Westinghouse Nuclear Fuel Division Quality Assurance Program Plan, as listed in the PG&E Qualified Suppliers List.

4.2.1.4.3 Onsite Inspection

Onsite inspection of fuel assemblies, control rods, and reactor internals is performed in accordance with the inspection program requirements discussed in Chapter 17.

Surveillance of fuel and reactor performance is routinely conducted on Westinghouse reactors. Power distribution is monitored using the excore fixed and incore movable detectors. Coolant activity and chemistry are followed, which permit early detection of any fuel cladding defects.

Visual examinations are routinely conducted during refueling outages. Additional fuel inspections are dependent on results of the operational monitoring and the visual examinations. Onsite examinations, if required, could include fuel integrity or other fuel performance evaluation examinations.

4.2.1.4.4 Removable Fuel Rod Assembly

As part of a continuing Westinghouse fuel performance evaluation program, one surveillance fuel assembly containing 88 removable fuel rods was included in Region 3 of the initial DCPP Unit 1 core loading. The objective of this program was to facilitate interim and end of life (EOL) fuel evaluation as a function of exposure. The rods could be removed, nondestructively examined, and reinserted at the end of intermediate fuel cycles. The rods could be removed easily and subjected to a destructive examination at EOL.

The overall dimensions, rod pitch, number of rods, and material are the same as for other Region 3 assemblies. These fuel rods were fabricated in parallel with the regular

Region 3 rods using selected Region 3 cladding and pellets fabricated to the same manufacturing tolerance limits. Mechanically, the special assemblies differ from other Region 3 assemblies only in those features that facilitate removal and reinsertion.

Figure 4.2-6 compares the mechanical design of a removable fuel rod to a standard rod. Figure 4.2-7 shows the removable rod fuel assembly, the modified upper nozzle adapter plate, and thimble plug assembly; it should be compared to the standard assembly shown in Figure 4.2-2. The location of the removable rods within the fuel assembly is shown in Figure 4.2-8. Fuel handling with removable fuel rods has been done routinely and without difficulty in many operating plants.

The same fuel rod design limits, indicated in Section 4.2.1 for standard fuel rods and assemblies, are maintained for these removable rods. Their inclusion in the initial Unit 1 core loading introduced no additional safety considerations and in no way changed the safeguard analyses and related engineering information formerly presented in support of the license application.

4.2.2 REACTOR VESSEL INTERNALS

4.2.2.1 Design Bases

The design bases for the mechanical design of the reactor vessel internals components are:

(1) The reactor internals, in conjunction with the fuel assemblies, shall direct reactor coolant through the core to achieve acceptable flow distribution and to restrict bypass flow so that the heat transfer performance requirements are met for all modes of operation. In addition, required cooling for the pressure vessel head shall be provided so that the axial and circumferential temperature gradients in the vessel and head flanges do not cause excessive rotation or warpage, which could result in leakage past the O-ring closure gaskets during reactor operation.

(2) In addition to neutron shielding provided by the reactor coolant, a thermal shield in Unit 1 and a neutron pad (Reference 7) assembly on Unit 2 limit the neutron exposure of the pressure vessel.

(3) Provisions shall be made to install incore instrumentation for plant operation and the vessel material test specimens required for the pressure vessel irradiation surveillance program (see Section 5.2).

(4) The core internals were designed to withstand mechanical loads arising from the design earthquake (DE), double design earthquake (DDE), Hosgri earthquake, and pipe ruptures. It has been verified that the core internals maintain their integrity during a Hosgri event. With the acceptance of the DCPP leak-before-break analysis by the NRC

(Reference 30), dynamic loading conditions resulting from pipe rupture events in the main reactor coolant loop piping no longer have to be considered in the design basis analyses. Only the much smaller loads from RCS branch line breaks have to be considered (see Section 3.6.2.1.1.1). The seismic design of core internals is further discussed in Section 3.7.

(5) The reactor has mechanical provisions to adequately support the core and internals and to ensure that the core is intact with acceptable heat transfer geometry following transients arising from abnormal operating conditions.

(6) Following the design basis accident, the plant shall be capable of being shut down and cooled in an orderly fashion so that fuel cladding temperature is kept within 10 CFR 50.46 limits. This implies that the deformation of certain critical reactor internals must be kept sufficiently small to allow core cooling.

Core structure functional limitations during the design basis accident are shown in Table 4.2-1. To ensure no column loading of rod cluster control guide tubes, the upper core plate deflection is limited to the value shown in Table 4.2-1.

Details of the dynamic analyses, input forcing functions, and response loadings are presented in Section 3.9. A dynamic analysis is performed on first-of-a-kind plants, in accordance with the requirements of the ASME B&PV Code, Section III, Subsection NG. Identical plants are qualified by this same analysis. With the acceptance of the DCPP leak-before-break analysis by the NRC (Reference 30), dynamic loading conditions resulting from pipe rupture events in the main reactor coolant loop piping no longer have to be considered in the design basis analyses. Only the much smaller loads from RCS branch line breaks have to be considered (see Section 3.6.2.1.1.1).

With respect to previous plants, there is no change in the design configuration of reactor internals and the reactor internals core support structures. Moreover, since their mechanical properties (e.g., fuel assembly weight, beam stiffness) are virtually the same, the response of the reactor internals core support structure will not change.

The qualification of identical plants by the first-of-a-kind analysis is further verified by the Internals Vibration Assurance Program discussed in Section 3.9.2.1.

4.2.2.2 Description and Drawings

The components of the reactor internals consist of the lower core support structure (including the entire core barrel, the thermal shield on Unit 1, and the neutron shield pad assembly on Unit 2), the upper core support structure, and the incore instrumentation support structure. The reactor internals support the core, maintain fuel alignment, limit fuel assembly movement, maintain alignment between fuel assemblies and control rod

drive mechanisms (CRDMs), direct coolant flow past the fuel elements, direct coolant flow to the pressure vessel head, and provide gamma and neutron shielding and guides for incore instrumentation.

The coolant flows from the vessel inlet nozzles down the annulus between the core barrel and the vessel wall and then into a plenum at the bottom of the vessel. The coolant then reverses and flows up through the core support and lower core plate. After passing through the core, the coolant enters the upper support structure and flows radially to the core barrel outlet nozzles and directly through the vessel outlet nozzles. In DCPP Unit 1, a small portion of the coolant flows downward between the baffle plates and the core barrel to provide additional cooling of the barrel. Similarly, a small amount of the entering flow is directed into the vessel head plenum and exits through the vessel outlet nozzles. For DCPP Unit 2, modifications have been performed to change the direction of flow between the baffle plates and core barrel to an upflow configuration. The modifications consist of plugging the core barrel flow holes and drilling flow holes in the top former. In a converted upflow configuration, all the flow entering the core barrel from the inlet nozzle flows downward into the lower plenum, reverses and flows upwards through the lower core plate and into the core and the baffle barrel region. Also for Unit 2, an additional modification has been made to reduce the upper head bulk fluid temperature to approximately T-cold. In this modification, reactor upper and lower internals were modified to provide additional flow in the upper head region. These two modifications have been evaluated and documented in Reference 31.

The major material for the reactor internals is Type 304 stainless steel. Parts not fabricated from Type 304 stainless steel include bolts and dowel pins, which are fabricated from Type 316 stainless steel, and the radial support clevis insert and bolts, which are fabricated of Inconel 718. Type 403 stainless steel is used for the hold-down springs in the reactor core support structures; they have a yield stress greater than 90,000 psi. These materials are compatible with the reactor coolant and are acceptable based on the 1971 ASME B&PV Code, Case Number 1337. Undue susceptibility to intergranular stress corrosion cracking is prevented by not using sensitized stainless steel, as recommended in Regulatory Guide 1.44 (Reference 23).

All reactor internals are removable, thus permitting inspection of the vessel internal surface.

4.2.2.2.1 Lower Core Support Structure

The reactor internals support member is the lower core support structure shown in Figures 4.2-9 and 4.2-10 for DCPP Units 1 and 2, respectively. This support structure assembly consists of the core barrel, the core baffle, the lower core plate and support columns, the thermal shield on Unit 1, and the neutron shield pad assembly on Unit 2 (the transition from a thermal shield to neutron shield pad assembly is explained in WCAP-7870 (Reference 7)), and the core support, which is welded to the core barrel. All the major material for this structure is Type 304 stainless steel. The lower core support structure is supported at its upper flange from a ledge in the reactor vessel and

its lower end is restrained from transverse motion by a radial support system attached to the vessel wall. Within the core barrel are an axial baffle and a lower core plate, both of which are attached to the core barrel wall and form the enclosure periphery of the core. The lower core support structure and core barrel provide passageways and direct the coolant flow. The lower core plate is positioned at the bottom level of the core below the baffle plates and provides support and orientation for the fuel assemblies.

The lower core plate contains the necessary flow distribution holes for each fuel assembly. On Unit 2, adequate coolant distribution is obtained through the use of the lower core plate and core support. Unit 1 contains an additional intermediate flow diffuser plate.

On Unit 1, the one-piece thermal shield is fixed to the core barrel at the top with rigid bolted connections. The bottom of the thermal shield is connected to the core barrel by means of axial flexures. Rectangular specimen guides in which material samples can be inserted, held by a preloaded spring device, and irradiated during reactor operation, are welded to the thermal shield.

On Unit 2, the neutron shield pad assembly, shown in Figure 4.2-11, consists of four panels, constructed of Type 304 stainless steel, that are bolted and pinned to the outside of the core barrel. Rectangular specimen guides in which material surveillance samples are inserted, held by a preloaded spring device, and irradiated during reactor operation, are bolted and pinned to the panels. Additional details of the neutron shielding pads and irradiation specimen holders are given in Reference 7.

Vertically downward loads from weight, fuel assembly preload, control rod dynamic loading, hydraulic loads, and earthquake acceleration are carried by the lower core plate into the lower core plate support flange on the core barrel shell, and through the lower support columns to the core support and then through the core barrel shell to the core barrel flange supported by the vessel flange. Transverse loads from earthquake acceleration, coolant cross flow, and vibration are carried by the core barrel shell and distributed between the lower radial support to the vessel wall and to the vessel flange. Transverse loads of the fuel assemblies are transmitted to the core barrel shell by direct connection of the lower core plate to the barrel wall, and by upper core plate alignment pins that are welded into the core barrel.

The radial support system of the core barrel is accomplished by "key" and "keyway" joints to the reactor vessel wall. At six equally spaced points around the circumference, an Inconel clevis block is welded to the vessel inner diameter. An Inconel insert block is bolted to each of these clevis blocks, and has a keyway geometry. Opposite each of these is a key that is welded to the lower core support. During assembly, as the internals are lowered into the vessel, the keys engage the keyways in the axial direction.

Radial and axial expansions of the core barrel are accommodated, but this design restricts transverse movement of the core barrel. With this system, cyclic stresses in

the internal structures are within the ASME B&PV Code, Section III limits. In the event of an abnormal downward vertical displacement of the internals following a hypothetical failure, the load is transferred through energy absorbing devices of the lower internals to the vessel. The number and design of these absorbers are determined so as to limit the stresses imposed on all components (except the energy absorber) to less than yield stress (ASME B&PV Code, Section III values).

To prevent fuel rod damage as a result of water jetting through lower internals baffle gaps in Unit 2, edge bolts have been added along the full length of the center injection baffle plate joints and the gaps have been peened after bolting. Unit 1 has edge bolts along the entire length of all corner and center injection baffle plate joints.

In addition, if baffle jetting is detected in Unit 2, anti-baffle jetting fuel clips may be used to dampen the amplitude of the fuel rod vibrations.

4.2.2.2.2 Upper Core Support Assembly

The upper core support assembly, shown in Figures 4.2-12, 4.2-13, and 4.2-14, consists of the upper support assembly and the upper core plate between which are contained support columns and guide tube assemblies. The support columns establish the spacing between the upper support assembly and the upper core plate, and transmit the mechanical loadings between the upper support and upper core plate. The guide tube assemblies shield and guide the control rod drive shafts and control rods. Flow restrictors are installed in the guide tubes that formerly housed the part length CRDM drive shafts.

The upper core support assembly, which is removed as a unit during the refueling operation, is positioned in its proper orientation with respect to the lower support structure by slots in the upper core plate. Fuel assembly locating pins protrude from the bottom of the upper core plate and engage the fuel assemblies as the upper assembly is lowered into place, thus ensuring proper alignment of the lower core support structure, the upper core support assembly, the fuel assemblies, and control rods. The upper core support assembly is restrained from any axial movements by a large circumferential spring that rests between the upper barrel flange and the upper core support assembly. The spring is compressed when the reactor vessel head is installed on the pressure vessel.

Vertical loads from weight, earthquake acceleration, hydraulic loads, and fuel assembly preload are transmitted through the upper core plate, via the support columns, to the upper support assembly and then into the reactor vessel head. Transverse loads from coolant cross flow, earthquake acceleration, and possible vibrations are distributed by the support columns to the upper support and upper core plate. The upper support plate is particularly stiff to minimize deflection.

4.2.2.2.3 Incore Instrumentation Support Structures

The incore instrumentation support structures consist of an upper system to convey and support thermocouples penetrating the vessel through the head, and a lower system to convey and support flux thimbles penetrating the vessel through the bottom (Figure 7.7-9 shows the basic flux-mapping system).

The upper system utilizes the reactor vessel head penetrations. Instrumentation port columns are slip-connected to in-line columns that are, in turn, fastened to the upper support plate. These port columns protrude through the head penetrations. The thermocouple conduits, made of Type 304 stainless steel, are supported from the columns of the upper core support system.

In addition to the upper incore instrumentation, there are reactor vessel bottom port columns that carry the retractable, cold-worked stainless steel flux thimbles that are pushed upward into the reactor core. Conduits extend from the bottom of the reactor vessel down through the concrete shield area and up to a thimble seal table. The thimbles are closed at the leading ends and serve as the pressure barrier between the reactor pressurized water and the containment atmosphere.
Mechanical seals between the retractable thimbles and conduits are provided at the seal table. During normal operation, the retractable thimbles are stationary and move only during refueling or for maintenance, at which time a space of approximately 15 feet above the seal table is cleared for the retraction operation.

The incore instrumentation support structure is designed for adequate support of instrumentation during reactor operation and is sturdy enough to resist damage or distortion under the conditions imposed by handling during the refueling sequence. Reactor vessel surveillance specimen capsules are covered in Section 5.2.4.

4.2.2.3 Design Loading Conditions

The design loading conditions for the reactor internals are:

(1) Fuel assembly weight

(2) Fuel assembly spring forces

(3) Internals weight

(4) Control rod scram (equivalent static load)

(5) Differential pressure

(6) Spring preloads

(7) Coolant flow forces (static)

(8) Temperature gradients

(9) Differences in thermal expansion

  (a) Due to temperature differences

  (b) Due to expansion of different materials

(10) Interference between components

(11) Vibration (mechanically or hydraulically induced)

(12) One or more loops out of service

(13) All operational transients listed in Table 5.2-4

(14) Pump overspeed

(15) Seismic loads (DE, DDE and Hosgri)

(16) Blowdown forces (due to RCS branch line breaks)

Combined seismic and blowdown forces are included in the stress analysis by assuming the maximum amplitude of each force to act concurrently. In the original analyses, the blowdown forces were those resulting from breaks in the RCS cold and hot legs. However, with the acceptance of the DCPP leak-before-break analysis by the NRC (Reference 30), the blowdown forces resulting from pipe rupture events in the main reactor coolant loop piping no longer have to be considered in the design basis analyses. Only the much smaller loads from RCS branch line breaks have to be considered (see Section 3.6.2.1.1.1).

The main objectives of the design analysis are to ensure that allowable stress limits are not exceeded, that an adequate design margin exists, and to establish deformation limits that are concerned primarily with components' operability. The stress limits are established not only to ensure that peak stresses do not reach unacceptable values, but also to limit the amplitude of the oscillatory stress component in consideration of material fatigue characteristics. Both low and high cycle fatigue stresses are considered when the allowable amplitude of oscillation is established. Dynamic analysis on the reactor internals is provided in Section 3.9.

As part of the evaluation of design loading conditions, extensive testing and inspections are performed from the initial selection of raw materials up to and including component installation and plant operation. Among these tests and inspections are those performed during component fabrication, plant construction, startup and checkout, and plant operation.

4.2.2.4 Design Loading Categories

The combination of design loadings fits into either the normal, upset, or faulted conditions as defined in the Summer 1968 Addenda to the ASME B&PV Code, Section III.

Loads and deflections imposed on components due to shock and vibration are determined analytically and experimentally in both scaled models and operating reactors. The cyclic stresses due to these dynamic loads and deflections are combined with the stresses imposed by loads from component weights, hydraulic forces, and thermal gradients for the determination of the total stresses of the internals.

The reactor internals are designed to withstand stresses originating from various operating conditions, as summarized in Table 5.2-4.

The scope and methodology of the stress analysis problem is discussed in Section 3.9.

4.2.2.4.1 Allowable Deflections

For normal operating conditions, downward vertical deflection of the lower core support plate is negligible.

Limiting deflection values from the LOCA plus the earthquake (larger of the DDE or Hosgri), and for the deflection criteria of critical internal structures, are given in Table 4.2-1. The corresponding no-loss-of-function limits are also included in Table 4.2-1 for comparison with the allowed criteria. Note, however, that with the acceptance of the DCPP leak-before-break analysis by the NRC (Reference 30), the LOCA loads resulting from pipe rupture events in the main reactor coolant loop piping no longer have to be considered in the design basis analyses. Only the much smaller LOCA loads from RCS branch line breaks have to be considered (see Section 3.6.2.1.1.1).

The criteria for the core drop accident are based on determining the total downward displacement of the internal structures following a hypothesized core drop resulting from loss of supports. The initial clearance between the secondary core support structures and the reactor vessel lower head in the hot condition is approximately ½ inch. An additional displacement of approximately 3/4 inch would occur due to strain of the energy absorbing devices of the secondary core support; thus the total drop distance is about 1-1/4 inches, which is insufficient to permit the grips of the RCCA to come out of the guide thimble.

Specifically, the secondary core support is a device that will never be used, except during a hypothetical accident of the core support (core barrel, barrel flange, etc.). There are four supports in each reactor. This device limits the fall of the core and absorbs the energy of the fall that otherwise would be imparted to the vessel. The energy of the fall is calculated assuming a complete and instantaneous failure of the

primary core support and is absorbed during the plastic deformation of the controlled stainless steel volume loaded in tension. The maximum deformation of this austenitic stainless piece is limited to approximately 15 percent, after which a positive step is provided to ensure support.

4.2.2.5 Design Criteria Bases

For normal operating conditions, Section III of the ASME B&PV Code is used as a basis for evaluating acceptability of calculated stresses. Both static and dynamic stress intensities are considered. Bolt material Type 316 stainless steel is covered in ASME B&PV Code, Section III, under Case Number 1618. It should be noted that the allowable stresses in Section III of the ASME B&PV Code are based on unirradiated material properties. Since irradiation increases the strength of the Type 304 stainless steel used for the internals, although decreasing its elongation, the allowable stresses in Section III are considered appropriate and conservative for irradiated internal structures.

The allowable stress limits used for analysis of the design basis accident for core support structures are based on the January 1971 draft of the ASME B&PV Code, Section III, Subsection NG, and the criteria for faulted conditions.

4.2.3 REACTIVITY CONTROL SYSTEM

4.2.3.1 Design Bases

Bases for temperature, stress on structural members, and material compatibility are imposed on the design of the reactivity control components.

4.2.3.1.1 Design Stresses

The reactivity control system is designed to withstand stresses originating from the operating transients summarized in Table 5.2-4.

Allowable stresses for normal operating conditions are in accordance with Section III of the ASME B&PV Code. All components are analyzed as Class I components under Article NB-3000.

The cyclic stresses due to dynamic loads and deflections are combined with the stresses imposed by loads from component weights, hydraulic forces, and thermal gradients to determine the total stresses of the reactivity control system.

4.2.3.1.2 Material Compatibility

Materials are selected for compatibility in a pressurized water reactor environment, adequate mechanical properties at room and operating temperature, resistance to adverse property changes in a radioactive environment, and compatibility with interfacing components.

4.2.3.1.3 Reactivity Control Components

The reactivity control components are subdivided into two categories:

(1) Permanent devices used to control or monitor the core

(2) Optional burnable absorber assemblies

The permanent type components are the RCCAs, control rod drive assemblies, and neutron source assemblies, and thimble plug assemblies. Although the latter is presented as a reactivity control system component in this document, it is done only because it is needed to restrict bypass flow through those thimbles not occupied by absorber, source, or burnable poison rods.

The purpose of the optional burnable absorber assemblies is to control assembly power and ensure that the temperature coefficient of reactivity is less positive under normal operating conditions.

The design bases for each of the components mentioned are presented below.

4.2.3.1.3.1 Absorber Rods

The following design conditions, based on Article NB-3000 of the ASME B&PV Code, Section III, are considered.

(1) The external pressure equal to the RCS operating pressure

(2) The wear allowance equivalent to 1000 reactor trips

(3) Bending of the rod due to a misalignment in the guide tube

(4) Forces imposed on the rods during rod drop

(5) Loads caused by accelerations imposed by the CRDM

(6) Radiation exposure for maximum core life.

The absorber material temperature shall not exceed its melting temperature (1470°F for silver-indium-cadmium absorber material (Reference 2)).

The Westinghouse RCCA and Enhanced Performance RCCA (EP-RCCA) model control rods that are cold-rolled Type 304 stainless steel is the only noncode material used in the control assembly. The stress intensity limit S_m for this material is defined as two-thirds of the 0.2 percent offset yield stress. The Framatome control rod noncode material stress intensity limit S_m is also two-thirds of the 0.2 percent offset yield stress.

4.2.3.1.3.2 Burnable Absorber Rods

The burnable absorber rod cladding (304SS for the borosilicate design and Zircaloy-4 for the wet annular burnable absorber (WABA) design) is designed as a Class I component under Article NB-3000 of the ASME B&PV Code, Section III, 1973, for Conditions I and II. For Conditions III and IV loads, code stresses are not considered limiting. Failures of the burnable absorber rods during these conditions must not interfere with reactor shutdown or emergency cooling of the fuel rods.

The structural elements of the burnable absorber rod are designed to maintain absorber geometry even if the borosilicate glass is fractured. The rods are designed so that the borosilicate absorber material is below its softening temperature (1492°F[a] for reference 12.5 weight percent boron rods), and the Al_2O_3-B_4C material is below 1200°F during normal operation or overpower transients.

4.2.3.1.3.3 Neutron Source Rods

The neutron source rods are designed to withstand:

(1) An external pressure equal to the RCS operating pressure

(2) An internal pressure equal to the pressure generated by gases released over the neutron source rod life.

4.2.3.1.3.4 Thimble Plug Assembly

The thimble plug assemblies:

(1) Accommodate the differential thermal expansion between fuel assembly and core internals

(2) Maintain positive contact with the fuel assembly and the core internals

(3) Can be inserted into, or withdrawn from, the fuel assembly by a force not exceeding 65 pounds.

4.2.3.1.4 Control Rod Drive Mechanisms

The CRDMs are Code Class I components designed to meet the stress requirements for normal operating conditions of Section III of the ASME B&PV Code. Both static and dynamic stress intensities are considered. The stresses originating from the required design transients are included in the analysis.

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[a] Borosilicate glass is accepted for use in burnable absorber rods if the softening temperature is greater than 1510°F (±18°F). The softening temperature is defined in ASTM Standard C 338.

A dynamic seismic analysis is performed on the CRDM to confirm its ability to trip under a postulated seismic disturbance while maintaining resulting stresses under ASME B&PV Code, Section III allowable values.

4.2.3.1.4.1 Control Rod Drive Mechanism Design Requirements

The CRDMs were designed to meet the following basic operational requirements:

(1) 5/8-inch step

(2) 150-inch travel (nominal)

(3) 360 pounds-force maximum load

(4) Step in or out at 45 inches per minute (72 steps per minute) maximum

(5) Power interruption shall initiate release of drive rod assembly

(6) Trip delay of 150 milliseconds or less - Free fall of drive rod assembly shall begin less than 150 milliseconds after power interruption, no matter what holding or stepping action is being executed, with any load and coolant temperatures between 100 and 550°F.

(7) 40-year design life with normal refurbishment

(8) 28,000 complete travel excursions equaling 13 million steps with normal refurbishment

4.2.3.2 Description and Drawings

Reactivity control is provided by neutron absorbing rods and a soluble chemical neutron absorber (boric acid). The boric acid concentration is varied to control long-term reactivity changes such as:

(1) Fuel depletion and fission product buildup

(2) Cold to hot, zero power reactivity change

(3) Reactivity change produced by intermediate-term fission products such as xenon and samarium

(4) Burnable poison depletion

The concentration of boric acid in the reactor coolant is regulated by the chemical and volume control system (CVCS), as described in Section 9.3.4.

The RCCAs provide reactivity control for:

(1) Shutdown

(2) Reactivity changes due to coolant temperature changes in the power range

(3) Reactivity changes associated with the power coefficient of reactivity

(4) Reactivity changes due to void formation

The neutron source assemblies provide a means of verifying that the neutron instrumentation performs its function during periods of low neutron activity. They also provide the required count rate during startup.

The most effective reactivity control component is the RCCA and its corresponding drive rod assemblies. Figure 4.2-15 identifies the rod cluster control and drive rod assembly, in addition to the interfacing fuel assembly, guide tubes, and CRDM.
Guidance for the control rod cluster is provided by the guide tube, as shown in Figure 4.2-15. The guide tube provides two regimes of guidance:

(1) In the lower section, a continuous guidance system provides support immediately above the core. This system protects the rod against excessive deformation and wear due to hydraulic loading.

(2) The region above the continuous section provides support and guidance at uniformly spaced intervals.

The support envelope is determined by the RCCA pattern, as shown in Figure 4.2-16. The guide tube ensures alignment and support of the control rods, spider body, and drive rod while maintaining trip times at or below required limits.

4.2.3.2.1 Reactivity Control Components

4.2.3.2.1.1 Rod Cluster Control Assembly

The RCCAs are divided into two categories: control and shutdown. Two criteria have been employed for selection of the control groups. First, the total reactivity worth must be adequate to meet the nuclear requirements. Second, because some of these rods may be partially inserted at power operation, the total power peaking factor should be low enough to ensure that the power capability is met. The control and shutdown groups provide adequate shutdown margin (SDM) which is defined as: the instantaneous amount of reactivity by which the reactor is subcritical, or would be subcritical from its present condition, assuming all rod cluster assemblies (shutdown and control) are fully inserted, except for the single rod cluster assembly of highest reactivity worth that is assumed to be fully withdrawn.

An RCCA comprises a group of individual neutron absorber rods fastened at the top end to a common spider assembly, as illustrated in Figure 4.2-16.

The absorber material used in the control rods is a silver-indium-cadmium alloy that is essentially "black" to thermal neutrons and has sufficient additional resonance absorption to significantly increase its worth. The alloy is in the form of extruded rods that are sealed in stainless steel tubes to prevent the rods from coming in direct contact with the coolant. The silver-indium-cadmium rods are inserted into cold-worked stainless steel tubing. It is sealed at the bottom and top by welded end plugs, as shown in Figure 4.2-17. Sufficient diametral and end clearance is provided to accommodate relative thermal expansions.

The bullet-nosed bottom plugs reduce the hydraulic drag during reactor trip and guide the absorber rods smoothly into the dashpot section of the fuel assembly guide thimbles. The upper plug is threaded for assembly to the spider and has a reduced end section to make the joint more flexible.

The spider assembly is in the form of a central hub with radial vanes containing cylindrical fingers from which the absorber rods are suspended. Handling detents and detents for connection to the drive rod assembly are machined into the upper end of the hub. A coil spring or, for the Westinghouse EP-RCCA spider only, two coiled springs inside the spider body absorbs the impact energy at the end of a trip insertion. All components of the spider assembly are made from Types 304 and 308 stainless steel, except for the retainer, which is made of 17-4 PH stainless steel material, and the springs, which are made of Inconel 718 alloy or, for the Westinghouse RCCA and EP-RCCA spiders only, an austenitic stainless steel where the springs do not contact the coolant. Other Framatome spider assembly components not made from 304 or 308 stainless steel are the spider itself, cast from Type 316L stainless steel, the cladding which is tempered and cold worked Type 316 stainless steel and the rod spring spacer which is Inconel 750. The absorber rods are fastened securely to the spider to ensure trouble-free service.

The overall length is such that when the assembly is withdrawn through its full travel, the tips of the absorber rods remain engaged in the guide thimbles so that alignment between rods and thimbles is always maintained. Because the rods are long and slender, they are relatively free to conform to any small misalignments with the guide thimble.

4.2.3.2.1.2 Burnable Absorber Assembly

Each burnable absorber assembly consists of borosilicate or WABA burnable absorber rods attached to a hold down assembly. Conceptual burnable absorber assemblies (containing borosilicate absorber) are shown in Figure 4.2-18. WABA rods may be used in place of the borosilicate absorber rods.

The borosilicate absorber rods consist of borosilicate glass tubes contained within Type 304 stainless steel tubular cladding, which is plugged and seal welded at the ends to encapsulate the glass. The glass is also supported along the length of its inside diameter by a thin wall tubular inner liner. The top end of the liner is open to permit the diffused helium to pass into the void volume and the liner overhangs the glass. The liner has an outward flange at the bottom end to maintain the position of the liner with the glass. A typical borosilicate burnable absorber rod is shown in longitudinal and transverse cross-sections in Figure 4.2-19.

A WABA rod (Figure 4.2-18a) consists of annular pellets of alumina-boron carbide (Al_2O_3-B_4C) burnable absorber material contained within two concentric Zircaloy tubes. These Zircaloy tubes, which form the inner and outer cladding for the WABA rod, are plugged and welded at each end to encapsulate the annular stack of absorber material. The assembled rod is then internally pressurized to 650 psig and seal welded. The absorber stack lengths are positioned axially within the WABA rods by the use of Zircaloy bottom-end spacers. An annular plenum is provided within the rod to accommodate the helium gas released from absorber material depletion during irradiation. The reactor coolant flows inside the inner tube and outside the outer tube of the annular rod. Further design details are given in Section 3.0 of Reference 28.
The burnable absorber rods are statically suspended and positioned in selected guide thimbles within the fuel assemblies. The absorber rods in each assembly are attached together at the top end of the rods to a hold down assembly by a flat, perforated retaining plate which fits within the fuel assembly top nozzle and rests on the adapter plate. The absorber rod assembly is held down and restrained against vertical motion through a spring pack which is attached to the plate and is compressed by the upper core plate when the reactor upper internals assembly is lowered into the reactor. This arrangement ensures that the absorber rods cannot be ejected from the core by flow forces. Each rod is permanently attached to the base plate by a nut, which is locked into place.

The borosilicated rod cladding is slightly cold worked Type 304 stainless steel, and the WABA rod cladding is Zircaloy-4. All other structural materials are Types 304 or 308 stainless steel except for the springs which are Inconel-718. The borosilicate glass tube provides sufficient boron content to meet the criteria discussed in Section 4.3.1.

4.2.3.2.1.3 Neutron Source Assembly

The neutron source assembly provides a base neutron level to ensure that the detectors are operational and responding to core multiplication neutrons. Because there is very little neutron activity during core loading, refueling, hot and cold shutdown, and approach to criticality, neutron sources are placed in the reactor to help determine if source range detectors are properly responding.

During core loading, it is verified that active source assemblies provide the responding source range detectors with a sufficient count rate. For normal source range detectors (N-31 and N-32), and for alternate source range detectors (N-51 and N-52), the

following count rate requirements must be met after an installed active source is neutronically coupled to a detector:

(1) For N-31 and N-32:
Count Rate ≥ Maximum (2B, B+0.5, 1.0) counts per second

(2) For N-51 and N-52:
Count Rate ≥ Maximum (2B, B+0.05, 0.1) counts per second

Where:
B = background count without fuel or sources in counts in per second

The differences in required count rates are due to differences in detector sensitivity between the proportional counters (N-31 and N-32) and the fission chambers (N-51 and N-52).

The source assembly also permits detection of changes in the core multiplication factor during core loading, refueling, and approach to criticality. This can be done since the multiplication factor is related to an inverse function of the detector count rate. Therefore, a change in the multiplication factor can be detected during addition of fuel assemblies while loading the core, a change in control rod positions, and changes in boron concentration.

The primary source rod, containing californium-252, spontaneously fissions and emits neutrons. After the primary source rod decays beyond the desired neutron flux level, neutrons are then supplied by the secondary source rod. The secondary source rod contains a mixture of approximately half antimony and half beryllium by volume, which is activated by neutron bombardment during reactor operation. Activation of antimony results in the subsequent release of neutrons by the (γ,n) reaction in beryllium. This becomes a source of neutrons during periods of low neutron flux, such as during refueling and subsequent startups.

The DCPP Units 1 and 2 reactor cores each employ two primary source assemblies and two secondary source assemblies in the first core. Each primary source assembly contains one primary source rod and between zero and twenty-three burnable absorber rods. Each secondary source assembly contains a symmetrical grouping of four secondary source rods and between zero and twenty burnable absorber rods. Source assemblies are shown in Figures 4.2-20 and 4.2-21.

Each of the two new secondary sources installed in Unit 2 starting with Cycle 10 and in Unit 1 starting with Cycle 11, have six secondary source rods and no burnable poison rods. See Figure 4.2-21A.

Neutron source assemblies are located at diametrically opposite sides of the core. The assemblies are inserted into the guide thimbles at selected unrodded locations.

The primary and secondary source rods both utilize slightly cold worked 304 SS material. The secondary source rods contain about 500 grams of stacked antimony-beryllium pellets, and the rod is internally prepressurized to 650 psig. The primary source rods contain capsules of Californium source material and alumina spacer rods to position the source material within the cladding. The rods in each assembly are permanently fastened at the top end to a hold down assembly, which is identical to that of the burnable absorber assemblies.

The other structural members are fabricated from Type 304 and 308 stainless steel except for the springs exposed to the reactor coolant. They are wound from an age hardened nickel base alloy for corrosion resistance and high strength.

4.2.3.2.1.4 Thimble Plug Assembly

Thimble plug assemblies are utilized, if desired, to further limit bypass flow through the guide thimbles in fuel assemblies that do not contain either control rods, source rods, or burnable absorber rods.

The thimble plug assemblies shown in Figure 4.2-22 consist of a flat base plate with short rods suspended from the bottom surface and a spring pack assembly. The 24 short rods, called thimble plugs, project into the upper ends of the guide thimbles to reduce the bypass flow area. Similar short rods may be also used on the source assemblies and burnable absorber assemblies to plug the ends of all vacant fuel assembly guide thimbles.

All components in the thimble plug assembly, except for the springs, are fabricated from Type 304 stainless steel. The springs are wound from an age-hardened nickel base alloy for corrosion resistance and high strength.

4.2.3.2.2 Control Rod Drive Mechanism

All parts exposed to reactor coolant are made of metals that resist the corrosive action of the water. Three types of metals are used exclusively: stainless steels, nickel alloy, and cobalt-based alloys. Wherever magnetic flux is carried by parts exposed to the main coolant, 400 series stainless steel is used. Cobalt-based alloys are used for the pins and latch tips. Nickel alloy is used for the springs of both latch assemblies, and Type 304 stainless steel for all pressure-containing parts. Hard chrome plating provides wear surfaces on the sliding parts and prevents galling between mating parts.

A position indicator assembly slides over the CRDM rod travel housing. This position indicator assembly detects the drive rod assembly position by means of 42 discrete coils that magnetically sense the entry and presence of the rod drive line through its centerline over the normal length of the drive rod travel.

The CRDMs are located on the head of the reactor vessel. They are coupled to RCCAs. An actual CRDM is shown in Figure 4.2-23, and a schematic in Figure 4.2-24.

The primary function of the CRDM is to insert or withdraw RCCAs into or from the core to control average core temperature and to shut down the reactor. The CRDM is a magnetically operated jack. A magnetic jack is an arrangement of three electromagnets that are energized in a controlled sequence by a power cycler to insert or withdraw the RCCAs of the reactor core in discrete steps. The CRDM consists of the pressure vessel, coil stack assembly, the latch assembly, and the drive rod assembly:

(1) The pressure vessel includes a latch housing and a rod travel housing that are connected by a threaded, seal-welded maintenance joint.

The latch housing is the lower portion of the vessel and contains the latch assembly. The rod travel housing is the upper portion of the vessel and provides space for the drive rod during its upward movement as the control rods are withdrawn from the core.

(2) The coil stack assembly includes the coil housings, an electrical conduit and connector, and three operating coils: (a) the stationary gripper coil, (b) the movable gripper coil, and (c) the lift coil.

Energizing the operation coils causes movement of the pole pieces and latches in the latch assembly.

(3) The latch assembly includes the guide tube, stationary pole pieces, movable pole pieces, and two sets of latches: (a) the movable gripper latch, and (b) the stationary gripper latch.

The latches engage grooves in the drive rod assembly. The movable gripper latches are moved up or down in 5/8-inch steps by the lift pole to raise or lower the drive rod. The stationary gripper latches hold the drive rod assembly while the movable gripper latches are repositioned for the next 5/8-inch step.

(4) The drive rod assembly includes a flexible coupling, a drive rod, a disconnect button, a disconnect rod, and a locking button.

The drive rod has 5/8-inch grooves that receive the latches during holding or moving of the drive rod.

The disconnect button, disconnect rod, and locking button provide positive locking of the coupling to the RCCA and permit remote disconnection.

The CRDM has a trip design. Tripping can occur during any part of the power cycler sequencing if power to the coils is interrupted.

The CRDM is threaded and seal-welded on an adapter on top of the reactor vessel, and is coupled to the RCCA directly below.

The mechanism can handle a 360-pound load, including the drive rod weight, at a rate of 45 inches per minute. Withdrawal of the RCCA is accomplished by magnetic forces while insertion is by gravity.

The mechanism internals are designed to operate in 650°F reactor coolant. The three operating coils are designed to operate at 392°F with forced air cooling required to maintain that temperature.

The CRDM, shown schematically in Figure 4.2-24, withdraws and inserts its control rod as electrical pulses are received by the operator coils. Position of the control rod is measured by 42 discrete coils mounted on the position indicator assembly surrounding the rod travel housing. Each coil magnetically senses the entry and presence of the top of the ferromagnetic drive rod assembly as it moves through the coil centerline.

During plant operation, the stationary gripper coil of the drive mechanism holds the control rod withdrawn from the core in a static position until the movable gripper coil is energized.

If power to the stationary gripper coil is cut off, the combined weight of the drive rod assembly and the RCCA is sufficient to move latches out of the drive rod assembly groove. The control rod falls by gravity into the core. The trip occurs as the magnetic field, holding the stationary gripper plunger half against the stationary gripper pole, collapses, and the stationary gripper plunger half is forced down by the weight acting upon the latches. After the drive rod assembly is released by the mechanism, it falls freely until the control rods enter the buffer section of their thimble tubes.

4.2.3.3 System Evaluation

4.2.3.3.1 Reactivity Control Components

The components are analyzed for loads corresponding to normal, upset, emergency, and faulted conditions. The analysis performed depends on the mode of operation under consideration.

The scope of the analysis requires many different techniques and methods, both static and dynamic.

Some of the loads that are considered on each component, where applicable, are:

(1) Control rod scram (equivalent static load)

(2) Differential pressure

(3) Spring preloads

(4) Coolant flow forces (static)
(5) Temperature gradients

(6) Differences in thermal expansion

(a) Due to temperature differences

(b) Due to expansion of different materials

(7) Interference between components

(8) Vibration (mechanically or hydraulically induced)

(9) All operational transients listed in Table 5.2-4

(10) Pump overspeed

(11) Seismic loads (DE, DDE and Hosgri earthquake)

The main objective of the analysis is to ensure that allowable stress limits are not exceeded, that an adequate design margin exists, and to establish deformation limits that are concerned primarily with the components' functioning. The stress limits are established not only to ensure that peak stresses will not reach unacceptable values, but also to limit the amplitude of the oscillatory stress component in consideration of fatigue characteristics of the materials. Standard methods of strength of materials are used to establish the stresses and deflections of these components. The dynamic behavior of the reactivity control components has been studied using experimental test data and experience from operating reactors.

The design of reactivity component rods provides sufficient cold void volume within the burnable absorber and source rods to limit internal pressures to a value that satisfies the criteria in Section 4.2.3.1. The void volume for the helium in the borosilicate glass burnable absorber rods is obtained through the use of glass in tubular form that provides a central void along the length of the rods. For the WABA rods, an annular void volume is provided between the two tubes at the top and along the length of each WABA rod (Figure 4.2-18a). Helium gas is not released by the neutron absorber rod material; thus the absorber rod is only exposed to an external pressure during operating conditions. The internal pressure of source rods continues to increase from ambient until EOL; the internal pressure never exceeds that allowed by the criteria in Section 4.2.3.1. Except for the WABA rods, the stress analysis of reactivity component rods assumes 100 percent gas release to the rod void volume, considers the initial pressure within the rod, and assumes that the pressure external to the component rod is zero. The stress analysis for the WABA rods assumed a maximum 30 percent gas release, consistent with Reference 28.

Based on available data on borosilicate glass properties, and on nuclear and thermal calculations for these burnable absorber rods, gross swelling or cracking of the glass tubing is not expected during operation. Some minor creep of the glass at the hot spot on the inner surface of the tube could occur, but would continue only until the glass came in contact with the inner liner. The wall thickness of the inner liner is sized to provide adequate support in the event of slumping and to collapse locally before rupture of the exterior cladding, should unexpected large volume changes due to swelling or cracking occur. The top of the inner liner is open to allow communication to the central void by the helium, which diffuses out of the glass.

An evaluation of the WABA rod design is given in Reference 28.

No bending or warping is induced in the rods, although the clearance offered by the guide thimble would permit a postulated warpage to occur without restraint on the rods.

The radial and axial temperature profiles have been determined by considering gap conductance, thermal expansion, and neutron and/or gamma heating of the contained material as well as gamma heating of the cladding. The maximum neutron absorber material temperature was found to be less than 850°F, which occurs axially at only the highest flux region. The maximum borosilicate glass temperature was calculated to be about 1200°F, and occurs after the initial rise to power. The glass temperature then decreases rapidly for the following reasons: (a) reduction in power generation due to B^{10} depletion, (b) better gap conductance as the helium produced diffuses to the gap, and (c) external gap reduction due to borosilicate glass creep. Rod, guide thimble, and dashpot flow analysis indicates that the flow is sufficient to prevent coolant boiling and maintain cladding temperatures at a value at which the cladding material has adequate strength to resist coolant operating pressures and rod internal pressures.

Analysis of the RCCA spider indicates it is structurally adequate to withstand the various operating loads, including the higher loads that occur during the drive mechanism stepping action and rod drop. Verification of the spider structural capability has been experimentally demonstrated.

The material was selected on the basis of resistance to irradiation damage and compatibility with the reactor environment. No apparent degradation of construction material has occurred in operating plants with the DCPP reactivity control design.

Regarding material behavior in a radioactive environment, it should be noted that at high fluences, the austenitic material increases in strength with a corresponding decreased ductility (as measured by tensile tests) but energy absorption (as measured by impact tests) remains quite high. Corrosion of the material exposed to the coolant is quite low, and proper control of Cl^- and O_2 in the coolant prevents stress corrosion. All of the austenitic stainless steel base material used is processed and fabricated to preclude sensitization.

Analysis of the RCCA shows that if the drive mechanism housing ruptures, the RCCA will be ejected from the core by the pressure differential of the operating pressure and ambient pressure across the drive rod assembly. The ejection is also predicated on the failure of the drive mechanism to retain the drive rod/RCCA position. It should be pointed out that a drive mechanism housing rupture causes the ejection of only one RCCA with the other assemblies remaining in the core. For the Westinghouse RCCA only, analysis also showed that a pressure drop in excess of 4000 psi must occur across a two-fingered vane to break the vane/spider body joint, causing ejection of two neutron absorber rods from the core. Since the highest normal pressure of the primary system coolant is only 2250 psi, with the safety valves set to lift at 2485 psig, a pressure drop in excess of 4000 psi is not expected. Thus, ejection of the neutron absorber rods is not possible.

Ejection of a burnable absorber or thimble plug assembly is conceivable if one postulates that the hold-down bar fails and that the base plate and burnable absorber rods are severely deformed. In the unlikely event of hold-down bar failure, the upward displacement of the burnable absorber assembly only permits the base plate to contact the upper core plate. Since this displacement is small, the major portion of the absorber material remains positioned within the core. In the case of the thimble plug assembly, the thimble plugs will partially remain in the fuel assembly guide thimbles, thus maintaining a majority of the desired flow impedance. Further displacement or complete ejection would necessitate that the square base plate and burnable absorber rods be forced, thus plastically deformed, to fit up through a smaller diameter hole. As expected, this condition requires a substantially higher force or pressure drop than that of the hold-down bar failure.

Experience with control rods, burnable absorber rods, and source rods is discussed in Reference 8.

The mechanical design of the reactivity control components provides for the protection of the active elements to prevent the loss of control capability and functional failure of critical components. The components have been reviewed for potential failure and consequences of a functional failure of critical parts. The results of the review are summarized below.

4.2.3.3.1.1 Rod Cluster Control Assembly

(1) The basic absorbing material is sealed from contact with the primary coolant and the fuel assembly and guidance surfaces by a high quality stainless steel cladding. Potential loss of absorber mass or reduction in reactivity control material due to mechanical or chemical erosion or wear is therefore reliably minimized.

(2) A breach of the cladding for any postulated reason does not result in serious consequences. The silver-indium-cadmium absorber material is relatively inert and would still remain remote from high coolant velocity

regions. Rapid loss of material resulting in significant loss of reactivity control material would not occur.

(3) The individually clad absorber rods are doubly secured to the retaining spider vane by a threaded joint and a welded lock pin. A failure of the joint would result in the insertion of the individual rod into the core. This results in reduced core reactivity which is a fail-safe condition.

(4) The spider finger braze joint that fastens the individual rods to the vanes on the Westinghouse RCCA and EP-RCCA models have also experienced many years of service, as described above, without failure. A failure of this joint would also result in insertion of the individual rod into the core. The Framatome RCCA spider is one-piece casting that includes vanes and fingers, a failure of which could also result in insertion of the individual rod into the core.

(5) The Westinghouse RCCA and EP-RCCA models radial vanes are brazed to the spider body and guidance of the rod cluster control is accomplished by the inner fingers of these vanes. They are therefore the most susceptible to mechanical damage. For the Framatome RCCA, the radial vanes are integral parts of the one-piece spider casting.

Failure of the vane-to-hub joint of a single rod vane could potentially result in failure of the separated vane and rod insertion. This could occur only at withdrawal elevation where the spider is above the continuous guidance section of the guide tube (in the upper internals). A rotation of the disconnected vane could cause it to hang on one of the guide cards in the intermediate guide tube. Such an occurrence would be evident from the failure of the rod cluster control to insert below a certain elevation, but with free motion above this point.

This possibility is considered extremely remote because the single rod vanes are subjected to only vertical loads and very light lateral reactions from the rods even during a seismic event. The consequences of such a failure are not considered critical since only one drive line of the reactivity control system would be involved. This condition is readily observed and can be cleared at shutdown.

(6) The spider hub, being of single unit cylindrical construction, is very rugged and has extremely low potential for damage. Should some unforeseen event cause fracture of the hub above the vanes, the lower portion with the vanes and rods attached would insert by gravity into the core causing reactivity decrease, again a fail-safe condition.

(7) The RCCA rods are provided a clear channel for insertion by the guide thimbles of the fuel assemblies. All fuel rod failures are protected against

by providing this physical barrier between the fuel rod and the intended insertion channel. Distortion of the fuel rods by bending cannot apply sufficient force to damage or significantly distort the guide thimble. Fuel rod distortion by swelling, though precluded by design, would be terminated by fracture before contact with the guide thimble occurs. If such were not the case, a force reaction at the point of contact would cause a slight deflection of the guide thimble. The radius of curvature of the deflected shape of the guide thimbles would be sufficiently large to have a negligible influence on rod cluster control insertion.

4.2.3.3.1.2 Burnable Absorber Assemblies

The burnable absorber assemblies are static temporary reactivity control elements. The axial position is ensured by the holddown assembly that bears against the upper core plate. Their lateral position is maintained by the guide thimbles of the fuel assemblies.

The individual rods are shouldered against the underside of the retainer plate and securely fastened at the top by a threaded nut that is then locked in place. The square dimension of the retainer plate is larger than the diameter of the flow holes through the core plate. Therefore, failure of the holddown bar or spring pack does not result in ejection of the burnable absorber rods from the core.

The only incident that could result in ejection of the burnable absorber rods is a multiple fracture of the retainer plate. This is not considered credible because of the light loads borne by this component.

The burnable absorber rods are clad with either stainless steel or Zircaloy 4. The burnable absorber is either a borosilicate glass tube which is maintained in position by a central hollow stainless steel tube or Al_2O_3-B_4C annular pellets contained within two concentric Zircaloy tubes. Burnable absorber rods are placed in static assemblies and are not subjected to motion which might damage the rods. Further, the guide thimble tubes of the fuel assembly afford additional protection from damage.

During the accumulated thousands of years of burnable absorber rodlet operating experience, only one instance of penetration of the stainless steel burnable absorber cladding has been observed. The consequences of cladding breach are also small. It is anticipated that upon cladding breach, the B_4C or borosilicate glass would be leached by the coolant water and that localized power peaking of a few percent would occur; no design criteria would be violated. Additional information on the consequences of postulated WABA rod failures is presented in Reference 28.

4.2.3.3.1.3 Drive Rod Assemblies

All postulated failures of the drive rod assemblies, either by fracture or uncoupling, lead to the fail-safe condition. If the drive rod assembly fractures at any elevation, that portion remaining coupled falls with, and is guided by, the RCCA. This always results in a reactivity decrease.

4.2.3.3.2 Control Rod Drive Mechanism

4.2.3.3.2.1 Material Selection

Materials for all pressure-containing CRDM components comply with Section III of the ASME B&PV Code and were fabricated from either austenitic (Type 304) stainless steel or CF-8 stainless steel.

Magnetic pole pieces are fabricated from Type 410 stainless steel. All nonmagnetic parts, except pins and springs, are fabricated from Type 304 stainless steel. Cobalt alloy is used to fabricate link pins. Springs are made from nickel alloy. Latch arm tips are clad with Stellite 6 or ERCoCrA to provide improved wearability. Hard chrome plate and Stellite 6 or ERCoCrA are used selectively for bearing and wear surfaces.

The cast coil housings require a magnetic material. The choice, made on the basis of cost, was the ductile iron used in the CRDM. The finished housings are zinc-plated to provide corrosion resistance.

Coils are wound on bobbins of molded Dow Corning 302 material, with double glass-insulated copper wire. Coils are then vacuum-impregnated with silicon varnish. A wrapping of mica sheet is secured to the coil outer surface. The result is a well-insulated coil capable of sustained operation at 200°C.

The drive shaft assembly uses a Type 410 stainless steel drive rod. The coupling is machined from Type 403 stainless steel. Other parts are Type 304 stainless steel with the exception of the springs, which are Inconel-X, and the locking button, which is Haynes 25.

4.2.3.3.2.2 Radiation Damage

As required by the equipment specification, the CRDMs are designed to accommodate a radiation dose rate of 10 rad/hr. The above radiation level, which amounts to 1.753×10^6 rads in 20 years, will not limit CRDM life.

4.2.3.3.2.3 Positioning Requirements

The mechanism has a step length of 5/8 inch that determines the positioning capabilities of the CRDM. (Note: Positioning requirements are determined by reactor physics.)

4.2.3.3.2.4 Evaluation of Materials' Adequacy

The ability of the pressure housing components to perform throughout the design lifetime as defined in the equipment specification is confirmed by the stress analysis report required by the ASME B&PV Code, Section III.

The CRDM latch assembly is a wear item that may require refurbishment after a minimum of two million steps.

4.2.3.3.2.5 Results of Dimensional and Tolerance Analysis

With respect to the CRDM systems as a whole, critical clearances are present in the following areas:

(1) Latch assembly (diametral clearances)

(2) Latch arm-drive rod clearances

(3) Coil stack assembly-thermal clearances

(4) Coil fit in coil housing

These clearances have been proven by life tests and actual field performance at operating plants:

(1) Latch Assembly - Thermal Clearances - The magnetic jack has several clearances where parts made of Type 410 stainless steel fit over parts made from Type 304 stainless steel. Differential thermal expansion is therefore important.

(2) Latch Arm - Drive Rod Clearances - The CRDM incorporates a load transfer action. The movable or stationary gripper latch is not under load during engagement due to load transfer action.

    Figure 4.2-25 shows latch clearance variation with the drive rod at minimum and maximum temperatures. Figure 4.2-26 shows clearance variations over the design temperature range.

(3) Coil Stack Assembly - Thermal Clearances - The assembly clearance of the coil stack assembly over the latch housing was selected so that the assembly could be removed under all anticipated conditions of thermal expansion.

(4) Coil Fit in Coil Housing - CRDM and coil housing clearances are selected so that coil heatup results in a close or tight fit. This facilitates thermal transfer and coil cooling in a hot CRDM.

4.2.3.4 Testing and Inspection Plan

4.2.3.4.1 Reactivity Control Components

Tests and inspections are performed on each reactivity control component to verify its mechanical characteristics. For the RCCA, prototype testing has been conducted and both manufacturing tests/inspections and functional testing are performed at the plant site.

During the component manufacturing phase, the following requirements apply to the reactivity control components to ensure proper functioning during reactor operation:

(1) To attain the desired standard of quality, all materials are procured to specifications.

(2) For the Westinghouse RCCA and EP-RCCA models only, all spiders are proof tested by an applied load to the spider body which is reacted on by the 16 peripheral, outermost fingers. This proof load subjects the spider assembly to a load greater than the acceleration loads caused by the CRDM stepping.

(3) All cladding/end plug welds are checked for integrity by visual inspection, X-ray, and helium leak tests. All the seal welds in the neutron absorber rods, burnable absorber rods, and source rods are checked in this manner.

(4) To ensure proper fitup with the fuel assembly, the rod cluster control, burnable absorber, and source assemblies are installed in the fuel assembly without restriction or binding in the dry condition.

The RCCAs are functionally tested following initial core loading, but prior to criticality, to demonstrate reliable operation of the assemblies. Each assembly is operated (and tripped) once each at the following conditions: no flow cold, full flow cold, no flow hot, and full flow hot. In addition, the slowest and fastest rods for each condition are tripped six more times. Rod drop tests following refueling outages will be performed in accordance with the DCPP Technical Specifications (Reference 24) requirements.

4.2.3.4.2 Control Rod Drive Mechanisms

Quality assurance procedures during production of CRDMs include material selection, process control, and mechanism component tests during production and hydrotests.

After all manufacturing procedures had been developed, several prototype CRDMs and drive rod assemblies were life tested with the entire drive line under normal environmental temperature, pressure, and flow conditions. All acceptance tests were of a duration equal to or greater than that required for plant operation. All drive rod assemblies tested in this manner have shown minimal wear damage.

These tests include verification that the trip time achieved by the CRDMs meets the design requirements from start of RCCA motion to dashpot entry. Trip time will be confirmed for each CRDM prior to initial reactor operation, and at periodic intervals thereafter. In addition, Technical Specifications ensure that the trip time requirement is met.

It is expected that all CRDMs will meet specified operating requirements for the duration of plant life with normal refurbishment. Nevertheless, a Technical Specification pertaining to an inoperable RCCA exists. If an RCCA cannot be moved by its mechanism, adjustments in the boron concentration ensure that adequate shutdown margin is achieved following a trip. Thus, inability to move one RCCA can be tolerated. More than one inoperable RCCA could be tolerated, but would impose additional demands on the plant operator. Therefore, the number of acceptable inoperable RCCAs is limited to one.

To demonstrate continuous free movement of the RCCA and to ensure acceptable core power distributions during operation, partial-movement checks are performed in accordance with Technical Specifications. In addition, periodic drop tests of the RCCAs are performed at each refueling shutdown to demonstrate continued ability to meet trip time requirements. During these tests, the acceptable trip time of each assembly is not greater than the requirements listed in the Technical Specifications at full flow and operating temperature, from decay of the gripper coil voltage to dashpot entry.

To confirm the mechanical adequacy of the fuel assembly and RCCA, functional test programs have been conducted on a full-scale control rod. The prototype assembly was tested under simulated conditions of reactor temperature, pressure, and flow for approximately 1000 hours. The prototype mechanism accumulated about 3,000,000 steps and 600 trips. At the end of the test, the control rod drive mechanism was still operating satisfactorily.

All units are production tested prior to shipment to confirm the ability of CRDMs to meet design specification-operational requirements. Periodic tests are also conducted during plant operation in accordance with the Technical Specifications.

4.2.3.5 Instrumentation

Instrumentation for determining reactor coolant average temperature (T_{avg}) is provided to create demand signals for moving groups of RCCAs to provide load follow (determined as a function of turbine impulse pressure) during normal operation, and to counteract operational transients. The hot and cold leg resistance temperature detectors (RTDs) are described in Section 7.2. The reactor control system, which controls the reactor coolant average temperature by regulation of control rod bank position, is described in Section 7.7.

Rod position indication instrumentation is provided to sense the actual position of each control rod so that it may be displayed to the operator. Signals are also supplied by this system as input to the rod deviation comparator. The rod position indication system is described in Chapter 7. The CVCS, one of whose functions is to permit adjustment of the reactor coolant boron concentration for reactivity control (as well as to maintain the desired operating fluid inventory in the volume control tank), consists of a group of instruments arranged to provide a manually preselected makeup composition that is borated or diluted, as required, to the charging pump suction header or the volume control tank. This system, as well as other systems, including boron sampling provisions that are part of the CVCS, is described in Section 9.3.

When the reactor is critical, the normal indication of reactivity status in the core is the position of the control bank in relation to reactor power (as indicated by the reactor coolant system loop ΔT) and coolant average temperature. These parameters are used to calculate insertion limits for the control banks to warn the operator of excessive rod insertion. Monitoring of the neutron flux for various phases of reactor power operation, as well as of core loading, shutdown, startup, and refueling is by means of the nuclear instrumentation system. The monitoring functions and readout and indication characteristics for the following reactivity monitoring systems are included in the discussion on safety-related display instrumentation in Section 7.5:

(1) Nuclear instrumentation system

(2) Temperature indicators

  (a) T average (measured)

  (b) ΔT (measured)

  (c) Auctioneered T average

(3) Demand position of rod cluster control assembly group

(4) Actual rod position indicator.

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4.3 NUCLEAR DESIGN

The nuclear design of the reactors for Units 1 and 2 at DCPP, including fuel and reactivity control systems, is described in this section; the analytical methods used in reactor design and evaluation are also discussed.

4.3.1 DESIGN BASES

The design bases and functional requirements for the nuclear design of the fuel and reactivity control system, and the relationship of these design bases to the GDC of July 1971, are presented in this section. Where appropriate, supplemental criteria, such as 10 CFR 50.46, are addressed.

Before discussing the nuclear design bases, a brief review of the four major plant operation conditions, categorized in accordance with their anticipated frequency of occurrence and risk to the public, (see Section 4.2) follows:

(1) Condition I - Normal Operation

(2) Condition II - Incidents of Moderate Frequency

(3) Condition III - Infrequent Faults

(4) Condition IV - Limiting Faults

In general, Condition I occurrences are accommodated with margin between any plant parameter and the value of that parameter which would require either automatic or manual protective action. Condition II incidents are accommodated with, at most, a shutdown of the reactor with the plant capable of returning to operation after corrective action. Fuel damage[a] is not expected during Conditions I and II events. It is not possible, however, to preclude a very small number of rod failures. These are within the capability of the plant cleanup system and are consistent with the plant design bases.

Condition III incidents shall not cause more than a small fraction of the fuel elements in the reactor to be damaged, although sufficient fuel element damage might occur to preclude immediate resumption of operation. The release of radioactive material due to Condition III incidents should not be sufficient to interrupt or restrict public use of those areas beyond the exclusion radius. Furthermore, a Condition III incident shall not, by itself, generate a Condition IV fault or result in a consequential loss of function of the reactor coolant system (RCS) or reactor containment barriers. Condition IV occurrences are faults that are not expected to occur, but are defined as limiting faults that must be considered in design. Condition IV faults shall not cause a release of radioactive material that results in an undue risk to public health and safety.

[a] Fuel damage as used here is defined as penetration of the fission product barrier (i.e., the fuel rod cladding).

The core design power distribution limits related to fuel integrity are met for Condition I occurrences through conservative design, and maintained by the action of the control system. The requirements for Condition II occurrences are met by providing an adequate protection system that monitors reactor parameters. The control and protection systems are described in Chapter 7 and the consequences of Conditions II, III, and IV occurrences are discussed in Chapter 15.

4.3.1.1 Fuel Burnup

4.3.1.1.1 Basis

Sufficient reactivity should be incorporated in the fuel to attain a desired region average discharge burnup. This, along with the design basis in Section 4.3.1.3, satisfies GDC 10.

4.3.1.1.2 Discussion

Fuel burnup is a measure of fuel depletion that represents the integrated energy output of the fuel (MWD/MTU) and is a convenient means for quantifying fuel exposure.

The core design lifetime or design discharge burnup is achieved by installing sufficient initial excess reactivity in each fuel region, and by following a fuel replacement program (such as that described in Section 4.3.2) that meets all safety-related criteria in each cycle of operation.

Initial excess reactivity in the fuel, although not a design basis, must be sufficient to maintain core criticality at full power operating conditions throughout cycle life with equilibrium xenon, samarium, and other fission products present. The end of design cycle life is defined to occur when the chemical shim concentration is essentially zero, with control rods present to the degree necessary for operational requirements (e.g., the controlling bank at the "bite" position). In terms of chemical shim boron concentration, this represents approximately 10 ppm with no control rod insertion.

4.3.1.2 Negative Reactivity Feedbacks (Reactivity Coefficients)

4.3.1.2.1 Basis

The fuel temperature coefficient of reactivity will be negative, and the moderator temperature coefficient (MTC) of reactivity will be nonpositive for full power operating conditions, thus providing negative reactivity feedback characteristics over the operating range. Below 70 percent power, an MTC of up to +5 pcm (percent mille)/°F is allowed. From 70 percent to 100 percent the MTC limit decreases linearly from +5 to 0 pcm/°F. The design basis meets GDC 11.

4.3.1.2.2 Discussion

When compensation for a rapid increase in reactivity is considered, there are two major effects. These are the resonance absorption effects (Doppler) associated with changing fuel temperature, and the spectrum effect resulting from changing moderator density. These basic physics characteristics are often identified by reactivity coefficients. The use of slightly enriched uranium ensures that the Doppler coefficient of reactivity, which provides the most rapid reactivity compensation, is negative. The core is also designed to have an overall negative MTC of reactivity at full power so that average coolant temperature or void content provides another, slower, compensatory effect. A small positive MTC is allowed at low power. The negative MTC at full power can be achieved through use of fixed burnable absorbers and/or boron coated fuel pellets and/or control rods by limiting the reactivity held down by soluble boron.

Burnable absorber content (quantity and distribution) is not stated as a design basis other than as it relates to achieving a nonpositive MTC at power operating conditions, as discussed above.

4.3.1.3 Control of Power Distribution

4.3.1.3.1 Basis

The nuclear design basis, with at least a 95 percent confidence level, is as follows:

(1) The fuel will not be operated at greater than 14.3 kW/ft under normal operating conditions, including an allowance of 2 percent for calorimetric error and not including the power spike factor due to densification effects (Reference 3).

(2) Under abnormal conditions, including the maximum overpower condition, the fuel peak power will not cause melting as defined in Section 4.4.1.2.

(3) The fuel will not operate with a power distribution that violates the departure from nucleate boiling (DNB) design basis (i.e., the departure from nucleate boiling ratio (DNBR) shall not be less than the design limit DNBR, as discussed in Section 4.4.1) under Conditions I and II events, including the maximum overpower condition.

(4) Fuel management will be such as to produce fuel rod powers and burnups consistent with the assumptions in the fuel rod mechanical integrity analysis of Section 4.2.

The above basis meets GDC 10.

4.3.1.3.2 Discussion

Calculation of the extreme power shapes that affect fuel design limits is performed with proven methods as described in Section 4.3.3 and verified frequently with results from measurements in operating reactors. The conditions under which limiting power shapes are assumed to occur are chosen conservatively with regard to any permissible operating state.

Even though there is good agreement between peak power calculations and measurements, a nuclear uncertainty margin is applied to calculated peak local power. Such a margin is provided both for the analysis of normal operating states and for anticipated transients.

4.3.1.4 Maximum Controlled Reactivity Insertion Rate

4.3.1.4.1 Basis

The maximum reactivity insertion rate due to withdrawal of RCCAs, or by boron dilution, is limited. This limit, expressed as a maximum reactivity change rate (75 pcm/sec)[a], is set such that the peak heat generation rate does not exceed the maximum allowable, and DNBR is not below the minimum allowable at overpower conditions. This satisfies GDC 25.

The maximum control rod reactivity worth and the maximum rates of reactivity insertion using control rods are limited to preclude either rupture of the coolant pressure boundary or disruption of the core internals to a degree that would impair core cooling capacity in the event of a rod withdrawal or ejection accident (see Chapter 15).

Following any Condition IV event (such as rod ejection and steam line break), the reactor can be brought to the shutdown condition and the core will maintain acceptable heat transfer geometry. This satisfies GDC 28.

4.3.1.4.2 Discussion

Reactivity addition associated with an accidental withdrawal of a control bank (or banks) is limited by the maximum rod speed (or travel rate) and by the worth of the bank(s). For this reactor the maximum control rod speed is 45 inches per minute and the maximum rate of reactivity change considering two control banks moving is less than 75 pcm/sec.

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[a] 1 pcm = $10^{-5}\,\Delta\rho$ where $\Delta\rho = \ln\left(\frac{k_2}{k_1}\right)$ (see footnote, Table 4.3-1).

4.3.1.5 Shutdown Margins

4.3.1.5.1 Basis

Minimum shutdown margin, as specified in the Core Operating Limits Reports, is required in all operational modes except refueling.

In all analyses involving reactor trip, the single, highest worth RCCA is postulated to remain untripped in its full-out position (stuck rod criterion). This satisfies GDC 26.

4.3.1.5.2 Discussion

Two independent reactivity control systems are provided: control rods and soluble boron in the coolant. The control rod system can compensate for the reactivity effects of the fuel and water temperature changes accompanying power level changes over the range from full load to no load. In addition, the control rod system provides the minimum shutdown margin under Condition I events and is capable of making the core subcritical rapidly enough to prevent exceeding acceptable fuel damage limits, assuming that the highest worth control rod is stuck out upon trip.

The boron system can compensate for all xenon burnout reactivity changes and will maintain the reactor in cold shutdown. Thus, backup and emergency shutdown provisions are provided by a mechanical and a chemical shim control system that satisfies GDC 26.

When fuel assemblies are in the pressure vessel and the vessel head is not in place, k_{eff} will be maintained at or below 0.95 with control rods and soluble boron. Further, the fuel will be maintained sufficiently subcritical that removal of all RCCAs will not result in criticality.

10 CFR 50.68(b) specifies a k_{eff} not to exceed 0.95 in spent fuel storage racks flooded with borated water and a k_{eff} not to exceed 0.98 in normally dry new fuel storage racks assuming optimum moderation. No criterion is given for the refueling operation; however, a 5 percent margin, which is consistent with spent fuel storage and 3 percent below the new fuel storage margin, is adequate for the controlled and continuously monitored operations involved.

An exemption granted from the NRC from the requirements of 10 CFR 50.68(b)(1) for the loading, unloading, and handling of components of the HI-STORM 100 dual-purpose dry cask storage system at DCPP is addressed in Section 9.1.4.3.8.

4.3.1.6 Stability

4.3.1.6.1 Basis

The core will be inherently stable to power oscillations of the fundamental mode. This satisfies GDC 12.

4.3.1.6.1.1 Discussion

Oscillations in total core power output, from whatever cause, are readily detected by loop temperature sensors and by nuclear instrumentation. If power increased unacceptably, a reactor trip would occur, thus preserving margins to fuel design limits. The stability of the turbine/steam generator/core systems and the reactor control system ensure that core power oscillations do not normally occur. Protection circuits' redundancy ensures an extremely low probability of exceeding design power levels.

4.3.1.6.2 Basis

Spatial power oscillations within the core, with a constant core power output, should they occur, can be reliably and readily detected and suppressed.

4.3.1.6.2.1 Discussion

The core is designed so that diametral and azimuthal oscillations due to spatial xenon effects are self-damping, and no operator action or control action is required to suppress them. Stability against diametral oscillations is so great that this excitation is highly improbable. Convergent azimuthal oscillations can be excited by prohibited motion of individual RCCAs. Such oscillations are readily observable and alarmed, using the excore long ion chambers. Indications are also continuously available from incore thermocouples and loop temperature measurements. Movable incore detectors can be activated to provide more detailed information. In all presently proposed cores, these horizontal plane oscillations are self-damping by virtue of reactivity feedback effects designed into the core.

Axial xenon spatial power oscillations can be excited by power level changes or by control rod motion/misalignments. The oscillations are inherently convergent at the beginning of core life, but become divergent as the core ages. The time in core life when oscillations may become divergent depends on core characteristics. Xenon oscillations studies performed for plants similar to DCPP concluded that oscillations can diverge as early as 50 EFPD. The magnitude of oscillations increases with increasing core burnup, although the period is unaffected. The type of oscillation (convergence or divergence) does not depend on the amplitude of the initial oscillation but is a function of initial conditions at the start of the transient.

The excore detectors provide monitoring of axial power distribution. The operator actions (control rod movement or power level changes) are expected to suppress and control axial xenon transients.

The limits on measured axial difference assure that the fuel design limits (F_q) are not exceeded during either normal operation or a xenon transient. The measured AFD is also used as an input to the OTT trip function so that the DNB design bases are not exceeded.

4.3.1.7 Anticipated Transients Without Scram

Each unit has an ATWS mitigation system actuation circuitry (AMSAC) system. Details of this system are given in Section 7.6.

4.3.2 DESCRIPTION

4.3.2.1 Nuclear Design Description

The reactor core consists of 193 fuel assemblies arranged in a pattern that approximates a right circular cylinder. Each fuel assembly contains a 17 x 17 rod array composed of 264 fuel rods, 24 RCCA guide tubes, and an incore instrumentation thimble. Each rod is held in place by spacer grids and top and bottom nozzles. The fuel rods are constructed of zirconium alloy tubing containing UO_2 fuel pellets. A limited substitution of fuel rods by filler rods of zirconium alloy or stainless steel may be made for a particular design if justified by a cycle-specific reload analysis. Figure 4.2-1 shows a cross-sectional view of a fuel assembly and the related RCCA locations. The fuel assembly design is discussed in Section 4.2.1.

All the fuel rods within a given assembly generally have the same nominal uranium enrichment. The exceptions are that the top and bottom portions of the rods may contain a low enriched or natural uranium blanket and that some assemblies may contain more than one enrichment as a result of reconstitution operations. Figure 4.3-1 shows a typical equilibrium 18-month cycle core loading of fresh and burned fuel assemblies. This "typical" loading pattern is modified for fuel cycles of longer length to accommodate the needed additional cycle energy.

A typical reload pattern employs low leakage fuel management in which more highly burned fuel is placed on the core periphery. Reload cores will operate approximately 12 months to 24 months between refuelings. The feed fuel enrichment is determined by the amount of fissionable material required to provide the desired core lifetime and energy production. Reactivity losses due to U-235 depletion and the buildup of fission products are partially offset by the buildup of plutonium produced by the capture of neutrons in U-238, as shown in Figure 4.3-2. At the beginning of any cycle, an excess reactivity to compensate for these losses over the specified cycle life must be "built" into the reactor. This excess reactivity is controlled by removable neutron absorbing

material in the form of boron dissolved in the primary coolant and burnable absorber rods or boron coated fuel pellets.

Boric acid concentration in the primary coolant is varied to control and to compensate for long-term reactivity requirements, such as those due to fuel burnup, fission product poisoning, including xenon and samarium, burnable absorber material depletion, and the cold-to-operating moderator temperature change. Using its normal makeup path, the chemical and volume control system (CVCS) is capable of inserting negative reactivity at a rate of approximately 30 pcm/min when the reactor coolant boron concentration is 1000 ppm, and approximately 35 pcm/min when the reactor coolant boron concentration is 100 ppm. In an emergency, the CVCS can insert negative reactivity at approximately 65 pcm/min when the reactor coolant concentration is 1000 ppm, and 75 pcm/min when the reactor coolant boron concentration is 100 ppm. The peak xenon burnout rate is 25 pcm/min (Section 9.3.4 discusses the capability of the CVCS to counteract xenon decay). Rapid transient reactivity requirements and safe shutdown requirements are met with control rods.

As the boron concentration increases, the MTC becomes less negative. Using soluble poison alone would result in a positive MTC at beginning of life (BOL) at full power operating conditions. Therefore, burnable absorber rods are used to reduce the soluble boron concentration sufficiently to ensure that the MTC is not positive for full power operating conditions. During operation, the absorber content in these rods is depleted, thus adding positive reactivity to offset some of the negative reactivity from fuel depletion and fission product buildup. The depletion rate of the burnable absorber material is not critical since chemical shim is always available and flexible enough to cover any possible deviations in the expected burnable absorber depletion rate. Figure 4.3-3 shows typical core depletion curves with burnable absorbers.

In addition to reactivity control, the burnable absorbers are strategically located to provide a favorable radial power distribution. Figures 4.3-4 and 4.3-5 show the typical burnable absorber distribution within a fuel assembly for the several burnable absorber patterns used for both discrete and integral fuel burnable absorbers. The burnable absorber loading pattern for a typical equilibrium cycle reload core is shown in Figure 4.3-6 using the integral fuel burnable absorber.

Tables 4.1-1, and 4.3-1 through 4.3-3, summarize the reactor core design parameters for a typical reload fuel cycle, including reactivity coefficients, delayed neutron fraction, and neutron lifetimes.

4.3.2.2 Power Distribution

DCPP employs two methods for performing core power distribution calculations. The Power Distribution Monitoring System (PDMS) generates a continuous measurement of the core power distribution using the methodology documented in References 32 and 33. The measured core power distribution is used to determine the

most limiting core peaking factors, which are used to verify that the reactor is operating within the design limits.

The PDMS requires information on current plant and core conditions in order to determine the core power distribution using the core peaking factor measurement and measurement uncertainty methodology described in References 32 and 33. The core and plant condition information is used as input to the continuous core power distribution measurement software that continuously and automatically determines the current core peaking factor values. The core power distribution calculation software provides the measured peaking factor values at nominal one-minute intervals to allow operators to confirm that the core peaking factors are within design limits. In order for the PDMS to accurately determine the peaking factor values, the core power distribution measurement software requires accurate information about the current reactor power level average reactor vessel inlet temperature, control bank positions, the power range detector currents, and the core exit thermocouples.

Data obtained from the movable neutron flux detectors, described in Section 7.7.2.9.2, are used to calibrate the PDMS, and may also be used independent of the PDMS to generate a flux map of the core power distribution. The accuracy of these power distribution calculations has been confirmed through more than 1,000 flux maps during some 20 years of operation, under conditions very similar to those expected for DCPP. Details of this confirmation are given in References 1 and 3 and in Section 4.3.2.2.7.

4.3.2.2.1 Definitions

Power distributions are quantified in terms of hot channel factors. These factors are a measure of the peak pellet power within the reactor core and the total energy produced in a coolant channel and are expressed in terms of quantities related to the nuclear or thermal design; namely:

Power density is the thermal power produced per unit volume of the core (kW/liter).

Linear power density is the thermal power produced per unit length of active fuel (kW/ft). Since fuel assembly geometry is standardized, this is the unit of power density most commonly used. For all practical purposes, it differs from kW/liter by a constant factor that includes geometry effects and the fraction of the total thermal power which is generated in the fuel rods.

Average linear power density is the total thermal power produced in the fuel rods divided by the total active fuel length of all rods in the core.

Local heat flux is the heat flux at the surface of the cladding (Btu $ft^{-2}hr^{-1}$). For nominal fuel rod parameters, this differs from linear power density by a constant factor.

Rod power or *rod integral power* is the linear power density in one rod integrated over its length (kW).

Average rod power is the total thermal power produced in the fuel rods divided by the number of fuel rods.

The hot channel factors used in the discussion of power distributions in this section are defined as follows:

F_Q^T, *heat flux hot channel factor*, is defined as the maximum local heat flux on the surface of a fuel rod divided by the average fuel rod heat flux, allowing for manufacturing tolerances on fuel pellets and rods.

F_Q^N, *nuclear heat flux hot channel factor*, is defined as the maximum local fuel rod linear power density divided by the average fuel rod linear power density, assuming nominal fuel pellet and rod parameters. (No densification effects included.)

F_Q^E, *engineering heat flux hot channel factor*, is the allowance on heat flux required for manufacturing tolerances. The engineering factor allows for local variations in enrichment, pellet density, and diameter.

Combined statistically, the net effect is a factor of 1.03 to be applied to the calculated linear power density.

$F_{\Delta H}^N$, *nuclear enthalpy rise hot channel factor*, is defined as the ratio of the integral of linear power along the rod with the highest integrated power to the average rod power.

Manufacturing tolerances, hot channel power distribution, and surrounding channel power distributions are treated explicitly in the calculation of DNB ratio described in Section 4.4.

For the purposes of discussion, it is convenient to define subfactors of F_Q^T; design limits are set, however, in terms of the total peaking factor:

$$F_Q^T = \text{Total peaking factor or heat flux hot channel factor}$$

$$= \frac{\text{Maximum kW/ft}}{\text{Average kW/ft}} \qquad (4.3\text{-}1)$$

without densification effects.

$$F_Q^T = F_Q^N \times F_Q^E$$

$$= \max\,[F_{XY}^N(z) \times P(z)] \times F_U^N \times F_Q^E \qquad (4.3\text{-}2)$$

where:

F_Q^N and F_Q^E are defined above.

F_U^N = the measurement uncertainty associated with a full core flux map with movable detectors or PDMS

$F_{XY}^N(z)$ = ratio of peak power density to average power density in the horizontal plane of peak local power

P(z) = ratio of the power per unit core height in the horizontal plane at elevation Z to the average value of power per unit core height

4.3.2.2.2 Radial Power Distributions

The power shape in horizontal sections of the core at full power is a function of the fuel and burnable absorber loading patterns, and the presence or absence of a single bank of control rods. Thus, at any time in the cycle, any horizontal section of the core can be characterized as unrodded, or with group D control rods. These two situations, combined with burnup effects, determine the radial power shapes that can exist in the core at full power. The effects on radial power shapes of power level, xenon, samarium, and moderator density effects are also considered, but these are smaller. While radial power distributions in various planes of the core are often illustrated, the core radial enthalpy rise distribution, as determined by the power integral of each channel, is of greater interest. Figures 4.3-7 through 4.3-12 show representative radial power distributions for one-eighth of the core for representative operating conditions during the initial cycle, as follows:

Figure	Conditions
4.3-7	Hot full power (HFP) at BOL unrodded no xenon
4.3-8	HFP at BOL unrodded equilibrium xenon
4.3-9	HFP at BOL Bank D in equilibrium xenon – Unit 1
4.3-10	HFP at BOL Bank D in equilibrium xenon – Unit 2
4.3-11	HFP at middle of life (MOL) unrodded equilibrium xenon, and
4.3-12	HFP at EOL unrodded equilibrium xenon.

Since hot channel location varies from time to time, a single reference radial design power distribution is selected for DNB calculations. This reference power distribution, normalized to core average power, is chosen conservatively to concentrate power in one area of the core, minimizing the benefits of flow redistribution.

4.3.2.2.3 Assembly Power Distributions

For the purpose of illustration, assembly power distributions for the BOL and EOL conditions corresponding to Figures 4.3-8 and 4.3-12 are given for the same assembly in Figures 4.3-13 and 4.3-14, respectively.

Since the detailed power distribution surrounding the hot channel varies from time to time, a conservatively flat assembly power distribution is assumed in the DNB analysis, described in Section 4.4, with the rod of maximum integrated power artificially raised to the design value of $F^{N}_{\Delta H}$. The nuclear design considers all fuel cycles and all operating conditions to ensure that a flatter assembly power distribution does not occur with limiting values of $F^{N}_{\Delta H}$.

4.3.2.2.4 Axial Power Distributions

The shape of the power profile in the axial direction is largely under the control of the operator either through the manual operation of the control rods or the automatic motion of rods responding to manual operation of the CVCS. Nuclear effects that cause variations in the axial power shape include moderator density, Doppler effect on resonance absorption, spatial xenon variations, fuel, burnable absorber material distribution, and burnup. Automatically controlled variations in total power output and control rod motion are also important in determining the axial power shape at any time. Signals are available to the operator from the excore ion chambers that run parallel to the axis of the core. Separate signals are taken from the top and bottom halves of the chambers. The difference between top and bottom signals for each of four pairs of detectors is called the flux difference, $\Delta\phi$. If it deviates from the flux difference target band, an alarm is actuated.

Calculations of core average peaking factor for many plants and measurements from operating situations are associated with either $\Delta\phi$ or axial offset to place an upper bound on the peaking factor. For these correlations, axial offset is defined as:

$$\text{Axial offset} = \frac{\phi_t - \phi_b}{\phi_t + \phi_b} \qquad (4.3\text{-}4)$$

(Multiply by 100 to get percent axial offset.)

where:

ϕ_t and ϕ_b are the top and bottom detector readings.

Representative axial power shapes for BOL, MOL, and EOL conditions covering a wide range, including power shape changes achieved by skewing xenon distributions, are shown in Figures 4.3-15 through 4.3-17.

4.3.2.2.5 Local Power Peaking

Fuel densification causes fuel pellets to shrink both axially and radially. Pellet shrinkage combined with random hang-up of fuel pellets results in gaps in the fuel column when the pellets below the hung-up pellet settle in the fuel rod. The gaps vary in length and location in the fuel rod. Because of decreased neutron absorption in the vicinity of the gap, power peaking occurs in the adjacent fuel rods resulting in an increased power peaking factor. A quantitative measure of this local power peaking is given by the power spike factor S(z) where z is the axial location in the core.

In previous analyses of power peaking factors for Diablo Canyon Units 1 and 2, it was necessary to apply a penalty on calculated overpower transient F_Q values to allow for interpellet gaps caused by pellet hang-ups and pellet shrinkage due to densification. This penalty is known as the densification spike factor. However, studies have shown (Reference 31) that this penalty can be eliminated for the fuel type present in the Diablo Canyon Units 1 and 2 cores.

4.3.2.2.6 Limiting Power Distributions

As discussed in Section 4.3.1, Condition I occurrences are those expected frequently or regularly in the course of power operation, maintenance, or maneuvering of the plant. Condition I occurrences are accommodated with margin between any plant parameter and the value of that parameter that would require either automatic or manual protective action. Since they occur frequently or regularly, Condition I occurrences affect the consequences of Conditions II, III, and IV events. Analysis of each fault condition is generally based on a conservative set of initial conditions corresponding to the most adverse set of conditions that can occur during Condition I operation.

The list of steady state and shutdown conditions, permissible deviations, and operational transients is given in Section 15.1. Implicit in the definition of normal operation is proper and timely action by the reactor operator. That is, the operator follows recommended operating procedures for maintaining appropriate power distributions and takes any necessary remedial actions when alerted to do so by plant instrumentation. Thus, as stated above, the worst or limiting power distribution that can occur during normal operation is considered as the starting point for analysis of Conditions II, III, and IV events.

Improper procedural actions or errors by the operator are assumed in the design as occurrences of moderate frequency (Condition II). The limiting power shapes that result from such Condition II events are, therefore, those power shapes, which deviate from the normal operating condition at the recommended axial offset band. Power shapes that fall in this category are used to determine reactor protection system setpoints and maintain margin to overpower or DNB limits.

Maintaining power distributions within the required hot channel factor limits is discussed in the Technical Specifications. A complete discussion of power distribution control in

Westinghouse pressurized water reactors is included in References 2, 29, and 30. Detailed background information on the following design constraints on local power density in a Westinghouse pressurized water reactor, on the defined operating procedures, and on the measures taken to preclude exceeding design limits is presented in References 23, 29, 30.

The upper bound on peaking factors, F_Q^T and $F_{\Delta H}^N$, includes all of the nuclear effects that influence the radial and/or axial power distributions throughout core life for various modes of operation, including load follow, reduced power operation, and axial xenon transients.

Radial power distributions are calculated for full power, and fuel and moderator temperature feedback effects are included for the average enthalpy plane of the reactor. Steady state nuclear design calculations are done for normal flow with the same mass flow in each channel, and flow redistribution effects are neglected. The effect of flow redistribution is calculated explicitly when important to the DNB analysis of accidents. The effect of xenon on radial power distribution is small (compare Figures 4.3-7 and 4.3-8), but is included as part of the normal design process.

The core average axial profile can experience significant changes that can occur rapidly as a result of rod motion and load changes, and more slowly due to xenon distribution. To study points of closest approach to axial power distribution limits, several thousand cases are examined. Since the nuclear design properties dictate what axial shapes can occur, the limits of interest can be set in terms of parameters, which are readily observed. Specifically, the following nuclear design parameters are significant to the axial power distribution analysis:

(1) Core power level

(2) Core height

(3) Coolant temperature and flow

(4) Coolant temperature program as a function of reactor power

(5) Fuel cycle lifetimes

(6) Rod bank worths

(7) Rod bank overlaps

Normal plant operation assumes compliance with the following conditions:

(1) Control rods in a single bank move together with no individual rod insertion differing by more than 12 steps (indicated) from the bank demand position

(2) Control banks are sequenced with overlapping banks

(3) Control bank insertion limits are not violated

(4) Axial power distribution procedures, which are given in terms of flux difference control and control bank position, are observed.

The above axial power distribution procedures are part of the normal plant operating procedures. Briefly, they require control of the axial offset (see Equation 4.3-4) at all power levels, within a permissible operating band. This minimizes xenon transient effects on the axial power distribution, since the procedures essentially keep the xenon distribution in phase with the power distribution.

Calculations are performed for normal reactor operation at beginning, middle, and end of cycle conditions. Different operation histories are implicitly included in the methodology. These different histories cover both base loaded operation and extensive load following.

These cases represent many possible reactor states in the life of one fuel cycle. They are considered to be necessary and sufficient to generate a local power density limit which, when increased by 5 percent for conservatism, will not be exceeded with a 95 percent confidence level. Many of the points do not approach the limiting envelope. However, they are generated as part of the process that leads to the shapes, which do define the envelope.

Thus, it is not possible to single out any transient or steady state condition that defines the most limiting case. It is not even possible to separate out a small number, which form an adequate analysis. The process of generating a myriad of shapes is essential to the philosophy that leads to the required level of confidence. A set of parameters that produces a limiting case for one reactor fuel cycle (defined as approaching the line of Figure 4.3-23) is not necessarily a limiting case for another reactor or fuel cycle with different control bank worths or insertion limits, enrichments, burnup, reactivity coefficient, etc. The shape of the axial power distribution calculated for a particular time depends on the operating history of the core up to that time, and on the manner in which the operator conditioned xenon in the days immediately before that time.

The calculated points are synthesized from axial calculations combined with the radial factors appropriate for rodded and unrodded planes. In these calculations, the effects on the radial peak of xenon redistribution that occur, following the withdrawal of a control bank (or banks) from a rodded region, are obtained from three-dimensional calculations. The factor to be applied to the radial peak is obtained from calculations in which the xenon distribution is preconditioned by the presence of control rods and then allowed to redistribute for several hours. A detailed discussion of this effect may be found in References 23 and 29. In addition to the 1.05 conservatism factor, the calculated values are increased by a factor of 1.03 for the engineering factor F_Q^E.

The envelope drawn over the calculated [max (F_Q^T Power)] points, as shown in Figure 4.3-23 from a past cycle, gives an example of an upper bound envelope on local power density versus elevation in the core. Figure 4.3-24 illustrates BOL, MOL, and EOL steady state conditions from a past cycle. Cycle-specific values are calculated each cycle.

Finally, this upper bound envelope is based on operation within an allowed range of axial flux steady state conditions. These limits are detailed in the Core Operating Limits Reports and rely only on excore surveillance supplemented by the required normal monthly power distribution measurement. If the axial flux difference exceeds the allowable range, an alarm is actuated.

Allowing for fuel densification, the average linear power is 5.445 kW/ft for both units at 3,411 MWt. The conservative upper bound value of normalized local power density, including uncertainty allowances, is 2.58, corresponding to a peak linear power of 14.3 kW/ft at 102 percent power.

To determine reactor protection system setpoints, with respect to power distributions, three categories of events are considered: rod control equipment malfunctions, operator errors of commission, and operator errors of omission. In evaluating these three categories, the core is assumed to be operating within the four constraints described above.

The first category is uncontrolled rod withdrawal (with rods moving in the normal bank sequence). Also included are motions of the banks below their insertion limits, which could be caused, for example, by uncontrolled dilution or primary coolant cooldown. Power distributions were calculated, assuming short-term corrective action. That is, no transient xenon effects were considered to result from the malfunction. The event was assumed to occur from typical normal operating situations, which include normal xenon transients. It was also assumed that the total power level would be limited by the reactor trip to below 118 percent. Results are given in Figure 4.3-21 in units of kW/ft. The peak power density, which can occur in such events, assuming reactor trip at or below 118 percent, is less than that required for fuel centerline melt, including uncertainties.

The second category, also appearing in Figure 4.3-21, assumes that the operator mispositions the rod bank in violation of insertion limits and creates short-term conditions not included in normal operating conditions.

The third category assumes that the operator fails to take action to correct a flux difference violation. The results shown in Figure 4.3-22 are F_Q^T multiplied by 102 percent power, including an allowance for calorimetric error. The peak linear power does not exceed 22.0 kW/ft, provided the operator's error does not continue for a period which is long compared to the xenon time constant. It should be noted that a reactor overpower accident is not assumed to occur coincident with an independent operator error. Additional detailed discussion of these analyses is presented in Reference 23.

Analyses of possible operating power shapes for the DCPP reactor show that the appropriate hot channel factors F_Q^T and $F_{\Delta H}^N$ for peak local power density, and for DNB analysis at full power, are the values given in Table 4.3-1 and addressed in the Technical Specifications.

The maximum allowable F_Q^T can increase with decreasing power, as shown in the Technical Specifications. Increasing $F_{\Delta H}^N$ with decreasing power is permitted by the DNB protection setpoints and allows radial power shape changes with rod insertion to the insertion limits, as described in Section 4.4.3.2. The allowances for increased $F_{\Delta H}^N$ permitted is:

$$F_{\Delta H}^N = 1.65 [1 + 0.3 (1\text{-}P)] \text{ for VANTAGE 5 fuel, and} \quad (4.3\text{-}5)$$

$$F_{\Delta H}^N = 1.62 [1 + 0.3 (1\text{-}P)] \text{ for LOPAR fuel} \quad (4.3\text{-}6)$$

This becomes a design basis criterion, which is used for establishing acceptable control rod patterns and control bank sequencing. Likewise, fuel loading patterns for each cycle are selected with consideration of this design criterion. The worst values of $F_{\Delta H}^N$ for possible rod configurations occurring in normal operation are used in verifying that this criterion is met. Typical radial factors and radial power distributions are shown in Figures 4.3-7 through 4.3-12. The worst values generally occur when the rods are assumed to be at their insertion limits. As discussed in Reference 3, it has been determined that the Technical Specification limits are met, provided the above conditions (1) through (4) are observed. These limits are taken as input to the thermal-hydraulic design basis, as described in Section 4.4.3.2.1.

If the possibility exists during normal operation of local power densities exceeding those assumed as the precondition for a subsequent hypothetical accident, but which would not itself cause fuel failure, administrative controls and alarms are provided to return the core to a safe condition. These alarms are described in Chapter 7 and in the Technical Specifications.

4.3.2.2.7 Experimental Verification of Power Distribution Analysis

This subject, which is discussed in depth in Reference 1, is summarized here.

To measure the peak local power density, F_Q^T, with the movable detector system described in Sections 7.7.2.9.2 and 4.4.5, the following uncertainties are considered:

(1) Reproducibility of the measured signal

(2) Errors in the calculated relationship between detector current and local flux

(3) Errors in the calculated relationship between detector flux and peak rod power some distance from the measurement thimble

Allowance for (1) has been quantified by repetitive measurements made with several intercalibrated detectors using the common thimble features of the incore detector system. This system allows more than one detector to access any thimble. Item (2) above is quantified to the extent possible by using the fluxes measured at one thimble location to predict fluxes at another location, which is also measured. Local power distribution predictions are verified in critical experiments on arrays of rods with simulated guide thimbles, control rods, burnable poisons, etc.

Reference 1 concludes that the uncertainty associated with the peak nuclear heat flux factor, F_Q^T, is 4.58 percent at the 95 percent confidence level with only 5 percent of the measurements greater than the inferred value.

In comparing measured power distributions (or detector currents) against the calculations for the same situations, it is not possible to subtract out the detector reproducibility. Thus, a comparison between measured and predicted power distributions must consider measurement error. Such a comparison is illustrated in Figure 4.3-25 for one of the maps of Reference 1, which is similar to hundreds of maps taken since then on various reactors, confirming the adequacy of the 5 percent uncertainty allowance on F_Q^T.

A similar analysis for the uncertainty in $F_{\Delta H}^N$ (rod integral power) measurements results in an allowance of 3.68 percent at the equivalent of a 2σ confidence level. For historical reasons, an 8 percent uncertainty factor is allowed in the nuclear design basis; that is, the predicted rod integrals at full power must not exceed the design $F_{\Delta H}^N$ less 8 percent. This 8 percent may be reduced in final design to 4 percent to allow a wider range of acceptable axial power distributions in the DNB analysis and still meet the design bases of Section 4.3.1.3.

A measurement in the second cycle of a 121-assembly, 12-foot core, is compared with a simplified one-dimensional core average axial calculation in Figure 4.3-26. This calculation does not give explicit representation to the fuel grids.

The accumulated data on power distributions in actual operation is basically of three types:

(1) Much of the data is obtained in steady state operation at constant power in the normal operating configuration.

(2) Data with unusual values of axial offset are obtained as part of the excore detector calibration exercise which is performed monthly.

(3) Special tests have been performed in load follow and other transient xenon conditions which have yielded useful information on power distributions.

These data are presented in detail in Reference 3. Figure 4.3-27 contains a summary of measured values of F_Q^T as a function of axial offset for five plants from that report.

4.3.2.2.8 Testing

An extensive series of physics tests is performed on first cores. These tests and the criteria for satisfactory results are described in detail in Chapter 14. Since not all limiting situations can be created at BOL, the main purpose of the tests is to provide a check on the calculation methods used in the predictions for the conditions of the test. Physics testing is also performed at the beginning of each reload cycle to ensure that the operating characteristics of the core are consistent with design predictions.

4.3.2.2.9 Monitoring Instrumentation

The adequacy of instrument numbers, spatial deployment, required correlations between readings and peaking factors, calibration, and errors is described in References 1, 2, and 3. The relevant conclusions are summarized in Sections 4.3.2.2.7 and 4.4.5.

Reference 32 describes the instrumentation requirements and calibration of the PDMS, and the uncertainties applied to the calculated peaking factors.

If the limitations given in Section 4.3.2.2.6 on rod insertion and flux difference are observed, the excore detector system provides adequate monitoring of power distributions.

Further details of specific limits on the observed rod positions and flux difference are given in the Core Operating Limits Reports, together with a discussion of their bases.

Limits for alarms, reactor trip, etc., are given in the Technical Specifications. System descriptions are provided in Section 7.7.

4.3.2.3 Reactivity Coefficients

Reactor core kinetic characteristics determine the response of the core to changing plant conditions, or to operator adjustments made during normal operation, as well as the core response during abnormal or accidental transients. These kinetic characteristics are quantified in reactivity coefficients. The reactivity coefficients reflect changes in the neutron multiplication due to varying plant conditions such as power, moderator or fuel temperatures, or, less significantly, due to a change in pressure or void conditions. Since reactivity coefficients change during the life of the core, ranges of coefficients are employed in transient analysis to determine the response of the plant

throughout life. The analytical methods and calculational models used in calculating the reactivity coefficients are given in Section 4.3.3. These models have been confirmed through extensive testing of more than 30 cores similar to DCPP, as discussed in Section 4.3.3.

4.3.2.3.1 Fuel Temperature (Doppler) Coefficient

The fuel temperature (Doppler) coefficient is defined as the change in reactivity per degree change in effective fuel temperature and is primarily a measure of the Doppler broadening of U-238 and Pu-240 resonance absorption peaks. Doppler broadening of other isotopes such as U-236, Np-237, etc., are also considered, but their contributions to the Doppler effect is small. An increase in fuel temperature increases the effective resonance absorption cross sections of the fuel and produces a corresponding reduction in reactivity.

The fuel temperature coefficient is calculated by two-group two or three-dimensional calculations. Moderator temperature is held constant and the power level is varied. Spatial variation of fuel temperature is taken into account by calculating the effective fuel temperature as a function of power density, as discussed in Section 4.3.3.1.

The Doppler temperature coefficient is shown in Figure 4.3-28 as a function of the effective fuel temperature (at BOL and EOL conditions). The effective fuel temperature is lower than the volume averaged fuel temperature since the neutron flux distribution is nonuniform through the pellet and gives preferential weight to the surface temperature. The Doppler-only contribution to the power coefficient (defined later) is shown in Figure 4.3-29 as a function of relative core power. The integral of the differential curve in Figure 4.3-29 is the Doppler contribution to the power defect and is shown in Figure 4.3-30 as a function of relative power. The Doppler coefficient becomes more negative as a function of life as the Pu_{240} content increases, thus increasing the Pu_{240} resonance absorption, but less negative as the fuel temperature changes with burnup, as described in Section 4.3.3.1. The upper and lower limits of Doppler coefficient used in accident analyses are given in Chapter 15.

4.3.2.3.2 Moderator Coefficients

The moderator coefficient is a measure of the change in reactivity due to a change in specific coolant parameters such as density, temperature, pressure, or void.

4.3.2.3.2.1 Moderator Density and Temperature Coefficients

The MTC (density) is defined as the change in reactivity per degree change in the moderator temperature. Generally, the effect of the changes in moderator density, as well as the temperature, are considered together. A decrease in moderator density means less moderation which results in a negative MTC. An increase in coolant temperature, keeping the density constant, leads to a hardened neutron spectrum resulting in greater resonance absorption in U_{238}, Pu_{240}, and other isotopes. The

hardened spectrum also causes a decrease in the fission to capture ratio in U_{235} and Pu_{239}. Both of these effects make the MTC more negative. Since water density decreases as temperature increases, the MTC (density) becomes more negative with increasing temperature.

The soluble boron also affects the MTC (density) since its density, like that of water, also decreases when the coolant temperature rises. Therefore, a decrease in the soluble poison concentration introduces a positive component into the moderator coefficient. Indeed, if the concentration of soluble poison is large enough, the net value of the coefficient may be positive. With the burnable poison rods present, however, the initial hot boron concentration is sufficiently low, making the MTC negative at full power operating temperatures. The effect of control rods is to make the moderator coefficient more negative by reducing the required soluble boron concentration and by increasing "leakage" from the core.

With burnup, the MTC normally becomes more negative primarily as a result of boric acid dilution, but also, to a significant extent, from the effects of plutonium and fission products buildup.

The MTC is calculated for various plant conditions by performing two-group two or three dimensional calculations, varying the moderator temperature (and density) by about ±5°F about each of the mean temperatures. The MTC is shown in Figures 4.3-31 through 4.3-33 as a function of core temperature and boron concentration for a typical reload unrodded and rodded core. The temperature range covered is from cold (68°F) to about 600°F. The contribution due to Doppler coefficient (because of change in moderator temperature) has been subtracted from these results. Figure 4.3-34 shows the hot, full power MTC as a function of cycle lifetime for the critical boron concentration condition based on the design boron letdown condition (Figure 4.3-3) for a typical reload cycle.

4.3.2.3.2.2 Moderator Pressure Coefficient

The moderator pressure coefficient relates the change in moderator density, resulting from a reactor coolant pressure change, to the corresponding effect on neutron production. This coefficient is of much less significance than the MTC. A change of 50 psi in pressure has approximately the same effect on reactivity as a half-degree change in moderator temperature. This coefficient can be determined from the MTC by relating change in pressure to the corresponding change in density. The moderator pressure coefficient is negative over a portion of the moderator temperature range at BOL (-0.004 pcm/psi, BOL) but is always positive at operating conditions and becomes more positive during life (+0.3 pcm/psi, EOL).

4.3.2.3.2.3 Moderator Void Coefficient

The moderator void coefficient relates the change in neutron multiplication to the presence of voids in the moderator. In a pressurized water reactor (PWR), this coefficient is not very significant because of the low void content in the coolant. The core void content is less than one-half of 1 percent and is due to local or statistical boiling. The void coefficient at BOL varies from 50 pcm/% void at BOL and low temperatures to -250 pcm/% void at EOL and at operating temperatures. The negative void coefficient at operating temperature becomes more negative with fuel burnup.

4.3.2.3.3 Power Coefficient

The combined effect of moderator temperature and fuel temperature change as the core power level changes is called the total power coefficient, and is expressed in terms of reactivity change per percent power change. The power coefficient at BOL and EOL conditions is given in Figure 4.3-35. It becomes more negative with burnup, reflecting the combined effect on moderator and fuel temperature coefficients of burnup. The power defect (integral reactivity effect) at BOL and EOL is given in Figure 4.3-36.

4.3.2.3.4 Comparison of Calculated and Experimental Reactivity Coefficients

Based on the comparison between calculated and experimental reactivity coefficients in Section 4.3.3, the accuracy of the current analytical model is:

$\pm$ 0.2% $\Delta\rho$ for Doppler effect and power defect

$\pm$ 2 pcm/°F for the moderator coefficient

Experimental verification of the calculated coefficients will be done during the physics startup tests described in Chapter 14.

4.3.2.3.5 Reactivity Coefficients Used in Transient Analysis

Table 4.3-1 gives representative ranges for the reactivity coefficients used in the transient analysis. The exact values of the coefficient used in the analysis depend on whether the transient of interest is examined at the BOL or EOL, whether the most negative or the most positive (least negative) coefficients are appropriate, and whether spatial nonuniformity must be considered in the analysis. Conservative values of coefficients are always used in the transient analysis, as described in Chapter 15.

The values listed in Table 4.3-1, and illustrated in Figures 4.3-29 through 4.3-36, apply to the core shown in Figure 4.3-1. Appropriate coefficients for use in other cycles depend on the core's operating history, the number and enrichment of fresh fuel assemblies, the loading pattern of burned and fresh fuel, and the number and location of any burnable poison rods. The need for a reevaluation of any accident in a subsequent cycle is contingent on whether or not the coefficients for that cycle fall within

the range used in the analysis presented in Chapter 15. Control rod requirements are given in Table 4.3-2 for the core described and for a hypothetical equilibrium cycle since these are markedly different. These latter numbers are provided for information only.

4.3.2.4 Control Requirements

To ensure shutdown margin availability under cooldown to ambient temperature conditions, concentrated soluble boron is added to the coolant. Boron concentrations for several core conditions are listed in Table 4.3-1. They are all well below the solubility limit. The RCCAs are employed to bring the reactor to the hot shutdown condition. The minimum shutdown margin required is given in the Core Operating Limits Reports.

The ability to shut down from hot conditions is demonstrated in Table 4.3-2 by comparing the difference between the reactivity available in the RCCA, allowing for the rod with the highest worth being stuck, with that required for control and protection. The shutdown margin allows 10 percent for analytic uncertainties (see Section 4.3.2.4.9). The largest reactivity control requirement appears at EOL when the MTC reaches its peak negative value as reflected in the larger power defect.

Control rods are required to provide sufficient reactivity to compensate for the power defect from full power to zero power and the required shutdown margin. The reactivity addition resulting from power reduction consists of contributions from Doppler, variable average moderator temperature, flux redistribution, and reduction in void content.

4.3.2.4.1 Doppler

Control requirements to compensate for the Doppler effect are listed in Tables 4.3-2 and 4.3-3, for DCPP Units 1 and 2, respectively.

4.3.2.4.2 Variable Average Moderator Temperature

When the core is shut down to the hot zero power condition, the average moderator temperature changes from the equilibrium full load value, determined by the steam generator and turbine characteristics (such as steam pressure, heat transfer, and tube fouling), to the equilibrium no-load value, which is based on the steam generator shell side design pressure. The design change in temperature is conservatively increased by 4°F to account for control dead band measurement errors.

Since the moderator coefficient is negative, there is a reactivity addition with power reduction. The MTC becomes more negative as the fuel depletes because the boron concentration decreases. This effect is the major contribution to the increased requirement at EOL.

4.3.2.4.3 Redistribution

During full power operation, the coolant density decreases with core height and this, together with partial insertion of control rods, results in less fuel depletion near the top of the core. Under steady state conditions, the relative power distribution will be slightly asymmetric towards the bottom of the core. On the other hand, at hot zero power conditions, the coolant density is uniform and there is no flattening due to Doppler. The result is a flux distribution that at zero power can be skewed toward the top of the core. The reactivity insertion due to the skewed distribution is calculated with an allowance for the most adverse effects of xenon distribution.

4.3.2.4.4 Void Content

A small void content in the core is due to nucleate boiling at full power. The void collapse that results from a power reduction makes a small reactivity contribution.

4.3.2.4.5 Rod Insertion Allowance

At full power, the control bank is operated within a prescribed travel band to compensate for small periodic changes in boron concentration, in temperature, and very small changes in the xenon concentration not compensated for by a change in boron concentration. When the control bank reaches either limit of this band, a change in boron concentration is required to compensate for additional reactivity changes. Since the insertion limit is set by a rod travel limit, a conservatively high calculation of the inserted worth is made which exceeds the normally inserted reactivity.

4.3.2.4.6 Burnup

Excess reactivity of 10 percent $\Delta\rho$ to 25 percent $\Delta\rho$ (hot) is installed at the beginning of each cycle to provide sufficient reactivity to compensate for fuel depletion and fission products buildup throughout the cycle. This reactivity is controlled by the addition of soluble boron to the coolant and by burnable absorber. The soluble boron concentrations for several core configurations, the unit boron worth, and burnable absorber worth are given in Tables 4.1-1 and 4.3-1. Since the excess reactivity for burnup is controlled by soluble boron and/or burnable absorber, it is not included in control rod requirements.

4.3.2.4.7 Xenon and Samarium Poisoning

Changes in xenon and samarium concentrations in the core occur at a sufficiently slow rate, even following rapid power level changes, so that the resulting reactivity change is controlled by changing the soluble boron concentration.

4.3.2.4.8 pH Effects

Changes in reactivity due to a change in coolant pH, if any, are sufficiently small in magnitude and occur slowly enough to be controlled by the boron system. Further details are available in Reference 4.

4.3.2.4.9 Experimental Confirmation

Following a normal shutdown, the total core reactivity change during cooldown with a stuck rod has been measured on a 121-fuel-assembly, 10-foot-high core, and a 121-fuel-assembly, 12-foot-high core. In each case, the core was allowed to cool down until it reached criticality, simulating the steam line break accident. For the 10-foot-core, the total reactivity change associated with the cooldown is overpredicted by about 0.3 percent $\Delta\rho$ with respect to the measured result. This represents an error of about 5 percent in the total reactivity change and is about half the uncertainty allowance for this quantity. For the 12-foot-core, the difference between the measured and predicted reactivity change was an even smaller 0.2 percent $\Delta\rho$. These and other measurements demonstrate the ability of the methods described in Section 4.3.3 to accurately predict the total shutdown reactivity of the core.

4.3.2.5 Control

Core reactivity is controlled by means of a chemical neutron absorber (chemical shim) dissolved in the coolant, RCCAs, and burnable poison rods as described below.

4.3.2.5.1 Chemical Shim

Boron in solution as boric acid is used to control relatively slow reactivity changes associated with:

(1) The moderator temperature defect in going from cold shutdown at ambient temperature to the hot operating temperature at zero power

(2) Transient xenon and samarium poisoning, such as that following power changes or changes in RCCA position

(3) The excess reactivity required to compensate for the effects of fissile inventory depletion and buildup of long-life fission products

(4) The burnable absorber depletion

The boron concentrations for various core conditions are presented in Table 4.3-1.

4.3.2.5.2 Rod Cluster Control Assemblies

As shown in Table 4.1-1, 53 RCCAs are used in these reactors. The RCCAs are used for shutdown and control purposes to offset fast reactivity changes associated with:

(1) The required shutdown margin in the hot zero power, stuck rods condition

(2) The increase in power above hot zero power (power defect including Doppler and moderator reactivity changes)

(3) Unprogrammed fluctuations in boron concentration, coolant temperature, or xenon concentration (with rods not exceeding the allowable rod insertion limits)

(4) Reactivity ramp rates resulting from load changes

Control bank reactivity insertion at full power is limited to maintain shutdown capability. As the power level is reduced, control rod reactivity requirements are reduced and more rod insertion is allowed. The control bank position is monitored and the operator is notified by an alarm if the limit is approached. The determination of the insertion limit uses conservative xenon distributions and axial power shapes. In addition, the RCCA withdrawal pattern obtained from these analyses is used in determining power distribution factors, and in determining the maximum reactivity worth during an ejection accident of an inserted RCCA. The Technical Specifications discuss rod insertion limits.

Power distribution, rod ejection, and rod misalignment analyses are based on the arrangement of the shutdown and control RCCA groups shown in Figures 4.3-37 and 4.3-38, for Units 1 and 2, respectively. All shutdown RCCAs are withdrawn before control banks withdrawal is initiated. In going from zero to 100 percent power, control banks A, B, C, and D are withdrawn sequentially. Rod position limits and the basis for rod insertion limits are provided in the Core Operating Limits Reports.

4.3.2.5.3 Burnable Absorber Rods

Burnable absorber rods (either discrete or integral type) provide partial control of excess reactivity during the fuel cycle. These rods prevent the MTC from being positive at normal operating conditions. They perform this function by reducing the requirement for soluble boron in the moderator at the beginning of the fuel cycle, as described above. The burnable absorber patterns used together with a typical number of rods per assembly, are shown in Figure 4.3-6 for a cycle using integral absorber exclusively. The arrangements within an assembly for discrete and integral absorber types are displayed in Figures 4.3-4 and 4.3-5 respectively. The critical concentration of soluble boron resulting from the slow burnup of boron in the rods is such that the MTC remains negative at all times for full power operating conditions.

4.3.2.5.4 Peak Xenon Startup

Peak xenon buildup is compensated by the boron control system. Startup from the peak xenon condition is accomplished with a combination of rod motion and boron dilution. Boron dilution may be made at any time, including the shutdown period, provided the shutdown margin is maintained.

4.3.2.5.5 Load Follow Control and Xenon Control

The DCPP units are usually base loaded; however, it is expected that during certain times of certain years some load following may be required.

Should load following become a desired mode of operation, then, during load follow maneuvers, power changes would be accomplished using control rod motion, dilution or boration by the boron systems as required, and reductions in coolant T_{avg}. Control rod motion limitations are discussed in Section 4.3.2.5.2 and the Technical Specifications. Reactivity changes due to the changing xenon concentration can be controlled by rod motion and/or soluble boron concentration changes.

4.3.2.5.6 Burnup

The excess reactivity available for burnup is controlled with soluble boron and/or burnable absorber. The boron concentration must be limited during operating conditions to ensure the MTC is negative at full power. Sufficient burnable absorber is installed at the beginning of a cycle to give the desired cycle lifetime without exceeding the boron concentration limit. The practical minimum boron concentration is 10 ppm.

4.3.2.6 Control Rod Patterns and Reactivity Worths

The RCCAs are designated by function as the control groups and the shutdown groups. The terms "group" and "bank" are used synonymously throughout this chapter to describe a particular grouping of control assemblies. The RCCA patterns are displayed in Figures 4.3-37 and 4.3-38 for Units 1 and 2, respectively. These patterns are not expected to change during the life of the units. The control banks are labeled A, B, C, and D, and the shutdown banks are labeled SA, SB, SC and SD.

The two criteria used to select the control groups are: (a) the total reactivity worth must be adequate to meet the requirements specified in Tables 4.3-2 and 4.3-3, and (b) because these rods may be partially inserted at power operation, the total power peaking factor should be low enough to ensure that power capability requirements are met. Analyses indicate that the first requirement can be met by one or more banks whose total worth equals at least the required amount. Since the shape of the axial power distribution would be more peaked following movement of a single group of rods worth 3 to 4 percent $\Delta\rho$, four banks, each worth approximately 1 percent $\Delta\rho$, were selected.

The position of control banks for criticality under any reactor condition is determined by the boron concentration in the coolant. On an approach to criticality, boron is adjusted to ensure criticality will be achieved with control rods above the insertion limit set by shutdown and other considerations (see Technical Specifications). Early in the cycle there may also be a withdrawal limit at low power to maintain an MTC more negative than the Technical Specification limit. Usual practice is to adjust boron to ensure that the rod position lies within the so-called maneuvering band so that an escalation from zero power to full power does not require further adjustment of boron concentration.

Ejected rod worths are given in Section 15.4.6 for several different conditions. Experimental confirmation of these worths can be found by reference to startup test reports such as Reference 5.

Allowable deviations due to misaligned control rods are discussed in the Technical Specifications.

A representative calculation for two banks of control rods withdrawn simultaneously (rod withdrawal accident) is shown in Figure 4.3-39. Calculation of control rod reactivity worth versus time following reactor trip involves both control rod velocity and differential reactivity worth. Rod position versus time of travel after rod release is shown in Figure 4.3-40. The reactivity worth versus rod position is calculated by a series of steady state calculations at various control rod positions assuming all rods out of the core as the initial position to minimize the initial reactivity insertion rate. To be conservative, the rod of highest worth is assumed stuck out of the core and the flux distribution (and thus reactivity importance) is assumed to be skewed to the bottom of the core. The result of these calculations is shown in Figure 4.3-41.

The shutdown groups provide additional negative reactivity to ensure an adequate shutdown margin. Shutdown margin is defined as the instantaneous amount of reactivity by which the core is, or would be, subcritical from its present condition if all RCCAs (shutdown and control) are fully inserted, but assuming that the RCCA with the highest reactivity worth remains fully withdrawn (N-1). The loss of control rod worth due to material irradiation is negligible, since only bank D rods may be in the core under normal operating conditions.

Tables 4.3-2 and 4.3-3 show that the available reactivity in withdrawn RCCAs provides the design bases minimum shutdown margin allowing for the highest worth cluster to be at its fully withdrawn position in DCPP Units 1 and 2, respectively. An allowance for uncertainty in the calculated worth of N-1 rods is made before determination of the shutdown margin.

4.3.2.7 Criticality of Fuel Assemblies

Criticality of fuel assemblies outside the reactor is precluded by adequate design of fuel transfer and fuel storage facilities, and by administrative control procedures.

New fuel can be stored in dry fuel storage facilities. To design storage facilities, the fuel assemblies are assumed to be in their most reactive condition, i.e., fresh or undepleted and with no control rods or removable neutron absorbers present. Assemblies cannot be closer together than the design separation provided by the storage facility, except in special cases, such as in fuel shipping containers where analyses are performed to establish design acceptability. The mechanical integrity of the fuel assembly is assumed.

Criticality analyses of the storage facilities must assume flooding with unborated water. To prevent accidental criticality, the fuel assembly spacing of the facility provides essentially full nuclear isolation and the effective multiplication factor (k_{eff}) for the array is no greater than k_{eff} for the single most reactive fuel assembly. The criterion for wet fuel storage criticality analyses is that there is a 95 percent probability, 95 percent confidence level for the k_{eff} of the fuel storage array being less than 1.0 if flooded with nborated water, per 10 CFR 50.68(b)(4). The two possible variations in the criticality analyses result from: (a) calculation uncertainties, and (b) fuel rack fabrication uncertainties.

Standard calculations have been compared to results of critical experiments. The results indicate the following:

(1) The average difference between the calculations and experimental results, or bias in the computations, was 0.0103 Δk (KENO5a) and 0.0000 (CASMO3).

(2) The standard deviation of the bias between the calculations and experimental results was 0.0018 Δk (KENO5a) and 0.0024 (CASMO3).

Fuel rack fabrication uncertainties are as follows:

(1) The analyzed tolerance on the inner stainless steel box dimension of a rack cell is $\pm$0.032 inch.

(2) The tolerance on the center-to-center spacing between fuel rack cells is $\pm$0.05.

As an example, a fuel assembly of standard design and 3.5 wt percent enriched uranium oxide, without a control rod or burnable absorber rods, fully flooded and reflected with cold clean water, has a k_{eff} of about 0.85. Two such fuel assemblies spaced 1 inch apart with parallel axes 9.5 inches apart have a k_{eff} of about 0.99. Three such fuel assemblies spaced 1 inch apart with parallel axes would be supercritical.

An infinite number of dry fuel assemblies of this design would have a k_{eff} < 0.80.

Verification that appropriate shutdown criteria, including uncertainties, are met during refueling is achieved using standard Westinghouse reactor design methods. Core subcriticality during refueling is continuously monitored as described in the Technical Specifications.

4.3.2.8 Stability

4.3.2.8.1 Introduction

The stability of PWR cores against xenon-induced spatial oscillations, and the control of such transients, are discussed extensively in References 2, 6, 7, and 8.

Due to the negative power coefficient of reactivity, PWR cores are inherently stable to oscillations in total power. In a large reactor core, however, xenon-induced oscillations can take place with no corresponding change in total core power. The oscillation may be caused by a power shift in the core that occurs rapidly in comparison with the xenon-iodine time constants. Such a power shift occurs in the axial direction when a plant load change is made by control rod motion, and results in a change in the moderator density and fuel temperature distributions. Such a power shift in the diametral plane of the core could result from abnormal control action.

4.3.2.8.2 Stability Index

Power distributions, either in the axial direction or in the X-Y plane, can undergo oscillations due to perturbations introduced in the equilibrium distributions without changing total core power. The xenon-induced oscillations are essentially limited to the first flux overtones in the current PWRs, and the stability of the core against xenon-induced oscillations can be determined in terms of the eigenvalues of the first flux harmonics. Writing the eigenvalue of the first flux harmonic, either in the axial direction or in the X-Y plane, as:

$$\xi = b + ic, \left(i^2 = -1\right); \qquad (4.3\text{-}7)$$

b is defined as the stability index and T = $2\pi/c$ as the oscillation period of the first harmonic. The time-dependence of the first harmonic in the power distribution can now be represented as:

$$\delta\phi(t) = A\,e^{\xi t} = ae^{bt}\cos ct \qquad (4.3\text{-}8)$$

where A and a are constants. The stability index can also be obtained approximately by:

$$b = \frac{1}{T} \ln \left[\frac{A_{n+1}}{A_n} \right] \qquad (4.3\text{-}9)$$

where A_n, A_{n+1} are the successive peak amplitudes of the oscillation, and T is the time period between the successive peaks.

4.3.2.8.3 Prediction of the Core Stability

The stability of the DCPP cores in relation to xenon-induced spatial oscillations is expected to be equal to that of earlier designs because: (a) the overall core size is unchanged and spatial power distributions are similar, (b) the MTC is expected to be similar, and (c) the Doppler coefficient of reactivity is expected to be similar at full power.

4.3.2.8.4 Stability Measurements

(1) Axial Measurements

Two axial xenon transient tests conducted in a PWR with a core height of 12 feet and 121 fuel assemblies, at approximately 10 and 50 percent of cycle life, are reported in Reference 9.

The axial offset (AO) of power was obtained as a function of time for both tests as shown in Figure 4.3-42. The total core power was maintained constant during these spatial xenon tests, and the stability index and the oscillation period were obtained from a least-square fit of the AO data to Equation 4.3-7. The conclusions of the tests are as follows:

(a) The core was stable against induced axial xenon transients both at the core average burnups of 1550 MWD/MTU and 7700 MWD/MTU.

(b) The reactor core becomes less stable as fuel burnup progresses, and the axial stability index was essentially zero at 12,000 MWD/MTU.

(2) Measurements in the X-Y Plane

Two X-Y xenon oscillation tests were performed at a PWR plant with a core height of 12 feet and 157 fuel assemblies. This plant had the highest power output of any Westinghouse PWR operating in 1972. The first test was conducted at a core average burnup of 1540 MWD/MTU and the second at a core average burnup of 12900 MWD/MTU. Both of the X-Y

xenon tests show that the core was stable in the X-Y plane at both burnups. The second test shows that the core became more stable as the fuel burnup increased and all Westinghouse PWRs with 121 and 157 assemblies are expected to be stable throughout their burnup cycles.

In each of the two X-Y tests, a perturbation was introduced to the equilibrium power distribution through an impulse motion of one RCC unit located along the diagonal axis. Following the perturbation, the uncontrolled oscillation was monitored using the movable detector and thermocouple system and the excore power range detectors. The quadrant tilt difference is the quantity that properly represents the diametral oscillation in the X-Y plane of the reactor core in that the difference of the quadrant average powers over two symmetrically opposite quadrants essentially eliminates the contribution to the oscillation from the azimuthal mode. The quadrant tilt difference (QTD) data were least-square fitted to the form of Equation 4.3-7. A stability index of 0.076 hr-1 with a period of 29.6 hours was obtained from the thermocouple data shown in Figure 4.3-43.

In the second X-Y xenon test, the PWR core with 157 fuel assemblies became more stable due to increased fuel depletion.

4.3.2.8.5 Comparison of Calculations with Measurements

Axial xenon transient tests were analyzed in an axial slab geometry using a flux synthesis technique. The PANDA code (Reference 11) was used for direct simulation of the AO data. X-Y xenon transient tests analyses are performed with the modified TURTLE code. Both the PANDA and TURTLE codes solve the two-group time-dependent neutron diffusion equation with time-dependent xenon and iodine concentrations. The fuel temperature and moderator density feedback is limited to a steady state model. All the X-Y calculations were performed in an average enthalpy plane.

The basic nuclear cross sections used in this study were generated from a unit cell depletion program that evolved from codes LEOPARD and CINDER (Reference 14). The detailed experimental data during the tests, including the reactor power level, enthalpy rise, and the impulse motion of the control rod assembly, as well as the plant follow burnup data, were closely simulated in the study.

The results of the stability calculation for the axial tests are compared with the experimental data in Table 4.3-4. The calculations show conservative results for both of the axial tests with a margin of approximately 0.01 hr^{-1} in the stability index.

An analytical simulation of the first X-Y xenon oscillation test shows a calculated stability index of -0.081 hr^{-1}, in good agreement with the measured value of -0.076 hr^{-1}. As indicated earlier, the second X-Y xenon test showed that the core had become more

stable compared to the first test. The increase in the core stability in the X-Y plane due to increased fuel burnup is due mainly to the increased magnitude of the negative MTC.

Previous studies of the physics of xenon oscillations, including three-dimensional analysis, are reported in References 6, 7, 8, 9, and Section 1 of Reference 10.

4.3.2.8.6 Stability Control and Protection

The excore detector system provides indications of xenon-induced spatial oscillations. The readings from the excore detectors are available to the operator and also form part of the protection system.

(1) Axial Power Distribution

To maintain proper axial power distributions, the operator is instructed to maintain an axial offset within a prescribed operating band, based on the excore detector readings. Should the axial offset move far enough outside this band, the protection limit will be reached and the power will be automatically cut back.

(2) Radial Power Distribution

The DCPP cores are calculated to be stable with respect to xenon-induced oscillations in the X-Y plane during the plant's lifetime.

The X-Y stability of large PWRs has been further verified as part of the startup physics test program at a PWR core with 193 fuel assemblies. The measured X-Y stability of the PWR core with 157 assemblies, and the good agreement between the calculated and measured stability index for this core, as discussed in Sections 4.3.2.8.4 and 4.3.2.8.5, make it very unlikely that a sustained X-Y oscillation can occur in a core with 193 assemblies. In the unlikely event that X-Y oscillations occur, backup actions are possible and would be implemented, if necessary, to increase the natural stability of the core until tests demonstrate a suitable stability, by making the MTC more negative.

A more detailed discussion of the power distribution control in PWR cores is presented in Reference 2.

4.3.2.9 Vessel Irradiation

Pressure vessel irradiation and the corresponding material surveillance program are discussed in Sections 5.4.1 and 5.2.4. A brief review of the methodology used to determine neutron and gamma flux attenuation between the core and pressure vessel follows.

The primary shielding material used to attenuate high energy neutron and gamma flux originating in the core consists primarily of the core baffle, core barrel, the thermal shield for Unit 1 and the neutron pads for Unit 2, and associated water annuli, all of which are within the region between the core and the pressure vessel.

In general, few group neutron diffusion theory codes are used to determine flux and fission power density distributions within the active core, and the accuracy of these analyses is verified by incore measurements on operating reactors. Outside the active core, methods such as those that use multigroup space-dependent slowing down codes, as described in Section 5.2.4, are used. Region-wise power sharing information from the core calculations is often used as reference source data for multigroup codes.

The neutron flux distribution and spectrum in the various structural components varies significantly from the core to the pressure vessel. Representative values of the neutron flux distribution and spectrum are presented in Table 4.3-5. The values listed are based on equilibrium cycle reactor core parameters and power distributions and are thus suitable for long-term neutron fluence projections and for correlation with radiation damage estimates.

4.3.3 ANALYTICAL METHODS

Calculations required in nuclear design consist of the following three distinct types, which are performed in sequence:

(1) Determination of effective fuel temperatures
(2) Generation of macroscopic few-group parameters

(3) Space-dependent, few-group diffusion calculations

4.3.3.1 Fuel Temperature (Doppler) Calculations

Temperatures vary radially within the fuel rod, depending on heat generation rate in the pellet, the conductivity of the materials in the pellet, gap and cladding, and coolant temperature.

Fuel temperatures for use in most nuclear design Doppler calculations are obtained from a simplified version of the Westinghouse fuel rod design model described in Section 4.2.1.3.1, which considers the effect of radial variation of pellet conductivity, expansion-coefficient and heat generation rate, elastic deflection of the cladding, and a gap conductance which depends on the initial fill gas, the hot open gap dimension, and the fraction of the pellet over which the gap is closed. The fraction of the gap assumed closed represents an empirical adjustment to produce good agreement with observed reactivity data at BOL. Further gap closure occurs with burnup and accounts for the decrease in Doppler defect with burnup which has been observed in operating plants. For detailed calculations of the Doppler coefficient, such as for use in xenon stability

calculations, a more sophisticated temperature model is used which accounts for the effects of fuel swelling, fission gas release, and plastic cladding deformation.

Radial power distributions in the pellet as a function of burnup are obtained from LASER (Reference 15) calculations.

The effective U-238 temperature for resonance absorption is obtained from the radial temperature distribution by applying a radially dependent weighting function. The weighting function was determined from REPAD (Reference 16) Monte Carlo calculations of resonance escape probabilities in several steady state and transient temperature distributions. In each case, a flat pellet temperature was determined which produced the same resonance escape probability as the actual distribution. The weighting function was empirically determined from these results.

The effective Pu-240 temperature for resonance absorption is determined by a convolution of the radial distribution of Pu-240 number densities from LASER burnup calculations and the radial weighting function. The resulting temperature is burnup dependent, but the difference between U-238 and Pu-240 temperatures, in terms of reactivity effects, is small.

The effective pellet temperature for pellet dimensional change is that value which produces the same outer pellet radius in a virgin pellet as that obtained from the temperature model. The effective cladding temperature for dimensional change is its average value.

The temperature calculational model has been validated by plant Doppler defect data as shown in Table 4.3-6 and Doppler coefficient data as shown in Figure 4.3-44. Stability index measurements also provide a sensitive measure of the Doppler coefficient near full power (see Section 4.3.2.8). It can be seen that Doppler defect data are typically within 0.2 percent $\Delta\rho$ of prediction.

4.3.3.2 Macroscopic Group Constants

There are two lattice codes used for the generation of macroscopic group constants for use in the spatial few group diffusion codes. They are a version of the LEOPARD and CINDER codes and PHOENIX-P. A detailed description of each follows. Macroscopic few-group constants and analogous microscopic cross sections (needed for feedback and microscopic depletion calculations) can be generated for fuel cells by a Westinghouse version of the LEOPARD and CINDER codes, which are linked internally and provide burnup-dependent cross sections. Normally, a simplified approximation of the main fuel chains is used; however, where needed, a complete solution for all the significant isotopes in the fuel chains from Th-232 to Cm-244 is available (Reference 17). Cross section library tapes contain microscopic cross sections from the ENDF/B (Reference 18) library, with a few exceptions, where other data provide better agreement with critical experiments, isotopic measurements, and plant critical boron values.

The effect on the unit fuel cell of nonlattice components in the fuel assembly is obtained by supplying an appropriate volume fraction of these materials in an extra region which is homogenized with the unit cell in the fast (MUFT) and thermal (SOFOCATE) flux calculations. In the thermal calculation, the fuel rod, cladding, and moderator are homogenized by energy-dependent disadvantage factors derived from an analytical fit to integral transport theory results.

Group constants for burnable absorber cells, guide thimbles, instrument thimbles, and interassembly gaps are generated in a manner analogous to the fuel cell calculation. Reflector group constants are taken from infinite medium LEOPARD calculations. Baffle group constants are calculated from an average of core and radial reflector microscopic group constants for stainless steel.

Group constants for control rods are calculated in a linked version of the HAMMER (Reference 19) and AIM (Reference 20) codes to provide an improved treatment of self-shielding in the broad resonance structure of the appropriate isotopes at epithermal energies than is available using LEOPARD. The Doppler broadened cross sections of the control rod material are represented as smooth cross sections in the 54-group LEOPARD fast group structure and in 30 thermal groups. The four-group constants in the rod cell and appropriate extra region are generated in the coupled space-energy transport HAMMER calculation. A corresponding AIM calculation of the homogenized rod cell with extra region is used to adjust the absorption cross sections of the rod cell to match the reaction rates in HAMMER. These transport-equivalent group constants are reduced to two-group constants for use in space-dependent diffusion calculations. In discrete X-Y calculations only one mesh interval per cell is used, and the rod group constants are further adjusted for use in this standard mesh by reaction rate matching the standard mesh unit assembly to a fine-mesh unit assembly calculation.

Validation of the cross section method is based on analysis of critical experiments (Table 4.3-7), isotopic data (Table 4.3-8), plant critical boron (C_B) values at hot zero power (HZP), BOL (Table 4.3-9), and at HFP as a function of burnup (Figures 4.3-45 through 4.3-47). Control rod worth measurements are shown in Table 4.3-10. Confirmatory critical experiments on burnable absorbers are described in Reference 21.

The PHOENIX-P computer code is a two-dimensional, multi-group, transport based lattice code and capable of providing all necessary data for PWR analysis. Being a dimensional lattice code, PHOENIX-P does not rely on pre-determined spatial/spectral interaction assumptions for a heterogeneous fuel lattice, hence, will provide a more accurate multi-group flux solution than versions of LEOPARD/CINDER. The PHOENIX-P computer code is approved by the USNRC as the lattice code for generating macroscopic and microscopic few group cross sections for PWR analysis (Reference 27).

The solution for the detailed spatial flux and energy distribution is divided into two major steps in PHOENIX-P (References 27 and 28). In the first step, a two-dimensional fine

energy group nodal solution is obtained which couples individual subcell regions (pellet, cladding and moderator) as well as surrounding pins. PHOENIX-P uses a method based on the Carlvik's collision probability approach and heterogeneous response fluxes which preserves the heterogeneity of the pin cells and their surroundings. The nodal solution provides accurate and detailed local flux distribution, which is then used to spatially homogenize the pin cells to fewer groups.

The second step in the solution process solves for the angular flux distribution using a standard S4 discrete ordinates calculation. This step is based on the group-collapsed and homogenized cross sections obtained from the first step of the solution. The S4 fluxes are then used to normalize the detailed spatial and energy nodal fluxes. The normalized nodal fluxes are used to compute reaction rates, power distribution and to deplete the fuel and burnable absorbers. A standard B1 calculation is employed to evaluate the fundamental mode critical spectrum and to provide an improved fast diffusion coefficient for the core spatial codes.

The PHOENIX-P code employs a 42 energy group library, which has been derived mainly from ENDF/B-V files. The PHOENIX-P cross sections library was designed to properly capture integral properties of the multi-group data during group collapse, and enabling proper modeling of important resonance parameters. The library contains all neutronic data necessary for modeling fuel, fission products, cladding and structural data, coolant, and control/burnable absorber materials present in Light Water Reactor cores.

Group constants for burnable absorber cells, guide thimbles, instrument thimbles, control rod cells and other non-fuel cells can be obtained directly from PHOENIX-P without any adjustments such as those required in the cell or 1D lattice a codes.

4.3.3.3 Spatial Few-Group Diffusion Calculations

Spatial few-group diffusion calculations have primarily consisted of two group X-Y calculations using an updated version of the TURTLE code, and two-group axial calculations using an updated version of the PANDA code. However, with the advent of VANTAGE 5 and hence axial features such as axial blankets and part length burnable absorbers, there will be a greater reliance on three-dimensional nodal codes such as 3D PALADON (Reference 25) and 3D ANC (Advanced Nodal Code) (Reference 26). The three dimensional nature of the nodal codes provide both the radial and axial power distributions.

Nodal three-dimensional calculations are carried out to determine the critical boron concentrations and power distributions. The moderator coefficient is evaluated by varying the inlet temperature in the same calculations used for power distribution and reactivity predictions.

Validation of TURTLE reactivity calculations is associated with the validation of the group constants themselves, as discussed in Section 4.3.3.2. Validation of the Doppler

calculations is associated with the fuel temperature validation, as discussed in Section 4.3.3.1. Validation of the moderator coefficient calculation is obtained by comparison with plant measurements at HZP conditions, as shown in Table 4.3-11.

Axial calculations are used to determine differential control rod worth curves (reactivity versus rod insertion) and axial power shapes during steady state and transient xenon conditions. Group constants are obtained from three-dimensional nodal calculations homogenized by flux volume weighting.

Validation of the spatial codes for calculating power distributions involves the use of incore and excore detectors, and is discussed in Section 4.3.2.2.7.

Based on comparison with measured data, it is estimated that the accuracy of current analytical methods is:

$\pm$0.2% $\Delta\rho$ for Doppler defect
$\pm$2 x $\Delta\rho$/°F for moderator temperature coefficient
$\pm$50 ppm for critical boron concentration with depletion
$\pm$3% for power distributions
$\pm$0.2% $\Delta\rho$ for rod bank worth

4.3.4 REFERENCES

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4.4 THERMAL AND HYDRAULIC DESIGN

This section discusses the thermal and hydraulic design of the DCPP reactors.

4.4.1 DESIGN BASES

The objective of the thermal and hydraulic design of the reactor core is to provide adequate heat transfer that is compatible with the heat generation distribution in the core, so that heat removal by the RCS or the emergency core cooling system (ECCS) (when applicable) meets the following performance and safety criteria:

(1) Fuel damage[a] is not expected during normal operation and operational transients (Condition I) or any transient conditions arising from faults of moderate frequency (Condition II). It is not possible, however, to preclude a very small number of rod failures. These will be within the capability of the plant cleanup system and are consistent with the plant design bases.

(2) The reactor can be brought to a safe state following a Condition III event with only a small fraction of fuel rods damaged[a] although sufficient fuel damage might occur to preclude resumption of operation without considerable outage time.

(3) The reactor can be brought to a safe state and the core can be kept subcritical with acceptable heat transfer geometry following transients arising from Condition IV events.

Accordingly, the following design bases have been established for the thermal and hydraulic design of the reactor core.

4.4.1.1 Departure from Nucleate Boiling Design Basis

4.4.1.1.1 Basis

Departure from nucleate boiling (DNB) will not occur on at least 95 percent of the limiting fuel rods during normal operation and operational transients and any transient conditions arising from faults of moderate frequency (Conditions I and II events) at a 95 percent confidence level.

This criterion has been conservatively met by adhering to the following thermal design basis: there must be at least a 95 percent probability that the minimum departure from nucleate boiling ratio (DNBR) of the limiting power rod during Condition I and II events is greater than or equal to the DNBR limit of the DNB correlation being used. The DNBR limit for the correlation is established based on the variance of the correlation such that

[a] Fuel damage as used here is defined as penetration of the fission product barrier (i.e., the fuel rod cladding).

there is a 95 percent probability with 95 percent confidence that DNB will not occur when the calculated DNBR is at the DNBR limit.

4.4.1.1.2 Discussion

Historically, this DNBR limit has been 1.30 for Westinghouse applications. In this application the WRB-1 correlation (Reference 84) for LOPAR fuel and the WRB-2 correlation (Reference 85) for VANTAGE 5 fuel are employed. With the significant improvement in the accuracy of the critical heat flux prediction by using these correlations instead of previous DNB correlations, a DNBR limit of 1.17 is applicable in this application.

The design method employed to meet the DNB design basis is the "Improved Thermal Design Procedure" (Reference 86). Uncertainties in plant operating parameters, nuclear and thermal parameters, and fuel fabrication parameters are considered statistically such that there is at least a 95 percent probability that the minimum DNBR will be greater than or equal to 1.17 for the limiting power rod. Plant parameter uncertainties are used to determine the plant DNBR uncertainties. These DNBR uncertainties, combined with the DNBR limit, establish a design DNBR value, which must be met in plant safety analyses. Since the parameter uncertainties are considered in determining the design DNBR value, the plant safety analyses are performed using values of input parameters without uncertainties.

This design procedure is illustrated in Figure 4.4-18. For this application, the minimum required DNBR values for the LOPAR fuel analysis are a 1.34 for thimble cold wall cells (three fuel rods and a thimble tube) and 1.38 for typical cell (four fuel rods). The design DNBR values for the VANTAGE 5 fuel are a 1.32 and 1.34 for thimble and typical cells, respectively.

In addition to the above considerations, a plant-specific DNBR margin has been considered in the analyses. In particular, safety analysis DNBR limits of 1.44 for thimble and 1.48 for typical cells for LOPAR fuel, and 1.68 and 1.71 for thimble and typical cells respectively for the VANTAGE 5 fuel, were employed in the safety analyses. The plant allowance available between the DNBRs used in the safety analyses and the design DNBR values is not required to meet the design basis discussed earlier. This allowance will be used for the flexibility in the design, operation, and analyses of DCPP.

By preventing DNB, adequate heat transfer is ensured between the fuel cladding and the reactor coolant, thereby preventing cladding damage. Maximum fuel rod surface temperature is not a design basis because it will be within a few degrees of coolant temperature during operation in the nucleate boiling region. Limits provided by the nuclear control and protection systems are such that this design basis will be met for transients associated with Condition II events including overpower transients. The DNBR margin at rated power operation and during normal operating transients is substantially larger (see Table 4.1-1).

4.4.1.2 Fuel Temperature Design Basis

4.4.1.2.1 Basis

During Conditions I and II modes of operation, the maximum fuel temperature shall be less than the melting temperature of UO_2. The UO_2 melting temperature for at least 95 percent of the peak kW/ft fuel rods will not be exceeded at the 95 percent confidence level. The melting temperature of UO_2 is taken as 5080°F (Reference 1) unirradiated, and decreasing 58°F per 10,000 megawatt days per metric ton of uranium (MWD/MTU). By precluding UO_2 melting, the fuel geometry is preserved and possible adverse effects of molten UO_2 on the cladding are eliminated. To preclude center melting and establish overpower protection system setpoints, a calculated centerline fuel temperature of 4700°F has been selected as the overpower limit, thus providing sufficient margin for uncertainties. The peak linear power value used in the design evaluation is 22.0 kW/ft. This value corresponds to a peak centerline temperature which is less than 4700°F.

4.4.1.2.2 Discussion

Fuel rod thermal evaluations are performed at rated power, maximum overpower, and during transients at various burnups. These analyses ensure that this design basis, as well as the fuel integrity design bases given in Section 4.2, are met. They also provide input for the evaluation of Conditions III and IV faults given in Chapter 15.

4.4.1.3 Core Flow Design Basis

4.4.1.3.1 Basis

A minimum of 92.5 percent of the thermal flowrate (see Section 5.1) will pass through the fuel rod region of the core and be effective for fuel rod cooling. Coolant flow through the thimble tubes, as well as leakage from the core barrel-baffle region into the core, is not effective for heat removal.

4.4.1.3.2 Discussion

Core cooling evaluations are based on the thermal flowrate (minimum flow) entering the reactor vessel. A maximum of 7.5 percent of this value is allotted as bypass flow. This includes rod cluster control (RCC) guide thimble cooling flow, head cooling flow, baffle leakage and leakage to the vessel outlet nozzle, and flow in the gaps between the peripheral assemblies and the baffle wall.

4.4.1.4 Hydrodynamic Stability Design Bases

4.4.1.4.1 Basis

Modes of operation associated with Conditions I and II events shall not lead to hydrodynamic instability.

4.4.1.5 Other Considerations

The above design bases, together with the fuel cladding and fuel assembly design bases given in Section 4.2.1.1, are sufficient. Fuel cladding integrity criteria cover possible effects of cladding temperature limitations. As noted in Section 4.2.1.3.1, the fuel rod conditions change with time. A single cladding temperature limit for Conditions I or II events is not appropriate since of necessity it would be overly conservative. A cladding temperature limit is applied to the loss-of-coolant accident (LOCA) (Section 15.4.1), control rod ejection accident (Reference 2), and locked rotor accident (Reference 67).

4.4.2 DESCRIPTION

4.4.2.1 Summary Comparison

The core design parameters of the DCPP Units 1 and 2 reactors are presented in Table 4.1-1.

The reactor core is designed to a minimum DNBR greater than or equal to the design limit DNBR as well as no fuel centerline melting during normal operation, operational transients, and faults of moderate frequency.

4.4.2.2 Fuel Cladding Temperatures

A discussion of fuel cladding integrity is presented in Section 4.2.1.3.1.

The thermal-hydraulic design ensures that the maximum fuel pellet temperature is below the melting point of UO_2 (see Section 4.4.1.2). To preclude center melting and establish overpower protection system setpoints, a calculated centerline fuel temperature of 4700°F has been selected as the overpower limit. The temperature distribution within the fuel pellet is predominantly a function of the local power density and UO_2 thermal conductivity. However, the computation of radial fuel temperature distributions combines crud, oxide, cladding, gap, and pellet conductances. The factors that influence these conductances, such as gap size (or contact pressure), internal gas pressure, gas composition, pellet density, and radial power distribution within the pellet, etc., have been combined into a semiempirical thermal model (see Section 4.2.1.3.1) with modifications for time-dependent fuel densification (Reference 68). The temperature predictions have been compared to incore fuel temperature measurements (References 3 through 9) and melt radius data (References 10 and 11) with good results.

4.4.2.2.1 Effect of Fuel Densification on Fuel Rod Temperatures

Fuel densification results in fuel pellet shrinkage. This affects the fuel temperatures in the following ways:

(1) Pellet radial shrinkage increases the pellet diametral gap that results in increased thermal resistance of the gap and thus higher fuel temperatures (see Section 4.2.1.3.1).

(2) Pellet axial shrinkage may produce pellet-to-pellet gaps that result in local power spikes, described in Section 4.3.2.2.1, and thus higher total heat flux hot channel factor, F_Q^T and local fuel temperatures.

(3) Pellet axial shrinkage results in a fuel stack height reduction and an increase in the linear power generation rate (kW/ft) for a constant core power level. Using the methods of Reference 68, the increase in linear power for the fuel rod specifications listed in Table 4.1-1 is 0.2 percent.

Fuel rod thermal parameters (fuel centerline, average, and surface temperatures) are determined throughout its lifetime considering time-dependent densification. Maximum fuel average and surface temperatures, shown in Figure 4.4-1 as a function of linear power density (kW/ft), are peak values attained during the fuel lifetime. Similarly, Figure 4.4-2 presents the peak value of fuel centerline temperature versus linear power density, attained during its lifetime.

The maximum pellet temperature at the hot spot during full power steady state and at the maximum overpower ΔT trip point is shown in Table 4.1-1 for Units 1 and 2. The principal factors employed in fuel temperature determinations are discussed below.

4.4.2.2.2 UO_2 Thermal Conductivity

The thermal conductivity of UO_2 was evaluated from data reported in References 12 through 24.

At the higher temperatures, thermal conductivity is best obtained by utilizing the integral conductivity to melt, which can be determined with more certainty. From an examination of the data, it has been concluded that the best estimate for the value of $\int_0^{2800^\circ C} k dT$ is 93 watts/cm. This conclusion is based on the integral values reported in References 10 and 24 through 28.

The design curve for the thermal conductivity is shown in Figure 4.4-3. The section of the curve at temperatures between 0 and 1300°C is in excellent agreement with the recommendation of the IAEA panel (Reference 29). The section of the curve above 1300°C is derived from an integral value of 94 watts/cm (References 10, 24 and 28).

Thermal conductivity for UO_2 at 95 percent theoretical density can be represented best by the following equation:

$$k = \frac{1}{(11.8 + 0.0238T)} + 8.775 \times 10^{-13}\ T^3 \qquad (4.4\text{-}1)$$

where:

k is in watts/cm-°C, and T is in °C

4.4.2.2.3 Radial Power Distribution in UO_2 Fuel Rods

An accurate radial power distribution as a function of burnup is needed to determine the power level for incipient fuel melting and other important performance parameters, e.g., pellet thermal expansion, fuel swelling, and fission gas release rates.

This UO_2 fuel rods radial power distribution is determined with the neutron transport theory LASER (Reference 81) code that has been validated by comparing code predictions on radial burnup and isotopic distributions with measured radial microdrill data[(a)] (References 30 and 31). A "radial power depression factor," f, is determined using radial power distribution predicted by LASER. The factor f enters into the determination of the pellet centerline temperature, T_c, relative to the pellet surface temperature, T_s, through the expression:

$$\int_{T_s}^{T_c} k(T)dT = \frac{q'f}{4\pi} \qquad (4.4\text{-}2)$$

where:

k(T) = the thermal conductivity for UO_2 with a uniform density distribution

q' = the linear power generation rate

4.4.2.2.4 Gap Conductance

The temperature drop across the pellet-cladding gap is a function of the gap size and the thermal conductivity of the gas in the gap. The gap conductance model is selected such that when combined with the UO_2 thermal conductivity model, the calculated fuel centerline temperatures reflect the inpile temperature measurements.

(a) "Microdrill data" are data obtained from the physical examination of irradiated pellets in a hot cell. Small core samples are removed from different radial positions in a pellet (using a "microdrill"). Isotopic measurements of the fuel samples determine actual UO_2 burnups at the sample points.

The temperature drop across the gap is calculated by assuming an annular gap conductance mode of the following form:

$$h = \frac{K_{gas}}{M\delta/2 + 14.4 \times 10^{-6}} \qquad (4.4\text{-}3)$$

or an empirical correlation derived from thermocouple and melt radius data:

$$h = 1500K_{gas} + \frac{4.0}{0.006 + 12\delta} \qquad (4.4\text{-}4)$$

where:

h = thermal gap conductance, Btu/hr-ft^2-°F
K_{gas} = thermal conductivity of the gas mixture including a correction factor (Reference 32) for the accommodation coefficient for light gases (e.g., helium), Btu/hr-ft-°F
δ = diametral gap size, ft
M = gap multiplication factor (Reference 83)

The larger gap conductance value from these two equations is used to calculate the temperature drop across the gap for finite gaps.

For evaluations in which the pellet-cladding gap is closed, a contact conductance is calculated. The contact conductance between UO_2 and Zircaloy has been measured and found to be dependent on the contact pressure, composition of the gas at the interface, and the surface roughness (References 32 and 33). This information, together with the surface roughness found in Westinghouse fuels, leads to the following correlation:

$$h = 0.6P + \frac{K_{gas}}{14.4 \times 10^{-6}} \qquad (4.4\text{-}5)$$

where:

h = contact conductance, Btu/hr-ft^2-°F
P = contact pressure, psi

4.4.2.2.5 Surface Heat Transfer Coefficients

The fuel rod surface heat transfer coefficients during subcooled forced convection and the outer cladding wall temperature for the onset of nucleate boiling is presented in Section 4.4.2.8.1.

4.4.2.2.6 Fuel Cladding Temperatures

The fuel rod outer surface at the hot spot operates at a temperature of approximately 660°F for steady state operation at rated power throughout core life, due to the onset of nucleate boiling. At beginning of life (BOL), this temperature is that of the cladding metal outer surface.

During operation over the life of the core, the buildup of oxides and crud on the fuel rod cladding outer surface causes the cladding surface temperature to increase. Allowance is made in the fuel center melt evaluation for this temperature rise. The thermal-hydraulic DNB limits ensure that adequate heat transfer is provided between the fuel cladding and the reactor coolant so that cladding temperature does not limit core thermal output. Figure 4.4-4 shows the axial variation of average cladding temperature for the average power rod both at beginning and end of life (EOL).

4.4.2.2.7 Treatment of Peaking Factors

The total heat flux hot channel factor, F_Q^T, is defined by the ratio of the maximum to core average heat flux. The design value of F_Q^T for normal operation is 2.58 including fuel densification effects as shown in Table 4.3-1. This results in a peak local linear power density of 14.3 kW/ft at full power. The corresponding peak local power at the maximum overpower trip point (118 percent total power) is 16.6 kW/ft. Centerline temperature at this kW/ft must be below the UO_2 melt temperature over the lifetime of the rod including allowances for uncertainties. From Figure 4.4-2, the centerline temperature at the maximum overpower trip point is well below that required to produce melting. Fuel centerline and average temperature at rated (100 percent) power and at the maximum overpower trip point for Units 1 and 2 are presented in Table 4.1-1.

4.4.2.3 Departure from Nucleate Boiling Ratio

The minimum DNBRs for the rated power, and anticipated transient conditions are given in Table 4.1-1 for Units 1 and 2. The minimum DNBR in the limiting flow channel will occur downstream of the peak heat flux location (hot spot) due to the increased downstream enthalpy rise.

DNBRs are calculated by using the correlation and definitions described in Section 4.4.2.3.1. The THINC-IV (Reference 47) computer code (discussed in Section 4.4.3.4.1) determines the flow distribution in the core and the local conditions in the hot channel for use in the DNB correlation. The use of hot channel factors is discussed in Section 4.4.3.2.1 (nuclear hot channel factors) and in Section 4.4.2.3.4 (engineering hot channel factors).

4.4.2.3.1 Departure from Nucleate Boiling Technology

The W-3 correlation, and several modifications, have been used in Westinghouse critical heat flux (CHF) calculations. The W-3 was originally developed from single tube data (Reference 34), but was subsequently modified to apply to the 0.422 inch, OD rod "R"-grid (Reference 35) and "L"-grid (Reference 36), as well as the 0.374 inch OD (References 37 and 38) rod bundle data. These modifications to the W-3 correlation have been demonstrated to be adequate for reactor rod bundle design.

A description of the 17 x 17 fuel assembly test program and a summary of the results are described in detail in Reference 37.

Figure 4.4-5 shows the data obtained in this test program. The test results indicate that a reactor core using this geometry may operate with a minimum DNBR of 1.28 and satisfy the design criterion.

The WRB-1 correlation (Reference 84) as developed based exclusively on the large bank of mixing vane grid rod bundle CHF data (over 1100 points) that Westinghouse has collected. The WRB-1 correlation, based on local fluid conditions, represents the rod bundle data with better accuracy over the wide range of variables than the previous correlation used in design. This correlation accounts directly for both typical and thimble cold wall cell effects, uniform and nonuniform heat flux profiles, and variations in rod heated length and in grid spacing.

Figure 4.4-19 shows measured critical heat flux plotted against predicted critical heat flux using the WRB-1 correlation.

Critical heat flux tests which model the 17x17 optimized fuel assembly have been performed with the results described in detail in Reference 87. It was concluded that the CHF characteristics of the 17x17 optimized fuel assembly design are not significantly different from those of 17x17 LOPAR design, and can be adequately described by the "R" grid form of the WRB-1 CHF correlation. Furthermore, the new data can be incorporated into the "R" grid data base such that the WRB-1 correlation can be applied to 17x17 LOPAR fuel design without changing the DNBR design criterion of 1.17.

The WRB-2 DNB correlation (Reference 85) was developed to take credit for the VANTAGE 5 fuel assembly mixing vane design. A DNBR limit of 1.17 is also applicable for the WRB-2 correlations. Figure 4.4-20 shows measured critical heat flux plotted against predicted critical heat flux using the WRB-2 correlation.

4.4.2.3.2 Definition of Departure from Nucleate Boiling Ratio

The DNBR, as applied to this design for both typical and thimble cold wall cells is:

$$DNB = \frac{q''_{DNB,\,Predicted}}{q''_{actual}} \tag{4.4-6}$$

For the W-3 (R-Grid) correlation,

$$q''_{DNB,Predicted} = \frac{q''_{EU,W-3} \times F'_S}{F} \tag{4.4-7}$$

when all flow cell walls are heated and q" $_{EU,\ W\text{-}3}$ is the uniform DNB heat flux as predicted by W-3 DNB correlation and F is the flux shape factor which accounts for nonuniform axial heat flux distributions (Reference 39) with the "C" term modified as in Reference 34.

F'_S is the modified spacer factor described in Reference 37 using an axial grid spacing coefficient, K_S = 0.046, and a thermal diffusion coefficient (TDC) of 0.038, based on the 26-inch grid spacing data. Since the actual grid spacing is approximately 20 inches, these values are conservative since the DNB performance was found to improve and TDC increase as axial grid spacing is decreased (References 35 and 40).

When a cold wall is present for the W-3 correlation,

$$q''_{DNB,Predicted} = q''_{EU,W-3,CW} \times F'_S \tag{4.4-8}$$

where:

$$q''_{EU,W-3,CW} = \frac{q''_{EU,W-e,Dh}}{F} \times CWF \tag{4.4-8A}$$

$q''_{EU,W-3,Dh}$ is the uniform DNB heat flux as predicted by the W-3 cold wall correlation (Reference 34) when not all flow cell walls are heated (thimble cold wall cell). The cold wall factor (CWF) is provided in References 34 and 39. For the WRB-1 and WRB-2 correlations,

$$q''_{DNB,Predicted} = \frac{q''_{WRB-1}}{F} \quad \text{for WRB–1 correlation} \tag{4.4-9}$$

$$= \frac{q''_{WRB-2}}{F} \quad \text{for WRB–2 correlation} \tag{4.4-9A}$$

where:

F is the same flux shape factor that is used with the W-3 correlation.

4.4.2.3.3 Mixing Technology

The rate of heat exchange by mixing between flow channels is proportional to the difference in the local mean fluid enthalpy of the respective channels, the local fluid density, and the flow velocity. The proportionality is expressed by the dimensionless TDC, which is defined as:

$$TDC = \frac{w'}{\rho V a} \qquad (4.4\text{-}10)$$

where:

w' = flow exchange rate per unit length, lbm/ft-sec
ρ = fluid density, 1bm/ft^3
V = fluid velocity, ft/sec
a = lateral flow area between channels per unit length, ft^2/ft

The application of the TDC in the THINC analysis for determining the overall mixing effect or heat exchange rate is presented in Reference 41.

The TDC is determined by comparing the THINC code predictions with the measured subchannel exit temperatures. Data for 26-inch axial grid spacing are presented in Figure 4.4-6 where the TDC is plotted versus the Reynolds number. The TDC is found to be independent of the Reynolds number, mass velocity, pressure, and quality over the ranges tested.

The two-phase data (local and subcooled boiling) fell within the scatter of the single-phase data. The effect of two-phase flow on the value of TDC has been demonstrated by Cadek (Reference 40), Rowe and Angle (References 42 and 43), and Gonzalez-Santalo and Griffith (Reference 44). In the subcooled boiling region, the values of TDC were indistinguishable from the single-phase values. In the quality region, Rowe and Angle show that in the case with rod spacing similar to that in PWR reactor core geometry, the value of TDC increased with quality to a point and then decreased but never below the single-phase value. Gonzalez-Santalo and Griffith showed that the mixing coefficient increased as the void fraction increased.

The data from these tests on the R grid showed that a design TDC value of 0.038 (for 26 inch grid spacing) can be used in determining the effect of coolant mixing in the THINC analysis. A mixing test program similar to the one described above was conducted at Columbia University for the 17 x 17 geometry and mixing vane grids on 26-inch spacing (Reference 45). The mean value of TDC obtained from these tests was 0.059, and all data were well above the current design value of 0.038.

Because the reactor grid spacing is approximately 20 inches, additional margin is available for this design, as the value of TDC increases as grid spacing decreases (Reference 40).

The inclusion of three intermediate flow mixer (IFM) grids in the upper span of the VANTAGE 5 fuel assembly results in a grid spacing of approximately 10 inches. Therefore, the design value of 0.038 for TDC is a conservatively low value for use in VANTAGE 5 to determine the effect of coolant mixing in the core thermal performance analysis.

4.4.2.3.4 Hot Channel Factors

The total hot channel factors for heat flux and enthalpy rise are defined as the maximum-to-core average ratios of these quantities. The heat flux hot channel factor considers the local maximum linear heat generation rate at a point (the "hot spot"), and the enthalpy rise hot channel factor involves the maximum integrated value along a channel (the "hot channel").

Each of the total hot channel factors considers a nuclear hot channel factor (see Section 4.4.3.2) describing the neutron power distribution and an engineering hot channel factor, which allows for variations in flow conditions and fabrication tolerances. The engineering hot channel factors are made up of subfactors that account for the influence of the variations of fuel pellet diameter, density, enrichment and eccentricity; fuel rod diameter pitch and bowing; inlet flow distribution; flow redistribution; and flow mixing.

4.4.2.3.4.1 Heat Flux Engineering Hot Channel Factor, F_Q^E

The heat flux engineering hot channel factor is used to evaluate the maximum heat flux. This subfactor is determined by statistically combining the tolerances for the fuel pellet diameter, density, enrichment, eccentricity, and the fuel rod diameter, and has a value of 1.03. Measured manufacturing data on Westinghouse fuel verify that this value was not exceeded for 95 percent of the limiting fuel rods at a 95 percent confidence level. As shown in Reference 99, no DNB penalty need be taken for the short, relatively low intensity heat flux spikes caused by variations in the above parameters.

4.4.2.3.4.2 Enthalpy Rise Engineering Hot Channel Factor, $F_{\Delta H}^E$

The effect of variations in flow conditions and fabrication tolerances on the hot channel enthalpy rise is directly considered in the THINC core thermal subchannel analysis (see Section 4.4.3.4.1) under any reactor operating condition. The following items contribute to the enthalpy rise engineering hot channel factor:

(1) Pellet Diameter, Density and Enrichment, Fuel Rod Diameter, Pitch, and Bowing

Design values employed in the THINC analysis are based on applicable limiting tolerances such that design values are met for 95 percent of the limiting channels at a 95 percent confidence level. The effect of variations in pellet diameter and enrichment is employed in the THINC analysis as a direct multiplier on the hot channel enthalpy rise, while the fuel rod diameter, pitch, and bowing variation, including incore effects, enter in the preparation of the THINC input values.

(2) Inlet Flow Maldistribution

Inlet flow maldistribution in the core thermal performances is discussed in Section 4.4.3.1.2. A design basis of 5 percent reduction in coolant flow to the hot assembly is used in the THINC-IV analysis.

(3) Flow Redistribution

The flow redistribution accounts for the flow reduction in the hot channel resulting from the high flow resistance in the channel due to the local or bulk boiling. The effect of the nonuniform power distribution is inherent to the THINC analysis.

(4) Flow Mixing

The subchannel mixing model incorporated in the THINC code and used in reactor design is based on experimental data (Reference 46), as discussed in Section 4.4.3.4.1. The mixing vanes incorporated in the spacer grid design induce additional flow mixing between the various flow channels in a fuel assembly, as well as between adjacent assemblies. This mixing reduces the enthalpy rise in the hot channel resulting from local power peaking or unfavorable mechanical tolerances.

4.4.2.3.5 Effects of Rod Bow on DNBR

The phenomenon of fuel rod bowing, as described in Reference 79, must be accounted for in the DNBR safety analysis of Condition I and Condition II events for each plant application. Applicable generic credits for margin resulting from retained conservatism in the evaluation of DNBR and/or margin obtained from measured plant operating parameters (such as $F^{N}_{\Delta H}$ or core flow), which are less limiting than those required by the plant safety analysis, can be used to offset the effect of rod bow.

The safety analysis for Diablo Canyon cores maintains sufficient margin between the safety analysis DNBR limits and the design DNBR limits and the design DNBR limits as shown below to accommodate full flow and low flow DNBR penalties identified in Reference 80, which are applicable to 17x17 LOPAR and VANTAGE 5 fuel assembly analysis utilizing the WRB-1 and WRB-2 correlations, respectively.

However, for the upper assembly span of VANTAGE 5 fuel where additional restraint is provided with the Intermediate Flow Mixer (IFM) grids, the grid-to-grid spacing in DNB limiting span is approximately 10 inches compared to approximately 20 inches in the LOPAR. Using the rod bow topical report methods (Reference 88), and scaling with the NRC approved factor results in predicted channel closure in the limiting spans of less than 50 percent closure; therefore, no rod bow DNBR penalty is required in the 10 inch spans in the VANTAGE 5 safety analyses.

	LOPAR	VANTAGE 5
Design Limit		
Typical Cell	1.38	1.34
Thimble Cell	1.34	1.32
Safety Limit		
Typical Cell	1.48	1.71
Thimble Cell	1.44	1.68

The maximum rod bow penalties accounted for in the design safety analysis are based on an assembly average burnup of 24,000 MWD/MTU based on Reference 88. At burnups greater than 24,000 MWD/MTU, credit is taken for the effect of $F_{\Delta H}^{N}$ burndown. Due to the decrease in fissionable isotopes and the buildup of fission product inventory, no additional rod bow penalty is required.

4.4.2.3.6 Transition Core

The Westinghouse transition core DNB methodology is given in References 89 and 90 and has been approved by the NRC via Reference 91. Using this methodology, transition cores are analyzed as if they were full cores of one assembly type (full LOPAR or full VANTAGE 5), applying the applicable transition core penalties. This penalty was included in the safety analysis limit DNBRs such that sufficient margin over the design limit DNBR existed to accommodate the transition core penalty and the appropriate rod bow DNBR penalty. However, since the transition to a full VANTAGE 5 core has been completed, various analyses, such as large break and small loss of coolant accident analysis, have assumed a full VANTAGE 5 core and no longer assume a transition core penalty.

The LOPAR and VANTAGE 5 designs have been shown to be hydraulically compatible in Reference 85.

4.4.2.4 Flux Tilt Considerations

Significant quadrant power tilts are not anticipated during normal operation since this phenomenon is caused by asymmetric perturbations. A dropped or misaligned RCCA could cause changes in hot channel factors. These events are analyzed separately in Chapter 15.

Other possible causes for quadrant power tilts include X-Y xenon transients, inlet temperature mismatches, enrichment variations within tolerances, and so forth.

In addition to unanticipated quadrant power tilts, other readily explainable asymmetries may be observed during calibration of the excore detector quadrant power tilt alarm. During operation, at least one power distribution measurement is taken per effective-full-power month. Each of these power distribution measurements is reviewed for deviations from the expected power distributions. The acceptability of an observed asymmetry, planned or otherwise, depends solely on meeting the required accident analyses assumptions. In practice, once acceptability has been established by review of the power distribution measurements, the quadrant power tilt alarms and related instrumentation are adjusted to indicate zero quadrant tilt, 1.00 quadrant power tilt ratio, as the final step in the calibration process. Proper functioning of the quadrant power tilt alarm is significant because no allowances are made in the design for increased hot channel factors due to unexpected developing flux tilts since all likely causes are prevented by design or procedures or specifically analyzed. Finally, in the event that unexplained flux tilts do occur, the Technical Specification (Reference 82) stipulates appropriate corrective actions to ensure continued safe operation of the reactor.

4.4.2.5 Void Fraction Distribution

The calculated core average and the hot subchannel maximum and average void fractions are presented in Tables 4.4-1 and 4.4-2 for operation at full power with design hot channel factors for Units 1 and 2, respectively. The void fraction distribution in the core is presented in Reference 47. The void fraction as a function of thermodynamic quality is shown in Figure 4.4-10. The void models used in the THINC-IV computer code are described in Section 4.4.2.8.3.

4.4.2.6 Core Coolant Flow Distribution

Coolant enthalpy rise and flow distributions are shown for the 4-foot elevation (1/3 of core height) in Figure 4.4-7, 8-foot elevation (2/3 of core height) in Figure 4.4-8, and at the core exit in Figure 4.4-9. These distributions correspond to a representative Westinghouse 4-loop plant. The THINC code analysis for this case utilized a uniform core inlet enthalpy and inlet flow distribution.

4.4.2.7 Core Pressure Drops and Hydraulic Loads

4.4.2.7.1 Core Pressure Drops

The analytical model and experimental data used to calculate the pressure drops, for the full power conditions given in Table 4.4-1, are described in Section 4.4.2.8.2. The core pressure drop consists of the fuel assembly, lower core plate, and upper core plate pressure drops. These pressure drops are based on the best estimate flow, as described in Section 5.1.5. Section 5.1.5 also defines the thermal design flow

(minimum flow), which is the basis for reactor core thermal performance, and the mechanical design flow (maximum flow), which is used in the mechanical design of the reactor vessel internals and fuel assemblies. Since the best estimate flow is that which is most likely to exist in an operating plant, the calculated core pressure drops in Table 4.1-1 are greater than pressure drops previously quoted using the thermal design flow. The relation between best estimate flow, thermal design flow, and mechanical design flow is illustrated in Figure 5.1-2.

4.4.2.7.2 Hydraulic Loads

The fuel assembly holddown springs, Figure 4.2-2, are designed to keep the fuel assemblies resting on the lower core plate under transients associated with Conditions I and II events. Maximum flow conditions are limiting because hydraulic loads are a maximum. The most adverse flow conditions occur during a LOCA, as discussed in Section 15.4.1.

Hydraulic loads at normal operating conditions are calculated based on the best estimate flow and best estimate core bypass flow. Core hydraulic loads at cold plant startup conditions are also based on this flow, but are adjusted to account for the coolant density difference. Conservative core hydraulic loads for a pump overspeed transient, that create flowrates 18 percent greater than the best estimate flow, are evaluated to be greater than twice the fuel assembly weight.

The hydraulic verification tests are discussed in Reference 48.

4.4.2.8 Correlation and Physical Data

4.4.2.8.1 Surface Heat Transfer Coefficients

Forced convection heat transfer coefficients are obtained from the familiar Dittus-Boelter correlation (Reference 49), with the properties evaluated at bulk fluid conditions:

$$\frac{hD_e}{k} = 0.023\left(\frac{D_eG}{m}\right)^{0.8}\left(\frac{C_p\mu}{k}\right)^{0.4} \qquad (4.4\text{-}11)$$

where:

h	=	heat transfer coefficient, Btu/hr-ft^2-°F
De	=	equivalent diameter, ft
k	=	thermal conductivity, Btu/hr-ft-°F
G	=	mass velocity, lb/hr-ft^2
μ	=	dynamic viscosity, lb/ft-hr
Cp	=	heat capacity, Btu/lb-°F

This correlation has been shown to be conservative (Reference 50) for rod bundle geometries with pitch-to-diameter ratios in the range used by PWRs.

The onset of nucleate boiling occurs when the cladding wall temperature reaches the amount of superheat predicted by Thom's (Reference 51) correlation. After this occurrence, the outer cladding wall temperature is determined by:

$$\Delta T_{sat} = [0.072 \exp(-P/1260)] (q'')^{0.5} \quad (4.4\text{-}12)$$

where:

ΔT_{SAT} = wall superheat, T_w - T_{sat}, °F
q'' = wall heat flux, Btu/hr-ft^2
P = pressure, psia
T_w = outer cladding wall temperature, °F
T_{SAT} = saturation temperature of coolant at P, °F

4.4.2.8.2 Total Core and Vessel Pressure Drop

Pressure losses occur as a result of viscous drag (friction) and/or geometry changes (form) in the fluid flowpath. The flow field is assumed to be incompressible, turbulent, single-phase water. Two-phase considerations are neglected in the vessel pressure drop evaluation because the core average void is negligible (see Section 4.4.2.5 and Tables 4.4-1 and 4.4-2).

Two-phase flow considerations in the core thermal subchannel analyses are considered and the models are discussed in Section 4.4.3.1.3. Core and vessel pressure losses are calculated by equations of the form:

$$\Delta P_L = \left(K + \frac{FL}{D_e}\right)\frac{\rho V^2}{2g_c(144)} \quad (4.4\text{-}13)$$

where:

ΔP_L = pressure drop, lb_f/in^2
ρ = fluid density, $1b_m/ft^3$
L = length, ft
D_e = equivalent diameter, ft
V = fluid velocity, ft/sec
g_c = $32.174 \frac{1b_m - ft}{1b_f - sec^2}$
K = form loss coefficient, dimensionless
F = friction loss coefficient, dimensionless

Fluid density is assumed to be constant at an appropriate value for each component in the core and vessel. Because of the complex core and vessel flow geometry, precise analytical values for the form and friction loss coefficients are not available. Therefore, experimental values for these coefficients are obtained from geometrically similar models.

The results of full-scale tests of core components and fuel assemblies were utilized in developing the core pressure loss characteristics. The pressure drop for the vessel was obtained by combining the core pressure loss with correlation of 1/7th scale model hydraulic test data on a number of vessels (References 52 and 53) and form loss relationships (Reference 54). Moody (Reference 55) curves were used to obtain the single-phase friction factors.

Tests of the primary coolant loop flowrates are made (see Section 4.4.4.1) prior to initial criticality to verify that the flowrates used in the design are conservative.

4.4.2.8.3 Void Fraction Correlation

Three separate void regions are considered in flow boiling in a PWR as illustrated in Figure 4.4-10. They are the wall void region (no bubble detachment), the subcooled boiling region (bubble detachment), and the bulk boiling region.

In the wall void region, local boiling begins at the point where the cladding temperature reaches the amount of superheat predicted by Thom's (Reference 51) correlation (discussed in Section 4.4.2.8.1). The void fraction in this region is calculated using Maurer's (Reference 56) relationship. The bubble detachment point, where the superheated bubbles break away from the wall, is determined by using Griffith's (Reference 57) relationship.

The void fraction in the subcooled boiling region (i.e., after the detachment point) is calculated from the Bowring (Reference 58) correlation. This correlation predicts the void fraction from the detachment point to the bulk boiling region.

The void fraction in the bulk boiling region is predicted by using homogeneous flow theory and assuming no slip. The void fraction in this region is, therefore, a function of steam quality only.

4.4.2.9 Thermal Effects of Operational Transients

DNB core safety limits are expressed as a function of coolant temperature, pressure, core power, and axial power imbalance. Steady state operation within these safety limits ensures that the minimum DNBR is not less than the safety limit DNBR.

Figure 15.1-1 shows lines at the safety limit DNBR and the resulting overtemperature ΔT trip lines (which are part of the Technical Specifications), plotted as ΔT versus T-average for various pressures. This system provides adequate protection against

anticipated operational transients that are slow with respect to fluid transport delays in the primary system. In addition, for fast transients (e.g., uncontrolled rod bank withdrawal at power incident (Section 15.2.2), specific protection functions are provided as described in Section 7.2; their use is described in Chapter 15 (see Table 15.1-2). Fuel rod thermal response is discussed in Section 4.4.3.7.

4.4.2.10 Uncertainties in Estimates

4.4.2.10.1 Uncertainties in Fuel and Cladding Temperatures

As discussed in Section 4.4.2.2, the fuel temperature is a function of crud, oxide, cladding, gap, and pellet conductances. Uncertainties in the fuel temperature calculation are essentially of two types: fabrication uncertainties, such as variations in the pellet and cladding dimensions and the pellet density; and model uncertainties, such as variations in the pellet conductivity and the gap conductance. These uncertainties have been quantified by comparison of the thermal model to the incore thermocouple measurements (References 3 through 9), by out-of-pile measurements of the fuel and cladding properties (References 12 through 23), and by measurements of the fuel and cladding dimensions during fabrication. The effect of densification on fuel temperature uncertainties is presented in Reference 68.

In addition, the measurement uncertainty in determining the local power, and the effect of density and enrichment variations on local power, are considered in establishing the heat flux hot channel factor.

Uncertainty in determining cladding temperature results from uncertainties in the crud and oxide thickness. Because of the excellent heat transfer between the surface of the rod and the coolant, the film temperature drop does not appreciably contribute to the uncertainty.

Reactor trip setpoints, as specified in the Technical Specifications, include allowance for instrument and measurement uncertainties such as calorimetric error, instrument drift, and channel reproducibility.

4.4.2.10.2 Uncertainties in Pressure Drops

Core and vessel pressure drops based on the best estimate flow, as described in Section 5.1, are quoted in Table 4.1-1. The uncertainties quoted are based on the uncertainties in both the test results and the analytical extension of these values to the reactor application.

4.4.2.10.3 Uncertainties Due to Inlet Flow Maldistribution

Uncertainties in the inlet flow maldistribution criteria used in the core thermal analyses are discussed in Section 4.4.3.1.2.

4.4.2.10.4 Uncertainty in DNB Correlation

The uncertainty in the DNB correlation (Section 4.4.2.3) can be written as a statement on the probability of not being in DNB based on the DNB data statistics. This is discussed in Section 4.4.2.3.2.

4.4.2.10.5 Uncertainties in DNBR Calculations

The uncertainties in the DNBRs calculated by THINC analysis (see Section 4.4.3.4.1) due to uncertainties in the nuclear peaking factors are accounted for by applying conservatively high values of the nuclear peaking factors and including measurement error allowances in the statistical evaluation of the limit DNBR (see Section 4.4.1.1.2) using the Improved Thermal Design Procedure (Reference 86). In addition, conservative values for the engineering hot channel factors are used (see Section 4.4.2.3.4). The results of a sensitivity study with THINC-IV show that the minimum DNBR in the hot channel is relatively insensitive to variations in the core-wide radial power distribution (for the same value of $F^{N}_{\Delta H}$).

The ability of the THINC-IV computer code to accurately predict flow and enthalpy distributions in rod bundles is discussed in Section 4.4.3.4.1 and in Reference 59. The sensitivity of the minimum DNBR in the hot channel to the void fraction correlation (see also Section 4.4.2.8.3), the inlet velocity and exit pressure distributions, and the grid pressure loss coefficients have been studied (Reference 47). The results show that the minimum DNBR in the hot channel is relatively insensitive to variations in these parameters.

4.4.2.10.6 Uncertainties in Flowrates

The uncertainties associated with loop flowrates are discussed in Section 5.1. For core thermal performance evaluations, a thermal design loop flow is used which is less than the best estimate loop flow (by approximately 4 percent). In addition, another 7.5 percent of the thermal design flow is assumed to be ineffective for core heat removal capability because it bypasses the core through the various available flowpaths described in Section 4.4.3.1.1.

4.4.2.10.7 Uncertainties in Hydraulic Loads

As discussed in Section 4.4.2.7.2, hydraulic loads on the fuel assembly are evaluated for a pump overspeed transient that creates flowrates 18 percent greater than the best estimate flow. A design uncertainty of 10 percent is applied.

4.4.2.10.8 Uncertainty in Mixing Coefficients

The value of the mixing coefficient, TDC, used in THINC analyses for this application is 0.038. The mean value of TDC obtained in the R grid mixing tests described in Section 4.4.2.3.1 was 0.042 (for 26-inch grid spacing). The value of 0.038 is one

standard deviation below the mean value and 90 percent of the data gives values of TDC greater than 0.038 (Reference 41).

The results of the mixing tests discussed in Section 4.4.2.3.3, had a mean value of TDC of 0.059 and standard deviation of σ = 0.007. Hence, the current design value of TDC is almost three standard deviations below the mean for 26-inch grid spacing.

4.4.2.11 Plant Configuration Data

Plant configuration data for the thermal-hydraulic and fluid systems external to the core are provided in Chapters 5, 6, and 9. Implementation of the ECCS is discussed in Chapters 6 and 15. Some specific areas of interest are:

(1) Total coolant flow rate for the RCS is provided in Table 5.1-1.

(2) Total RCS volume is given in Table 5.1-1.

(3) The flowpath length through each volume can be calculated from physical data provided in the referenced tables.

(4) The height of fluid in each component of the RCS may be determined from the physical data presented in Section 5.5. The RCS components are water-filled during power operation with the pressurizer being approximately 60 percent water-filled.

(5) ECCS components are located to meet the criteria for net positive suction head (NPSH) described in Section 6.3.

(6) Line lengths and sizes for the safety injection system (SIS) are determined so as to guarantee a total system resistance that will provide, as a minimum, the fluid delivery rates assumed in the safety analyses described in Chapter 15.

(7) The minimum flow areas for RCS components are presented in Section 5.5.

(8) RCS steady state pressure and temperature distribution are presented in Table 5.1-1.

4.4.3 EVALUATION

4.4.3.1 Core Hydraulics

4.4.3.1.1 Flowpaths Considered in Core Pressure Drop and Thermal Design

The following flowpaths are considered:

(1) Flow through the spray nozzles into the upper head for cooling purposes

(2) Flow entering the RCC guide thimbles to cool core components

(3) Leakage flow from the vessel inlet nozzle directly to the vessel outlet nozzle through the gap between vessel and barrel

(4) Flow entering the core from the baffle-barrel region through the gaps between the baffle plates

(5) Flow introduced between baffle and barrel to cool these components

(6) Flow through the empty guide thimble tubes

The above contributions are evaluated to confirm that the design basis value of $\leq$ 7.5 percent core bypass flow is met.

4.4.3.1.2 Inlet Flow Distribution

Data from several 1/7 scale hydraulic reactor model tests (References 52, 53, and 60) have been considered in arriving at the core inlet flow maldistribution criteria to be used in the THINC analyses (see Section 4.4.3.4.1). THINC-I (Reference 41) analyses have indicated that a conservative design basis is to consider a 5 percent reduction in the flow to the hot assembly (Reference 61). The same 5 percent reduction to the hot assembly inlet is used in THINC-IV analyses.

The experimental error in the inlet velocity distribution has been estimated in Reference 47. The sensitivity of changes in inlet velocity distributions to hot channel thermal performance is shown to be small.

The effect of the total flowrate on the inlet velocity distribution was studied in the experiments of Reference 52. As expected, no significant variation could be found in inlet velocity distribution with reduced flowrate.

4.4.3.1.3 Empirical Friction Factor Correlations, F_Q^E

Two empirical friction factor correlations are used in the THINC-IV computer code (described in Section 4.4.3.4.1). The friction factor in the axial direction, parallel to the fuel rod axis, uses the Novendstern-Sandberg (Reference 62) correlation. This correlation consists of the following:

(1) For isothermal conditions, this correlation uses the Moody (Reference 55) friction factor, including surface roughness effects.

(2) Under single-phase heating conditions, a factor is applied based on the values of the coolant density and viscosity at the temperature of the heated surface and at the bulk coolant temperature.

(3) Under two-phase flow conditions, the homogeneous flow model proposed by Owens (Reference 63) is used with a modification to account for a mass velocity and heat flux effect.

The flow in the lateral directions, normal to the fuel rod axis, views the reactor core as a large tube bank. Thus, the lateral friction factor proposed by Idel'chick (Reference 54) is applicable. This correlation is of the form:

$$F_L = ARe_L^{-0.2} \qquad (4.4\text{-}14)$$

where:

A is a function of the rod pitch and diameter as given in Reference 54
Re_L is the lateral Reynolds number based on rod diameter

Extensive comparisons of THINC-IV predictions using these correlations to experimental data are given in Reference 59, and verify the applicability of these correlations in PWR design.

4.4.3.2 Influence of Power Distribution

The core power distribution, which at BOL is largely established by fuel enrichment, loading pattern, and core power level, is a function of variables such as control rod worth and position and fuel depletion throughout lifetime. Although radial power distributions in various planes of the core are often illustrated for general interest, the core radial enthalpy rise distribution, as determined by the integral of power over each channel, is of greater importance for DNB analyses. These radial power distributions, characterized by $F_{\Delta H}^N$ (defined in Section 4.3.2.2.2), as well as axial heat flux profiles, are discussed in the following two sections.

4.4.3.2.1 Nuclear Enthalpy Rise Hot Channel Factor, $F^N_{\Delta H}$

Given the local power density q' (kW/ft) at a point x, y, z in a core with N fuel rods and height H:

$$F^N_{\Delta H} = \frac{\text{hot rod power}}{\text{average rod power}} = \frac{\text{Max} \int_o^H q'(x_o, y_o, z)dz}{\frac{1}{N} \sum_{\substack{\text{all}\\ \text{rods}}} \int_o^H q'(x,y,z)dz} \qquad (4.4\text{-}15)$$

The location of minimum DNBR depends on the axial profile and its magnitude depends on the enthalpy rise up to that point. The maximum value of the rod integral is used to identify the most likely rod for minimum DNBR. An axial power profile is obtained which, when normalized to the design value of $F^N_{\Delta H}$, recreates the axial heat flux along the limiting rod. The surrounding rods are assumed to have the same axial profile with rod average powers that are typical of distributions found in hot assemblies. In this manner, worst case axial profiles can be combined with worst case radial distributions for reference DNB calculations.

Local heat fluxes are obtained by using hot channel and adjacent channel explicit power shapes which take into account variations in horizontal power shapes throughout the core. The sensitivity of the THINC-IV analysis to radial power shapes is discussed in Reference 47.

For operation at a fraction P of full power, the design $F^N_{\Delta H}$ is given by:

$$F^N_{\Delta H} = 1.56\ [1 + 0.3\ (1\text{-}P)]\ (\text{LOPAR}) \qquad (4.4\text{-}16)$$
$$F^N_{\Delta H} = 1.59\ [1 + 0.3\ (1\text{-}P)]\ (\text{VANTAGE 5})$$

The permitted relaxation of $F^N_{\Delta H}$ is included in the DNB protection setpoints and allows radial power shape changes with rod insertion to the insertion limits (Reference 64), thus allowing greater flexibility in the nuclear design.

4.4.3.2.2 Axial Heat Flux Distributions

As discussed in Section 4.3.2.2, the axial heat flux distribution can vary as a result of rod motion, power change, or due to spatial xenon transients that may occur in the axial direction. Consequently, it is necessary to measure the axial power imbalance by means of the excore nuclear detectors (as discussed in Section 4.3.2.2.7) and protect the core from excessive axial power imbalance. The reactor trip system provides automatic reduction of the trip setpoint in the overtemperature ΔT channels on excessive axial power imbalance, i.e., when an extremely large axial offset corresponds to an axial shape that could lead to a DNBR, which is less than that calculated for the reference DNB design axial shape.

The reference DNB design axial shape is a chopped cosine with a peak-to-average ratio of 1.55.

4.4.3.3 Core Thermal Response

A general summary of the steady state thermal-hydraulic design parameters including thermal output, flowrates, etc., is provided in Table 4.1-1. As stated in Section 4.4.1, the design bases are to prevent DNB and to prevent fuel melting for Conditions I and II events. The protective systems described in Chapter 7 (Instrumentation and Controls) are designed to meet these bases. The response of the core to Condition II transients is given in Chapter 15.

4.4.3.4 Analytical Techniques

4.4.3.4.1 Core Analysis

The objective of reactor core thermal analysis is to determine the maximum heat removal capability in all flow subchannels, and to show that the core safety limits, as presented in the Technical Specifications, are not exceeded. The thermal design considers local variations in dimensions, power generation, flow redistribution, and mixing. THINC-IV is a realistic three-dimensional matrix model developed to account for hydraulic and nuclear effects on the enthalpy rise in the core (References 47 and 59). The behavior of the hot assembly is determined by superimposing the power distribution among the assemblies upon the inlet flow distribution, while allowing for flow mixing and distribution between assemblies. The average flow and enthalpy in the hottest assembly is obtained from the core-wide assembly-by-assembly analysis. The local variations in power, fuel rod and pellet fabrication, and mixing within the hottest assembly are then superimposed on the average conditions of the hottest assembly to determine conditions in the hot channel.

The following sections describe the use of the THINC code in the thermal-hydraulic design evaluation.

4.4.3.4.1.1 Steady State Analysis

The THINC-IV computer program determines coolant density, mass velocity, enthalpy, vapor void, static pressure, and DNBR distributions along parallel flow channels within a reactor core under all expected operating conditions. The core region being studied is made up of a number of contiguous elements in a rectangular array extending the full length of the core. An element may represent any region of the core from a single assembly to a subchannel.

The momentum and energy exchange between elements in the array are described by the conservation of energy and mass equations, the axial momentum equation, and two lateral momentum equations that couple each element with its neighbors. The momentum equations used in THINC-IV incorporate frictional loss terms that represent

the combined effects of frictional and form drag due to the presence of the grids and fuel assembly nozzles in the core. The cross flow resistance model used in the lateral momentum equations was developed from experimental data for flow normal to tube banks (Reference 54). The energy equation for each element also contains additional terms that represent the energy gain or loss due to the cross flow between elements.

The unique feature in THINC-IV is that lateral momentum equations, which include both inertial and cross flow resistance terms, are incorporated into the calculation scheme. Another important consideration in THINC-IV is that the entire velocity field is solved, en masse, by a field equation, while in other codes, such as THINC-I and COBRA (Reference 65), the solutions are obtained by stepwise integration throughout the array. The resulting formulation of the conservation equations is more rigorous for THINC-IV and the solution is, therefore, more accurate. The solution method is complex and some simplifying techniques must be employed. Because the reactor flow is chiefly in the axial direction, the core flow field is primarily one-dimensional, and it is reasonable to assume that the lateral velocities and the parameter gradients are larger in the axial direction than the lateral direction. Thus, a perturbation technique is used to represent separately the axial and lateral parameters in the conservation equations.

Three THINC-IV computer runs constitute one design run: a core-wide analysis, a hot-assembly analysis, and a hot subchannel analysis.

The first computation is a core-wide assembly-by-assembly analysis that uses an inlet velocity distribution modeled from experimental reactor models (References 52, 53, and 60) (see Section 4.4.3.1.2). The core is made up of a number of contiguous fuel assemblies divided axially into increments of equal length. The system of perturbed and unperturbed equations are solved for this array giving the flow, enthalpy, pressure drop, temperature, and void fraction in each assembly. This computation determines the interassembly energy and flow exchange at each elevation for the hot assembly. THINC-IV stores this information, then uses it for the subsequent hot assembly analysis in which each computational element represents one-fourth of the hot assembly. The inlet flow and the amount of momentum and energy interchange at each elevation are known from the previous core-wide calculation. The same solution technique is used to solve for the local parameters in the hot one-quarter assembly.

The third computation further divides the hot assembly into channels consisting of individual fuel rods to form flow channels. The local variations in power, fuel rod and pellet fabrication, fuel rod spacing and mixing (engineering hot channel factors) within the hottest assembly are imposed on the average conditions of the hottest fuel assembly to determine the conditions in the hot channel. Engineering hot channel factors are described in Section 4.4.2.3.4.

4.4.3.4.1.2 Experimental Verification

An experimental verification (Reference 59) of the THINC-IV analysis for core-wide assembly-by-assembly enthalpy rises, as well as enthalpy rises in a nonuniformly heated rod bundle, have been obtained. In these tests, system pressure, inlet temperature, mass flowrate, and heat fluxes were typical of present PWR core designs.

During reactor operation, various incore monitoring systems obtain measured data indicating core performance. Assembly power distributions and assembly mixed mean temperature are measured and can be converted into the proper three-dimensional power input needed for the THINC programs. These data can then be used to verify the Westinghouse thermal-hydraulic design codes.

One standard startup test is the natural circulation test in which the core is held at a very low power (2 percent) and the pumps are turned off. The core will then be cooled by the natural circulation currents created by the power differences in the core and the annulus. During natural circulation, a thermal siphoning effect occurs, resulting in the hotter assemblies gaining flow, thereby creating significant interassembly cross flow. Tests with significant cross flow are of more value in code verification.

Interassembly cross flow is caused by radial variations in pressure, that are caused in turn by variations in the axial pressure drops in different assemblies. Under normal operating conditions (subcooled forced convection), the axial pressure drop is due mainly to friction losses. Because all assemblies have the same geometry, all assemblies have nearly the same axial pressure drops, and cross flow velocities are small. However, under natural circulation conditions (low flow) the axial pressure drop is due primarily to the difference in elevation head (or coolant density) between assemblies. This phenomenon can result in relatively large radial pressure gradients and, therefore, in higher cross flow velocities than at normal reactor operating conditions.

Incore instrumentation was used to obtain the assembly-by-assembly core power distribution during a natural circulation test. Assembly exit temperatures during the natural circulation test on a 157-assembly three-loop plant were predicted using THINC-IV. The predicted data points were plotted as assembly temperature rise versus assembly power, and a least squares fitting program was used to generate an equation that best fits the data. The result is the straight line presented in Figure 4.4-11 and is predicted closely by THINC-IV. This agreement verifies the lateral momentum equations and the cross flow resistance model used in THINC-IV.

Data have been obtained for Westinghouse plants operating from 67 to 101 percent of full power. A representative cross section of the data obtained from a two-loop and a three-loop reactor was analyzed to verify the THINC-IV predictions that are compared with the experimental data in Figures 4.4-12 and 4.4-13.

The predicted assembly exit temperatures were compared with the measured exit temperatures for each data run. Measured and predicted assembly exit temperatures are compared for both THINC-IV and THINC-I, and are given in Table 4.4-3. THINC-IV generally fits the data somewhat more accurately than THINC-I. Both codes are conservative and predict exit temperatures higher than measured values for the high-powered assemblies. Experimental verification of the THINC-IV subchannel calculation has been obtained from exit temperature measurements in a nonuniformly heated rod bundle (Reference 66).

Figure 4.4-14 compares, for a typical run, the measured and predicted temperature rises as a function of the power density in the channel. The THINC-IV results correctly predict the temperature gradient across the bundle.

In Figure 4.4-15, the measured and predicted temperature rises are compared for a series of runs at different pressures, flows, and power levels. Again, the measured points represent the average of the measurements taken in the various quadrants. The THINC-IV predictions provide a good representation of the data.

Thus, the THINC-IV analysis provides a realistic evaluation of the core performance and is used in the thermal analyses as described above.

4.4.3.4.1.3 Transient Analysis

The THINC-III thermal-hydraulic computer code (Reference 41) is the third section of the THINC-I program that has transient DNB analysis capability.

The conservation equations needed for the transient analysis are included in THINC-III by adding the necessary accumulation terms to the conservation equations used in the steady state (THINC-I) analysis. The input description must now include one or more of the following time arrays:

(1) Inlet flow variation

(2) Heat flux distribution

(3) Inlet pressure history

At the beginning of the transient, the calculation procedure is carried out as in the steady state analysis. The THINC-III code is first run in the steady state mode to ensure conservatism with respect to THINC-IV and to provide the steady state initial conditions at the start of the transient. The time is incremented by an amount determined either by the user or by the program. At each new time step, the accumulation terms are evaluated using the information from the previous time step. This procedure is continued until a preset maximum time is reached.

At various times during the transient, steady state THINC-IV is applied to show that the application of THINC-III is conservative. The THINC-III code does not have the capability for evaluating fuel rod thermal response. This is treated by the methods described in Section 15.1.9.

4.4.3.4.2 Fuel Temperatures

As discussed in Section 4.4.2.2, fuel rod behavior is evaluated with a semiempirical thermal model that considers, in addition to the thermal aspects, such items as cladding creep, fuel swelling, fission gas release, release of absorbed gases, cladding corrosion and elastic deflection, and helium solubility.

A detailed description of the thermal model can be found in References 67 and 83 with the modification for the time-dependent densification given in Reference 68.

4.4.3.4.3 Hydrodynamic Instability

The analytical methods used to determine hydraulic instability are discussed in Section 4.4.3.5.

4.4.3.5 Hydrodynamic and Flow-Power Coupled Instability

Boiling flow may be susceptible to thermohydrodynamic instabilities (Reference 69). These instabilities may cause a change in thermohydraulic conditions that may lead to a reduction in the DNB heat flux relative to that observed during a steady flow condition, or to undesired forced vibrations of core components. Thus, the thermohydraulic design criterion states that operation under Conditions I and II modes shall not lead to thermohydrodynamic instabilities.

Two specific types of flow instabilities are considered by Westinghouse for PWR operation. These are the Ledinegg, or flow excursion, type of static instability and the density wave type of dynamic instability.

A Ledinegg instability involves a sudden change in flowrate from one steady state to another. This instability occurs (Reference 69) when the slope of the RCS pressure drop-flowrate curve becomes algebraically smaller than the slope of the loop supply (pump head) pressure drop-flowrate curve. The Westinghouse pump head curve has a negative slope whereas the RCS pressure drop-flow curve has a positive slope over the Conditions I and II operational ranges. Thus, Ledinegg instability will not occur.

The mechanism of density wave oscillations in a heated channel has been described by Lahey and Moody (Reference 70).

The method developed by Ishii (Reference 71) for parallel closed channel systems evaluates if a given condition is stable with respect to the density wave type of dynamic instability. This method had been used to assess the stability of typical Westinghouse

reactor designs (References 72, 73, 74) under operating Conditions I and II. The results indicate that a large margin to density wave instability exists (e.g., an increase in the order of 200 percent of rated reactor power would be required) for the inception of this type of instability.

Flow instabilities that have been observed have occurred almost exclusively in closed channel systems operating at low pressures relative to the Westinghouse PWR operating pressures. Kao, Morgan, and Parker (Reference 75) analyzed parallel closed channel stability experiments simulating a reactor core flow. These experiments were conducted at pressures up to 2200 psia. The results showed that for flow and power levels typical of power reactor conditions, no flow oscillations could be induced above 1200 psia. Additional evidence that flow instabilities do not adversely affect thermal margin is provided by data from rod bundle DNB tests.

In summary, it is concluded that thermohydrodynamic instabilities will not occur under Conditions I and II modes of operation for Westinghouse PWR reactor designs. A large power margin exists to predicted inception of such instabilities. Analysis has been performed and shows that minor plant-to-plant differences in Westinghouse reactor designs such as fuel assembly arrays, core power flow ratios, fuel assembly length, etc., will not result in gross deterioration of the above power margins.

4.4.3.6 Temperature Transient Effects Analysis

Waterlogging damage of a fuel rod could occur as a consequence of a power increase on a rod after water has entered the fuel rod through a cladding defect and will continue until the fuel rod internal pressure equals the reactor coolant pressure. A subsequent power increase raises the temperature and, hence, could raise the pressure of the water contained within the fuel rod. Zircaloy-clad fuel rods, which have failed due to waterlogging (References 76 and 77) indicate that very rapid power transients are required for fuel failure. Release of the internal fuel rod pressure is expected to have a minimal effect on the RCS (Reference 76) and is not expected to result in failure of additional fuel rods (Reference 77). Ejection of fuel pellet fragments into the coolant stream is not expected (References 76 and 77). A cladding breach due to waterlogging is thus expected to be similar to any fuel rod failure mechanism that exposes fuel pellets to the reactor coolant stream. Waterlogging has not been identified as the mechanism for cladding distortion or perforation of any Westinghouse Zircaloy-4-clad rods.

An excessively high fuel rod internal gas pressure could cause cladding failure. During operational transients, fuel rod cladding rupture due to high internal gas pressure is precluded by adopting a design basis that the fuel rod internal gas pressure remains below the value that causes the fuel-cladding diametral gap to increase due to outward cladding creep.

4.4.3.7 Potentially Damaging Temperature Effects During Transients

A fuel rod experiences many operational transients (intentional maneuvers) while in the core. Several thermal effects must be considered when designing and analyzing fuel rod performance.

The cladding can be in contact with the fuel pellet at some time in the fuel lifetime. Cladding-pellet interaction occurs if fuel pellet temperature is increased after the cladding is in contact with the pellet. Cladding-pellet interaction is discussed in Section 4.2.1.3.1.

Increasing fuel temperature results in an increased fuel rod internal pressure. One of the fuel rod design bases is that the fuel rod internal pressures remain below values that can cause the fuel-cladding diametral gap to increase due to outward cladding creep (Section 4.2.1.1.1).

The potential effects of operation with waterlogged fuel were discussed in Section 4.4.3.6, which concluded that waterlogging is not a concern during operational transients.

Clad flattening, as noted in Section 4.2.1.3.1, has been observed in some operating power reactors. Thermal expansion (axial) of the fuel rod stack against a flattened section of cladding could cause cladding failure. This is no longer a concern because clad flattening is precluded by prepressurization.

A differential thermal expansion between the fuel rods and the guide thimbles can occur during a transient. Excessive bowing of fuel rods can occur if the grid assemblies do not allow axial movement of the fuel rods relative to the grids. Thermal expansion of fuel rods is considered in the grid design so that axial loads imposed on the fuel rods during a thermal transient will not result in excessively bowed fuel rods (see Section 4.2.1.2.2).

4.4.3.8 Energy Release During Fuel Element Burnout

As discussed in Section 4.4.3.3, the core is protected from going through DNB over the full range of possible operating conditions. At full power operation, the typical minimum DNBR was calculated for VANTAGE 5 fuel for Unit 1 and for Unit 2 and is listed in Table 4.1-1. This means that, for these conditions, the probability of a rod going through DNB is less than 0.1 percent at 95 percent confidence level based on the statistics of the WRB-2 correlations (References 84 and 85). In the extremely unlikely event that DNB should occur, cladding temperature will rise due to steam blanketing the rod surface and the consequent degradation in heat transfer. During this time a potential for a chemical reaction between the cladding and the coolant exists. Because of the relatively good film boiling heat transfer following DNB, the energy release from this reaction is insignificant compared to the power produced by the fuel. These results

have been confirmed in DNB tests conducted by Westinghouse (References 66 and 78).

4.4.3.9 Energy Release During Rupture of Waterlogged Fuel Elements

A full discussion of waterlogging including energy release is contained in Section 4.4.3.6.

4.4.3.10 Fuel Rod Behavior Effects from Coolant Flow Blockage

Coolant flow blockage can occur within the coolant channels of a fuel assembly or external to the reactor core. The effect of coolant flow blockage within the fuel assembly on fuel rod behavior is more pronounced than external blockages of the same magnitude. In both cases, the flow blockages cause local reductions in coolant flow. The amount of local flow reduction, its location in the reactor, and how far downstream does the reduction persist, are considerations that influence fuel rod behavior. Coolant flow blockage effects in terms of maintaining rated core performance are determined both by analytical and experimental methods. The experimental data are usually used to augment analytical tools such as the THINC-IV program. Inspection of the DNB correlation (Section 4.4.2.3) shows that the predicted DNBR depends on local values of quality and mass velocity.

The THINC-IV code can predict the effects of local flow blockages on DNBR within the fuel assembly on a subchannel basis, regardless of where the flow blockage occurs. THINC-IV accurately predicts the flow distribution within the fuel assembly when the inlet nozzle is completely blocked (Reference 59). For the DCPP reactors operating at nominal full power conditions as specified in Table 4.1-1, the effects of an increase in enthalpy and decrease in mass velocity in the lower portion of the fuel assembly would not result in the reactor reaching the safety limit DNBR.

The analyses, which assume fully developed flow along the full channel length, show that a reduction in local mass velocity greater than approximately 53 percent would be required to reduce the DNBRs from the DNBRs at the nominal conditions shown in Table 4.4-1 to the safety limit DNBRs. In reality, a local flow blockage is expected to promote turbulence and thus would likely not effect DNBR.

Coolant flow blockages induce local cross flows as well as promoting turbulence. Fuel rod vibration could occur, caused by this cross flow component, through vortex shedding or turbulent mechanisms. If the cross flow velocity exceeds the limit established for fluid elastic stability, large amplitude whirling will result in, and can lead to, mechanical wear of the fuel rods at the grid support locations. The limits for a controlled vibration mechanism are established from studies of vortex shedding and turbulent pressure fluctuations. Fuel rod wear due to flow-induced vibration is considered in the fuel rod fretting evaluation (Section 4.2).

4.4.3.11 Pressurization Analyses for Shutdown Conditions

The objective of these analyses is to evaluate, for low-to-high decay heat shutdown conditions, the thermal hydraulic response, particularly the maximum RCS pressure limits, if no operator recovery actions were taken to limit or prevent boiling in the RCS (References 97 and 98). The results of these analyses are used to determine acceptable RCS vent path configurations used during outage conditions as a contingency to mitigate RCS pressurization upon a postulated loss of residual heat removal (RHR). Typical RCS vent path openings capable of use include the reactor vessel head flange, one or more pressurizer safety valves, steam generator primary hot leg manways, or combinations of these openings depending on the decay heat load.

4.4.4 TESTING AND VERIFICATION

4.4.4.1 Testing Prior to Initial Criticality

Reactor coolant flow tests, as noted in Tests 3.9 and 3.10 of Table 14.1-2, are performed following fuel loading, but prior to initial criticality. Coolant loop pressure drop data are obtained in this test. These data, in conjunction with coolant pump performance information, allow determination of the coolant flowrates at reactor operating conditions. This test verifies that proper coolant flowrates have been used in the core thermal and hydraulic analysis.

4.4.4.2 Initial Power Plant Operation

Core power distribution measurements are made at several core power levels (see Section 4.3.2.2.7) during startup and initial power operation. These tests are used to verify that conservative peaking factors were used in the core thermal and hydraulic design and analysis.

4.4.4.3 Component and Fuel Inspections

Inspections performed on the manufactured fuel are delineated in Section 4.2.1.4. Fabrication measurements critical to thermal and hydraulic analysis are obtained to verify that the engineering hot channel factors employed in the design analyses (Section 4.4.2.3.4) are met.

4.4.5 INSTRUMENTATION REQUIREMENTS

4.4.5.1 Incore Instrumentation

Instrumentation is located in the core so that by correlating movable neutron detector information with fixed thermocouple information the radial core characteristics may be obtained for all core quadrants.

The incore instrumentation system is composed of thermocouples, positioned to measure fuel assembly coolant outlet temperatures at preselected positions, and movable fission chamber detectors positioned in guide thimbles that run the length of selected fuel assemblies to measure the neutron flux distribution. Figures 4.4-16 and 4.4-17 show the number and location of instrumented assemblies in the core for Units 1 and 2, respectively. In the Unit 1 reactor, four of these thermocouples have been moved to the upper head for monitoring conditions in the upper head.

The core exit thermocouples provide a backup for the flux monitoring instrumentation to monitor power distribution. The routine, systematic collection of thermocouple readings provides a data base. From this data base, abnormally high or abnormally low readings, quadrant temperature tilts, or systematic departures from a prior reference map can be deduced.

The movable incore neutron detector system is used for more detailed mapping should the thermocouple system indicate an abnormality. These two complementary systems are more useful when taken together than taken alone. The incore instrumentation system is described in more detail in Section 7.7.2.9.

Incore instrumentation is provided to obtain data from which fission power density distribution in the core, coolant enthalpy distribution in the core, and fuel burnup distribution may be determined.

4.4.5.2 Overtemperature and Overpower ΔT Instrumentation

The overtemperature ΔT trip protects the core against low DNBR. The overpower ΔT trip protects against excessive power (fuel rod rating protection).

As discussed in Section 7.2.2.1.2, factors included in establishing the overtemperature ΔT and overpower ΔT trip setpoints include the reactor coolant temperature in each loop. The axial distribution of core power, as determined by the two-section (upper and lower) excore neutron detectors, is also a factor in establishing the overtemperature ΔT trip.

4.4.5.3 Instrumentation to Limit Maximum Power Output

The output of the three ranges (source, intermediate, and power) of detectors, with the associated nuclear instrumentation electronics, is used to limit the maximum power output of the reactor.

Eight instrument wells are located around the reactor periphery in the primary shield, 45° apart from each other, at an equal distance from the reactor vessel.

Two of the positions, on opposite flat portions of the core, directly across from the primary startup neutron source positions, each contain a BF_3 proportional counter to cover the source range, and a compensated ionization chamber for the intermediate

range. The source range detector is located at an elevation of approximately one-fourth of the core height; the compensated ionization chambers are positioned at an elevation corresponding to one-half of the core height. The two positions opposite the other two flat portions of the core house the post-accident neutron flux monitor detectors.

Four dual-section uncompensated ionization chamber assemblies are installed vertically in the instrumentation wells directly across from the four corners of the core. They are used as power range detectors. To minimize neutron flux pattern distortions, they are placed within 1 foot of the reactor vessel. Each dual-section uncompensated ionization chamber assembly provides two signals that correspond to the neutron flux in the upper and in the lower positions of a core quadrant, thus permitting the determination of relative axial power production.

Signals from the detectors in the three ranges (source, intermediate, and power) provide inputs which, when combined, monitor neutron flux from a completely shutdown condition to 120 percent of full power, with the capability of recording overpower excursions up to 200 percent of full power.

The difference in neutron flux readings between the upper and lower sections of the power range detectors is used to limit the overtemperature ΔT and overpower ΔT trip setpoints and to provide the operator with an indication of the core power axial offset. In addition, the output of the power range channels are used as follows:

(1) For the rod speed control function

(2) To alert the operator to an excessive power unbalance between the quadrants

(3) To protect the core against rod ejection accidents

(4) To protect the core against adverse power distributions resulting from dropped rods

Details of the neutron detectors and nuclear instrumentation design and the control and trip logic are given in Chapter 7. The limits on neutron flux operation and trip setpoints are given in the Technical Specifications.

4.4.5.4 Loose Parts Monitoring

A Westinghouse loose parts and vibration monitoring system is provided for early detection of possible loose parts in the RCS and to reduce their probability of causing damage to RCS components.

Accelerometers (piezoelectric crystals) are located in areas where loose parts are most likely to become entrapped. Redundant accelerometers are installed on the top and the bottom of the reactor vessel and on the lower head of each of the four steam

generators. Signals from the accelerometers are transmitted by high-temperature leads to preamplifiers located in the containment. From the preamplifiers, the signals are sent to the data acquisition and control panel located in the control room. All components are designed to remain operational over the life of the plant in the temperature, humidity, and radiation environment in which they are installed.

When the output of an individual transducer channel exceeds an adjustable setpoint:

(1) The condition activates a local alarm at the control cabinet.

(2) The output of the alarmed channel is evaluated for validity and logged before being transmitted to the main control board annunciator.

The output of the transducers can be audiomonitored by the operator at the control panel. The alarm monitoring of the selected channel continues during audiomonitoring.

In the event that the output of a loose part channel exceeds the alarm value, the record of the event will be available to the operator and plant staff for analysis. The event will be compared with other previously recorded signatures of the RCS. If necessary, consultants will be contacted to further evaluate the event. This analysis, together with other plant instrumentation, will form the basis for judgment of the effects and significance of the loose parts event.

The sensitivity of the loose parts channels is such that a loose part striking the reactor vessel or steam generators with as little as one-half-foot-pound of energy produces signals of sufficient strength to be detected over the normal background signals.

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TABLE 4.1-1

REACTOR DESIGN COMPARISON

Thermal and Hydraulic Design Parameters (Using ITDP)[a]	Unit 1	Unit 2
Reactor Core Heat Output, MWt	3,411	3,411
Reactor Core Heat Output, 10^6 Btu/hr	11,641.7	11,641.7
Heat Generated in Fuel, %	97.4	97.4
Core Pressure, Nominal, psia[b]	2,280	2,280
Core Pressure, Min Steady State[b] psia	2,250	2,250
Fuel Type	Vantage 5	Vantage 5
Minimum DNBR at nominal Conditions[c]		
Typical Flow Channel	2.63[n]	2.63
Thimble (Cold Wall) Flow Channel	2.47[n]	2.47
Limit DNBR for Design Transients		
Typical Flow Channel	1.71	1.71
Thimble (Cold Wall) Flow Channel	1.68	1.68
DNB Correlation	WRB-2	WRB-2

HFP Nominal Coolant Conditions[d]		Unit 1	Unit 2
Vessel Minimum Measured Flow[e] Rate (including Bypass)			
10^6 lbm/hr		135.4	136.6
gpm		359,200	362,500
Vessel Thermal Design Flow[e] Rate (including Bypass)			
10^6 lbm/hr		132.2	133.4
gpm		350,800	354,000
Core Flow Rate (excluding Bypass, based on TDF)			
10^6 lbm/hr		122.3	123.4
gpm		324,490	327,450
Effective Flow Area[f] for Heat Transfer, ft^2		54.13	54.13
Average Velocity along Fuel[f,k] Rods, ft/sec (Based on TDF)		14.0	14.2
Core Inlet Mass Velocity,[f] 10^6 lbm/hr-ft (Based on TDF)	(V-5)	2.26	2.28

Thermal and Hydraulic Design Parameters (Based on Thermal Design Flow)	Unit 1	Unit 2
Nominal Vessel/Core Inlet Temperature, °F	544.5[(g)]	545.1[(g)]
Vessel Average Temperature, °F	577.3	577.6
Core Average Temperature, °F	581.5	582.3
Vessel Outlet Temperature, °F	610.1	610.1
Average Temperature Rise in Vessel, °F	65.6	65.0
Average Temperature Rise in Core, °F	70.4	70.7
Heat Transfer		
Active Heat Transfer Surface Area,[(f)] ft^2	57,505	57,505
Average Heat Flux, Btu/hr-ft^2	197,180	197,180
Maximum Heat Flux for Normal[(h)] Operation, Btu/hr-ft^2	508,720	508,720
Average Linear Power, kW/ft	5.445	5.445
Peak Linear Power for Normal Operation,[(h)] kW/ft	14.3	14.3
Peak Linear Power for Prevention of Centerline Melt, kW/ft	22.0[(i)]	22.0[(i)]
Pressure Drop[(j)]		
Across Core, psi *	25.5 + 2.6	27.2 + 2.7
Across Vessel,[(n)] including nozzle, psi *	52.8 + 5.3	48.2 + 4.8
Thermal and Hydraulic Design Parameters		
Heat Flux Hot Channel Factor, F_Q^T	2.58	2.58
Temperature at Peak Linear Power for Prevention of Centerline Melt, °F	4,700	4,700
Fuel Central Temperature, °F		
Peak at 100% power	<3,230[m]	<3,230
Peak at maximum thermal output for maximum overpower DT trip point	<4,080[1]	<4,080

* Pressure drop values for mechanical design flow and low inlet temperatures of 531.7°F and 531.9°F for Units 1 and 2.

Core Mechanical Design Parameters	Unit 1	Unit 2
Fuel Assemblies		
Design	RCC Canless	RCC Canless
Number of fuel assemblies	193	193
Rod array	17 X 17	17 X 17
$U0_2$ rods per assembly	264	264
Rod pitch, in	0.496	0.496
Overall dimensions, in	8.426 x 8.426	8.426 x 8.426
Fuel weight (as $U0_2$) lb	222,645/204,200*	222,645/204,200*
Zirconium alloy weight, lb	46,993/52,300	46,993/52,300
Number of grids per assembly	8-12 2 non-mixing vane type 6 mixing vane type 3 IFM; 1 P-Grid	8-12 2 non-mixing vane type 6 mixing vane type 3 IFM; 1 P-Grid
Composition of grids	INC718/ Zircaloy-4 or ZIRLO	INC718/ Zircaloy-4 or ZIRLO
Weight of grids, lb	1841/2820	1841/2820
Number of guide thimbles per assembly	24	24
Composition of guide thimbles	Zircaloy-4 or ZIRLO	Zircaloy-4 or ZIRLO
Diameter of guide thimbles (ID x OD), in.		
Upper part	0.450 x 0.482/ 0.442 x 0.474	0.450 x 0.482/ 0.442 x 0.474
Lower part	0.397 x 0.430	0.397 x 0.430
Diameter of instrument guide thimbles, in.	0.450 x 0.482/ 0.442 x 0.474	0.450 x 0.482/ 0.442 x 0.474

* Values following a diagonal are applicable to the VANTAGE 5 fuel assembly, including those with a P-Grid

Core Mechanical Design Parameters (Cont'd)	Unit 1	Unit 2
Fuel Rods		
Number	50,952	50,952
Outside diameter, in	0.374/0.360*	0.374/0.360*
Diametral gap, in	0.0065/0.0062	0.0065/0.0062
Cladding thickness, in	0.0225	0.0225
Cladding material	Zircaloy-4 or ZIRLO	Zircaloy-4 or ZIRLO
Gap material	Helium	Helium
Fuel Pellets		
Material	UO_2 sintered	UO_2 sintered
Density, % of theoretical	95	95
Diameter, in	0.3225/0.3088	0.3225/0.3088
Length, in	0.530/0.507	0.530/0.507
Mass of UO_2, lb/ft of fuel rod	0.364/0.334	0.364/0.334
Rod Cluster Control Assemblies		
Neutron absorber,	Ag-In-Cd	Ag-In-Cd
Composition	80%, 15%, 5%	80%, 15%, 5%
Diameter, in	0.341	0.341**
Nominal length of absorber material, in.	142	142
Density, lb/in^3	0.367	0.367
Cladding material	Type 304 SS-cold worked	Type 304** SS-cold worked
Cladding thickness, in	0.0185	0.0185
Number of RCCAs	53	53
Number of absorber rods per cluster	24	24
Core Structure		
Core barrel, ID/OD, in	148.0/152.5*	148.0/152.5*
Thermal shield, ID/OD, in	158.5/164.0	Neutron pad Design

* Values following a diagonal are applicable to the VANTAGE 5 assembly

** Diameter reduced to 0.336 over bottom 12 inches and ion-nitrided cold-worked Type 316L-SS cladding material applicable to Framatome RCCA only. Diameter reduced to 0.336 over bottom 12 inches and chrome plated cladding material applicable to Westinghouse EP-RCCA only.

Nuclear Design Parameters	Unit 1	Unit 2
Structure Characteristics		
Core diameter, in (equivalent)	132.7	132.7
Core average active fuel height, in.	144	144
Reflector Thickness and Composition		
Top - water plus steel, in.	10	10
Bottom - water plus steel, in.	10	10
Side - water plus steel, in	15	15
$H_2 0$/U, cold molecular ratio lattice	2.41/2.74*	2.41/2.74*
Fuel Enrichment, wt% (Cycle 1)(1)		
Region 1	2.10	2.10
Region 2	2.60	2.60
Region 3	3.10	3.10
Burnable Poison Rods (First Core)		
Number	1518	1518
Material	Borosilicate glass	Borosilicate glass
Outside diameter, in.	0.381	0.381
Inner tube, OD, in.	0.1815	0.1815
Cladding material	Stainless steel	Stainless steel
Inner tube material	Stainless steel	Stainless steel
Boron loading (w/o B_2O_3 in glass rod)	12.5	12.5
Weight of Boron-10 per ft of rod, lb/ft	0.00419	0.00419
Initial reactivity worth, %$\Delta\rho$ hot (cold)	7.63 (~5.5)	7.63 (~5.5)
Excess Reactivity (First Core)		
Maximum fuel assembly, %$\Delta\rho$ (cold, clean, unborated water)	1.39	1.39
Maximum core, %$\Delta\rho$ (cold, zero power, beginning of cycle)	1.221	1.221
Fuel Enrichment, Wt%		
Maximum feed enrichment	5.0	5.0
Burnable Absorbers (VANTAGE 5 reloads)		
Type	IFBA	IFBA
Number (typical range)	2000 - 15000	2000 - 15000
Material	ZrB_2	ZrB_2
B10 Loading, mg/inch (typical)	2.25	2.25

* These values are applicable to the VANTAGE 5 fuel assembly

(a) Includes the effect of fuel densification

(b) Values used for thermal hydraulic core analysis

(c) Based on T_{in} = 545.1°F (Unit 1) and T_{in} = 545.7°F (Unit 2) corresponding to Minimum Measured Flow of each unit

(d) Based on Safety Analysis T_{in} = 548.4°F and Pressure = 2280 psia

(e) Includes 15 percent steam generator tube plugging

(f) Assumes all LOPAR or VANTAGE 5 core

(g) Safety Analysis T_{in} = 548.4°F for both units

(h) This limit is associated with the value of F_Q^T = 2.58

(i) See Section 4.3.2.2.6

(j) Based on best estimate reactor flow rate, Section 5.1

(k) At core average temperature

(l) Enrichments for subsequent regions can be found in the Nuclear Design Report issued each cycle

(m) Assuming mechanical design flow

(n) Values need review by Westinghouse

TABLE 4.1-2

ANALYTICAL TECHNIQUES IN CORE DESIGN

Analysis	Technique	Computer Code	Section Referenced
Mechanical Design of Core Internals			
Loads, deflections, and stress analysis	Static and dynamic modeling	Blowdown code, FORCE finite element structural analysis code, and others	3.7.2.1 3.9.1 3.9.3
Fuel Rod Design			
Fuel performance characteristics (temperature, internal pressure, cladding stress, etc.)	Semiempirical thermal model of fuel rod with consideration of fuel density changes, heat transfer, fission gas release, etc.	Westinghouse fuel rod design model	4.2.1.3.1 4.3.3.1 4.3.3.2 4.4.3.4.2

TABLE 4.1-2

Analysis	Technique	Computer Code	Section Referenced
Nuclear Design			
(1) Cross sections and group constants	Microscopic data	Modified/ENDF/B library	4.3.3.2
	Macroscopic constants for homogenized core regions	LEOPARD /CINDER type and PHOENIX	4.3.3.2
	Group constants for control rods with self-shielding	HAMMER-AIM	4.3.3.2
(2) X-Y power distributions, fuel depletion, critical boron concentrations, X-Y xenon distributions, reactivity coefficients and control rod worths	2-D, 2-group diffusion theory	TURTLE and ANC	4.3.3.3
(3) X-Y-Z power distributions, fuel depletion, critical boron concentrations, X-Y-Z xenon distributions, reactivity coefficients and control rod worth	3-D, 2-group diffusion theory	3D PALADON and ANC	4.3.3.3
(4) Axial power distributions and axial xenon distribution	1-D, 2-group diffusion theory	PANDA	4.3.3.3
(5) Fuel rod power	Integral transport theory	LASER	4.3.3.1
(6) Effective resonance temperature	Monte Carlo weighting function	REPAD	

TABLE 4.1-2

Analysis	Technique	Computer Code	Section Referenced
Thermal-Hydraulic Design			
(1) Steady state	Subchannel analysis of local fluid conditions in rod bundles, including inertial and crossflow resistance terms, solution progresses from core-wide to hot assembly to hot channel	THINC-IV	4.4.3.4.1
(2) Transient DNB analysis	Subchannel analysis of local fluid conditions in rod bundles during transients by including accumulation terms in conservation equations; solution progresses from core-wide to hot assembly to hot channel	THINC-I (THINC-III)	4.4.3.4.1

TABLE 4.1-3

DESIGN LOADING CONDITIONS FOR REACTOR CORE COMPONENTS

(1) Fuel assembly weight

(2) Fuel assembly spring forces

(3) Internals weight

(4) Control rod scram (equivalent static load)

(5) Differential pressure

(6) Spring preloads

(7) Coolant flow forces (static)

(8) Temperature gradients

(9) Differences in thermal expansions

    (a) Due to temperature differences

    (b) Due to expansion of different materials

(10) Interference between components

(11) Vibration (mechanically or hydraulically induced)

(12) One or more loops out of service

(13) All operational transients listed in Table 5.2-4

(14) Pump overspeed

(15) Seismic loads (DE and DDE)

(16) Blowdown forces (due to RCS branch line breaks)[a]

(a) In the original analysis, the blowdown forces used were those resulting from breaks in the RCS cold and hot legs. However, with the acceptance of the DCPP leak-before-break analysis by the NRC, the blowdown forces resulting from pipe rupture events in the main reactor coolant loop piping no longer have to be considered in the design basis structural analyses and included in the loading combinations. Only the much smaller forces from RCS branch line breaks have to be considered (see Section 3.6.2.1.1.1).

TABLE 4.2-1

MAXIMUM DEFLECTIONS ALLOWED FOR
REACTOR INTERNAL SUPPORT STRUCTURES

Component	Allowable Deflections, in.	No-loss-of-function Deflections, in.
Upper Barrel		
Radial inward	4.1	8.2
Radial outward	0.5	1.0
Upper Package	0.10	0.15
Rod Cluster Guide Tubes	1.00	1.75

TABLE 4.3-1

NUCLEAR DESIGN PARAMETERS
(Typical)

Core Average Linear Power, kW/ft, including densification effects	5.445[(a)]
Total Heat Flux Hot Channel Factor, F_Q^T	2.58
Nuclear Enthalpy Rise Hot Channel Factor,	
$F_{\Delta H}^N$	1.65 VANTAGE 5
	1.62 LOPAR
Reactivity Coefficients	
Doppler coefficient	See Figures 4.3-28 and 4.3-29
Moderator temperature coefficient at operating conditions, pcm/°F[(b)]	0 to -40
Boron coefficient in primary coolant, pcm/ppm	-16 to -8
Delayed Neutron Fraction and Lifetime	
β_{eff} BOL, (EOL)	0.0069, (0.0051)
ℓ^*, BOL, (EOL), μsec	19.2 (18.6)
Control Rod Worths	
Rod requirements	See Table 4.3-2
Maximum bank worth, pcm	< 2000
Maximum ejected rod worth	See Chapter 15

Boron Concentrations (ppm)	
Refueling	≥ 2000
k_{eff} = 0.95, cold, rod cluster control assemblies in	≥ 2000
Full power, no xenon, k_{eff} = 1.0, hot, rod cluster control assemblies out	1876[(d)]
Full power, equilibrium xenon, k_{eff} = 1.0, hot, rod cluster control assemblies out	1536[(d)]
Reduction with fuel burnup Typical reload cycle, ppm/GWD/MTU[(c)]	See Figure 4.3-3

(a) Data in table based on Units 1 and 2

(b) 1 pcm = percent mille
= $10^{-5}\,\Delta\rho$ where $\Delta\rho$ is calculated from two state point values of k_{eff} by 1n (k_2/k_1)

(c) Gigawatt day (GWD) = 1000 megawatt days (1000 MWD)

(d) These values are representative values used for analytical purposes only.

TABLE 4.3-2

UNIT 1 - REACTIVITY REQUIREMENTS FOR ROD CLUSTER CONTROL ASSEMBLIES

Reactivity Effects, %$\Delta\rho$	Beginning of Life (First Cycle)	End of Life (First Cycle)	End of Life (Equilibrium Cycle) (Typical)
1. Control Requirements			
Fuel temperature (Doppler)	1.39[a]	1.12[a]	1.00
Moderator temperature(includes void)	0.16	0.89	0.80
Redistribution	0.50	0.85	0.90
Rod insertion allowance	0.50	0.50	0.50
2. Total Control	2.55	3.36	3.20
3. Estimated Rod Cluster Control Assembly Worth (53 Rods) All but one (highest worth) assemblies inserted	7.18	7.05	6.50
4. Estimated Rod Cluster Control Assembly-Credit with 10% adjustment to accommodate uncertainties	6.46	6.34	5.85
5. Shutdown Margin Available (Section 4.2)	3.91	2.98	2.65[b]

(a) Includes 0.1 percent $\Delta\rho$ uncertainty

(b) The design basis minimum shutdown is 1.6% $\Delta\rho$

TABLE 4.3-3

UNIT 2 - REACTIVITY REQUIREMENTS FOR ROD CLUSTER CONTROL ASSEMBLIES

Reactivity Effects, $\%\Delta\rho$	Beginning of Life (First Cycle)	End of Life (First Cycle)	End of Life (Equilibrium Cycle) (Typical)
1. Control Requirements			
Fuel temperature (Doppler)	1.39[a]	1.12[a]	1.00
Moderator temperature (includes void)	0.29	0.96	0.94
Redistribution	0.50	0.85	0.90
Rod insertion allowance	0.50	0.50	0.50
2. Total Control	2.68	3.43	3.34
3. Estimated Rod Cluster Control Assembly Worth (53 Rods) All but one (highest worth) assemblies inserted	6.48	6.38	5.70
4. Estimated Rod Cluster Control Assembly (Credit with 10% adjustment to accommodate uncertainties	5.83	5.74	5.13
5. Shutdown Margin Available (Section 4.2)	3.15	2.31	1.79[b]

(a) Includes 0.1% $\Delta\rho$ uncertainty

(b) The design basis minimum shutdown is 1.6% $\Delta\rho$

TABLE 4.3-4

AXIAL STABILITY INDEX
PWR CORE WITH A 12-FT HEIGHT

Burnup (MWD/T)	F_Z	C_B (ppm)	Stability Index, hr^{-1} Exp.	Calc.
1550	1.34	1065	-0.041	-0.032
7700	1.27	700	-0.014	-0.006
		Difference:	+0.027	+0.026

TABLE 4.3-5

TYPICAL NEUTRON FLUX LEVELS (n/cm^2-sec) AT FULL POWER

	$E > 1$ MeV	5.53 keV $\leq E \leq$ 1 MeV	0.625 eV $\leq E <$ 5.53 keV	$E <$ 0.625 eV $(nv)_0$
Core center	6.51×10^{13}	1.12×10^{14}	8.50×10^{13}	3.00×10^{13}
Core outer radius at midheight	3.23×10^{13}	5.74×10^{13}	4.63×10^{13}	8.60×10^{12}
Core top, on axis	1.53×10^{13}	2.42×10^{13}	2.10×10^{13}	1.63×10^{13}
Core bottom, on axis	2.36×10^{13}	3.94×10^{13}	3.50×10^{13}	1.46×10^{13}
Pressure vessel inner wall, azimuthal peak, core midheight	2.77×10^{10}	5.75×10^{10}	6.03×10^{10}	8.38×10^{10}

TABLE 4.3-6

COMPARISON OF MEASURED AND CALCULATED DOPPLER DEFECTS

Plant	Fuel Type	Core Burnup (MWD/MTU)	Measured (pcm)[a]	Calculated (pcm)
1	Air filled	1800	1700	1710
2	Air filled	7700	1300	1440
3	Air and helium filled	8460	1200	1210

(a) pcm = $10^{-5}\,\Delta\rho$. See footnote in Table 4.3-1

TABLE 4.3-7

BENCHMARK CRITICAL EXPERIMENTS

Description of Experiments	No. of Experiments	LEOPARD k_{eff} Using Experimental Bucklings
UO_2		
Al clad	14	1.0012
SS clad	19	0.9963
Borated H_2O	7	0.9989
Total	40	0.9985
U-metal		
Al clad	41	0.9995
Unclad	20	0.9990
Total	61	0.9993
Grand Total	101	0.9990

TABLE 4.3-8

SAXTON CORE II ISOTOPICS
ROD MY, AXIAL ZONE 6

Atom Ratio	Measured	2σ Precision, %	LEOPARD Calculation
U-234/U	4.65×10^{-5}	$\pm$ 29	4.60×10^{-5}
U-235/U	5.74×10^{-3}	$\pm$ 0.9	5.73×10^{-3}
U-236/U	3.55×10^{-4}	$\pm$ 5.6	3.74×10^{-4}
U-238/U	0.99386	$\pm$ 0.01	0.99385
Pu-238/Pu	1.32×10^{-3}	$\pm$ 2.3	1.222×10^{-3}
Pu-239/Pu	0.73971	$\pm$ 0.03	0.74497
Pu-240/Pu	0.19302	$\pm$ 0.2	0.19102
Pu-241/Pu	6.014×10^{-2}	$\pm$ 0.3	5.74×10^{-2}
Pu-242/Pu	5.81×10^{-3}	$\pm$ 0.9	5.38×10^{-3}
Pu/U[(a)]	5.938×10^{-2}	$\pm$ 0.7	5.970×10^{-2}
Np-237/U-238	1.14×10^{-4}	$\pm$ 15	0.86×10^{-4}
Am-241/Pu-239	1.23×10^{-2}	$\pm$ 15	1.08×10^{-2}
Cm-242/Pu-239	1.05×10^{-4}	$\pm$ 10	1.11×10^{-4}
Cm-244/Pu-239	1.09×10^{-4}	$\pm$ 20	0.98×10^{-4}

(a) Weight ratio

TABLE 4.3-9

CRITICAL BORON CONCENTRATIONS, AT HZP, BOL

Plant Type	Measured	Calculated
2-loop, 121 assemblies, 10-foot core	1583	1589
2-loop, 121 assemblies, 12-foot core	1625	1624
2-loop, 121 assemblies, 12-foot core	1517	1517
3-loop, 157 assemblies, 12-foot core	1169	1161
3-loop, 157 assemblies, 12-foot core	1344	1319
4-loop, 193 assemblies, 12-foot core	1370	1355
4-loop, 193 assemblies, 12-foot core	1321	1306

TABLE 4.3-10

COMPARISON OF MEASURED AND CALCULATED ROD WORTH

2-Loop Plant, 121 Assemblies, 10-foot core	Measured, pcm	Calculated, pcm
Group B	1885	1893
Group A	1530	1649
Shutdown group	3050	2917
ESADA Critical, 0.69-in pitch, 2 wt.% PuO_2, 8% Pu^{240}, 9 Control Rods		
6.21-in rod separation	2250	2250
2.07-in rod separation	4220	4160
1.38-in rod separation	4100	4010

TABLE 4.3-11

COMPARISON OF MEASURED AND CALCULATED MODERATOR TEMPERATURE COEFFICIENTS AT HZP, BOL

Plant Type/Control Bank Configuration	Measured α_{iso}[(a)] pcm/°F	Calculated α_{iso} pcm/°F
3-Loop, 157 Assemblies, 12-foot core		
D at 160 steps	-0.50	-0.50
D in, C at 190 steps	-3.01	-2.75
D in, C at 28 steps	-7.67	-7.02
B, C, and D in	-5.16	-4.45
2-Loop, 121 Assemblies, 12-foot core		
D at 180 steps	+0.85	+1.02
D in, C at 180 steps	-2.40	-1.90
C and D in, B at 165 steps	-4.40	-5.58
B, C, and D in, A at 174 steps	-8.70	-8.12

(a) Isothermal coefficients, which include the Doppler effect in the fuel

$\alpha_{iso} = 10^5 \ln(\frac{k_2}{k_1})/\Delta T(°F)$

TABLE 4.4-1

UNIT 1
VOID FRACTIONS AT NOMINAL REACTOR CONDITIONS WITH
DESIGN HOT CHANNEL FACTORS

		Average	Maximum
Core	(LOPAR)	0.14%	--
	(V-5)	0.17%	--
Hot subchannel	(LOPAR)	0.75%	1.80%
	(V-5)	0.89%	2.11%

TABLE 4.4-2

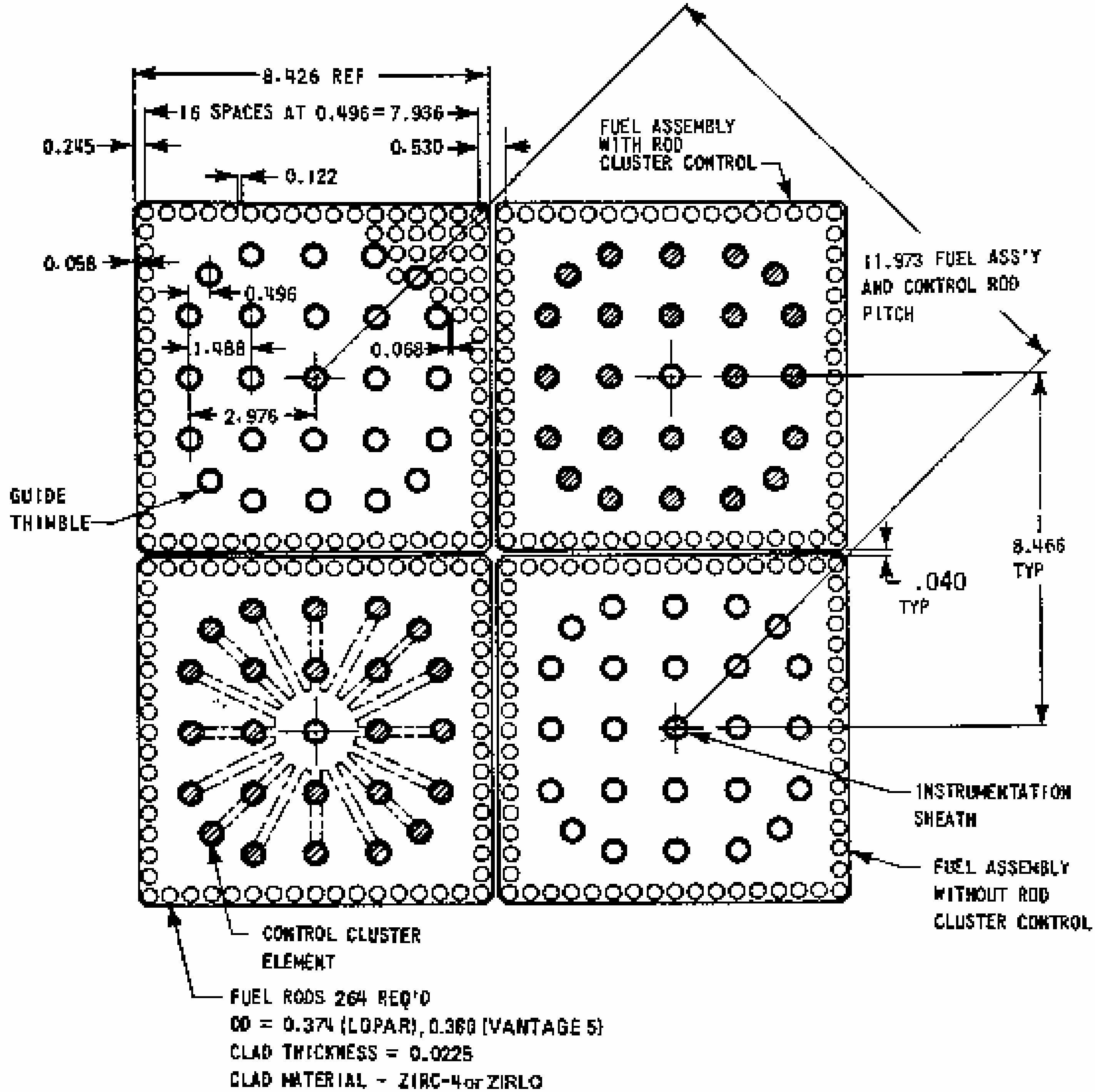
UNIT 2
VOID FRACTIONS AT NOMINAL REACTOR CONDITIONS WITH
DESIGN HOT CHANNEL FACTORS

		Average	Maximum
Core	(LOPAR)	0.16%	--
	(V-5)	0.19%	--
Hot subchannel	(LOPAR)	0.83%	1.99%
	(V-5)	3.92%	14.51%

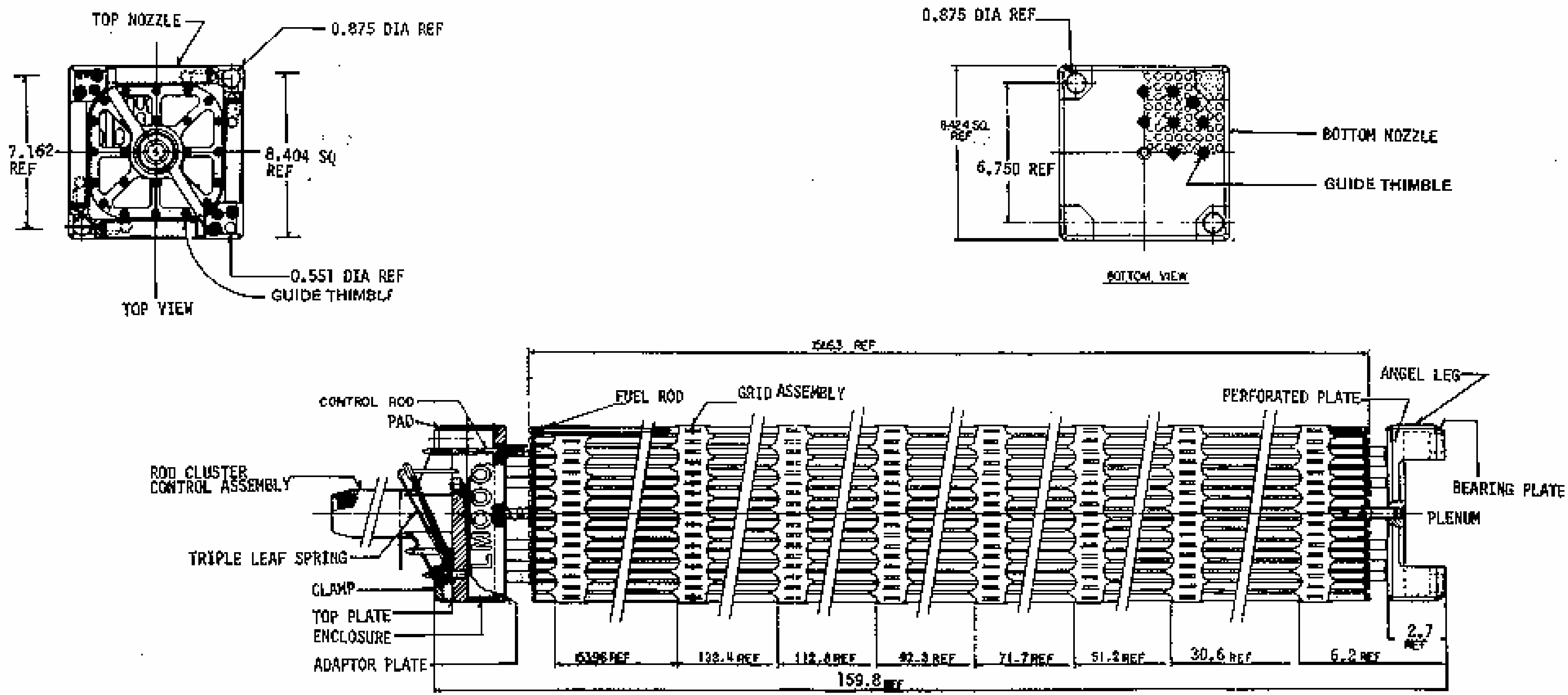
TABLE 4.4-3

COMPARISON OF THINC-IV AND THINC-I PREDICTIONS WITH DATA
FROM REPRESENTATIVE WESTINGHOUSE TWO- AND THREE-LOOP REACTORS

Reactor	Power, MWt	% Full Power	Measured Inlet Temp, °F	σ_{rms}, °F THINC-I	σ, °F THINC-IV	Improvement, °F for THINC-IV over THINC-1
Ginna	847	65.1	543.7	1.97	1.83	0.14
	854	65.7	544.9	1.56	1.46	0.10
	857	65.9	543.9	1.97	1.82	0.15
	947	72.9	543.8	1.92	1.74	0.18
	961	74.0	543.7	1.97	1.79	0.18
	1091	83.9	542.5	1.73	1.54	0.19
	1268	97.5	542.0	2.35	2.11	0.24
	1284	98.8	240.2	2.69	2.47	0.22
	1284	98.9	541.0	2.42	2.17	0.25
	1287	99.0	544.4	2.26	1.97	0.29
	1294	99.5	540.8	2.20	1.91	0.29
	1295	99.6	542.0	2.10	1.83	0.27
Robinson	1427.0	65.1	548.0	1.85	1.88	0.03
	1422.6	64.9	549.4	1.39	1.39	0.00
	1929.0	88.0	550.0	2.35	2.34	0.01
	2207.3	100.7	534.0	2.41	2.41	0.00
	2213.9	101.0	533.8	2.52	2.44	0.08



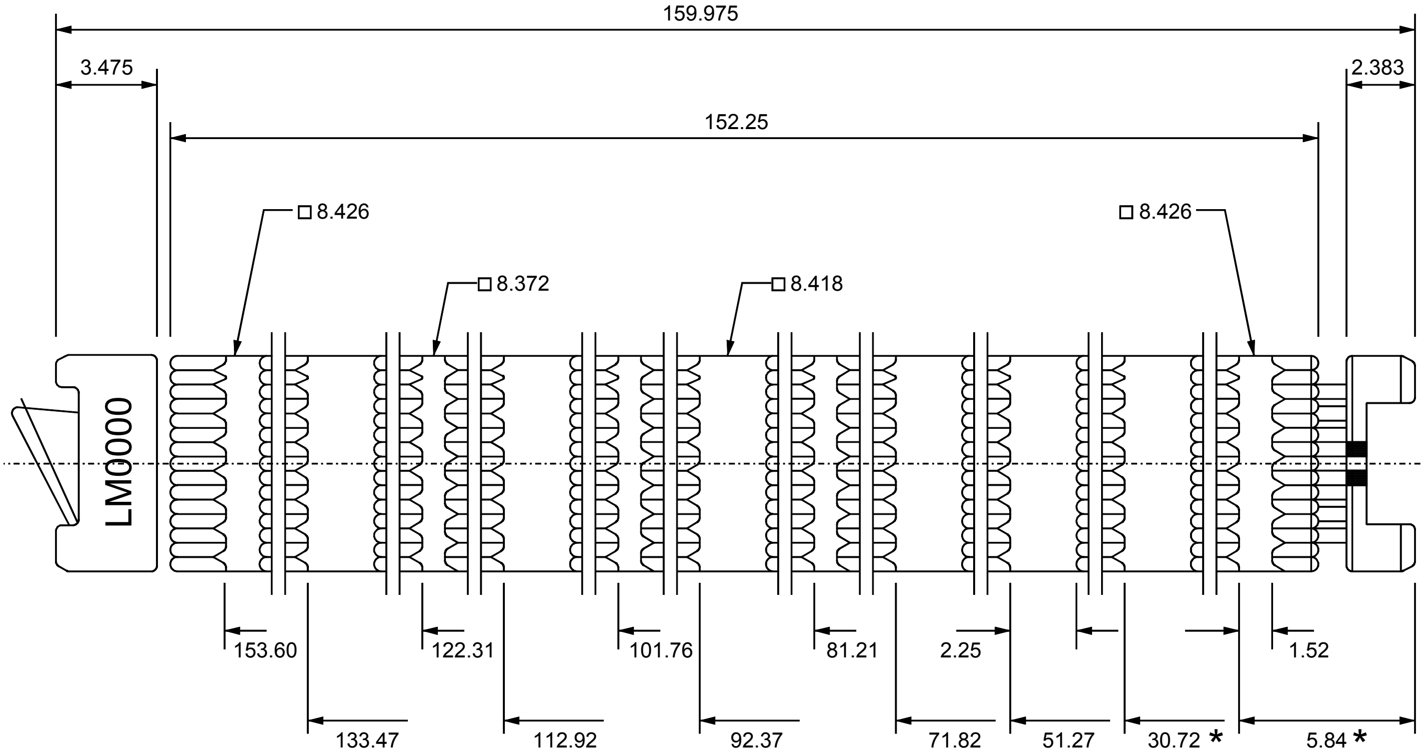
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.2-1 FUEL ASSEMBLY CROSS SECTION



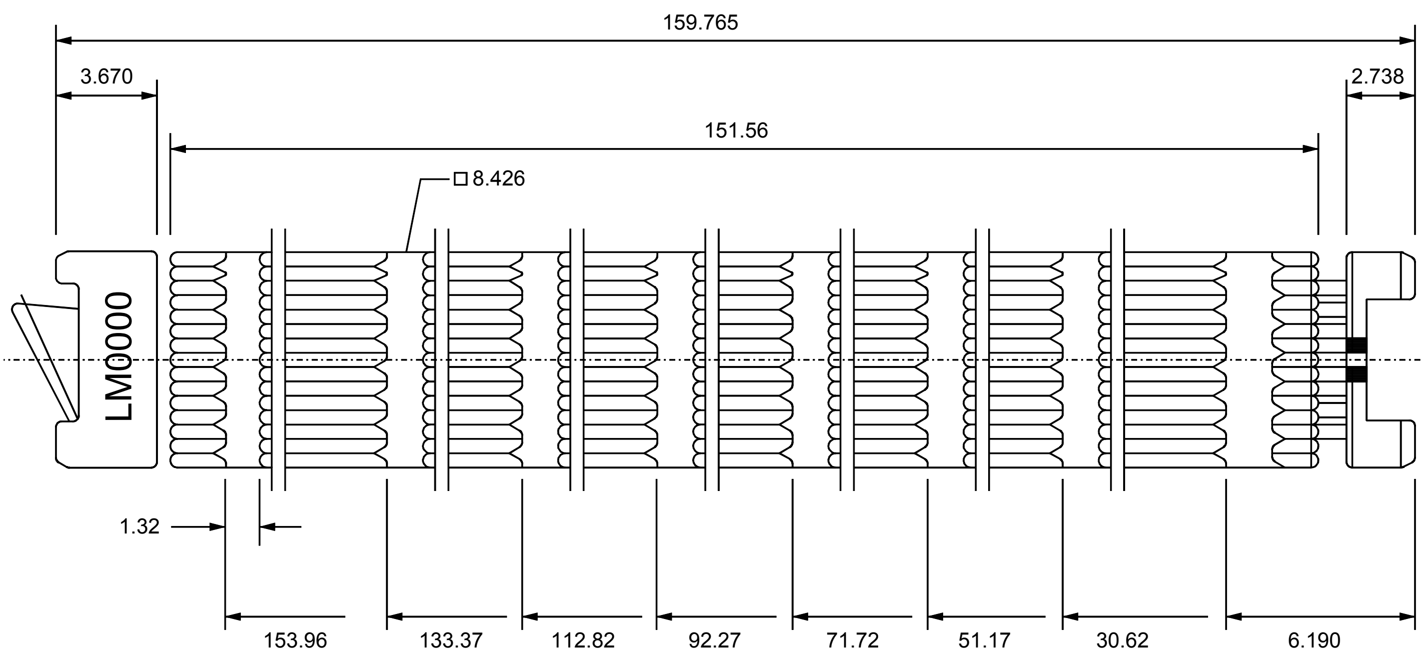
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.2-2
FUEL ASSEMBLY OUTLINE
(LOPAR)



17 x 17 VANTAGE 5 FUEL ASSEMBLY



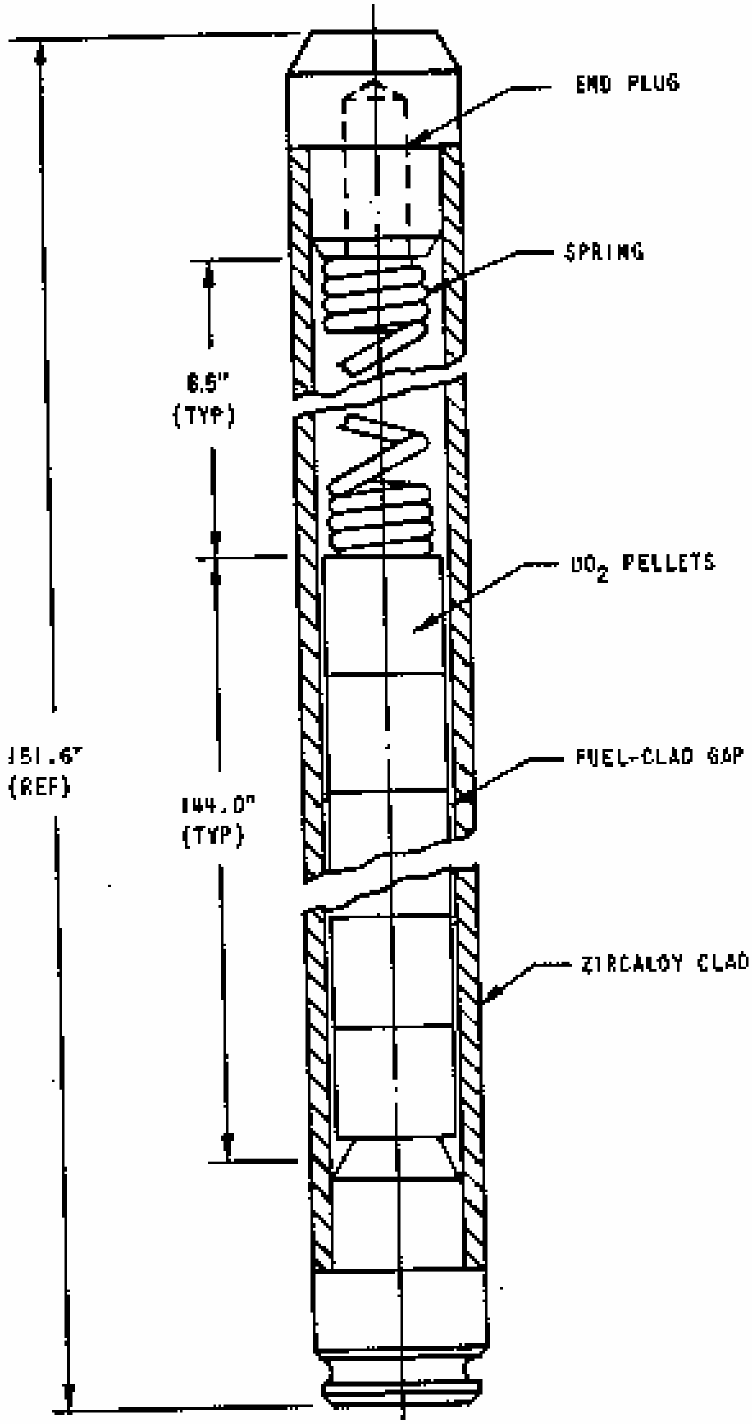
17 x 17 RECONSTITUTABLE LOPAR FUEL ASSEMBLY

* FOR VANTAGE 5 ASSEMBLIES WITH A P-GRID (NOT SHOWN) INSTALLED. P-GRID REFERENCE DIMENSION IS 3.093". GRID 1 AND GRID 2 REFERENCE DIMENSIONS ARE 6.535" AND 30.42", RESPECTIVELY.

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.2-2A
17 x 17 VANTAGE 5 / LOPAR FUEL ASSEMBLY COMPARISON



SPECIFIC DIMENSIONS DEPEND ON DESIGN VARIABLES SUCH AS PRE-PRESSURIZATION, POWER HISTORY, AND DISCHARGE BURNUP

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.2-3 FUEL ROD SCHEMATIC (LOPAR)

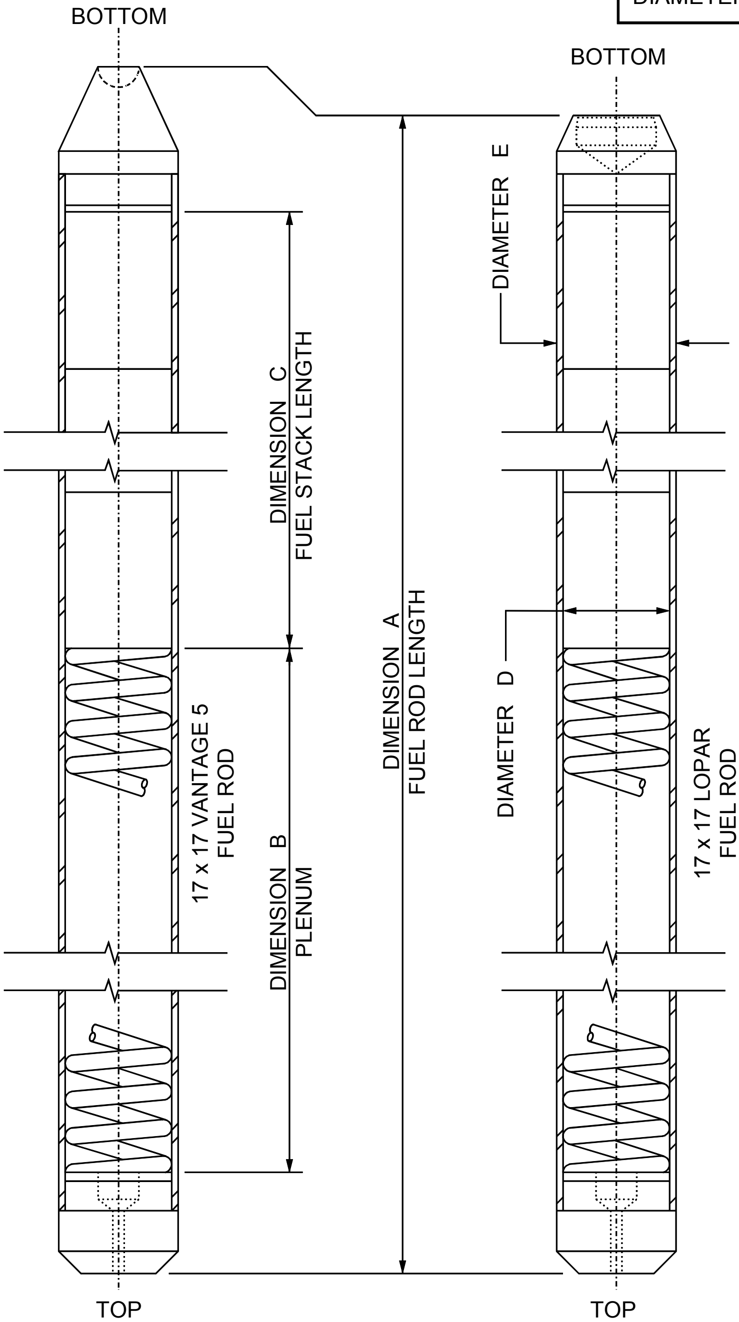
DIMENSION	17 x 17 V-5	17 x 17 LOPAR
A	152.285 *	151.56
B	7.525 *	6.90
C	144.00	144.00
DIAMETER D	.315	.329
DIAMETER E	.360	.374

DIMENSIONS ARE IN INCHES

BOTTOM END PLUG SHOWS INTERNAL GRIP TYPE FOR V-5 FUEL RODS.

NOT SHOWN IS THE EXTERNAL GRIP TYPE OF THE LOPAR FUEL ROD BOTTOM END PLUG.

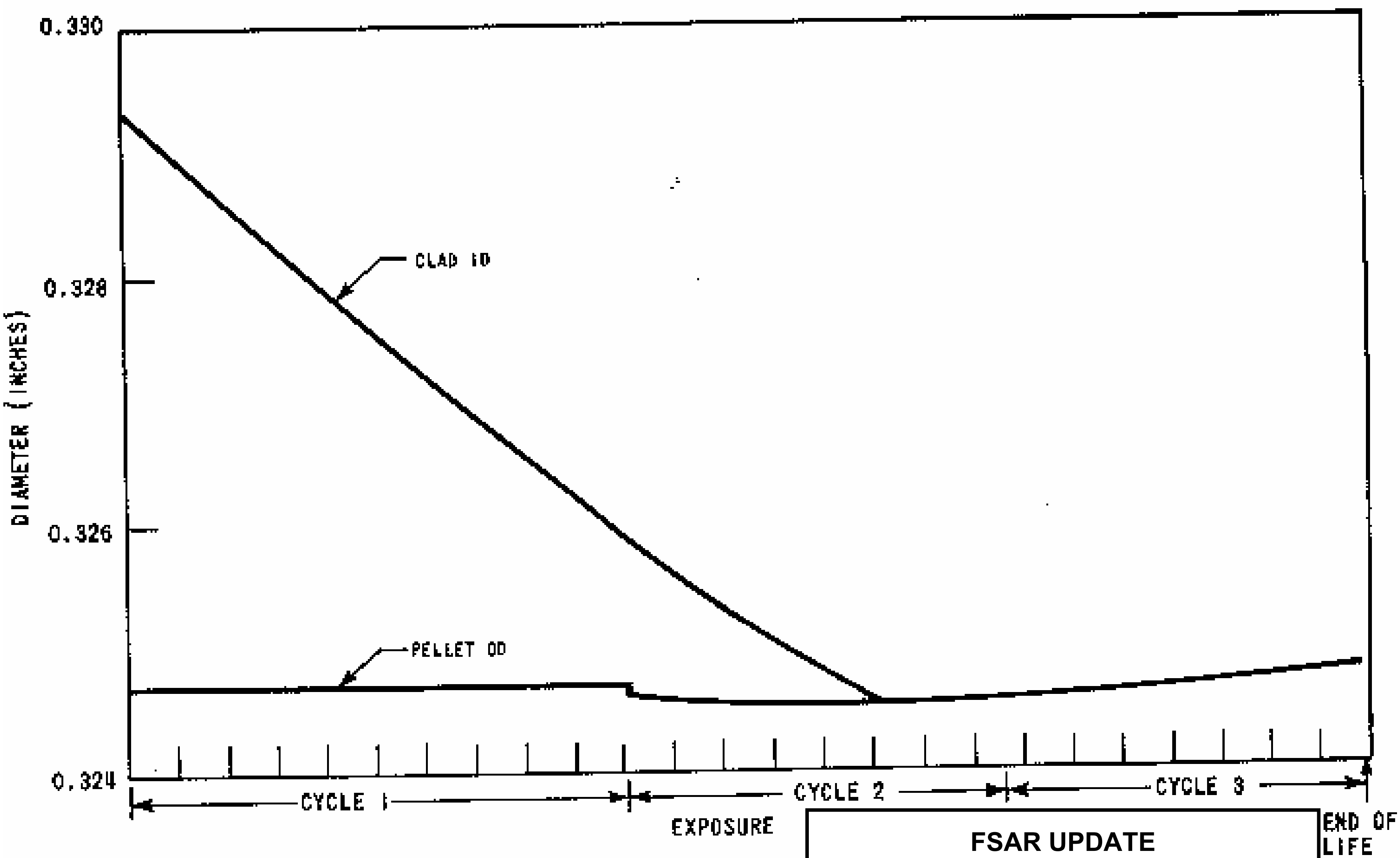
* FOR VANTAGE 5 WITH P-GRID FUEL ROD DIMENSION "A" IS 152.870" AND DIMENSION "B" IS 7.730".



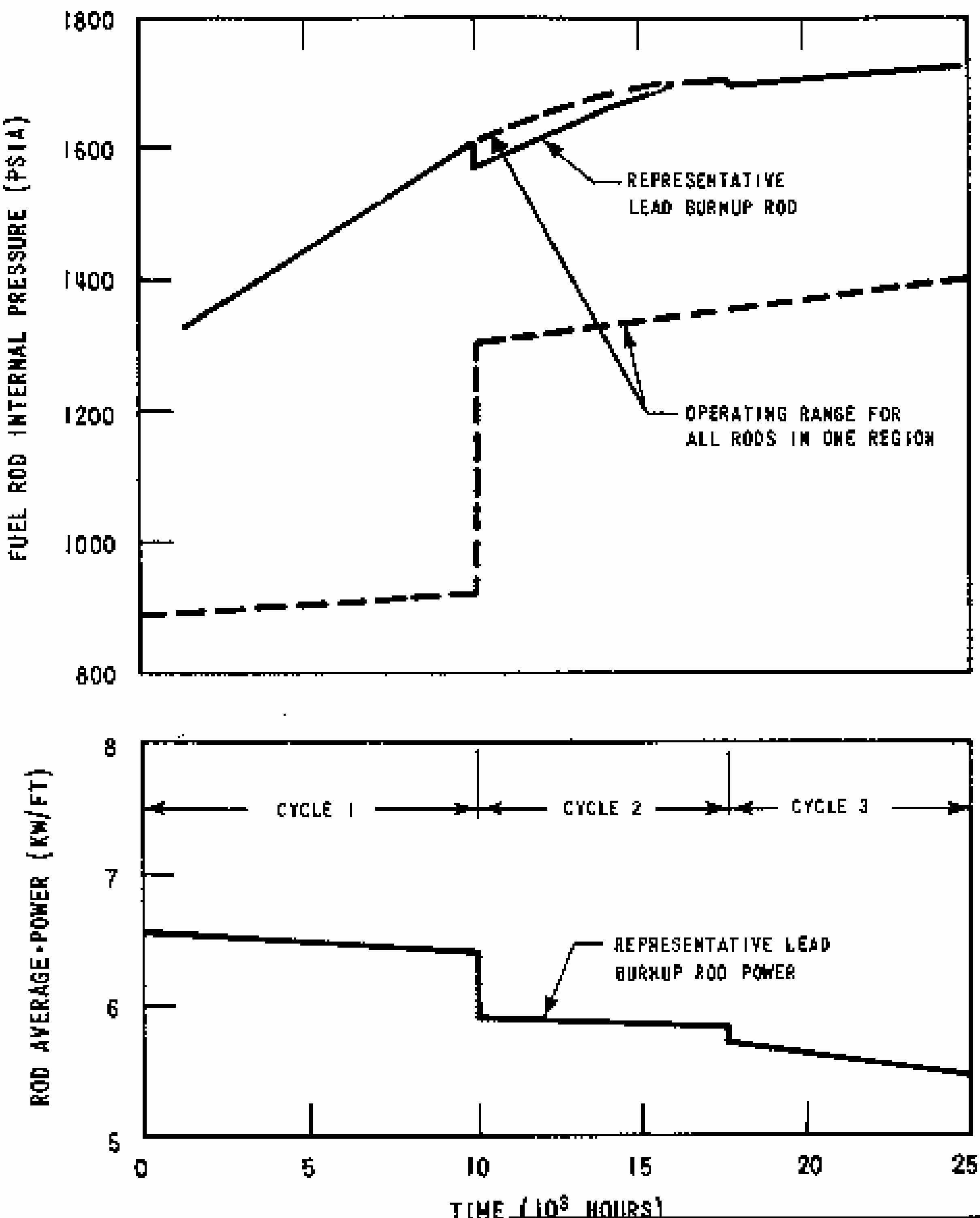
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

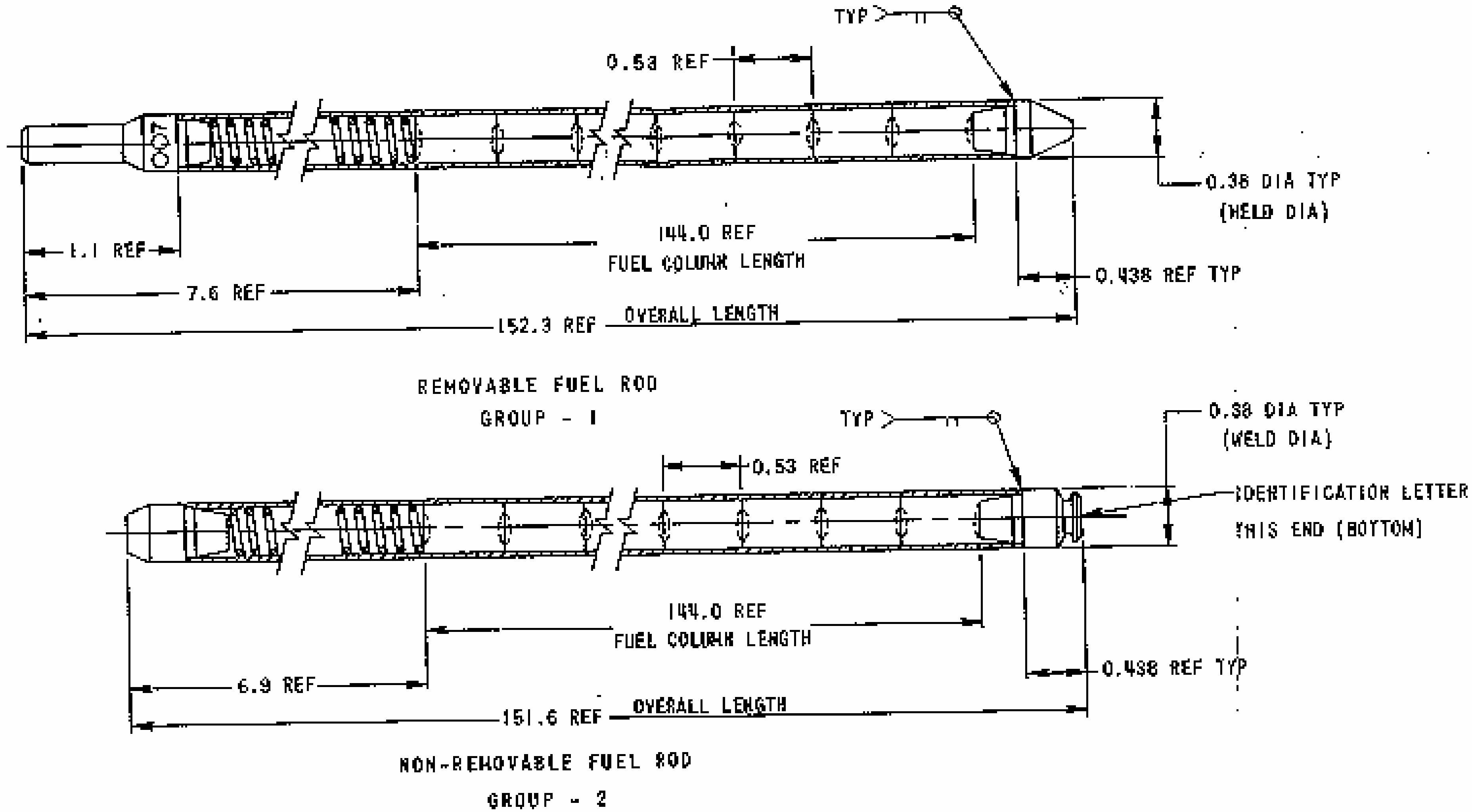
FIGURE 4.2-3A
17x17 VANTAGE 5 / LOPAR FUEL ROD ASSEMBLY COMPARISON



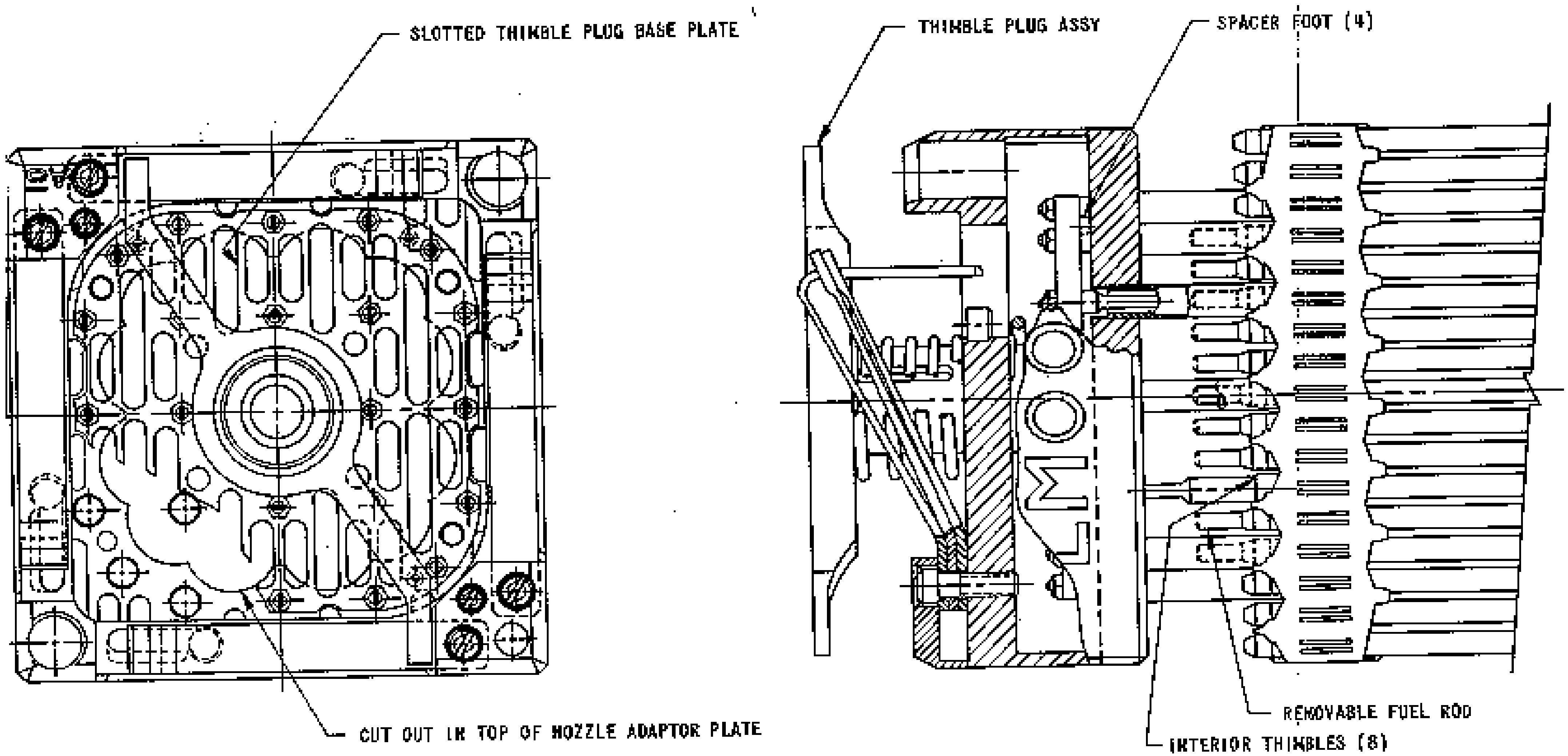
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.2-4 TYPICAL CLAD AND PELLET DIMENSIONS AS A FUNCTION OF EXPOSURE



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.2-5 REPRESENTATIVE FUEL ROD INTERNAL PRESSURE AND LINEAR POWER DENSITY FOR THE LEAD BURNUP AS A FUNCTION OF TIME

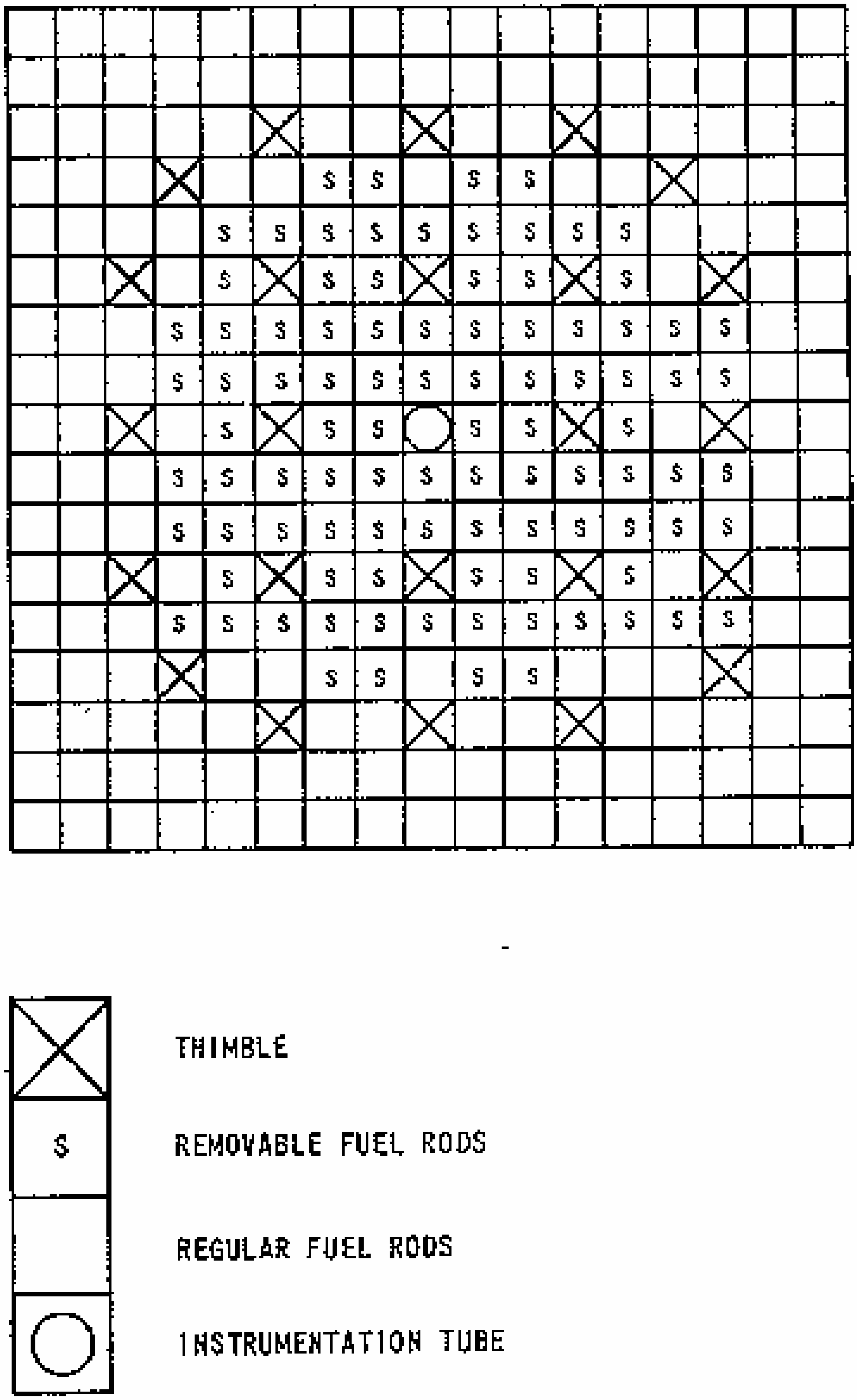


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.2-6 REMOVABLE ROD COMPARED TO STANDARD ROD



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.2-7 REMOVABLE FUEL ROD ASSEMBLY OUTLINE

Revision 11 November 1996

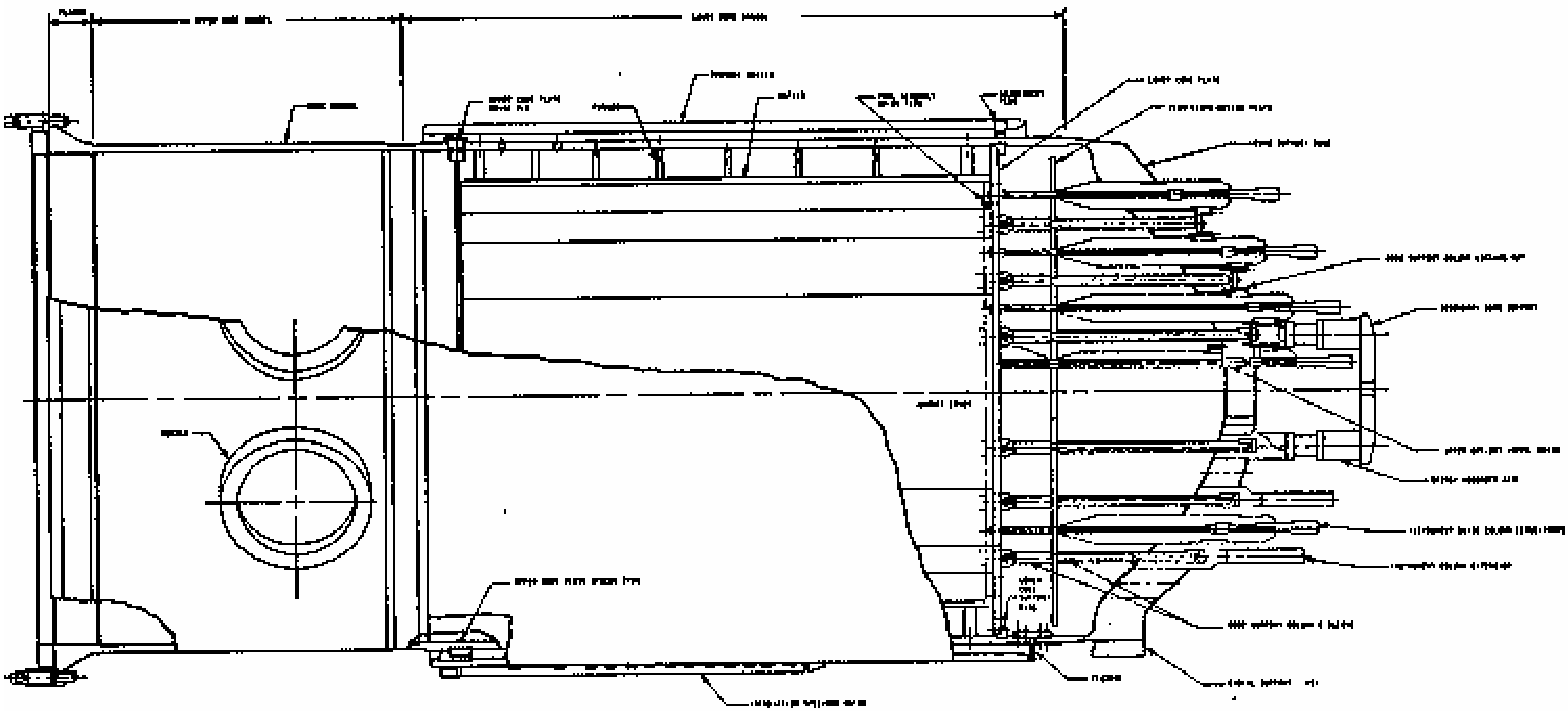


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.2-8

LOCATION OF REMOVABLE RODS WITHIN AN ASSEMBLY

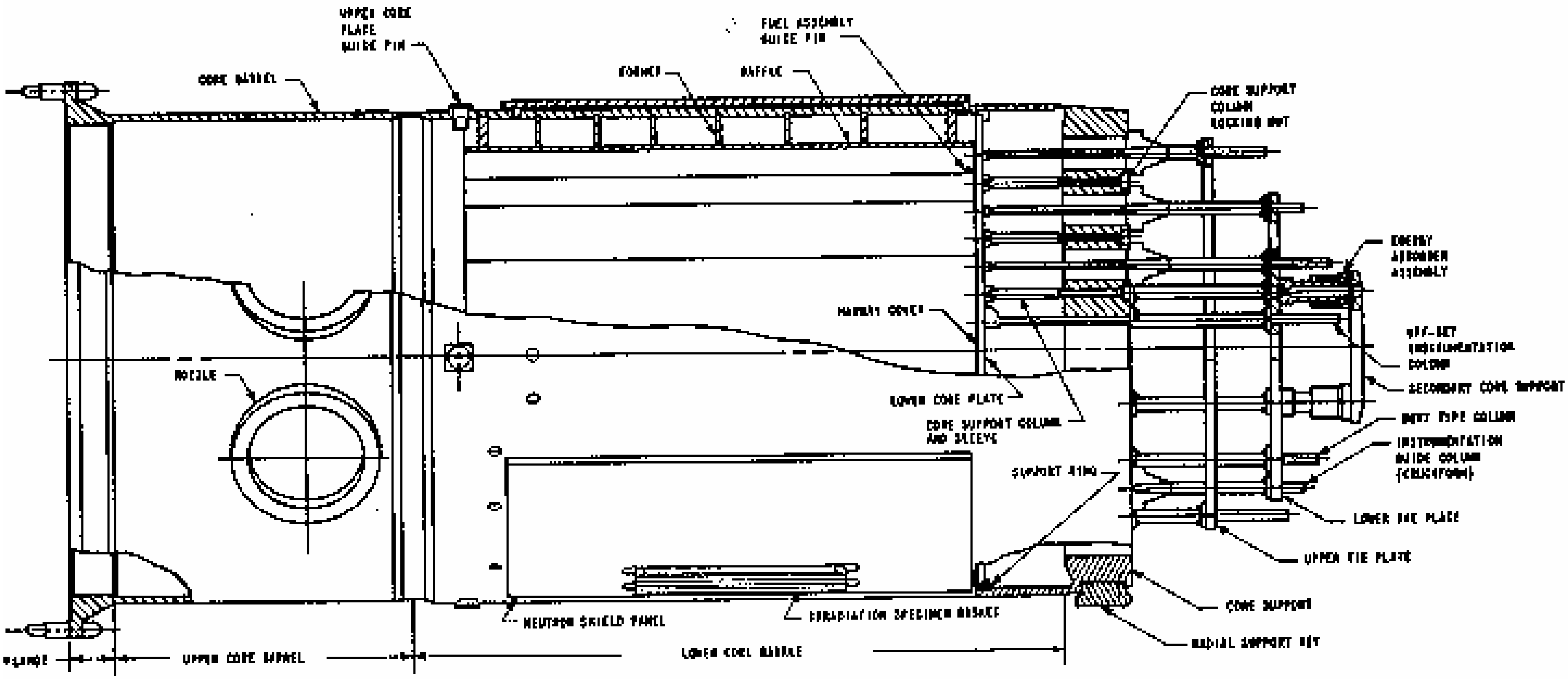


FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

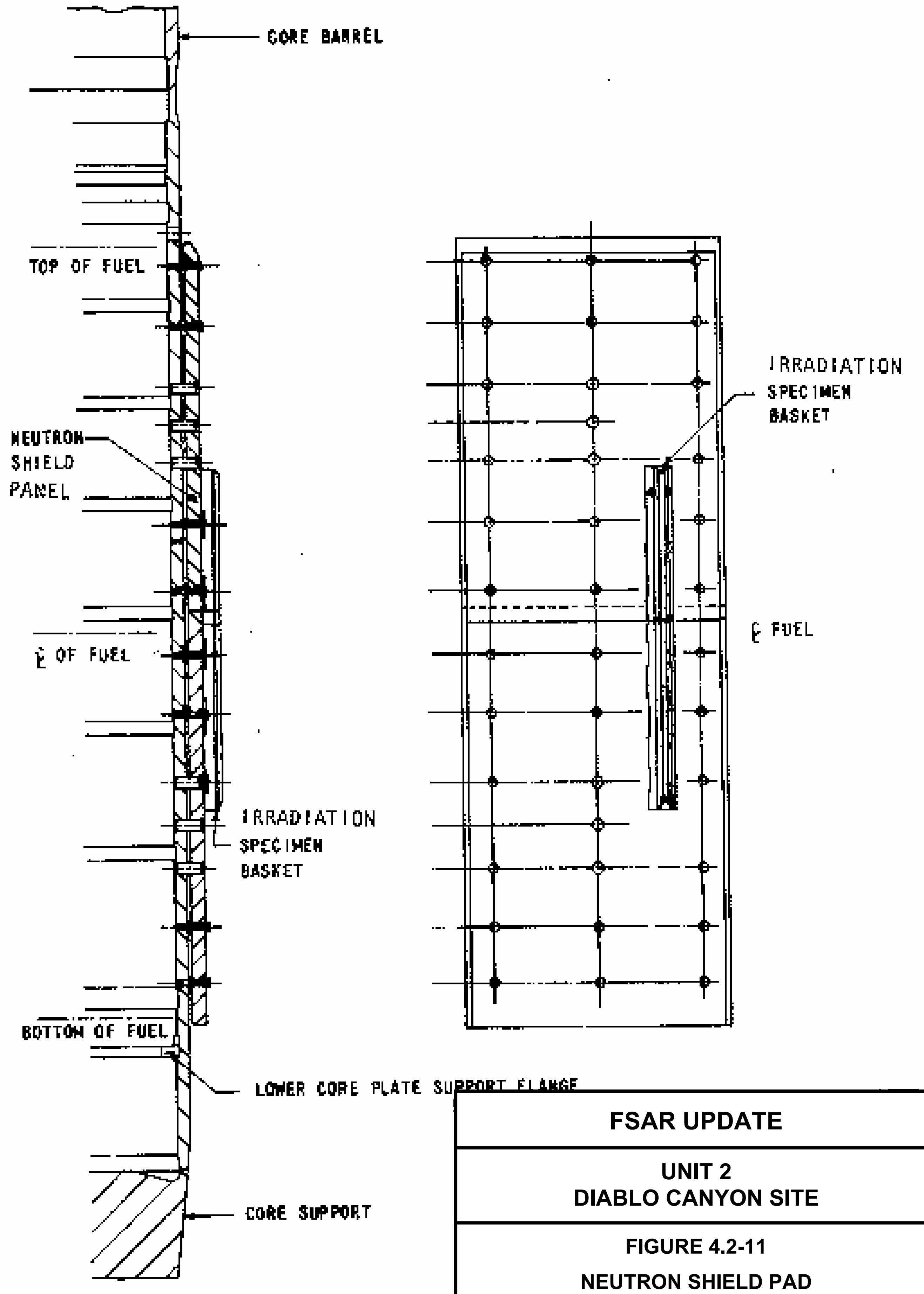
FIGURE 4.2-9

LOWER CORE SUPPORT ASSEMBLY



FSAR UPDATE
UNIT 2 **DIABLO CANYON SITE**
FIGURE 4.2-10 **LOWER CORE SUPPORT ASSEMBLY**

Revision 11 November 1996

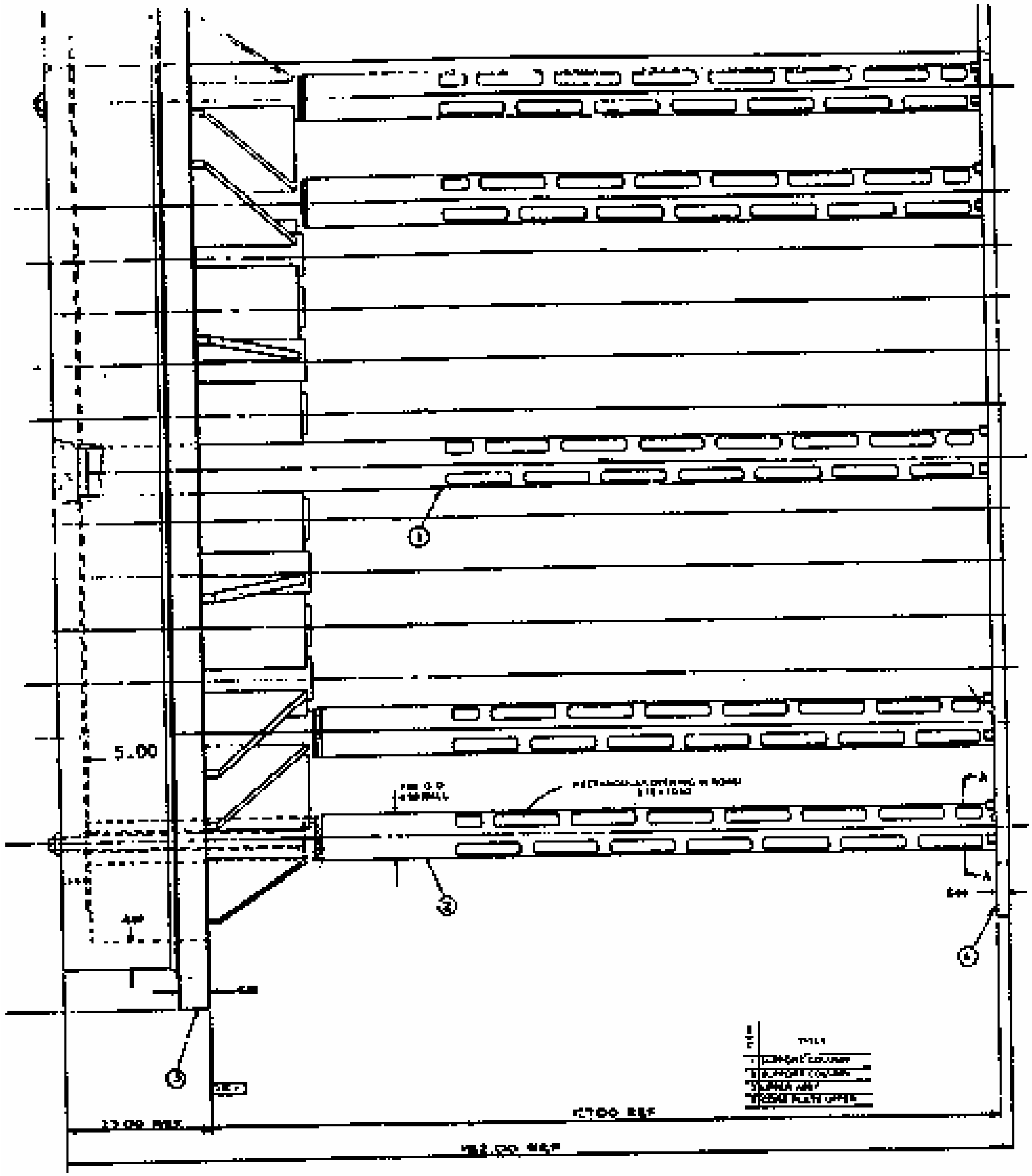


FSAR UPDATE

UNIT 2
DIABLO CANYON SITE

FIGURE 4.2-11

NEUTRON SHIELD PAD
LOWER CORE SUPPORT STRUCTURE

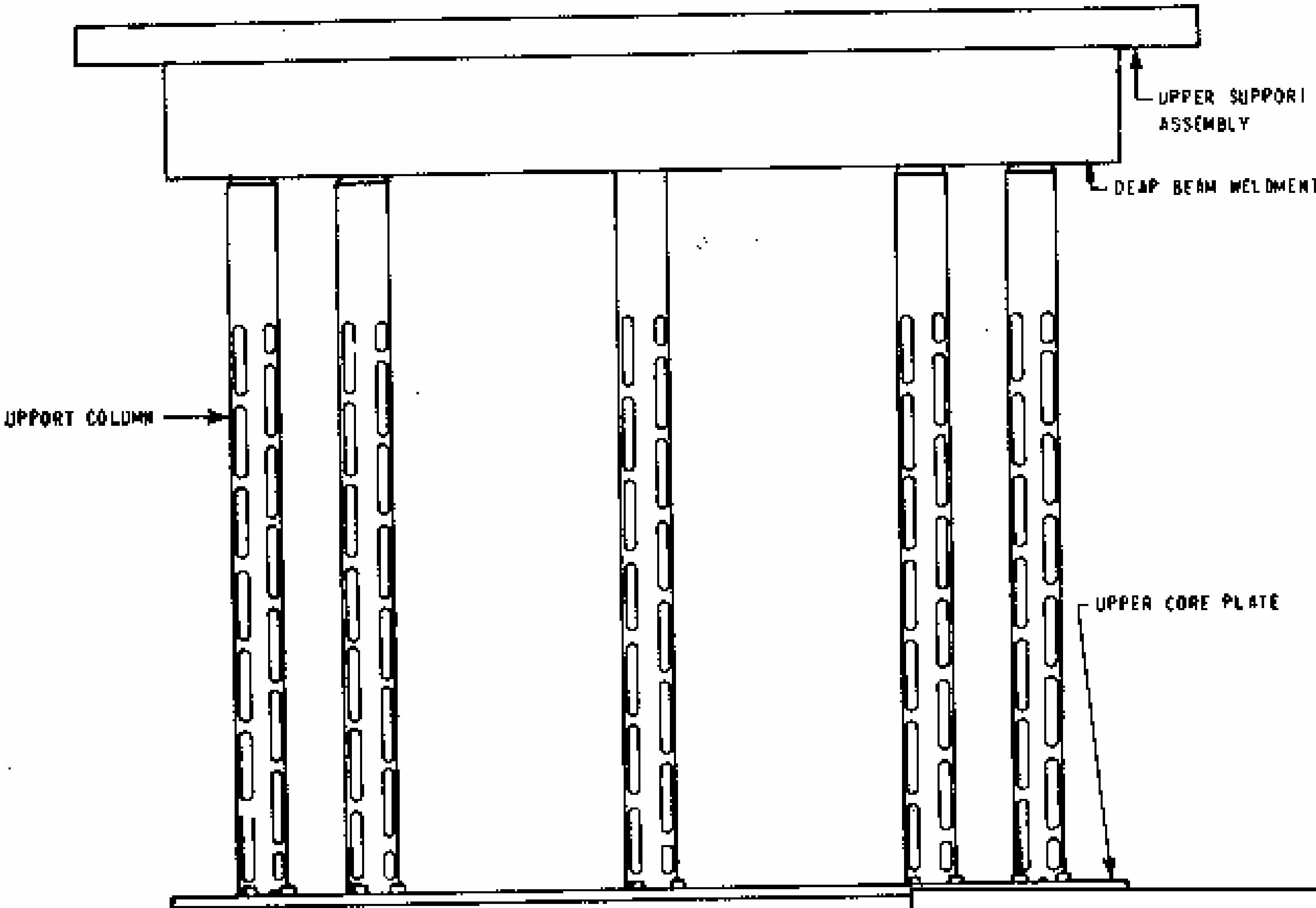


FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

FIGURE 4.2-12

UPPER CORE SUPPORT STRUCTURE

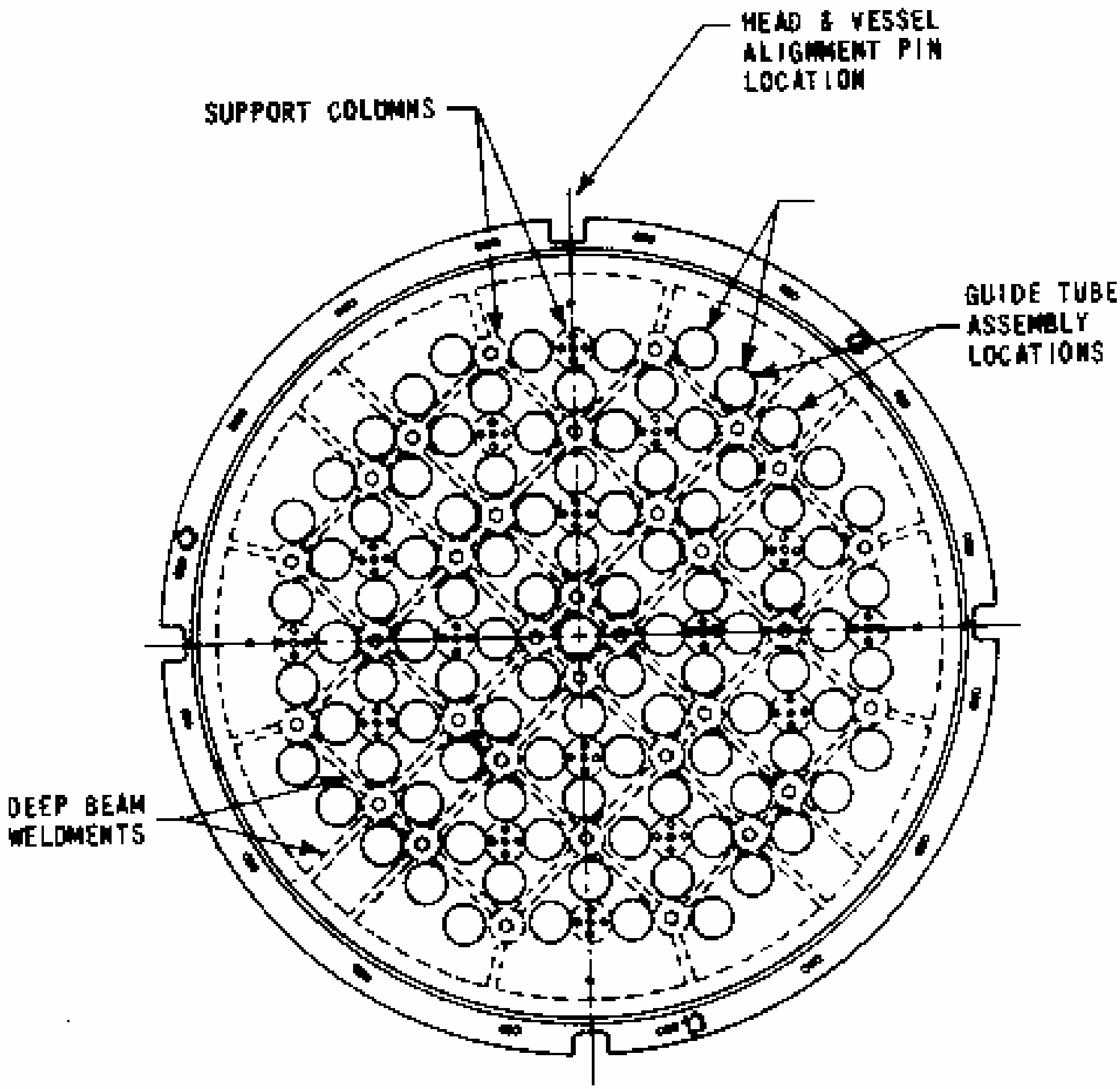


FSAR UPDATE

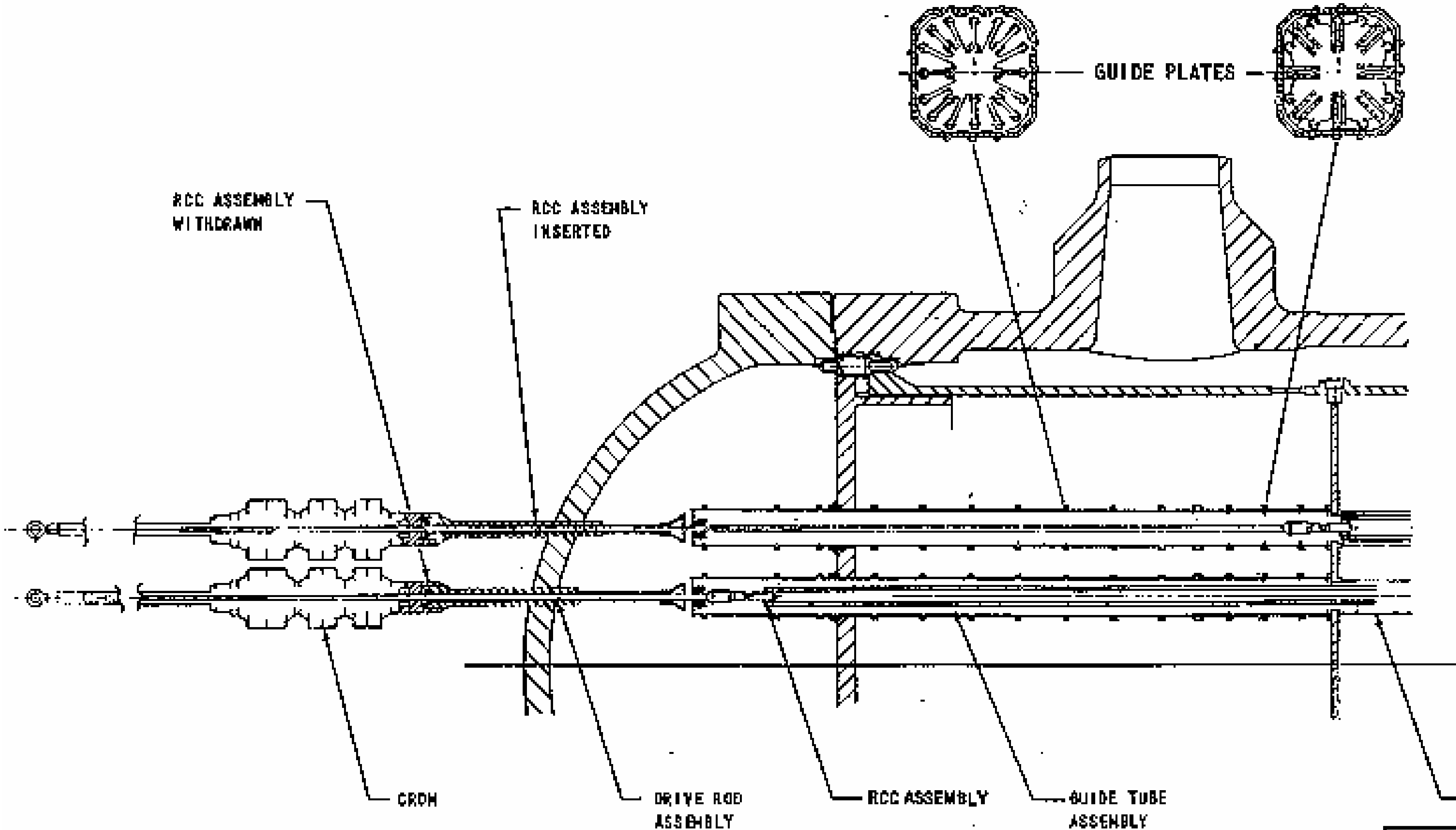
UNIT 2
DIABLO CANYON SITE

FIGURE 4.2-13

UPPER CORE SUPPORT STRUCTURE



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.2-14 PLAN VIEW OF UPPER CORE SUPPORT STRUCTURE



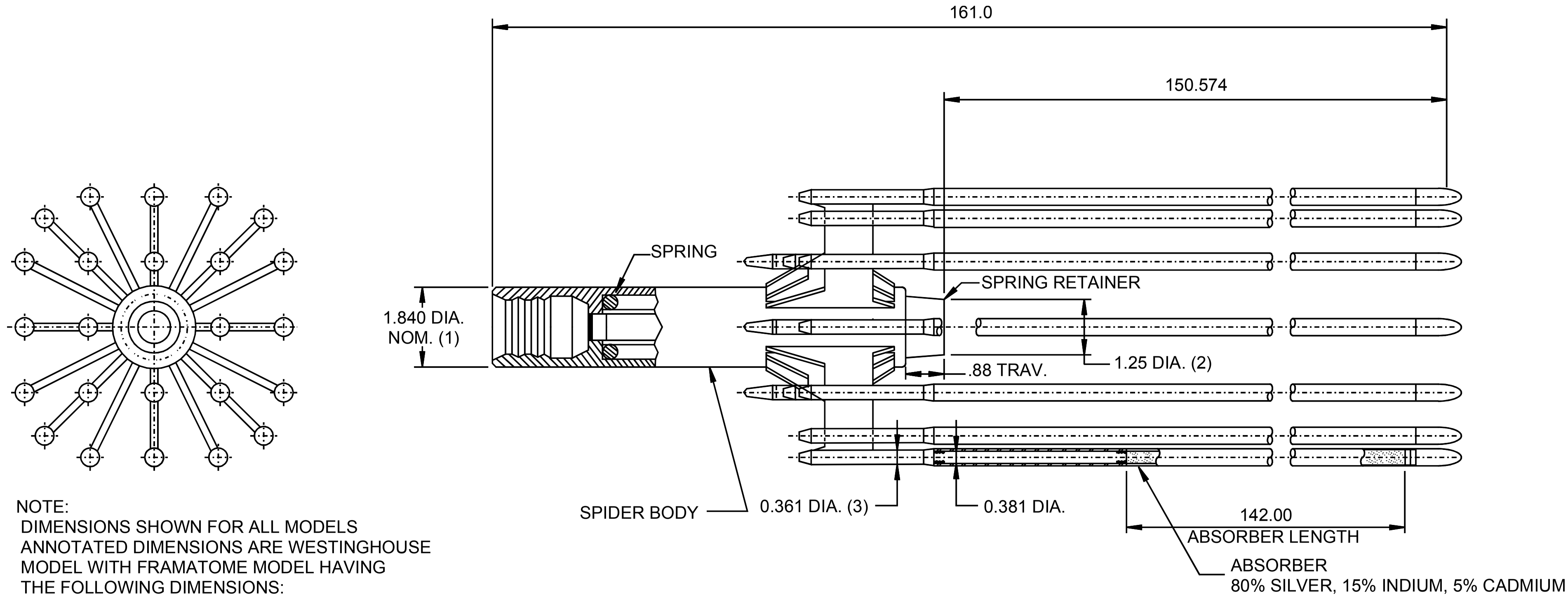
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.2-15

ROD CLUSTER CONTROL AND DRIVE ROD ASSEMBLY WITH INTERFACING COMPONENTS

Revision 11 November 1996



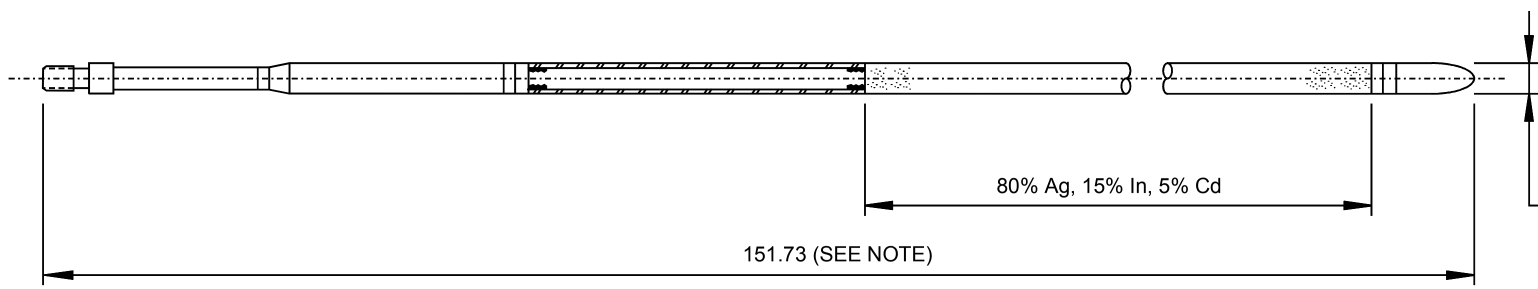
NOTE:
DIMENSIONS SHOWN FOR ALL MODELS
ANNOTATED DIMENSIONS ARE WESTINGHOUSE MODEL WITH FRAMATOME MODEL HAVING THE FOLLOWING DIMENSIONS:
(1) 1.804
(2) 1.240
(3) 0.354

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.2-16
ROD CLUSTER CONTROL ASSEMBLY OUTLINE

Revision 14 November 2001

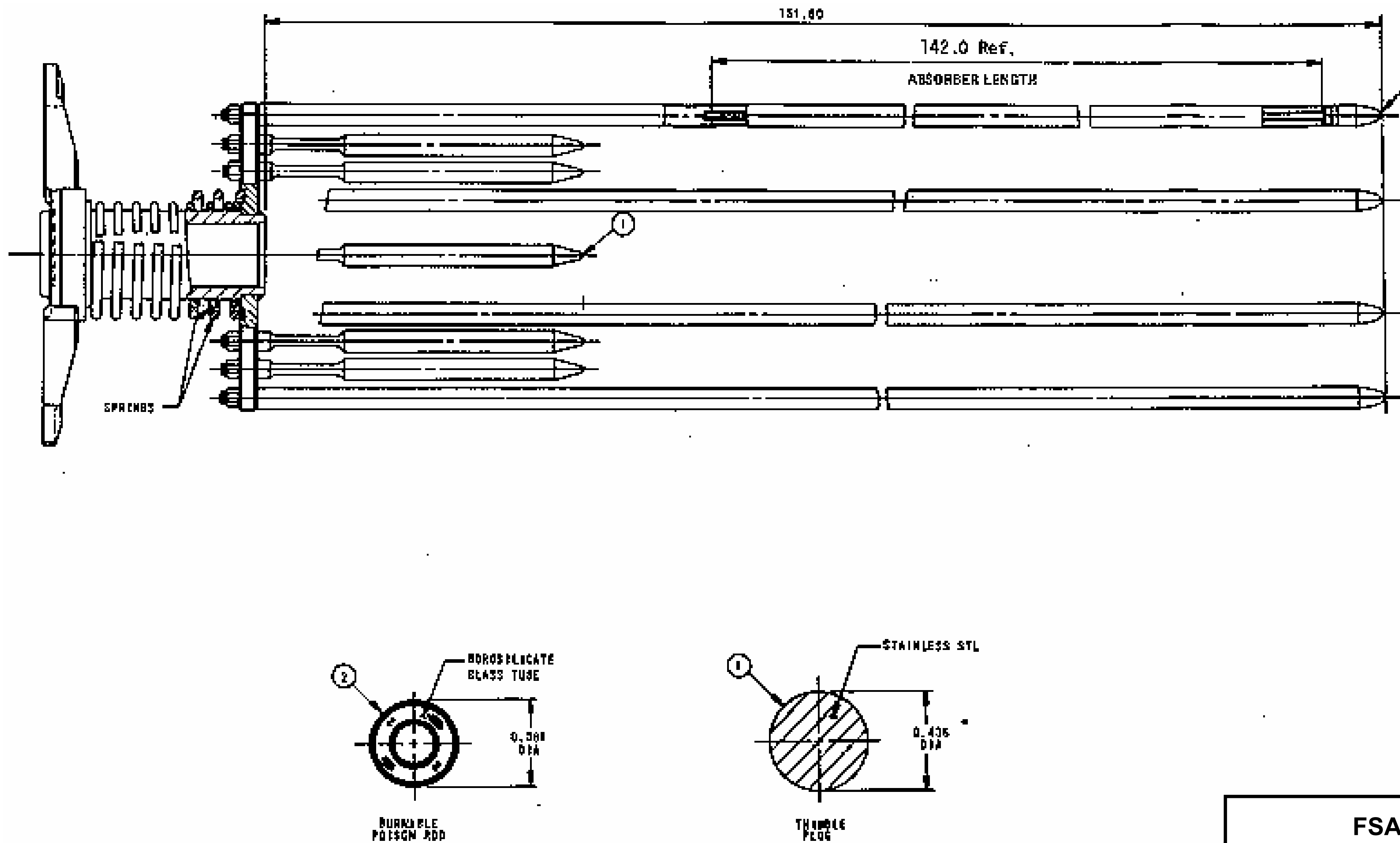


NOTE:
WESTINGHOUSE DIMENSION SHOWN.
FRAMATOME ROD LENGTH IS 153.658-154.468.

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.2-17
ABSORBER ROD



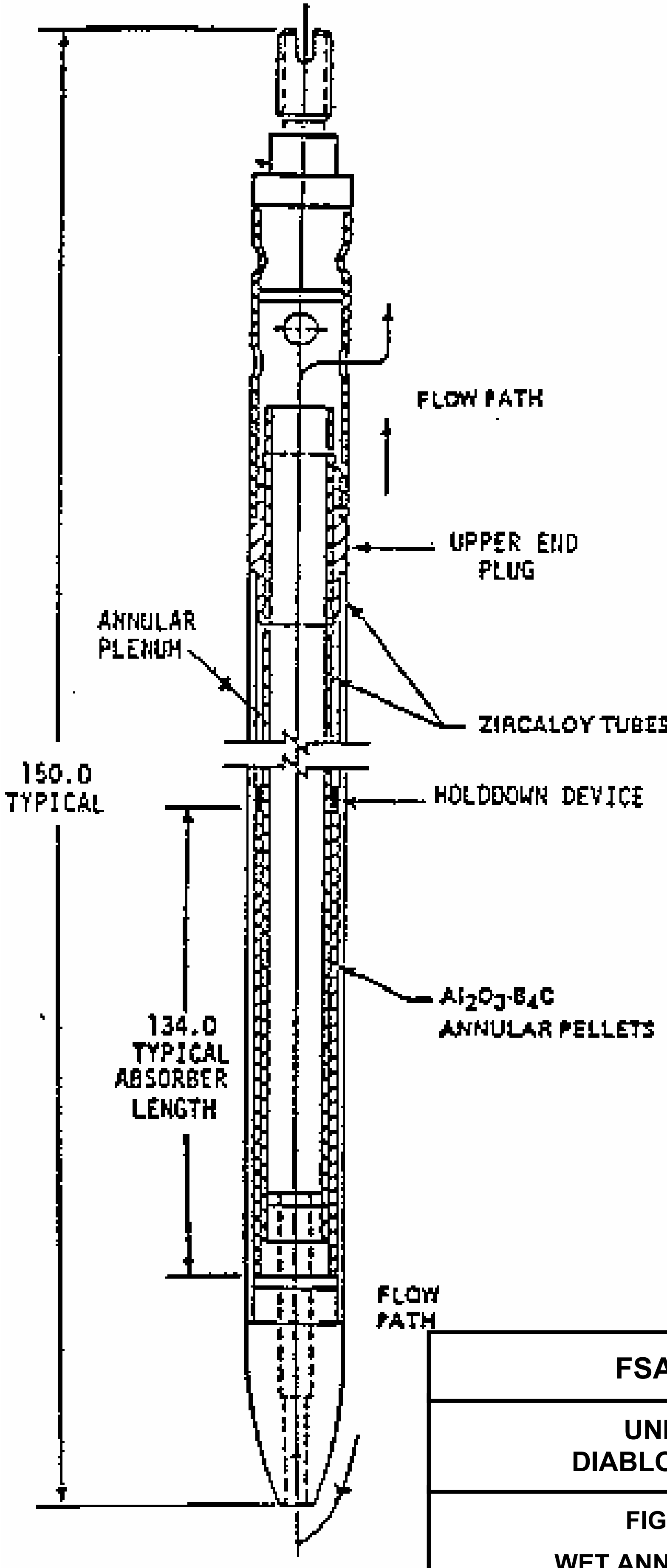
*) FITS ONLY LOPAR ASSEMBLY THIMBLE TUBES; TO FIT INTO VANTAGE 5 THIMBLE TUBES, DUALLY COMPATIBLE PLUG DESIGN MUST BE USED WITH A 0.424" DIAMETER.

FSAR UPDATE

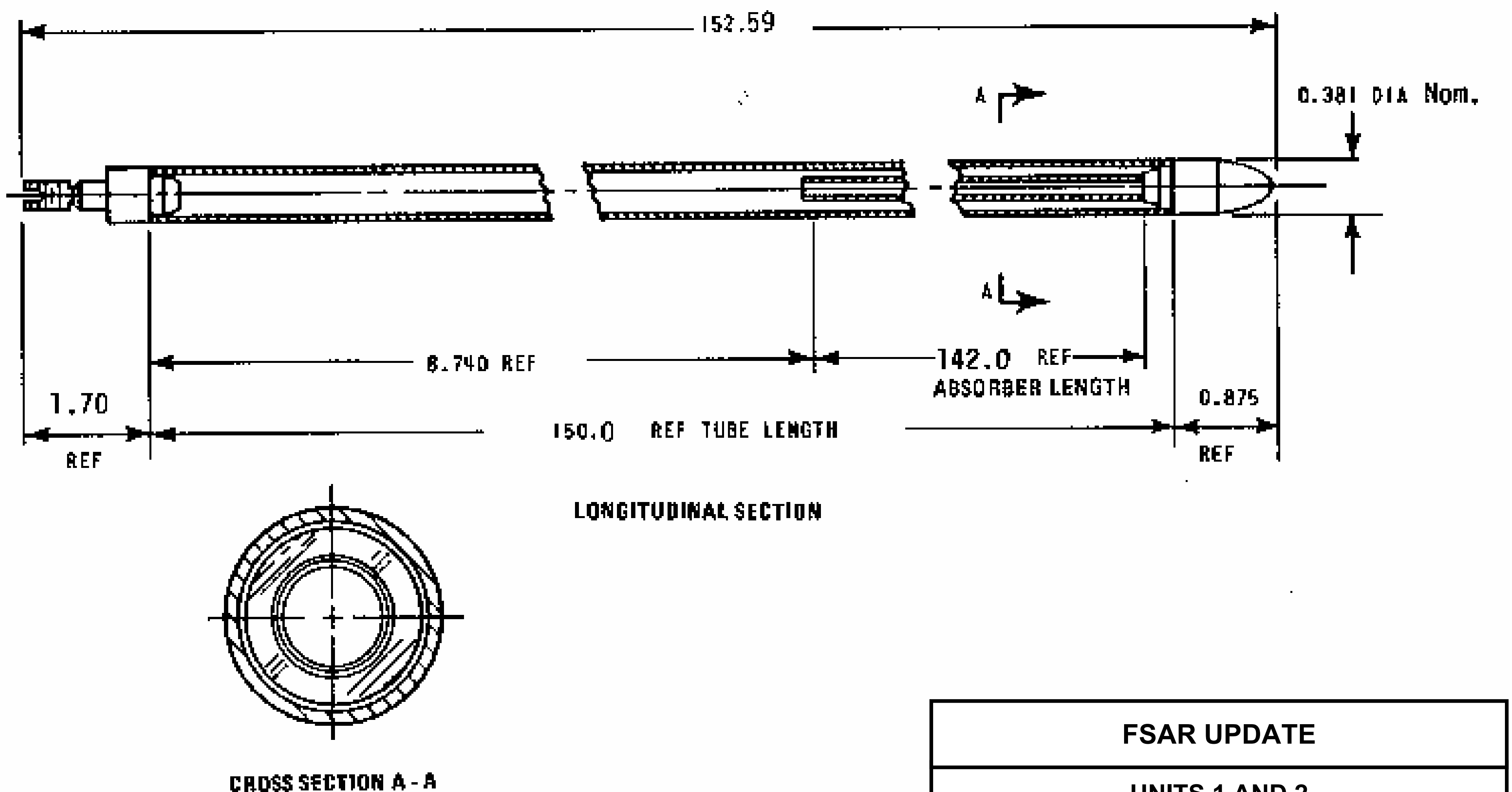
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.2-18

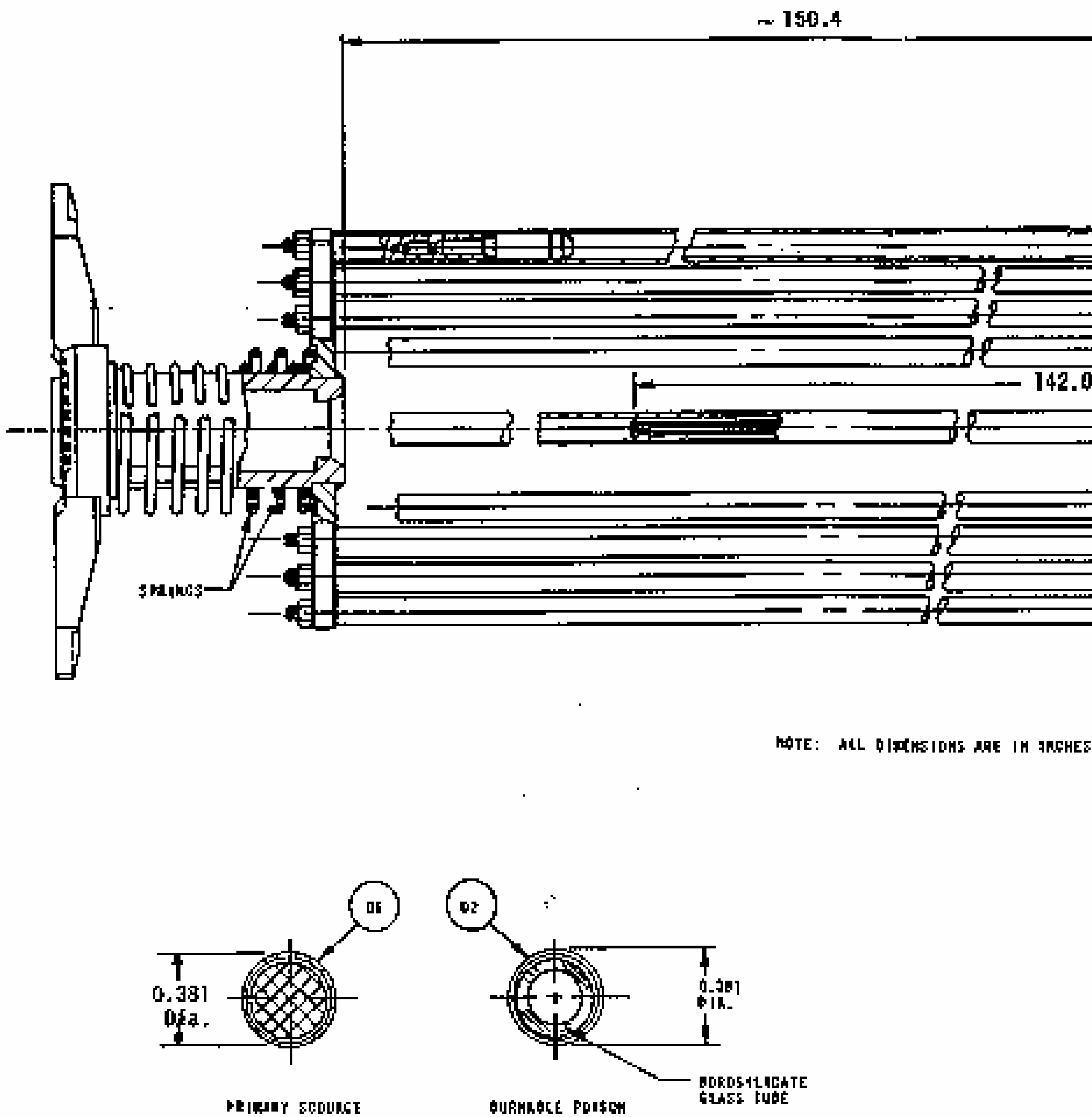
BURNABLE ABSORBER ASSEMBLY



FSAR UPDATE
UNITS 1 AND 2 **DIABLO CANYON SITE**
FIGURE 4.2-18A **WET ANNULAR BURNABLE ABSORBER ROD**



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.2-19 BURNABLE ABSORBER ROD SECTIONS

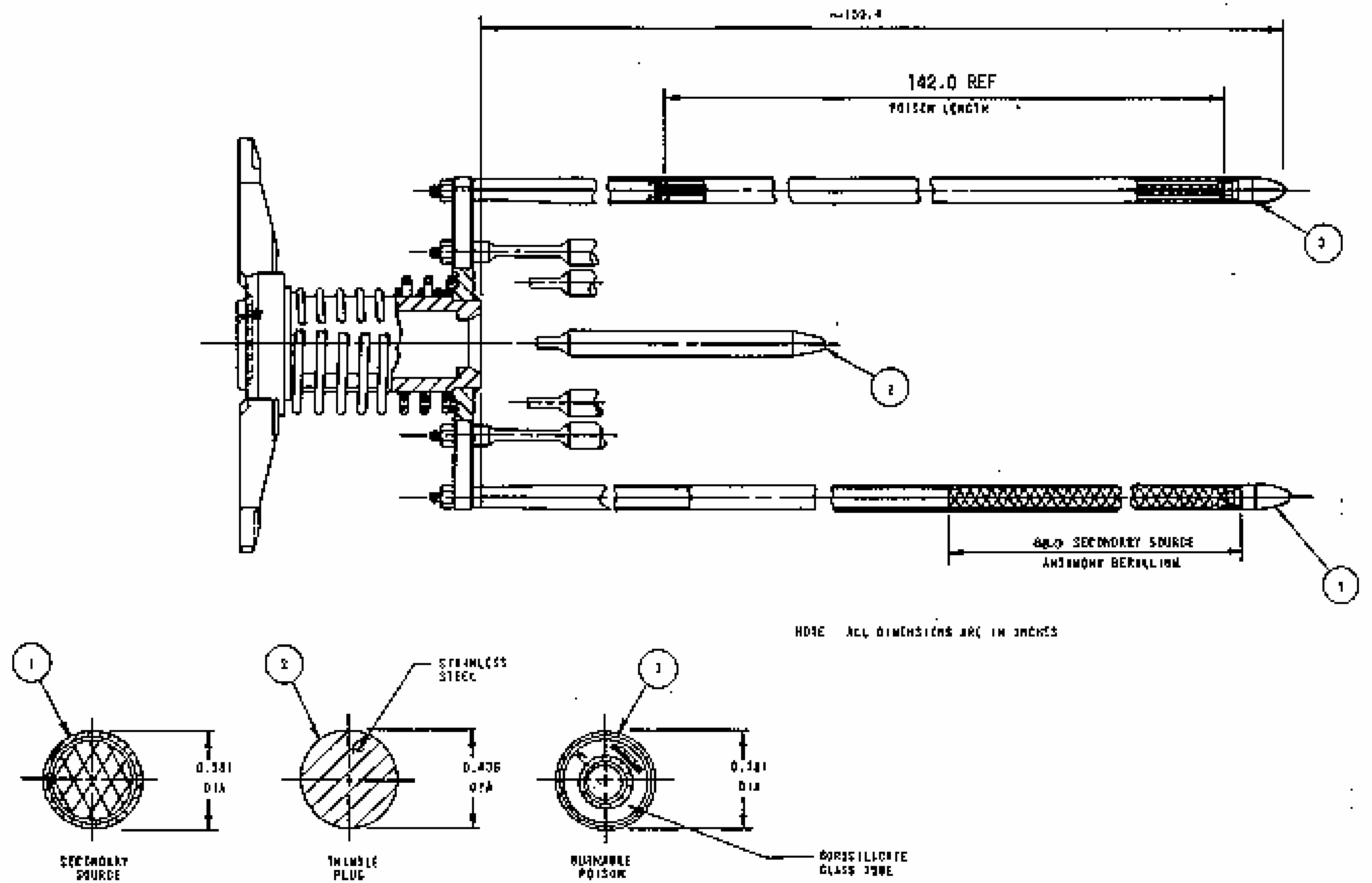


FSAR UPDATE

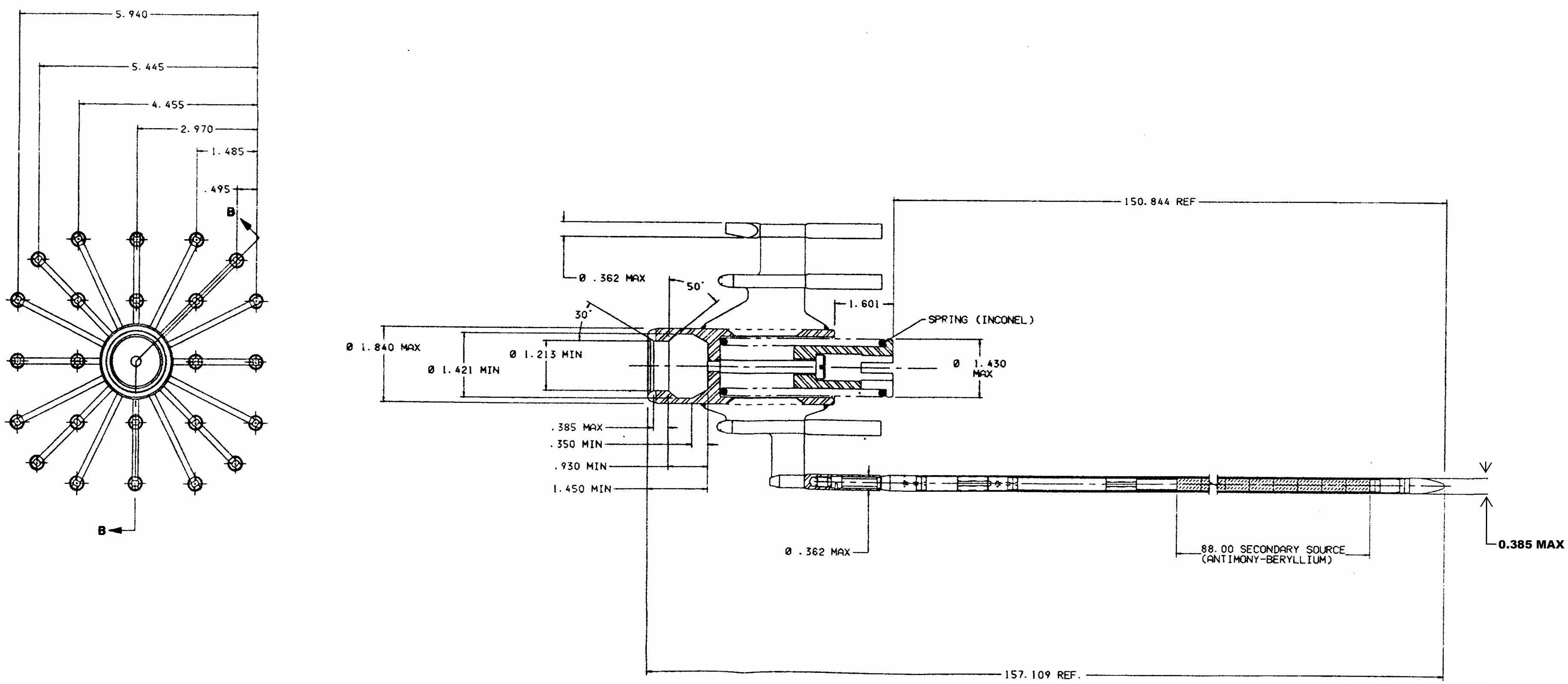
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.2-20

PRIMARY SOURCE ASSEMBLY



FSAR UPDATE
UNITS 1 AND 2 **DIABLO CANYON SITE**
FIGURE 4.2-21 **SECONDARY SOURCE ASSEMBLY**

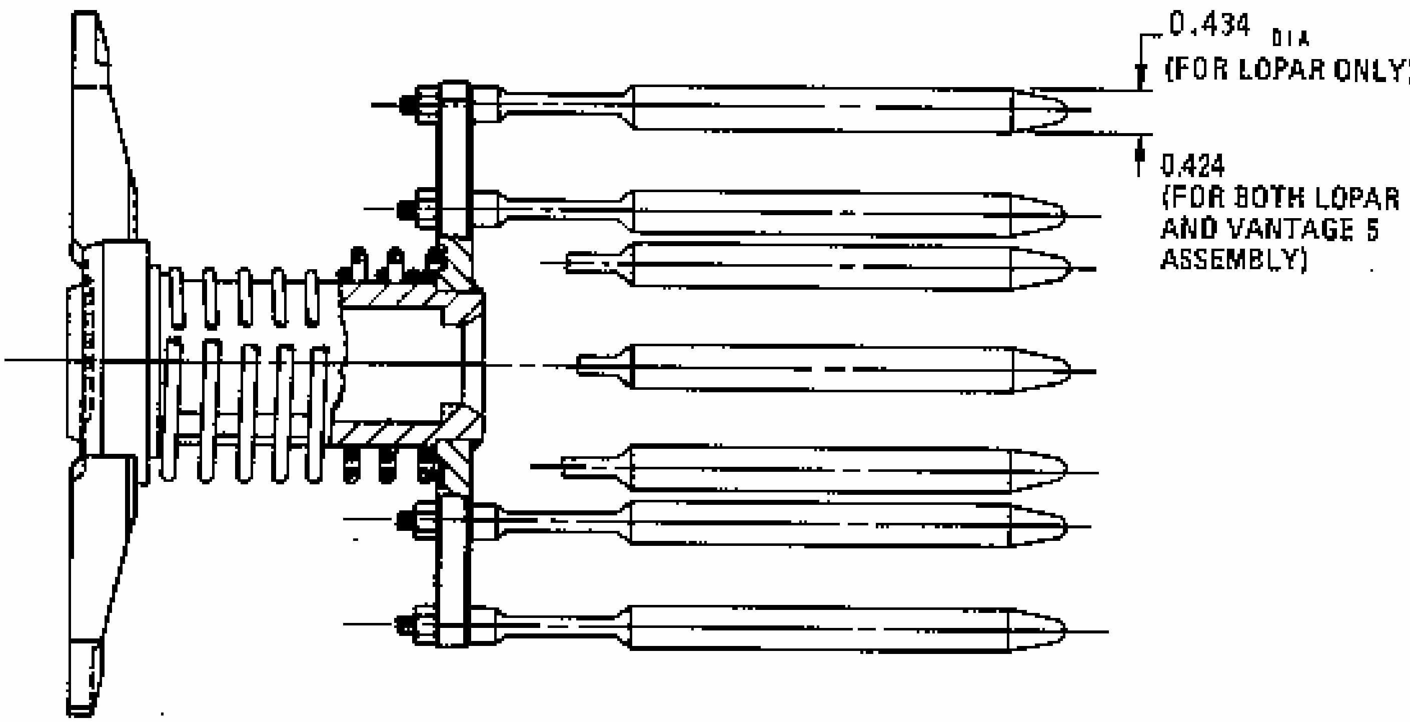


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.2-21A

SECONDARY SOURCE ASSEMBLY

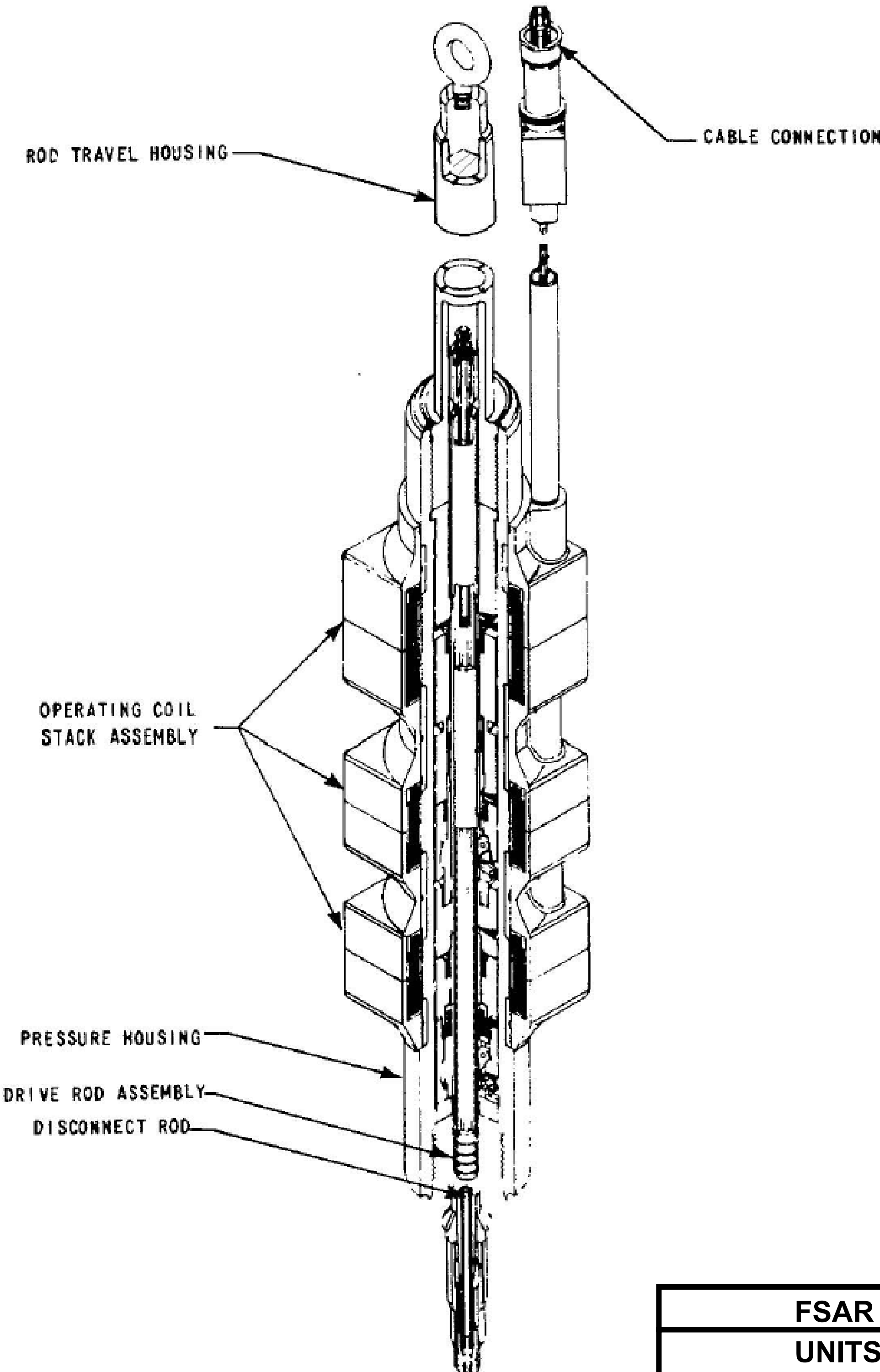


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.2-22
THIMBLE PLUG ASSEMBLY

Revision 11 November 1996

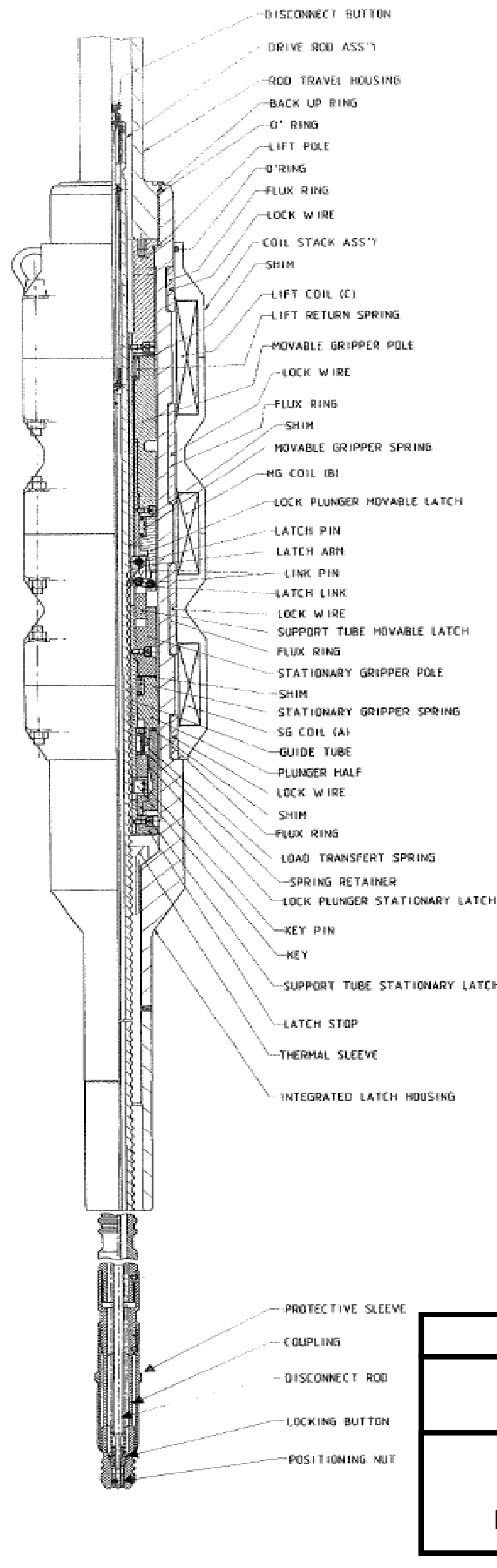


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

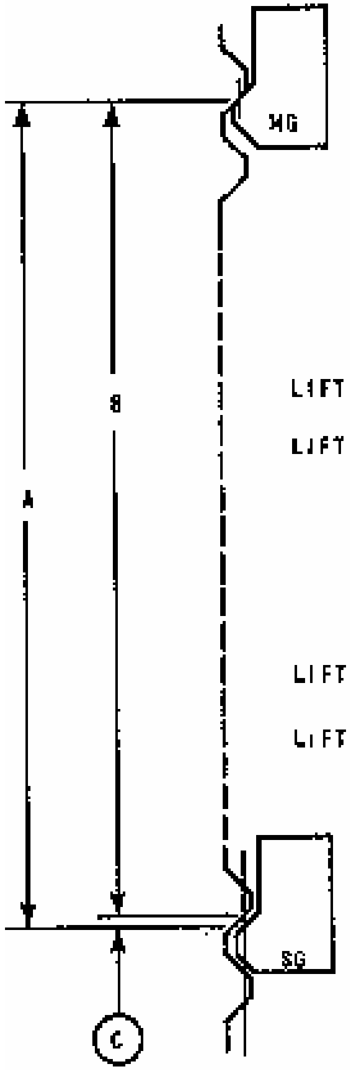
FIGURE 4.2-23

CONTROL ROD DRIVE MECHANISM



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.2-24 CONTROL ROD DRIVE MECHANISM SCHEMATIC

BEFORE LOAD TRANSFER

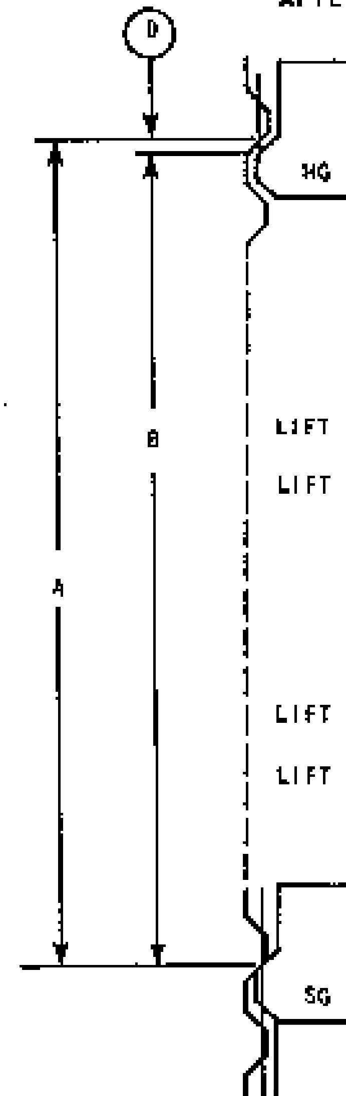


	AT 70°		
	A	B	C
LIFT COIL OFF	15.640	15.625	0.015
LIFT COIL ON	16.265	16.250	0.015

	AT 650°		
	A	B	C
LIFT COIL OFF	15.725	15.679	0.046
LIFT COIL ON	16.375	16.387	0.068

NOTE: Units in tables are inches.

AFTER LOAD TRANSFER



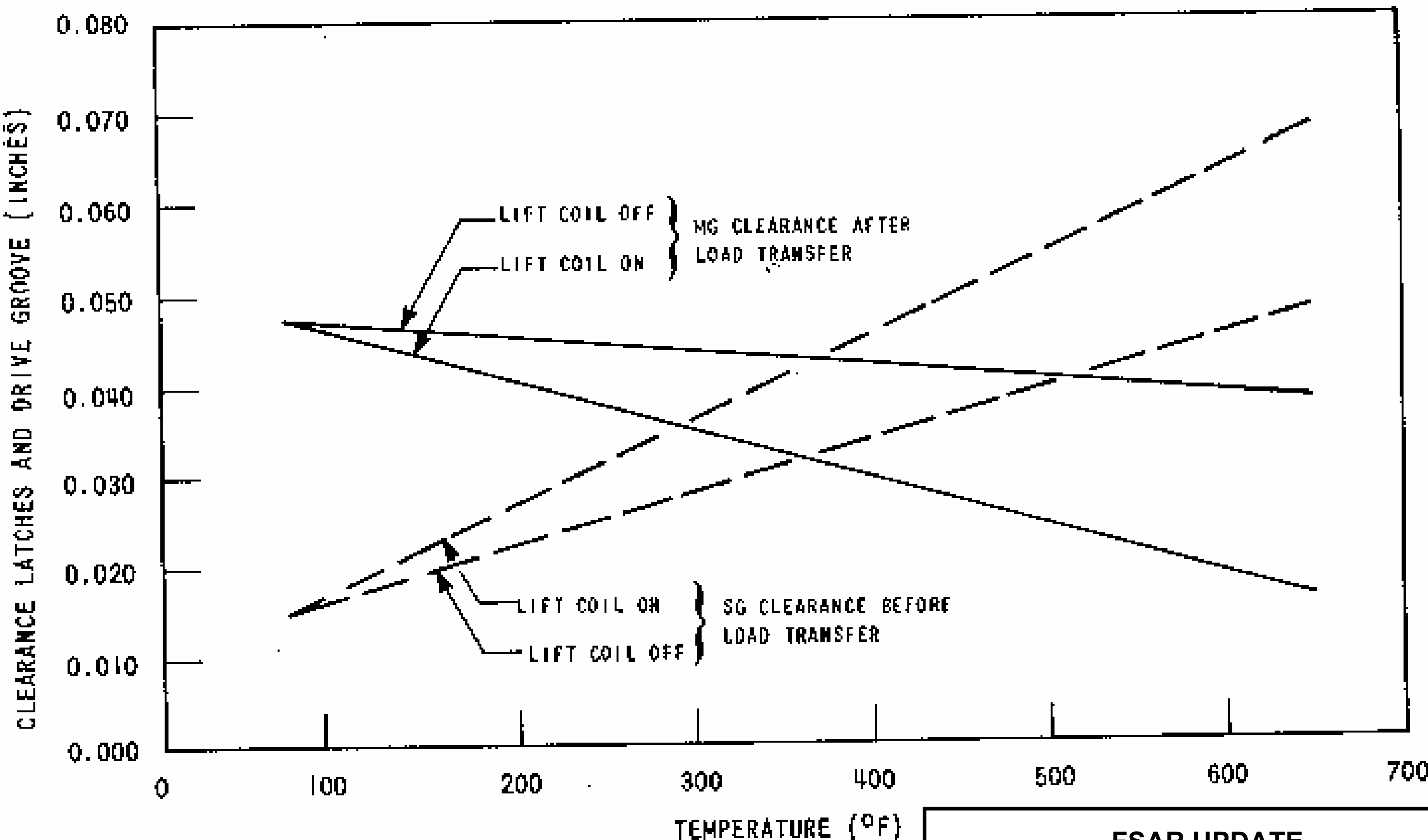
	AT 70°		
	A	B	D
LIFT COIL OFF	15.625	15.578	0.047
LIFT COIL ON	16.258	16.203	0.047

	AT 650°		
	A	B	D
LIFT COIL OFF	15.679	15.641	0.038
LIFT COIL ON	16.367	16.291	0.016

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

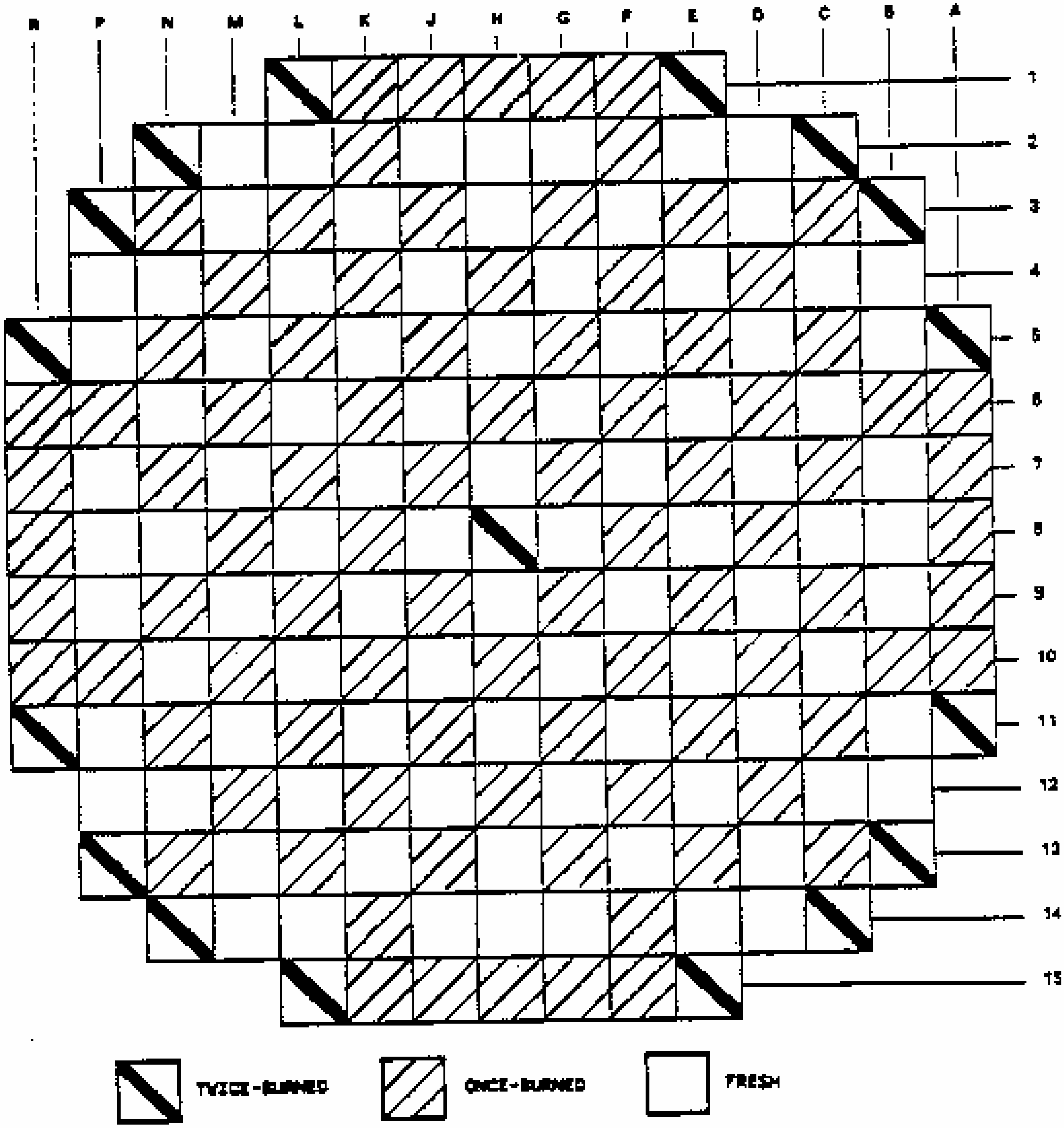
FIGURE 4.2-25
NORMAL LATCH CLEARANCE AT MINIMUM AND MAXIMUM TEMPERATURE



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

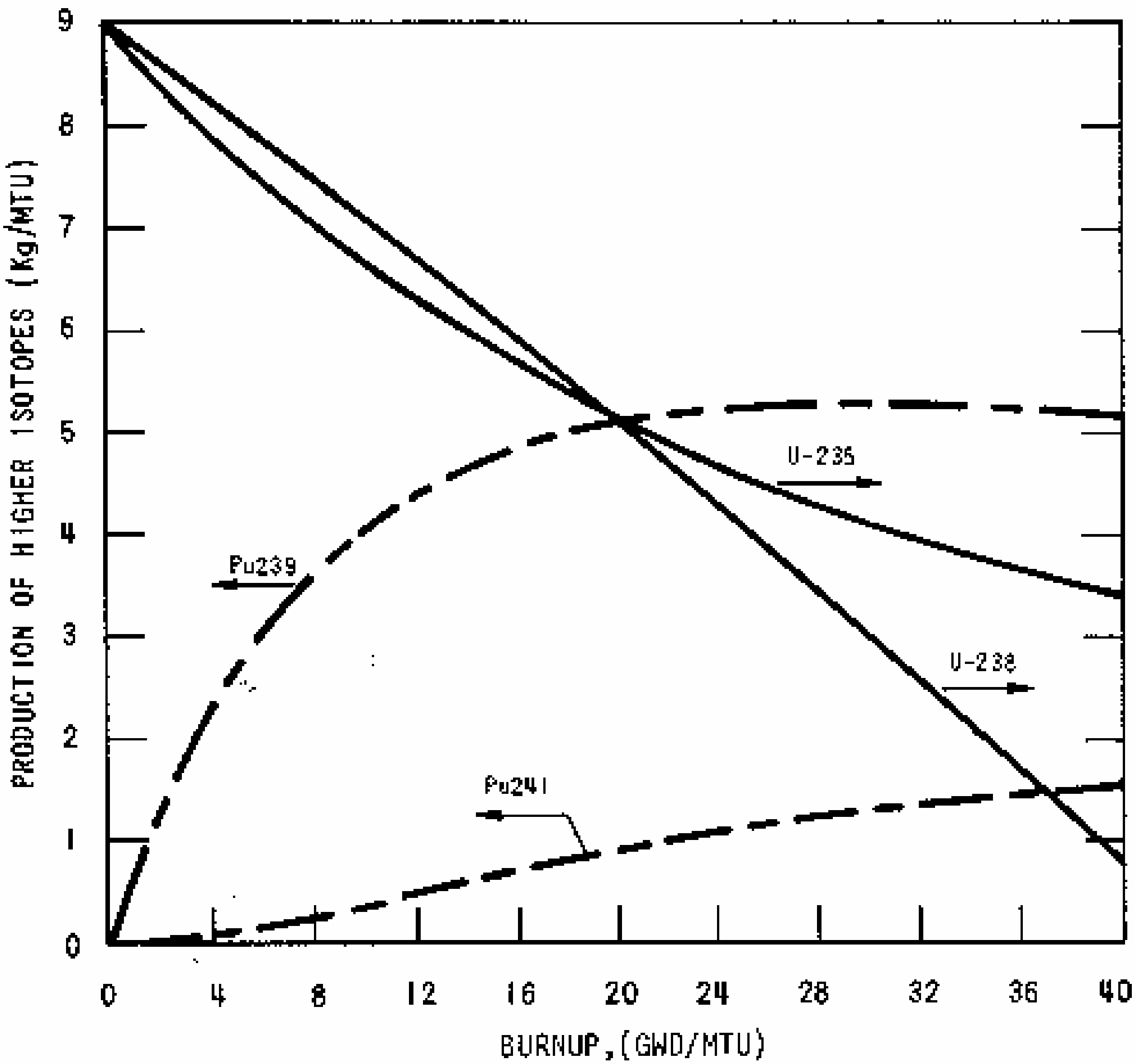
FIGURE 4.2-26
CONTROL ROD DRIVE MECHANISM
LATCH CLEARANCE THERMAL EFFECT



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

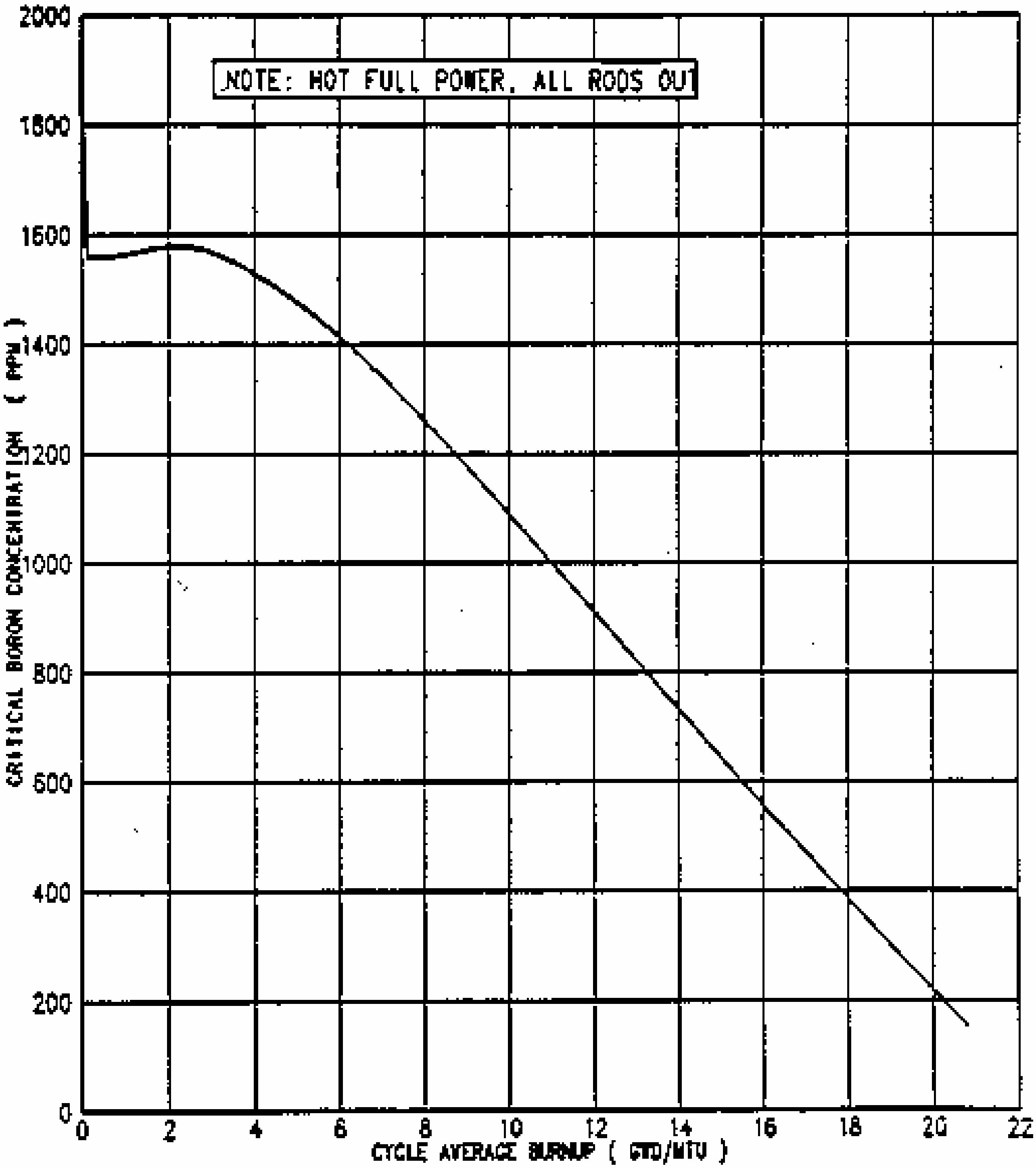
FIGURE 4.3-1
FUEL LOADING ARRANGEMENT



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.3-2
PRODUCTION AND CONSUMPTION
OF HIGHER ISOTOPES

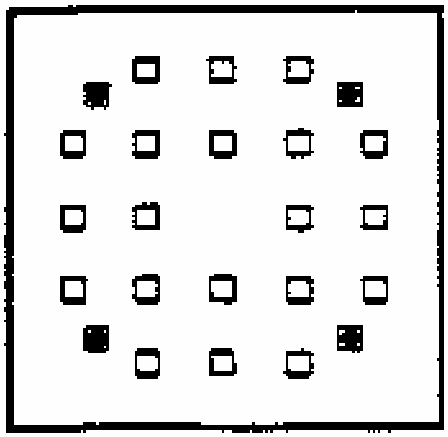


FSAR UPDATE

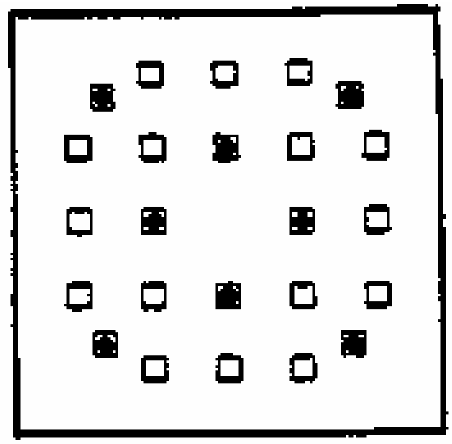
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.3-3

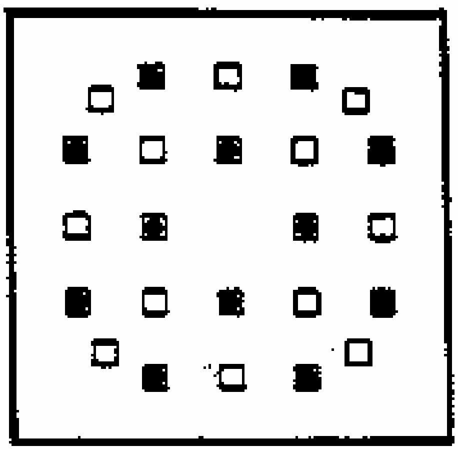
BORON CONCENTRATION VS
CYCLE BURNUP WITH
BURNABLE ABSORBER RODS



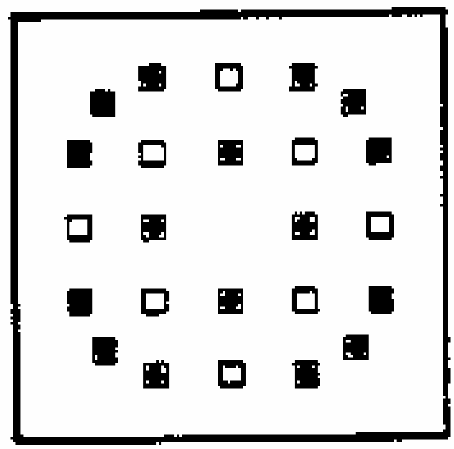
4 Fresh BA



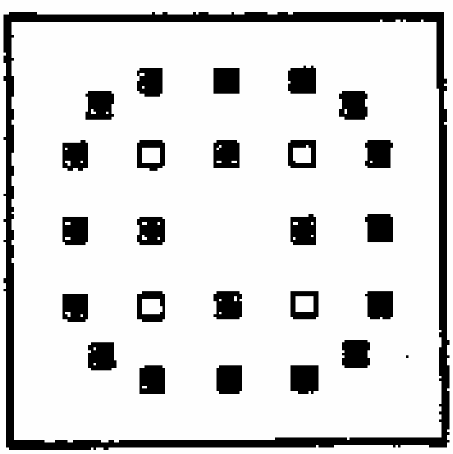
8 Fresh BA



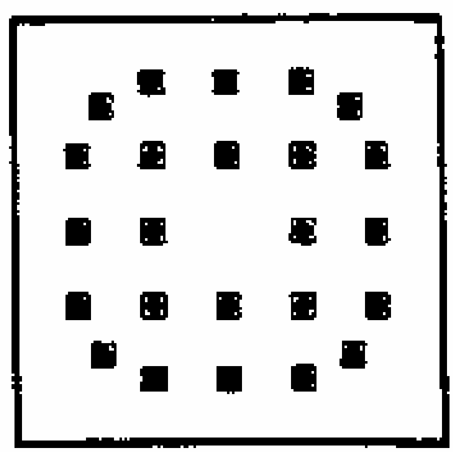
12 Fresh BA



16 Fresh BA



20 Fresh BA

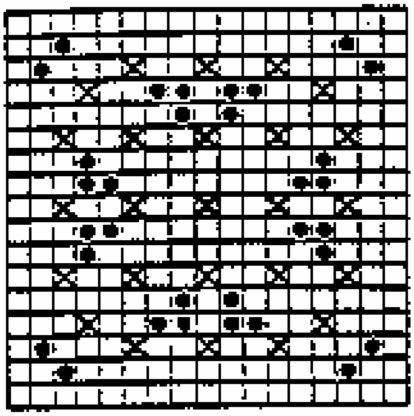


24 Fresh BA

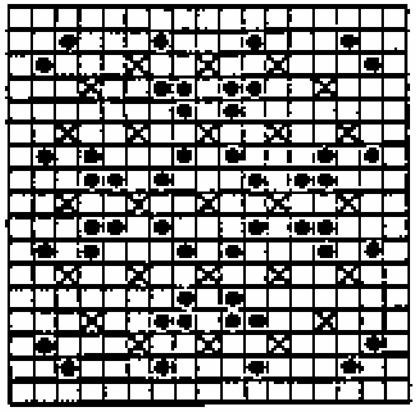
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

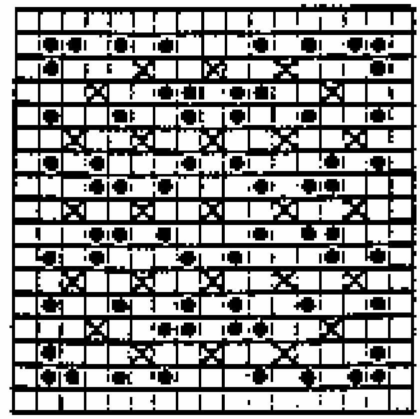
FIGURE 4.3-4
BURNABLE ABSORBER ROD
ARRANGEMENT WITHIN AN ASSEMBLY



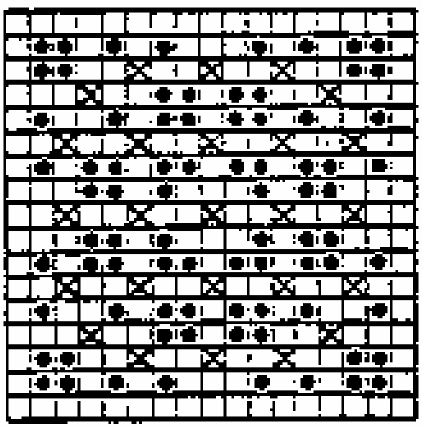
32 IFBA Pattern



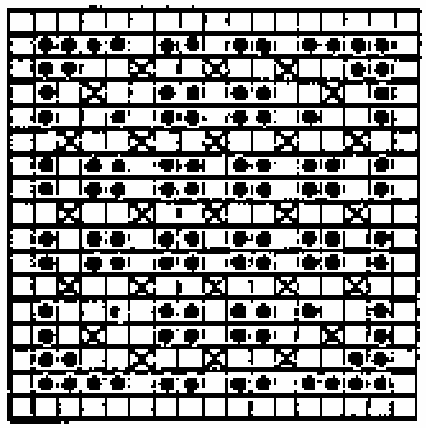
48 IFBA Pattern



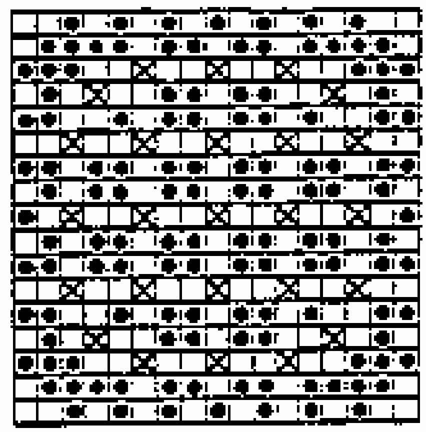
64 IFBA Pattern



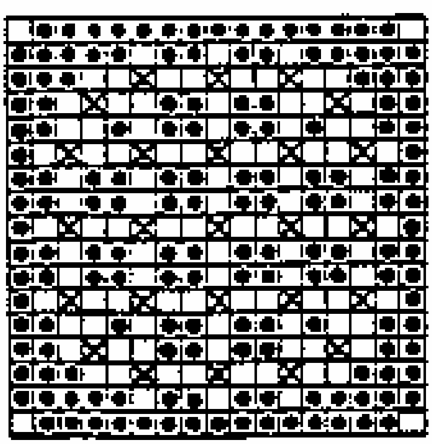
80 IFBA Pattern



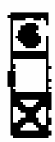
100 IFBA Pattern



128 IFBA Pattern



160 IFBA Pattern



- IFBA Rod
- Non Poisoned Rod
- Guide Tube

* IFBA patterns can change at vendor's discretion

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-5 TYPICAL INTEGRAL FUEL BURNABLE ABSORBER ROD ARRANGEMENT WITHIN AN ASSEMBLY

180

	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
1															
2					48		80	128	80		48				
3				128		128		128		128		128			
4			128		128		128		128		128		128		
5		48		128		128		128		128		128		48	
6			128		128		128		128		128		128		
7		80		128		128		128		128		128 4S		80	
8		128	128		128		128		128		128		128	128	
9		80		128 4S		128		128		128		128		80	
10			128		128		128		128		128		128		
11		48		128		128		128		128		128		48	
12			128		128		128		128		128		128		
13				128		128		128		128		128			
14					48		80	128	80		48				
15															

270

0

number indicates number of IFBA rods.

S indicates secondary source rod.

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.3-6
BURNABLE ABSORBER
LOADING PATTERN

0.889					
1.210	1.029				
1.033	1.264	1.084			
1.232	1.073	1.236	1.079		
1.099	1.309	1.068	1.308	1.083	
1.215	1.049	1.300	1.143	1.152	0.879
1.153	1.165	0.988	1.130	0.849	0.331
0.493	0.465	0.412	0.261		

AP	AVERAGE POWER

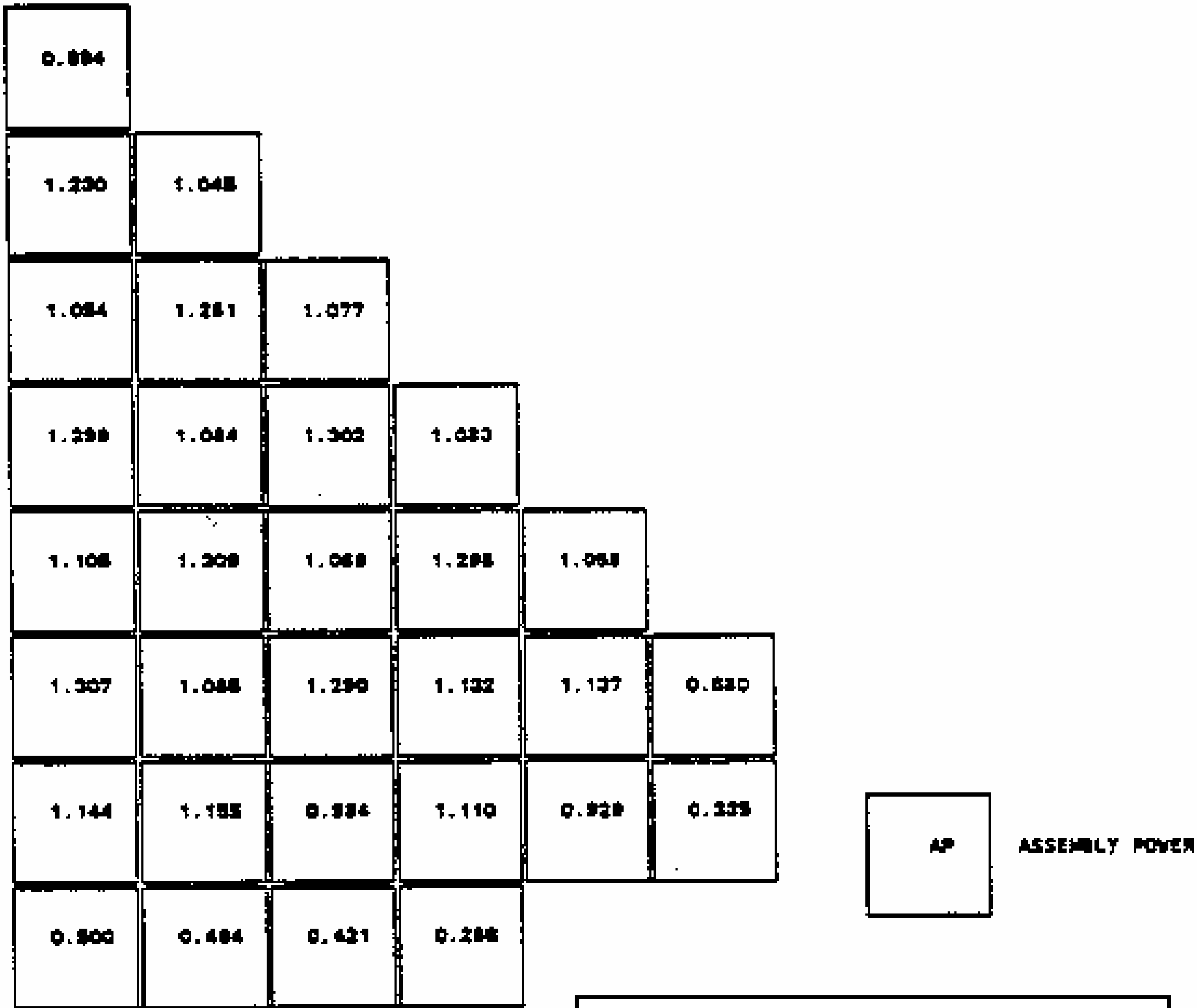
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.3-7

NORMALIZED POWER DENSITY DISTRIBUTION NEAR BEGINNING OF LIFE (BOL), UNRODDED CORE, HOT FULL POWER, NO XENON

Revision 11 November 1996



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.3-8

NORMALIZED POWER DENSITY
DISTRIBUTION NEAR BOL
UNRODDED CORE, HOT FULL POWER,
EQUILIBRIUM XENON

Revision 11 November 1996

0.846					
1.227	1.084				
1.070	1.300	1.067			
1.322	1.103	1.325	1.100		
1.118	1.324	1.069	1.312	1.070	
1.310	1.062	1.278	1.130	1.146	0.857
1.136	1.133	0.824	1.061	0.832	0.336
0.483	0.482	0.401	0.278		

AP	ASSEMBLY POWER

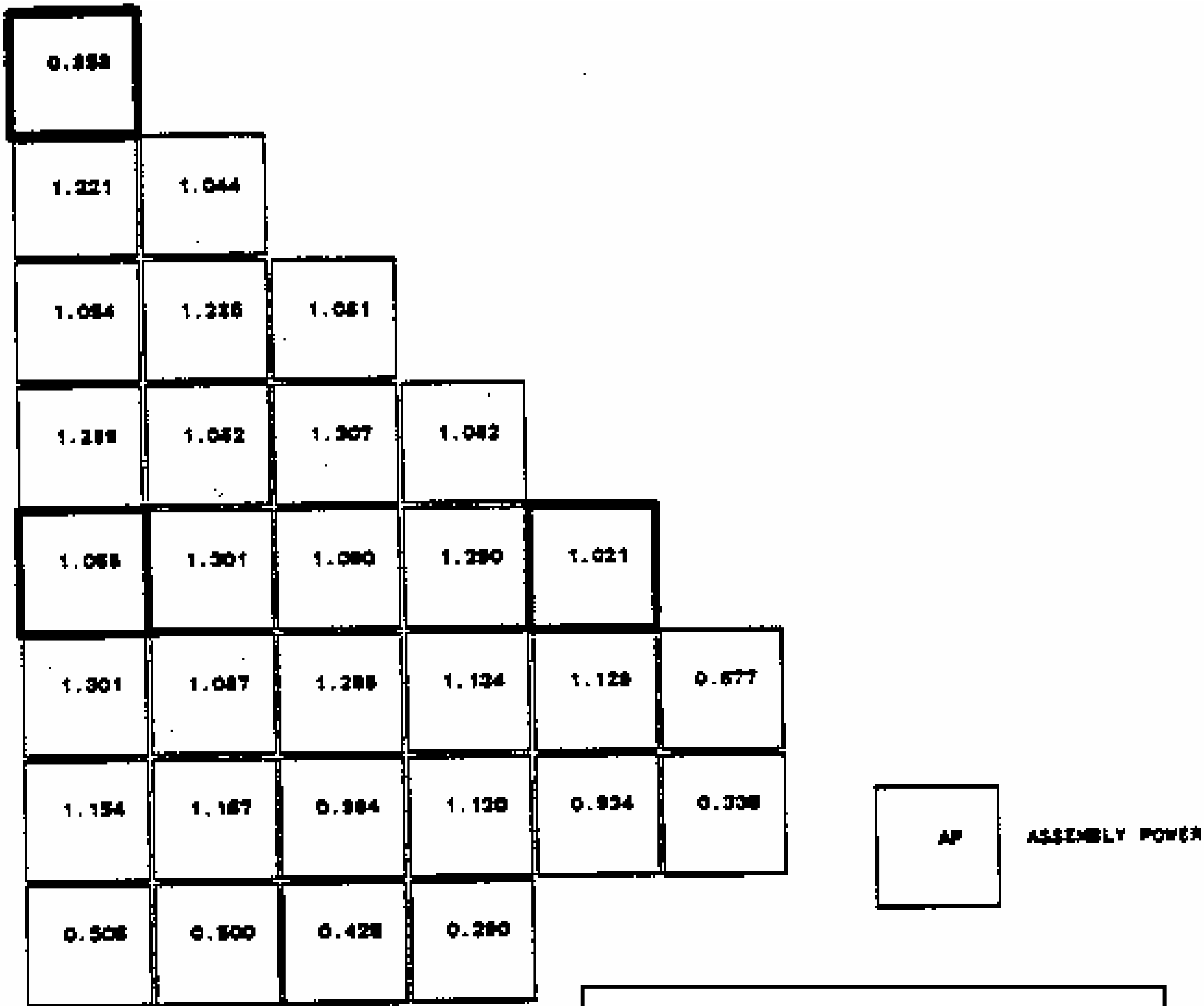
FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

FIGURE 4.3-9

NORMALIZED POWER DENSITY DISTRIBUTION NEAR BOL GROUP D AT INSERTION LIMIT, HOT FULL POWER, EQUILIBRIUM XENON

Revision 11 November 1996



FSAR UPDATE

UNIT 2
DIABLO CANYON SITE

FIGURE 4.3-10

NORMALIZED POWER DENSITY DISTRIBUTION NEAR BOL GROUP D AT INSERTION LIMIT, HOT FULL POWER, EQUILIBRIUM XENON

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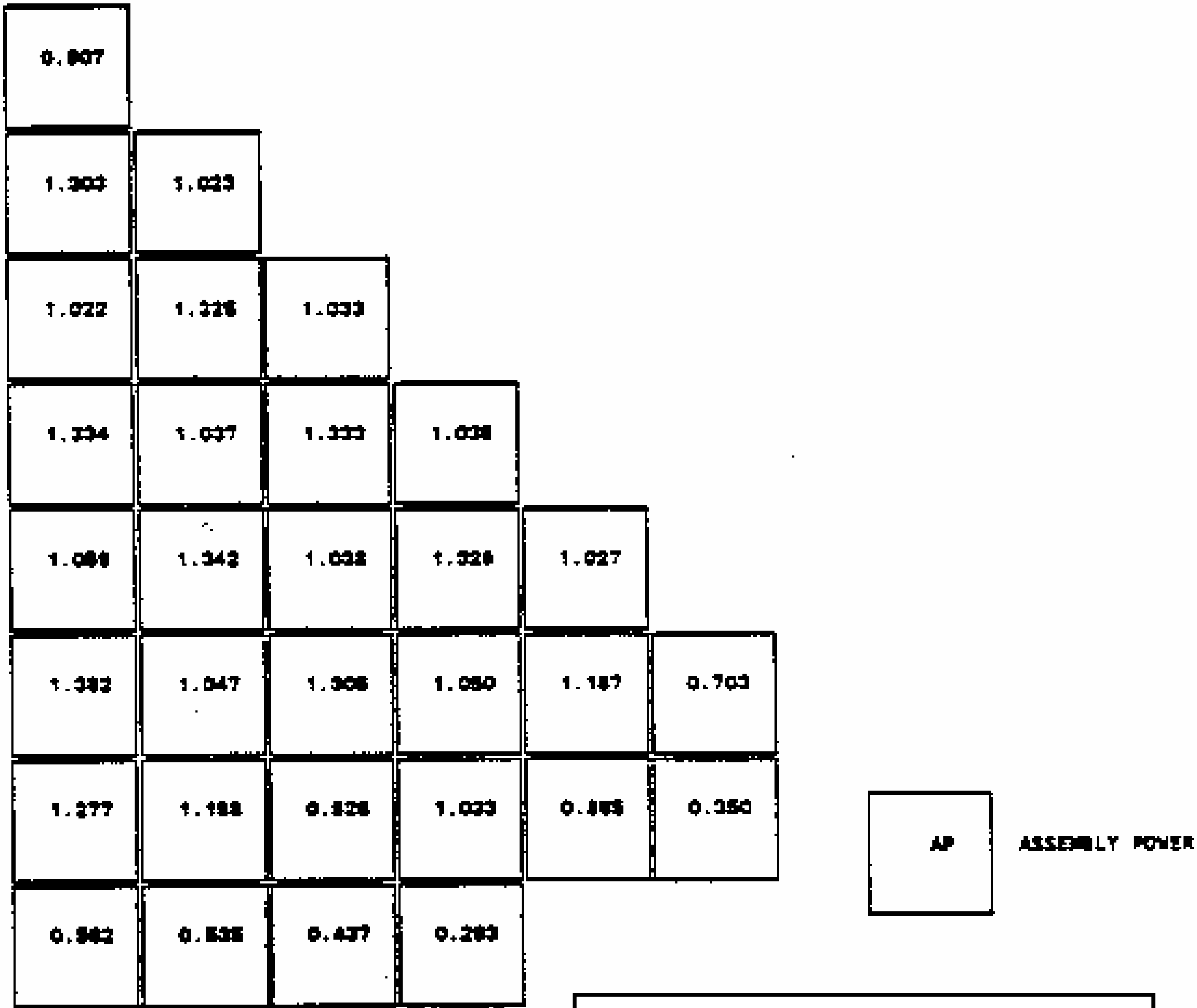
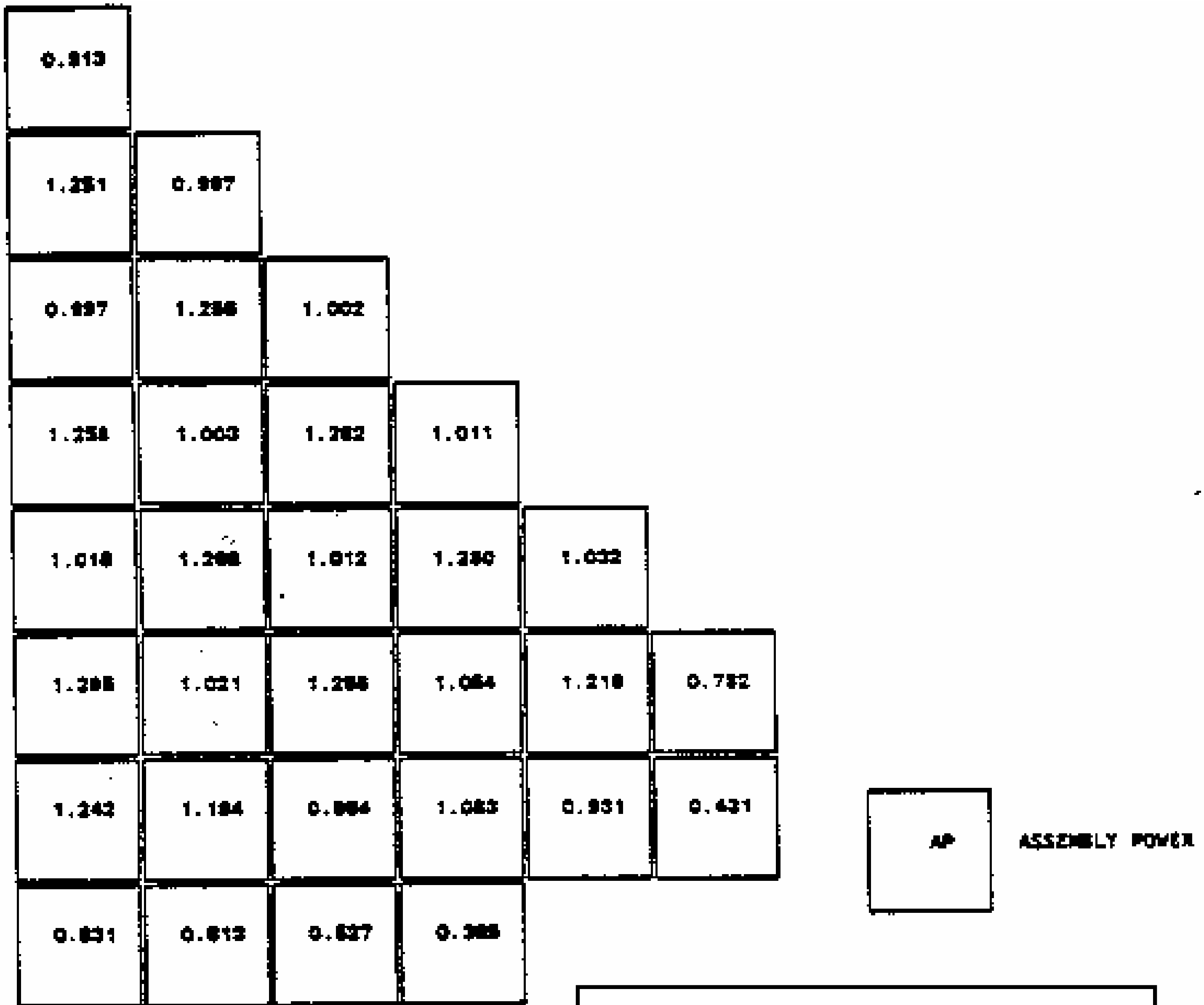


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.3-11

NORMALIZED POWER DENSITY DISTRIBUTION NEAR MIDDLE OF LIFE (MOL) UNRODDED CORE, HOT FULL POWER, EQUILIBRIUM XENON



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.3-12

NORMALIZED POWER DENSITY DISTRIBUTION NEAR END OF LIFE (EOL) UNRODDED CORE, HOT FULL POWER, EQUILIBRIUM XENON

Revision 11 November 1996

1.240	1.208	1.141	1.208	1.163	1.241	1.172	1.234	1.185	1.236	1.177	1.248	1.172	1.220	1.154	1.224	1.258
1.210	1.124	1.129	1.182	1.177	1.282	1.183	1.126	1.281	1.186	1.148	1.289	1.185	1.162	1.135	1.138	1.227
1.143	1.124	1.186	1.280	1.320		1.305	1.302		1.305	1.308		1.329	1.300	1.169	1.137	1.158
1.211	1.184	1.281		1.345	1.328	1.308	1.204	1.317	1.308	1.213	1.345	1.354		1.303	1.167	1.227
1.167	1.180	1.322	1.344	1.252	1.335	1.213	1.208	1.318	1.211	1.217	1.342	1.260	1.286	1.334	1.182	[illegible]
1.248	1.236		1.340	1.336		1.335	1.322		1.324	1.327		1.344	1.350		1.298	1.260
1.177	1.187	1.308	1.211	1.218	1.224	1.215	1.215	1.325	1.216	1.218	1.230	1.221	1.220	1.318	1.199	1.190
1.240	1.181	1.307	1.207	1.213	1.323	1.216	1.217	1.327	1.218	1.219	1.324	1.218	1.214	1.317	1.202	1.253
1.191	1.257		1.315	1.321		1.326	1.324		1.328	1.329		1.327	1.321		1.294	1.202
1.244	1.184	1.310	1.210	1.215	1.327	1.218	1.220	1.330	1.221	1.221	1.331	1.220	1.217	1.319	1.204	1.255
1.184	1.194	1.315	1.218	1.221	1.331	1.221	1.221	1.331	1.222	1.224	1.335	1.227	1.225	1.334	1.203	1.195
1.257	1.237		1.351	1.347		1.333	1.331		1.339	1.336		1.352	1.358		1.304	1.267
1.181	1.183	1.336	1.360	1.285	1.348	1.226	1.221	1.330	1.222	1.228	1.353	1.270	1.267	1.344	1.201	1.190
1.229	1.170	1.304		1.363	1.356	1.224	1.218	1.326	1.219	1.227	1.360	1.368		1.316	1.176	1.238
1.163	1.143	1.177	1.310	1.341		1.324	1.321		1.222	1.326		1.345	1.316	1.189	1.150	1.171
1.234	1.146	1.148	1.174	1.188	1.305	1.204	1.206	1.302	1.207	1.206	1.308	1.202	1.178	1.150	1.152	1.242
1.267	1.225	1.166	1.253	1.167	1.265	1.196	1.256	1.206	1.257	1.194	1.268	1.191	1.238	1.171	1.241	1.275

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.3-13

RODWISE POWER DISTRIBUTION
IN A TYPICAL ASSEMBLY (G-10)
NEAR BOL, HOT FULL POWER,
EQUILIBRIUM XENON, UNRODDED CORE

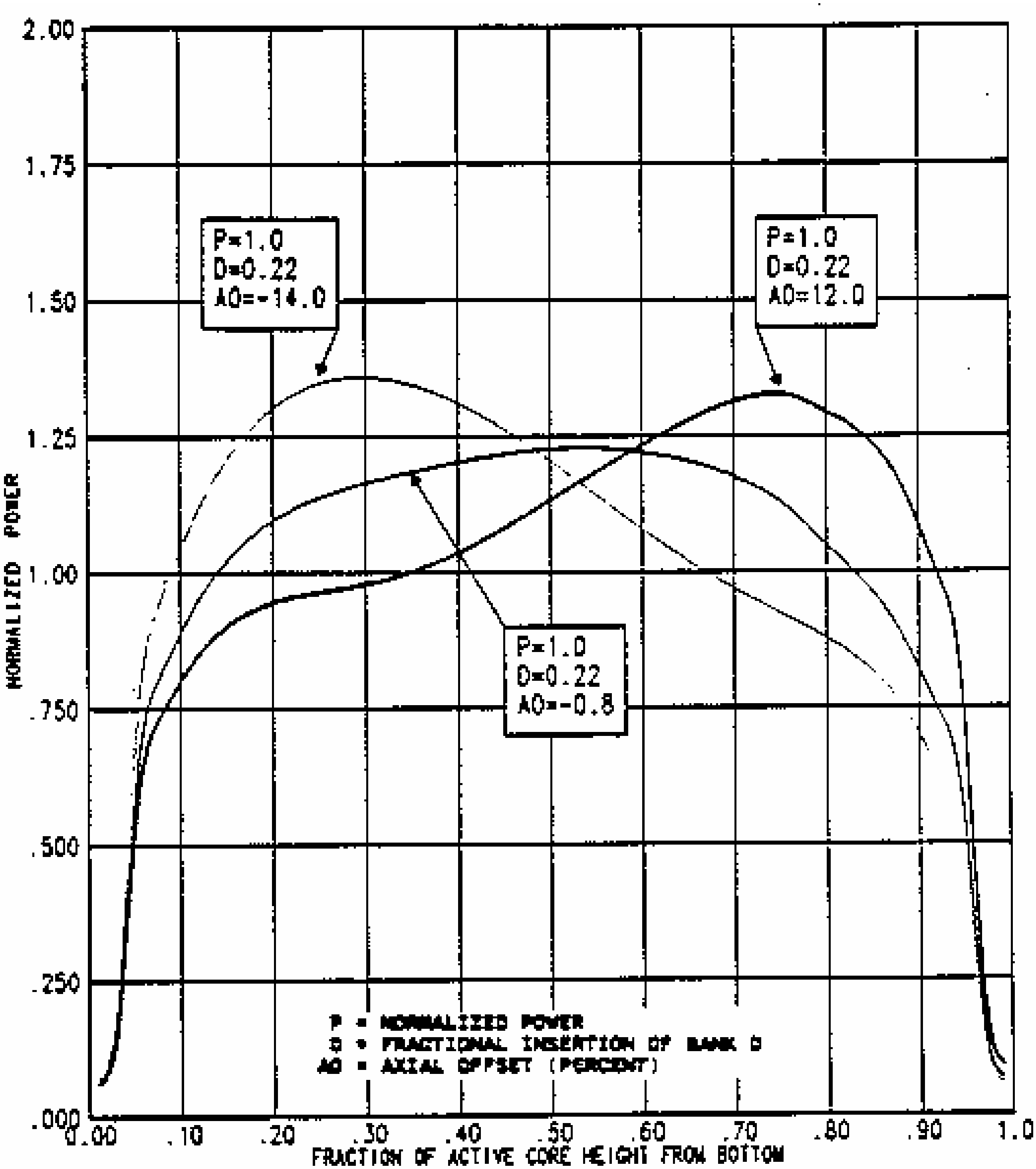
1.218	1.198	1.218	1.205	1.237	1.226	1.244	1.223	1.250	1.223	1.244	1.227	1.238	1.206	1.219	1.200	1.220
1.189	1.199	1.202	1.220	1.237	1.246	1.243	1.243	1.247	1.243	1.249	1.246	1.238	1.221	1.202	1.200	1.200
1.218	1.202	1.223	1.247	1.264		1.258	1.257		1.257	1.258		1.265	1.248	1.223	1.204	1.220
1.205	1.220	1.247		1.277	1.275	1.258	1.259	1.282	1.255	1.282	1.276	1.278		1.248	1.221	1.206
1.237	1.237	1.264	1.277	1.281	1.273	1.261	1.259	1.267	1.258	1.262	1.276	1.282	1.278	1.265	1.239	1.238
1.226	1.246		1.275	1.275		1.270	1.270		1.270	1.271		1.276	1.276		1.247	1.228
1.244	1.243	1.258	1.258	1.261	1.270	1.263	1.263	1.272	1.264	1.263	1.271	1.262	1.258	1.259	1.244	1.245
1.223	1.243	1.257	1.255	1.258	1.270	1.263	1.264	1.273	1.265	1.264	1.270	1.260	1.256	1.254	1.245	1.225
1.251	1.247		1.262	1.267		1.272	1.273		1.273	1.272		1.265	1.263		1.248	1.252
1.223	1.243	1.257	1.256	1.259	1.270	1.264	1.265	1.273	1.265	1.264	1.271	1.260	1.256	1.258	1.245	1.225
1.244	1.244	1.259	1.258	1.262	1.271	1.264	1.264	1.272	1.264	1.264	1.272	1.263	1.259	1.260	1.245	1.246
1.227	1.247		1.276	1.276		1.271	1.271		1.271	1.272		1.277	1.277		1.248	1.229
1.238	1.276	1.265	1.278	1.282	1.276	1.262	1.260	1.268	1.260	1.263	1.277	1.283	1.278	1.266	1.240	1.240
1.206	1.221	1.248		1.278	1.276	1.258	1.258	1.263	1.256	1.260	1.277	1.279		1.249	1.222	1.204
1.220	1.204	1.223	1.246	1.265		1.259	1.256		1.258	1.260		1.266	1.248	1.225	1.205	1.222
1.200	1.200	1.204	1.221	1.238	1.247	1.244	1.245	1.248	1.245	1.245	1.248	1.240	1.222	1.205	1.202	1.202
1.218	1.200	1.218	1.206	1.238	1.227	1.245	1.224	1.251	1.224	1.245	1.228	1.238	1.207	1.221	1.202	1.221

FSAR UPDATE

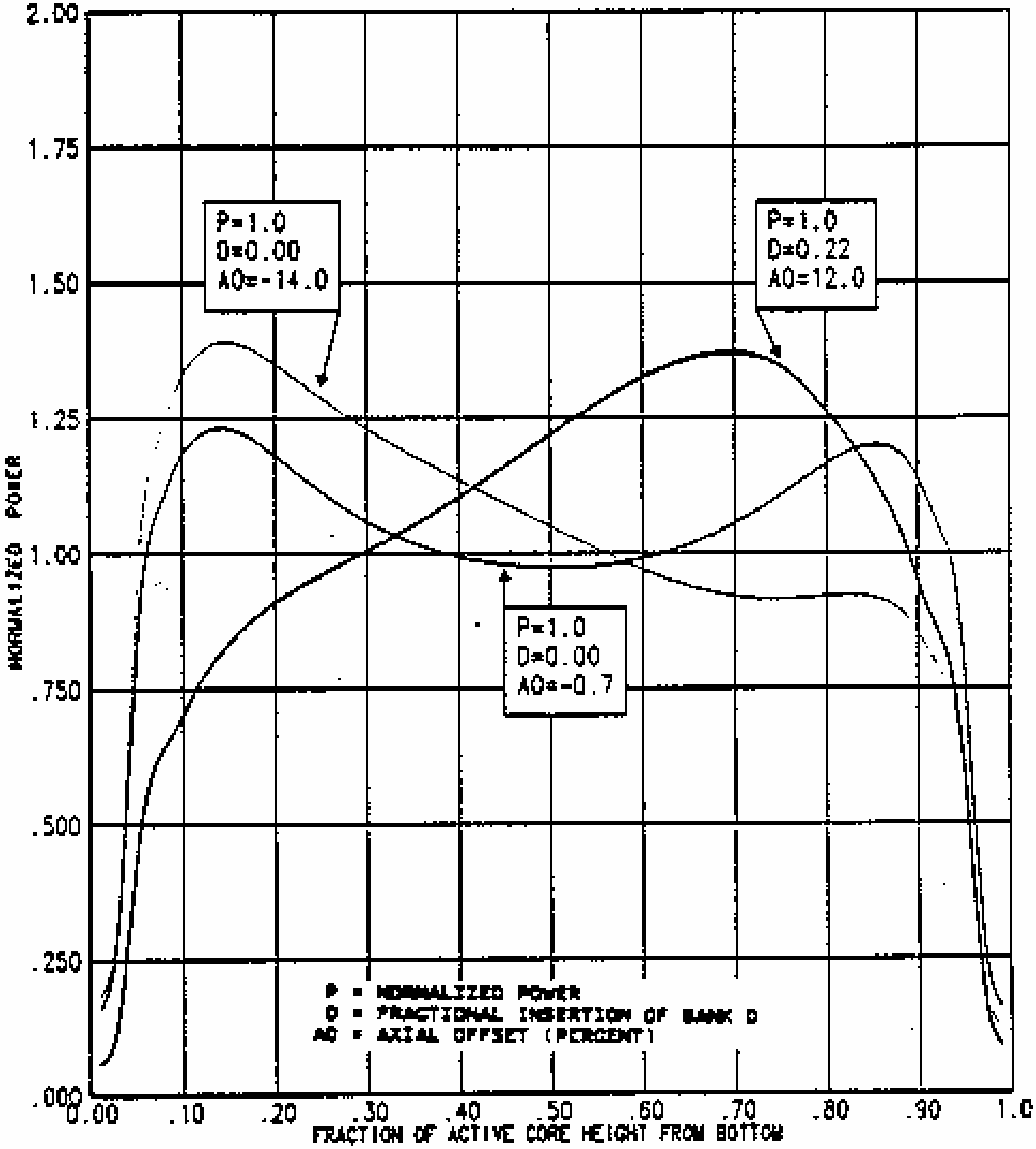
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.3-14

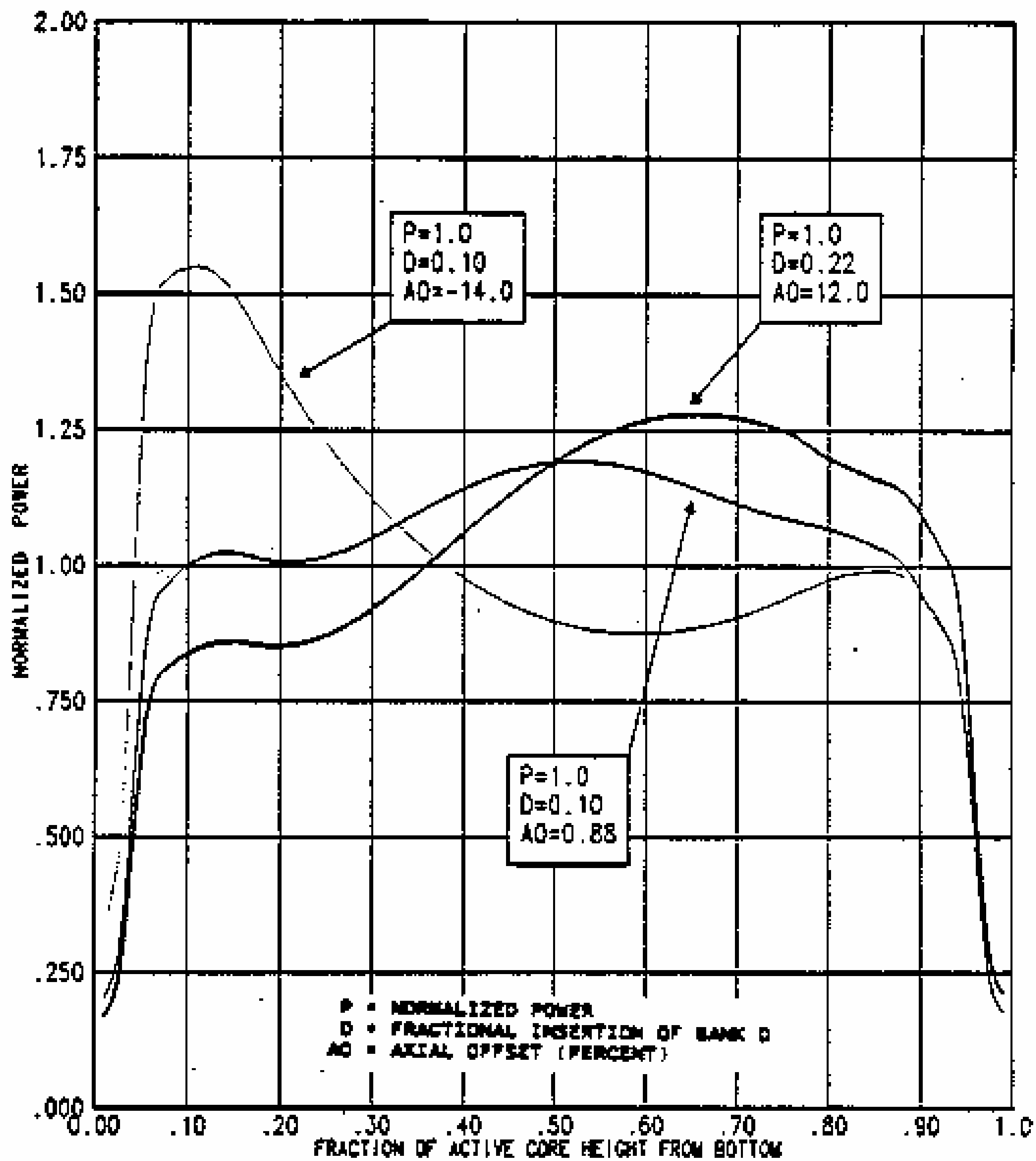
RODWISE POWER DISTRIBUTION
IN A TYPICAL ASSEMBLY (G-10)
NEAR EOL, HOT FULL POWER,
EQUILIBRIUM XENON, UNRODDED CORE



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-15 POSSIBLE AXIAL POWER SHAPES AT BOL DUE TO ADVERSE XENON DISTRIBUTIONS



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-16 POSSIBLE AXIAL POWER SHAPES AT MOL DUE TO ADVERSE XENON DISTRIBUTIONS

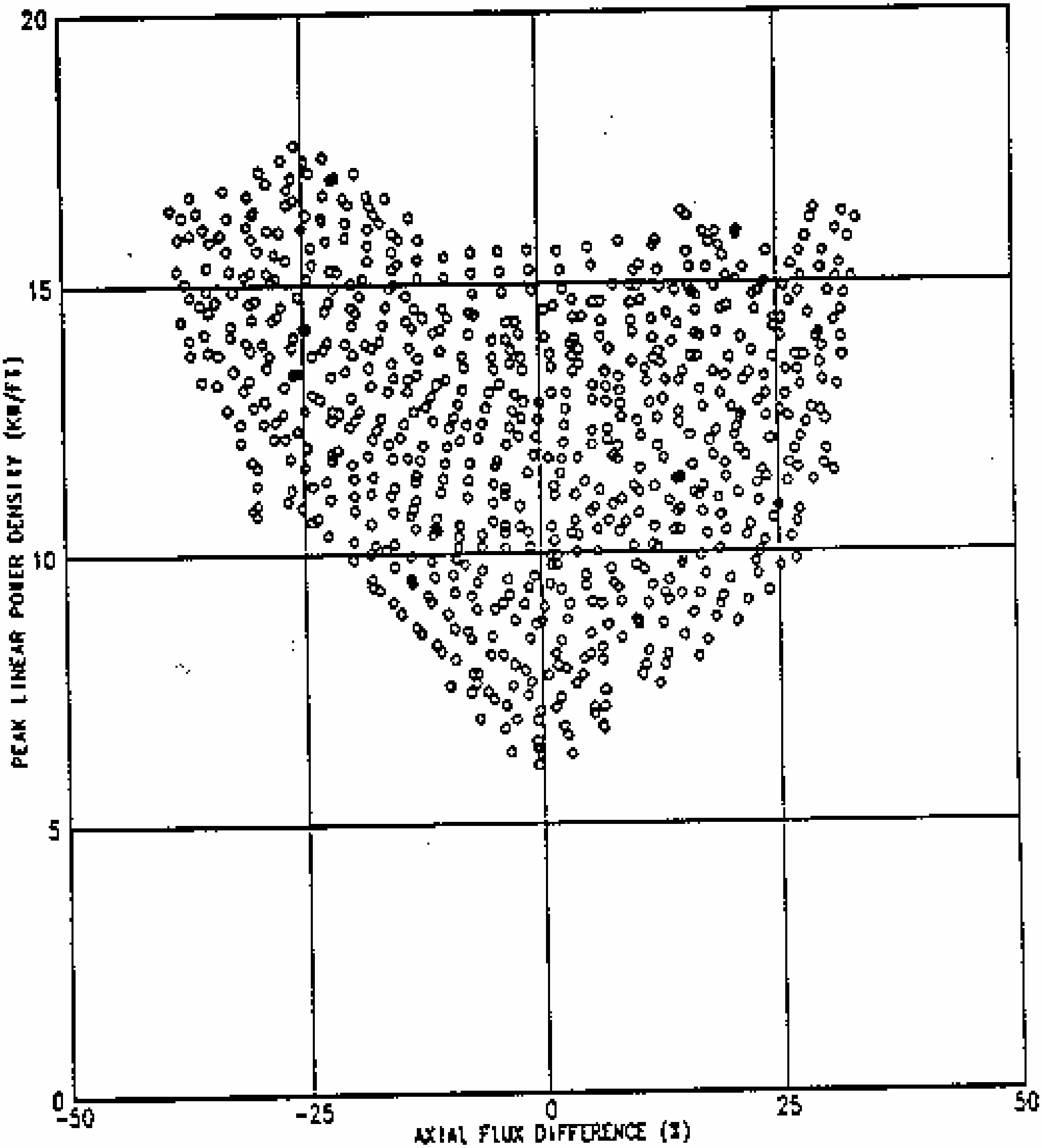


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.3-17

POSSIBLE AXIAL POWER SHAPES AT EOL DUE TO ADVERSE XENON DISTRIBUTIONS

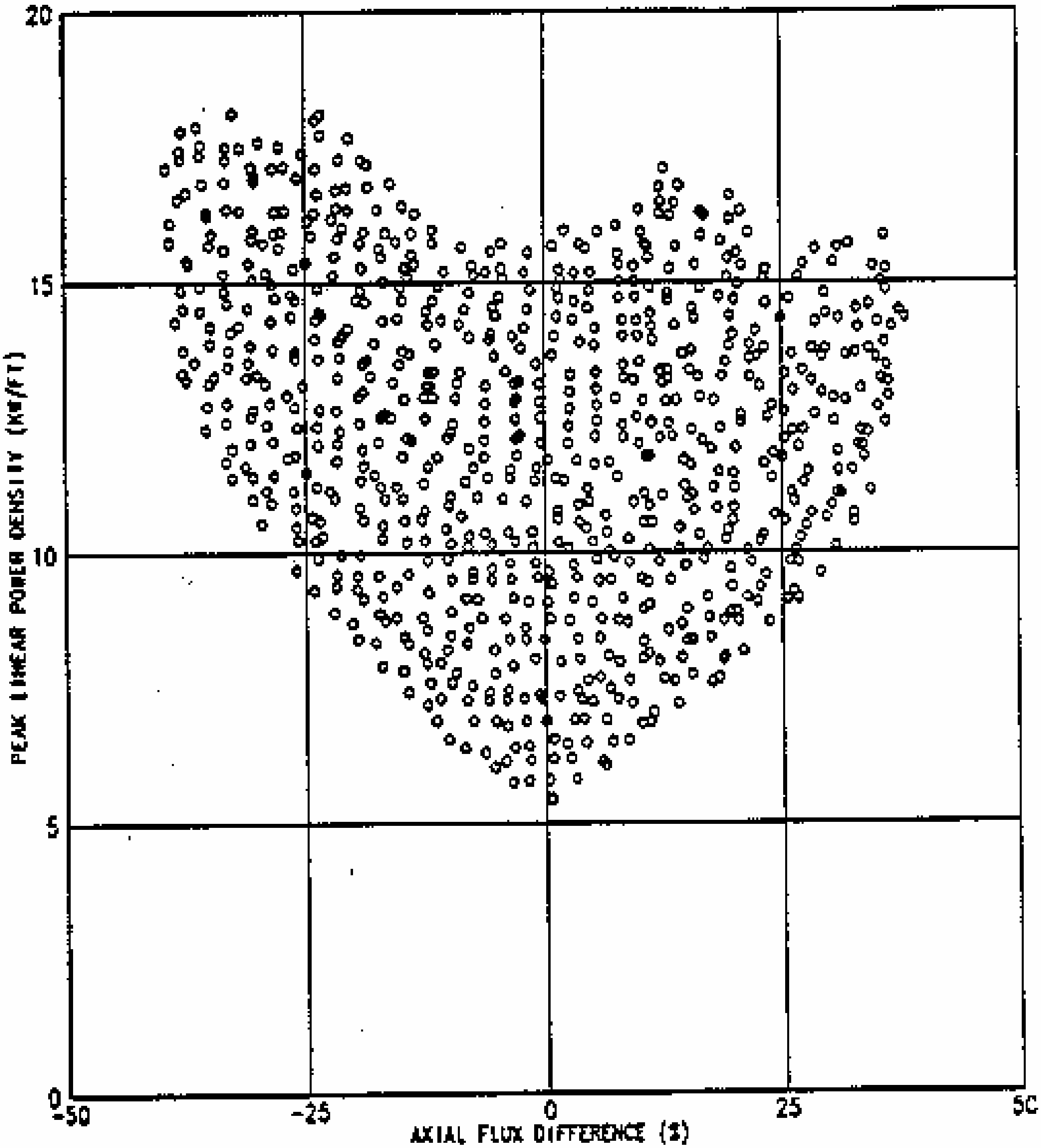


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.3-21

PEAK POWER DENSITY DURING
CONTROL ROD MALFUNCTION
OVER POWER TRANSIENTS

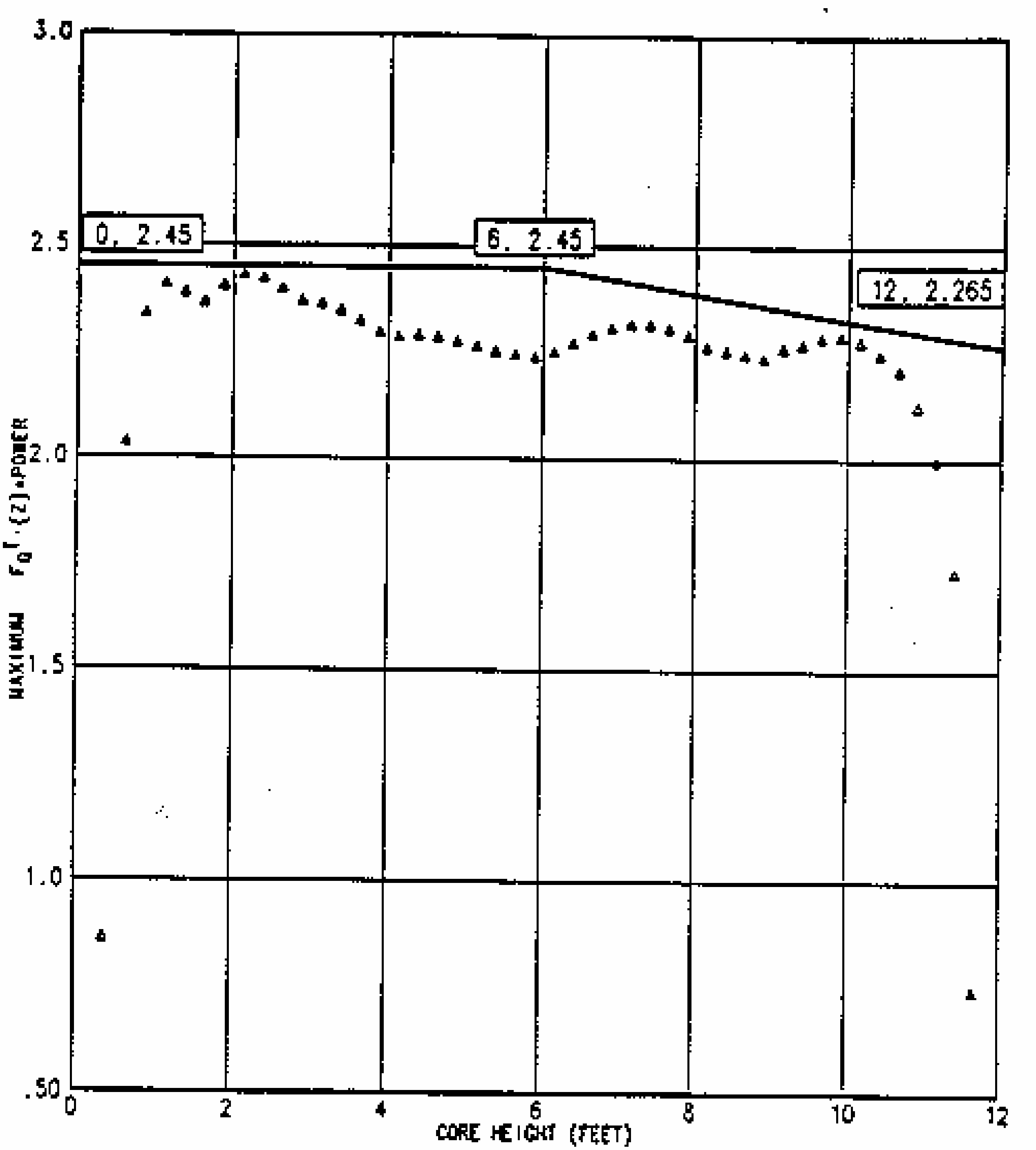


FSAR UPDATE

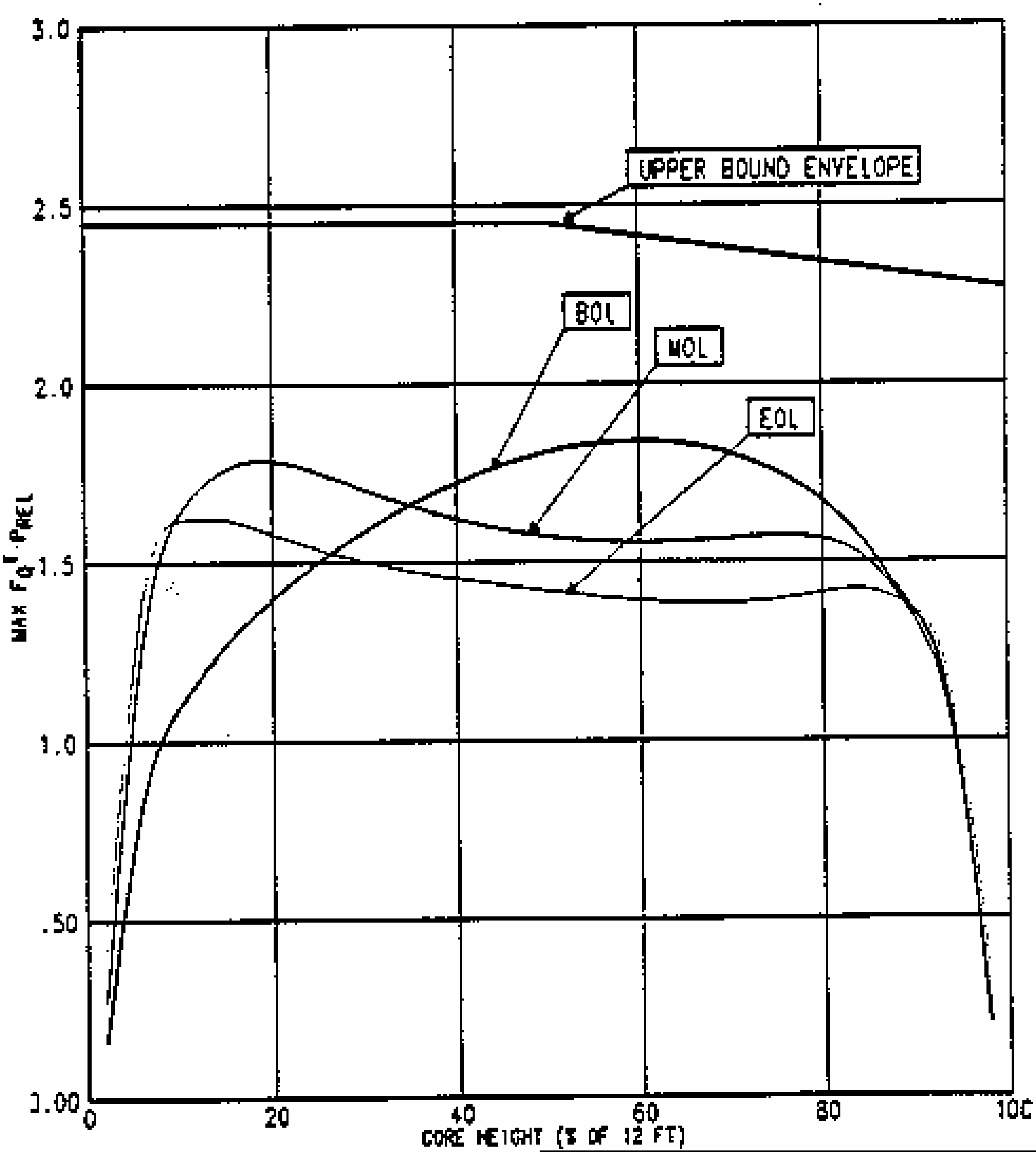
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.3-22

PEAK LINEAR POWER DURING
BORATION / DILUTION
OVER POWER TRANSIENTS



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-23 MAXIMUM F_Q^T x POWER vs AXIAL HEIGHT DURING NORMAL OPERATIONS

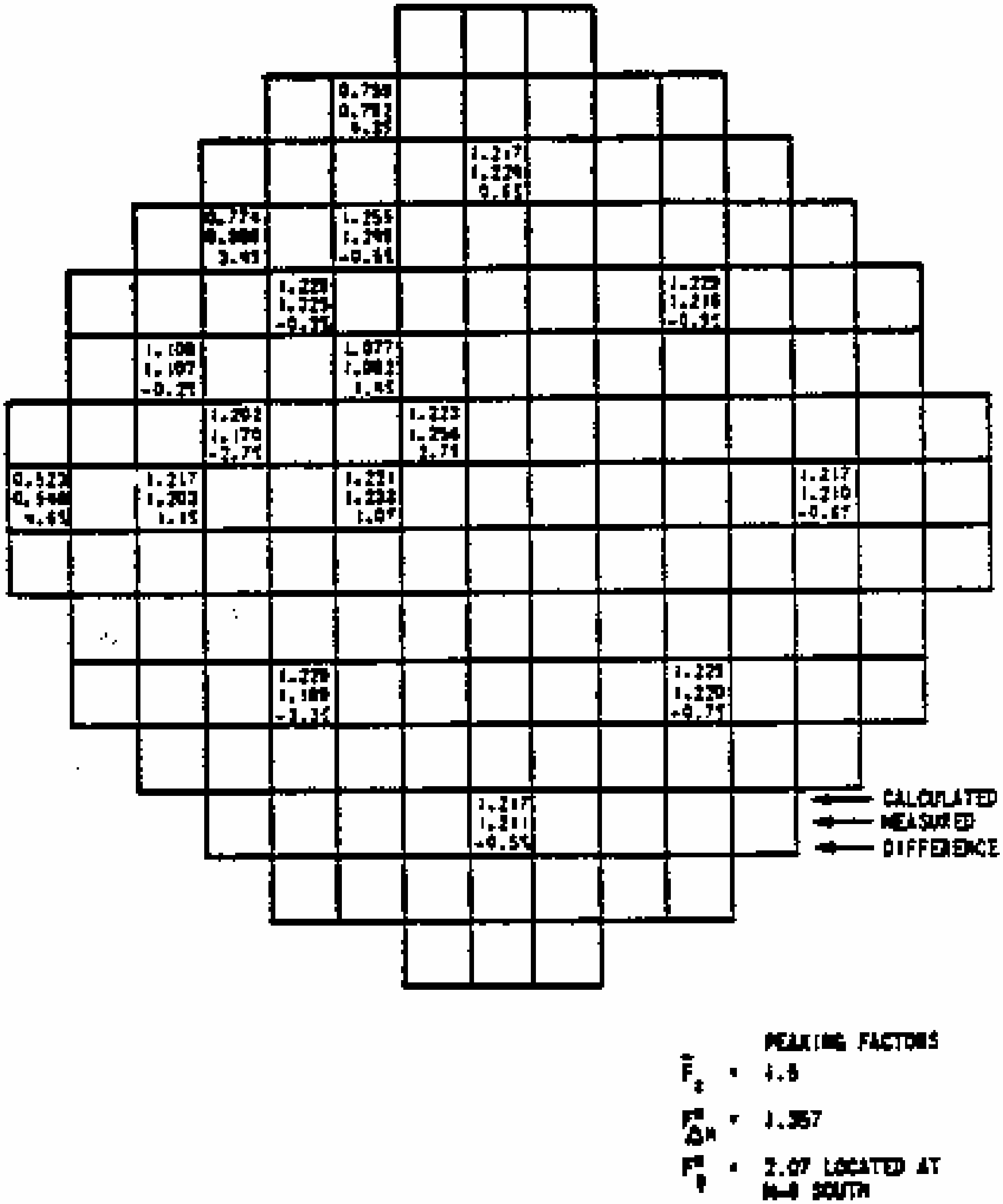


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.3-24

COMPARISON OF EXPECTED STEADY STATE POWER DISTRIBUTIONS WITH THE PEAKING FACTOR ENVELOPE

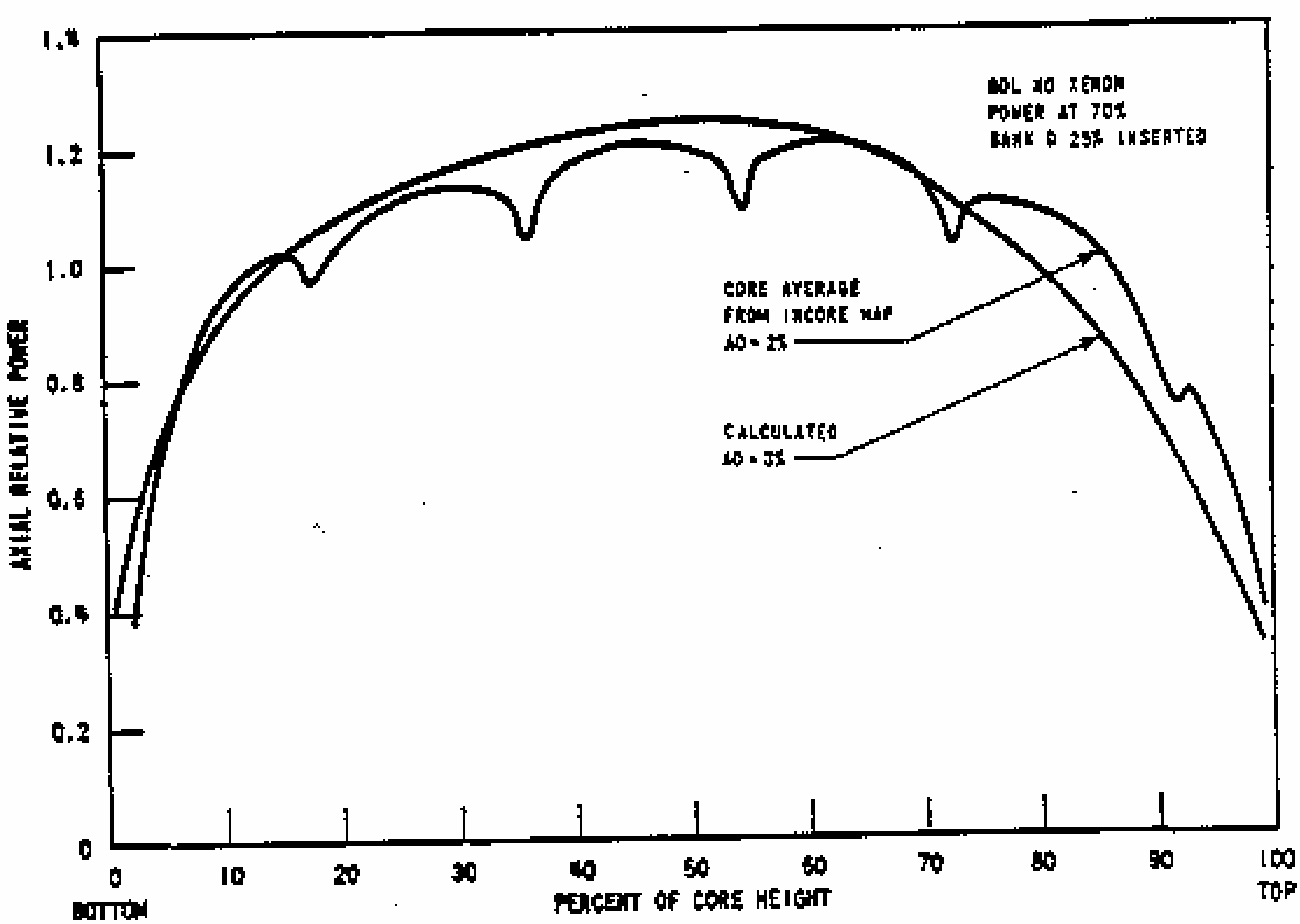


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.3-25

COMPARISON BETWEEN CALCULATED AND MEASURED RELATIVE FUEL ASSEMBLY POWER DISTRIBUTION



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-26 COMPARISON OF CALCULATED AND MEASURED AXIAL SHAPE

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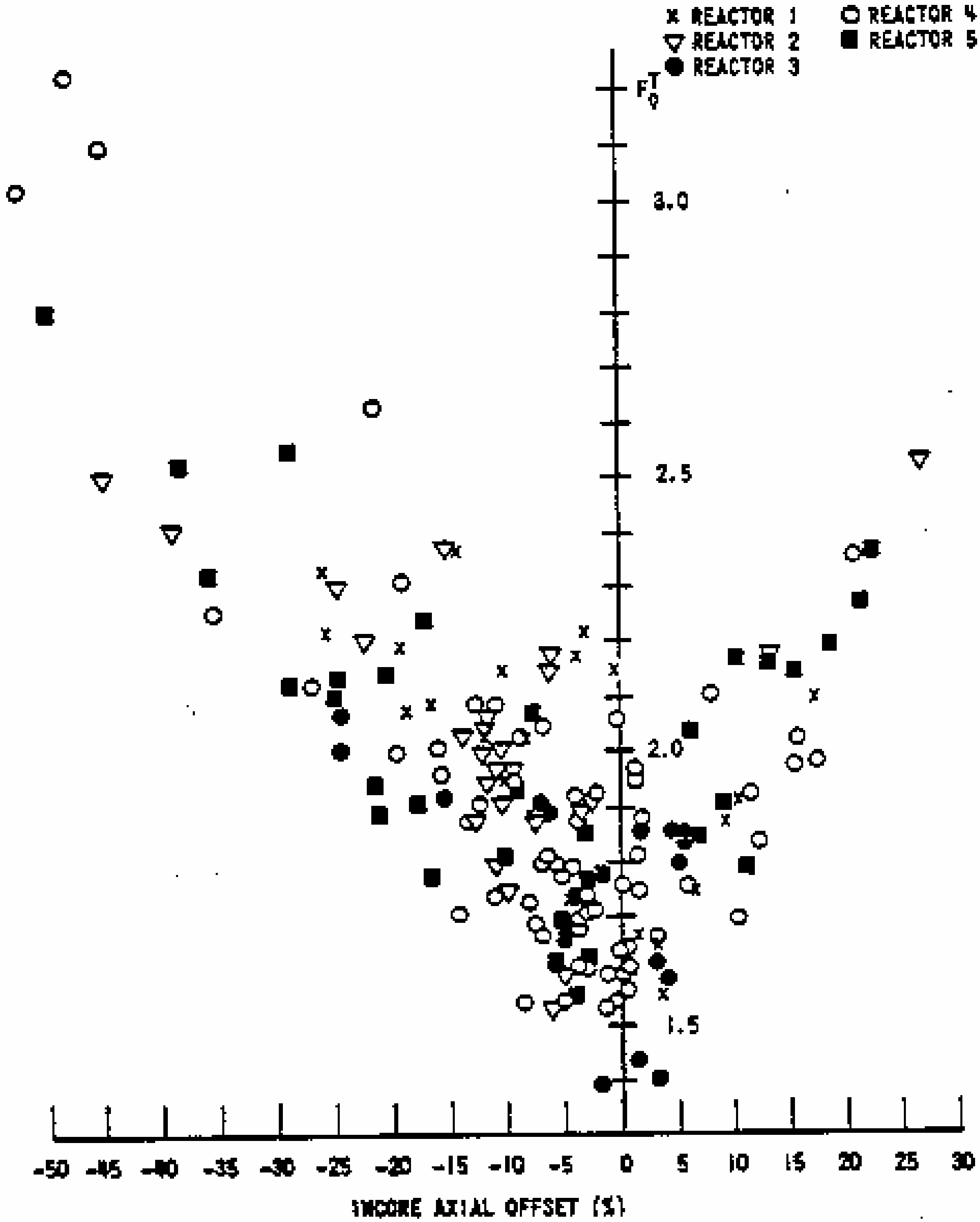
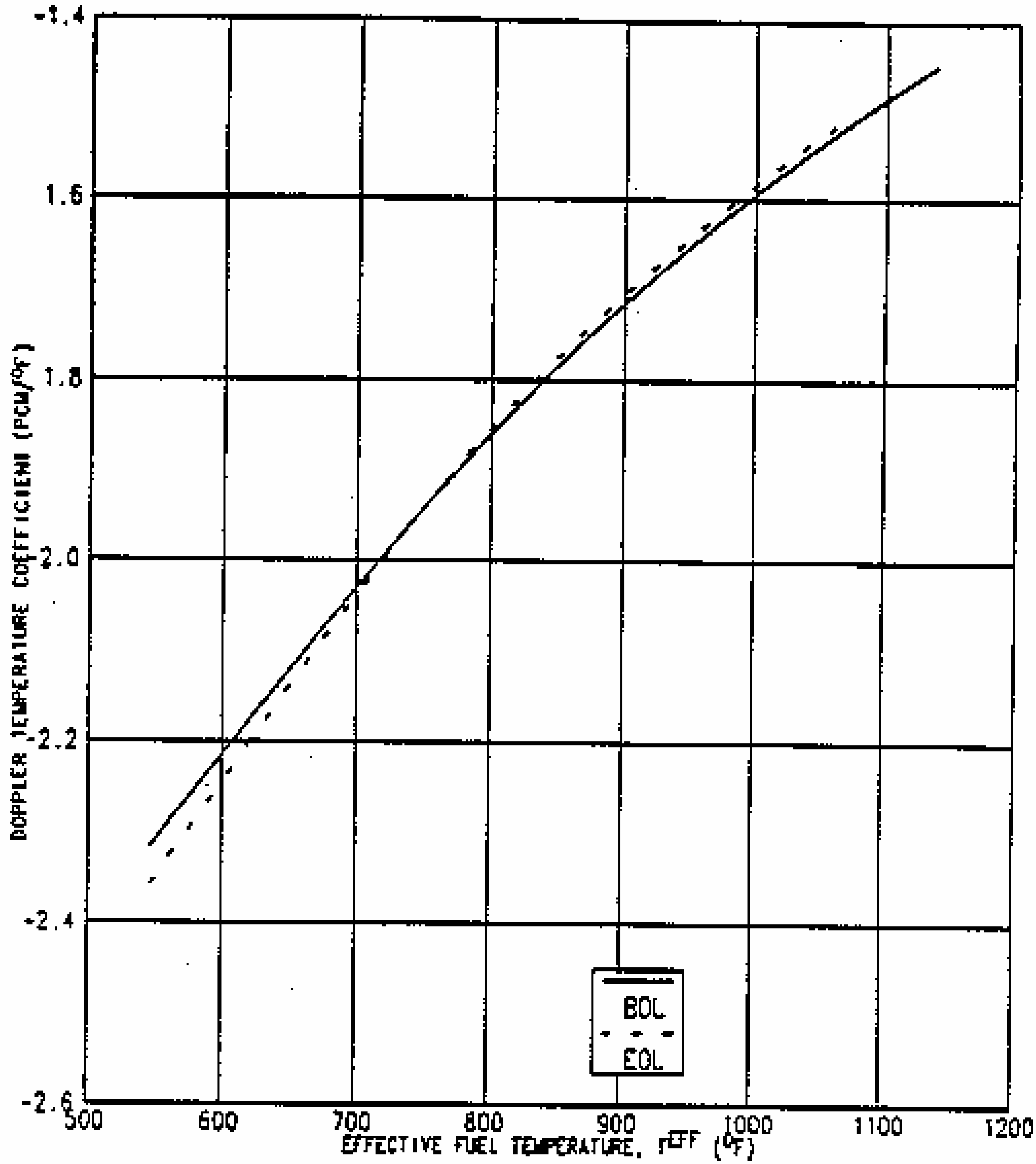


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.3-27
MEASURED VALUES OF F_Q^T FOR FULL POWER ROD CONFIGURATIONS

Revision 11 November 1996

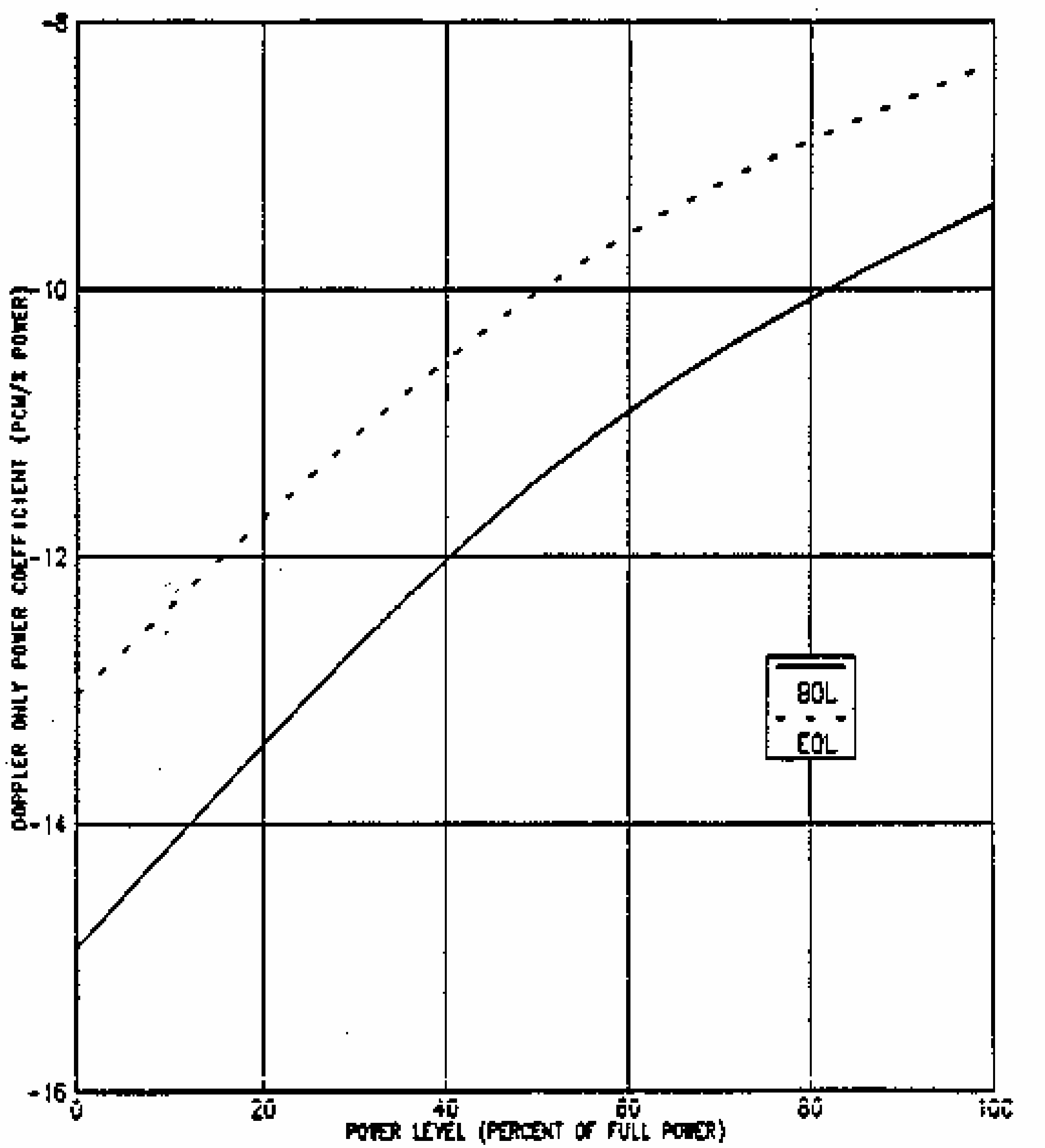


FSAR UPDATE

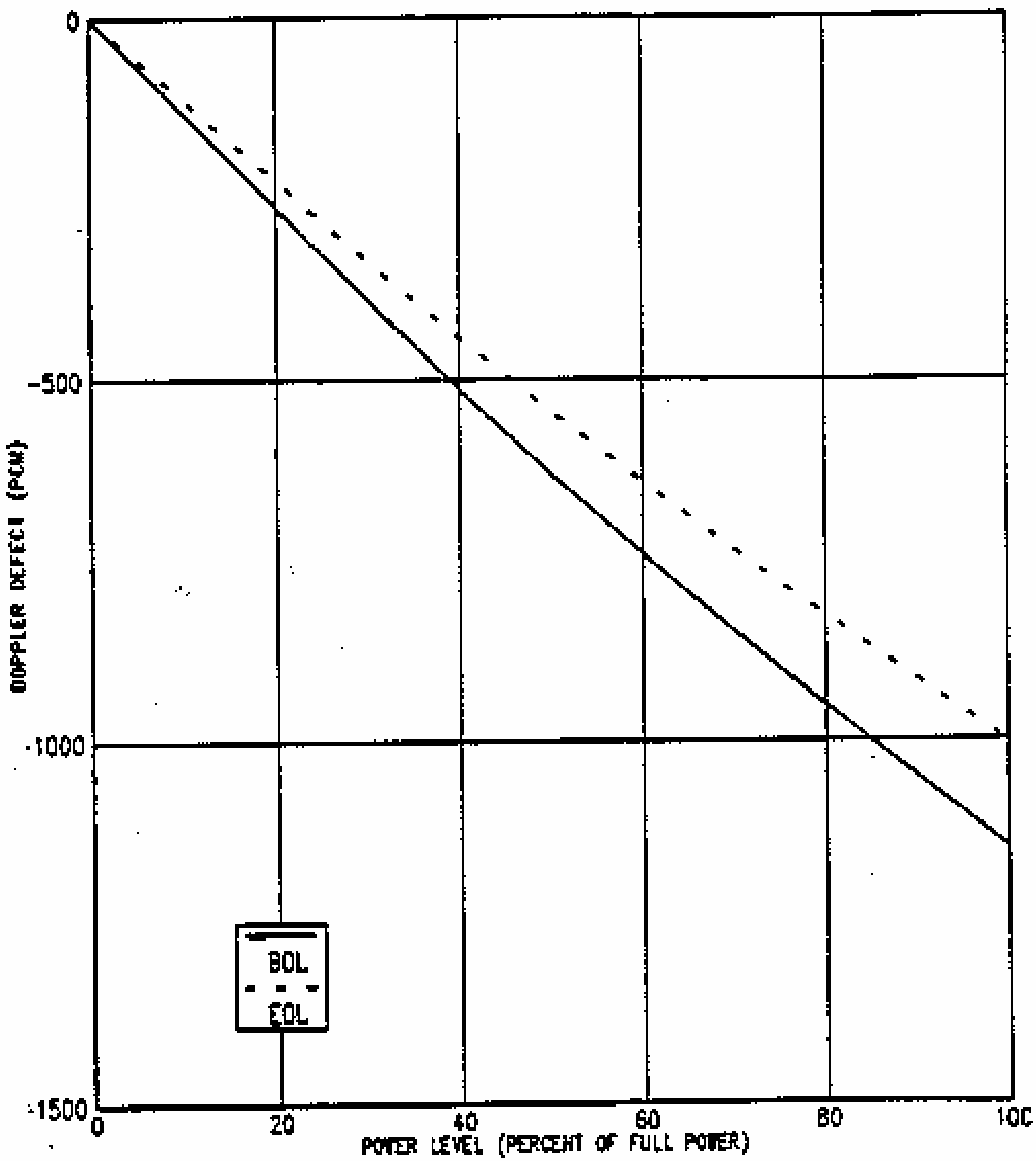
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.3-28

DOPPLER TEMPERATURE COEFFICIENT AT BOL AND EOL



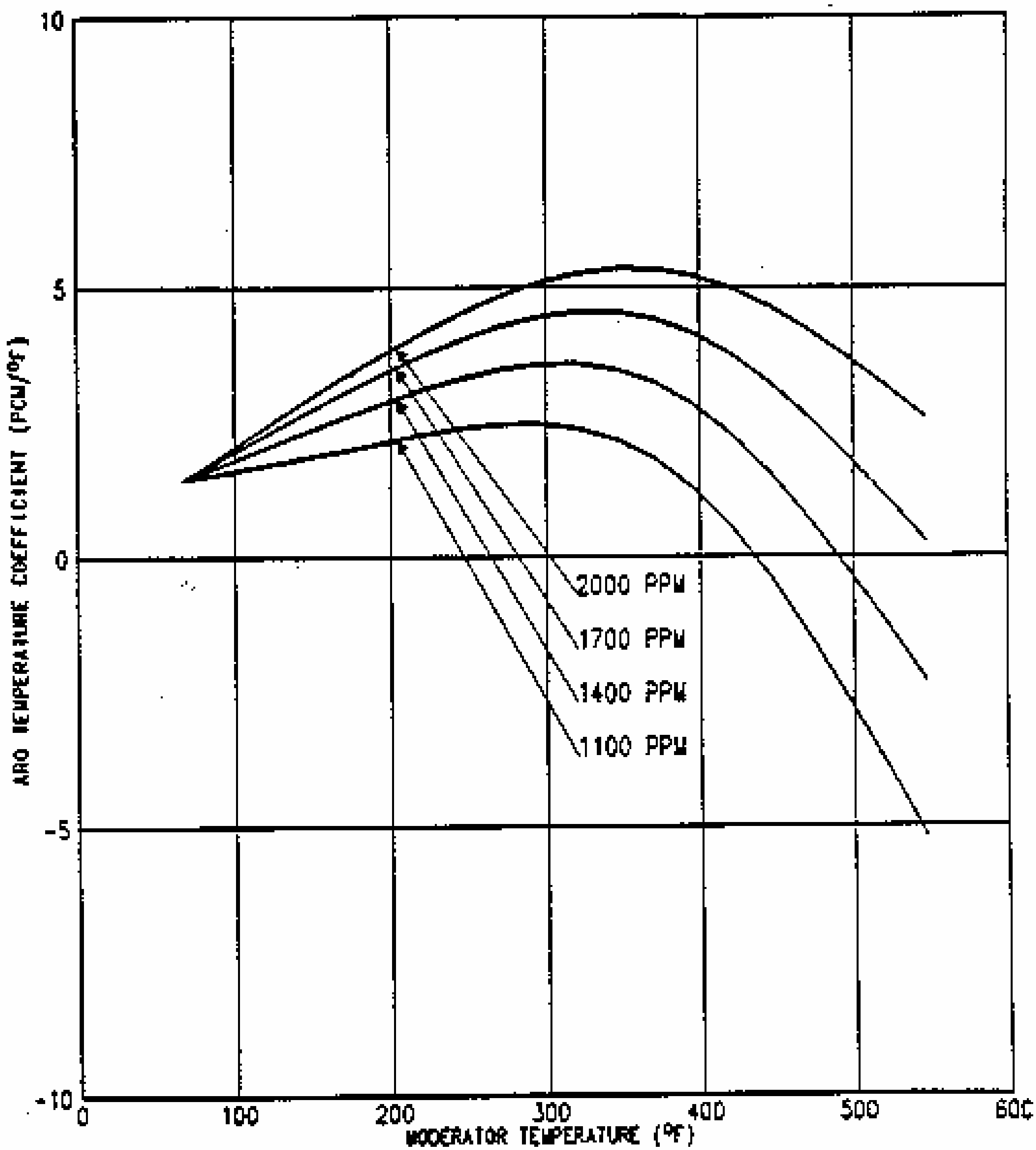
FSAR UPDATE
UNITS 1 AND 2 **DIABLO CANYON SITE**
FIGURE 4.3-29 **DOPPLER ONLY POWER COEFFICIENT AT BOL AND EOL**



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

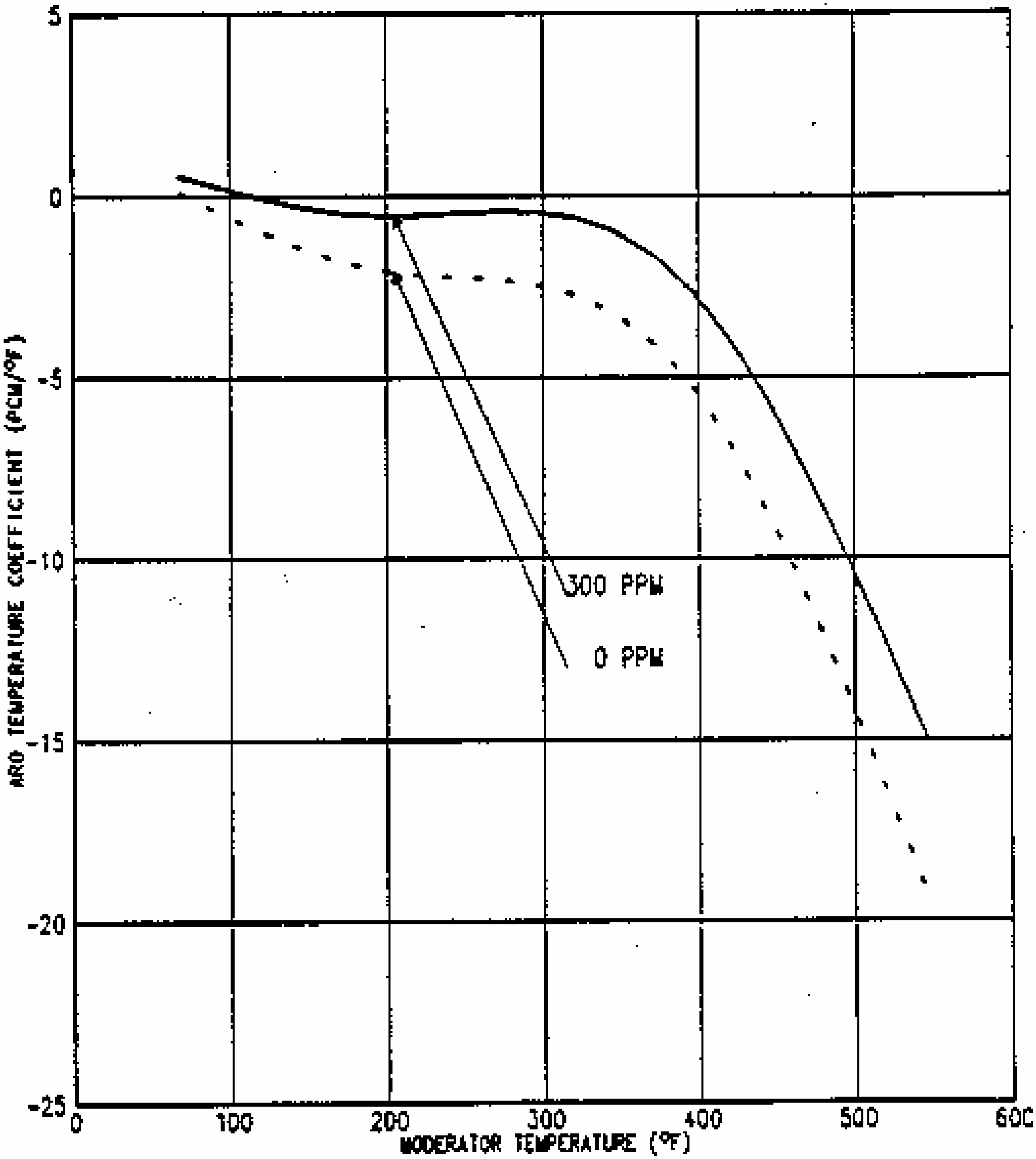
FIGURE 4.3-30
DOPPLER ONLY POWER DEFECT
AT BOL AND EOL



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

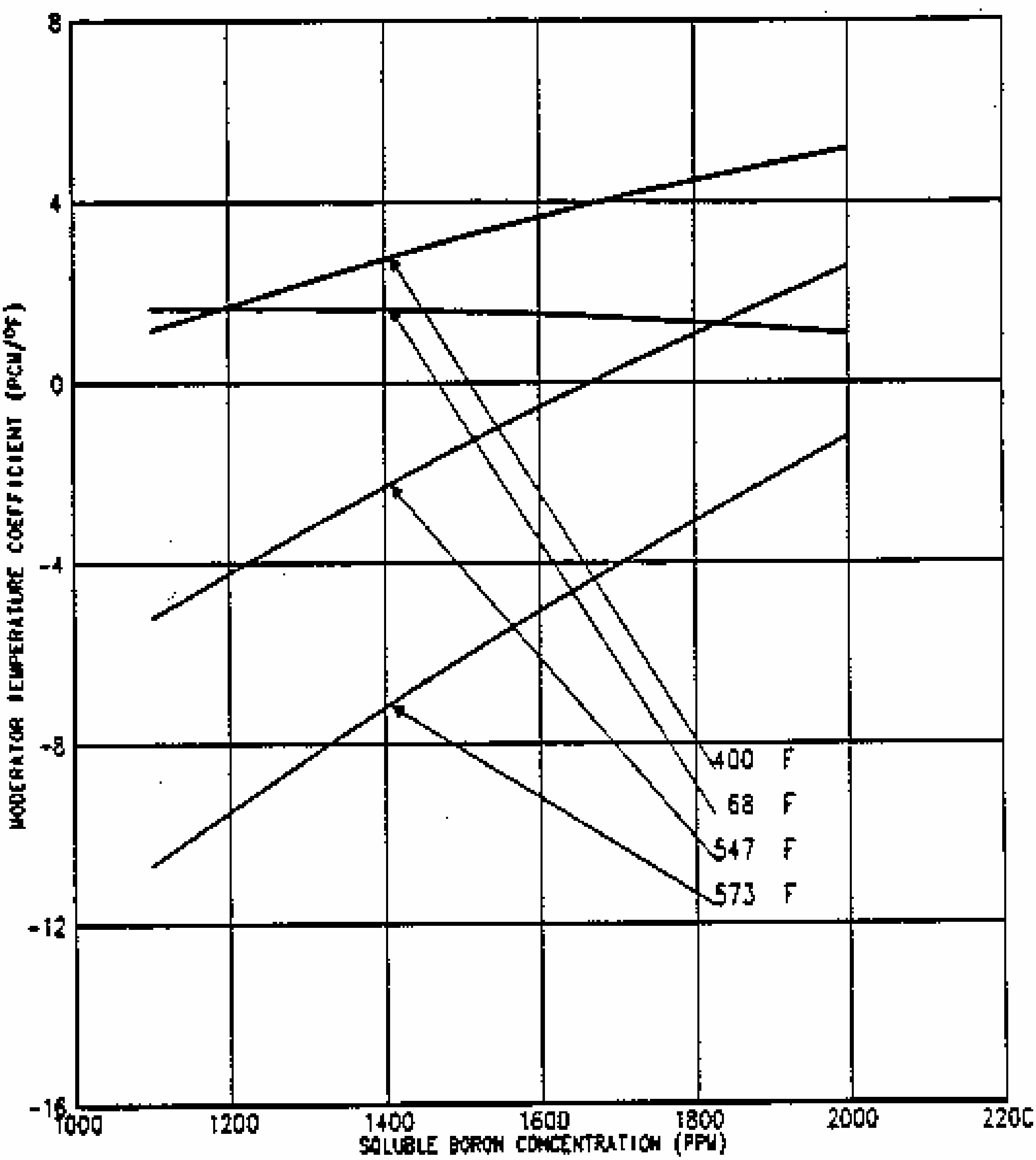
FIGURE 4.3-31
MODERATOR TEMPERATURE COEFFICIENT AT BOL, NO RODS



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.3-32
MODERATOR TEMPERATURE COEFFICIENT AT EOL

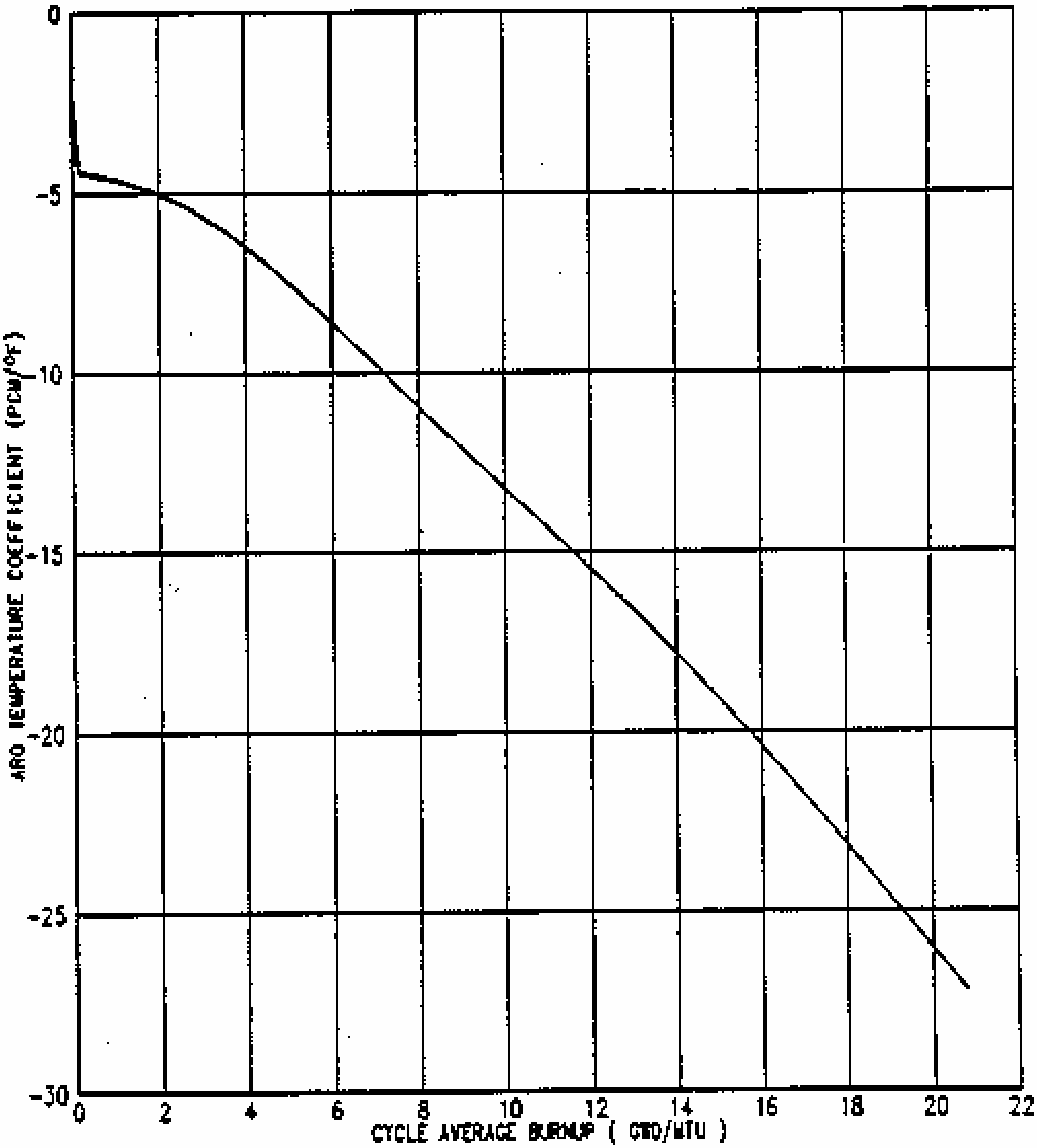


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.3-33

MODERATOR TEMPERATURE COEFFICIENT AS A FUNCTION OF BORON CONCENTRATION AT BOL, NO RODS

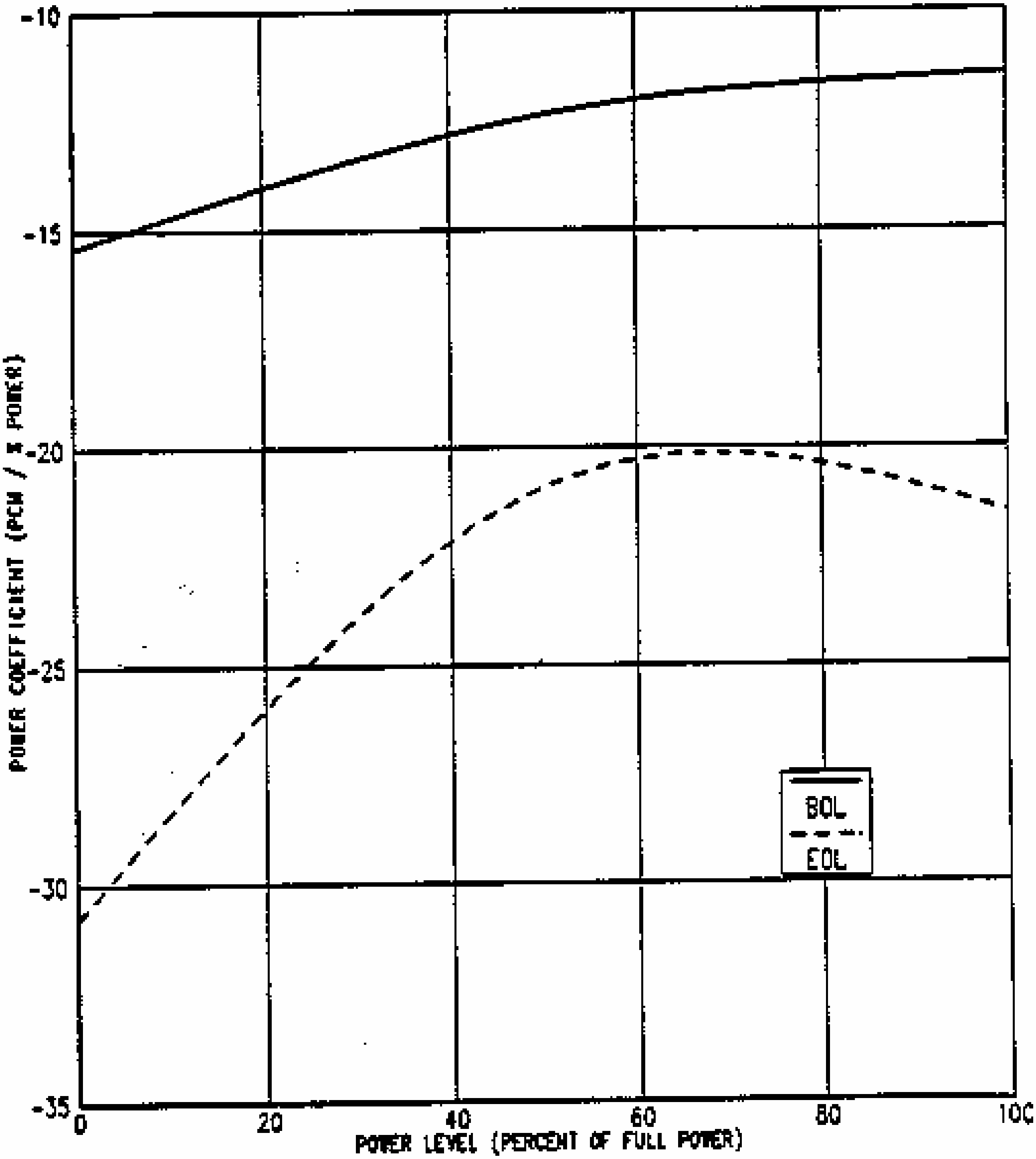


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.3-34

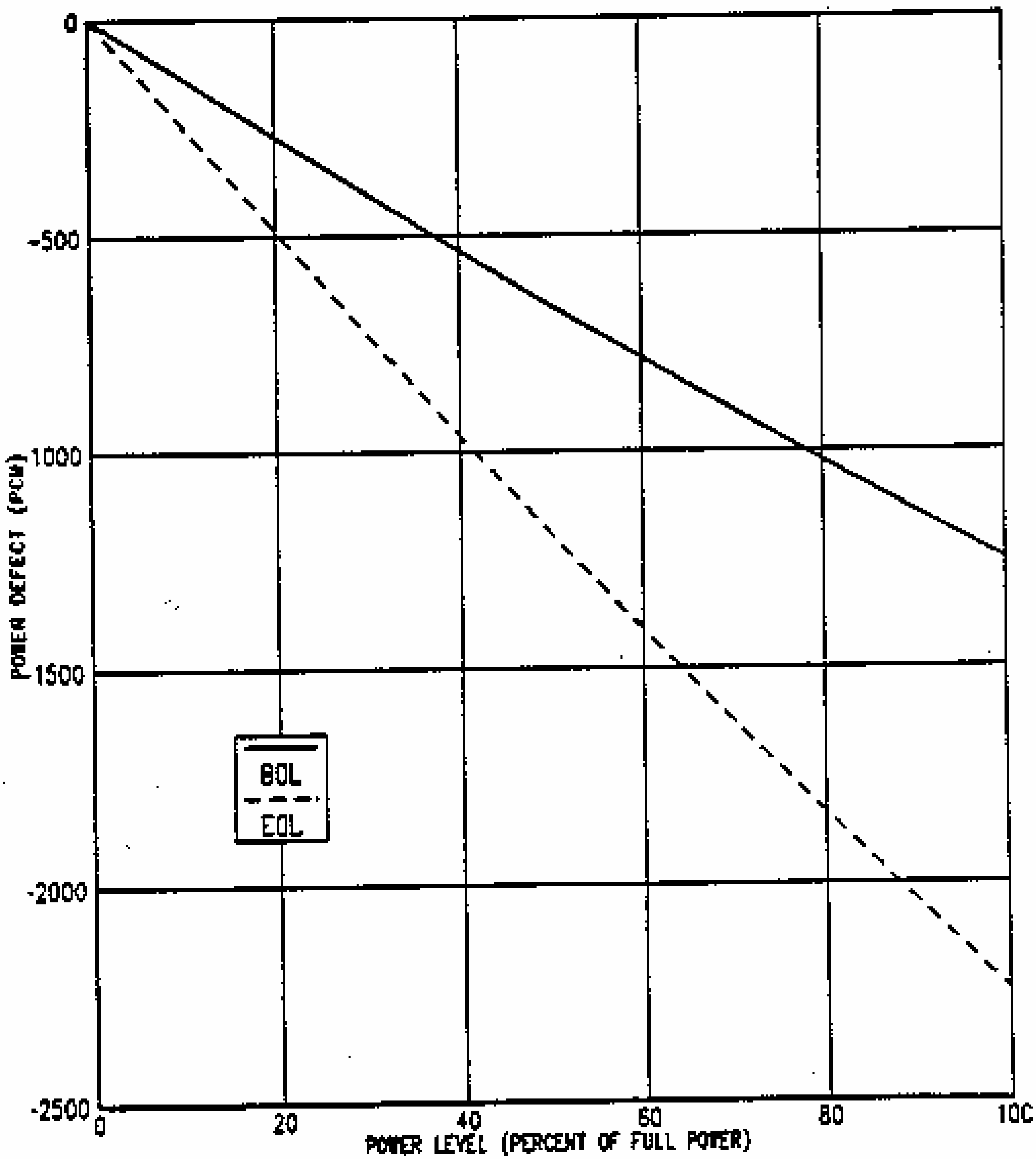
HOT FULL POWER
MODERATOR TEMPERATURE COEFFICIENT
FOR CRITICAL BORON CONCENTRATION



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

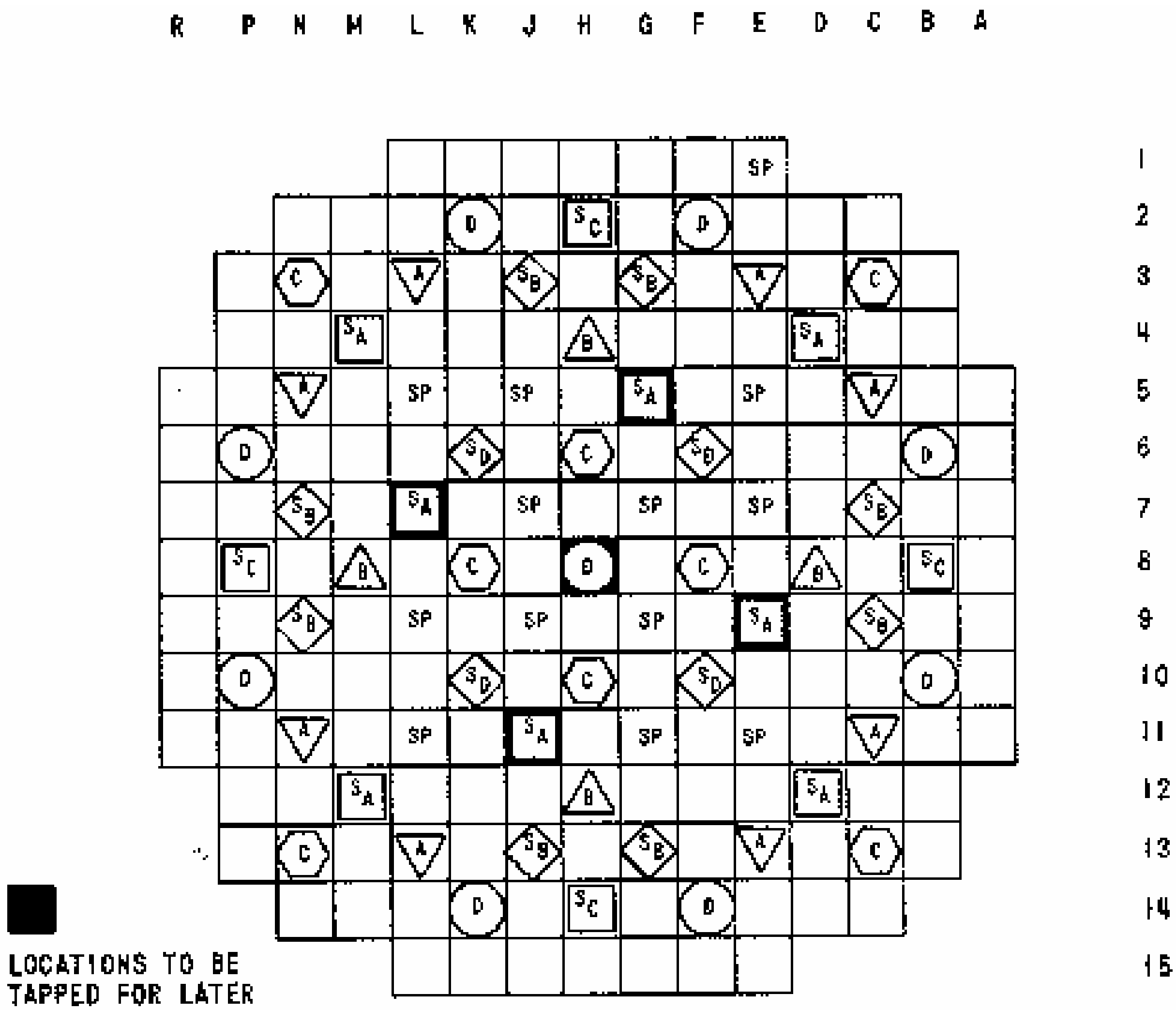
FIGURE 4.3-35
TOTAL POWER COEFFICIENT
AT BOL AND EOL



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.3-36
TOTAL POWER DEFECT
AT BOL AND EOL



LOCATIONS TO BE TAPPED FOR LATER ACCOMODATION OF ORIFICE PLATE

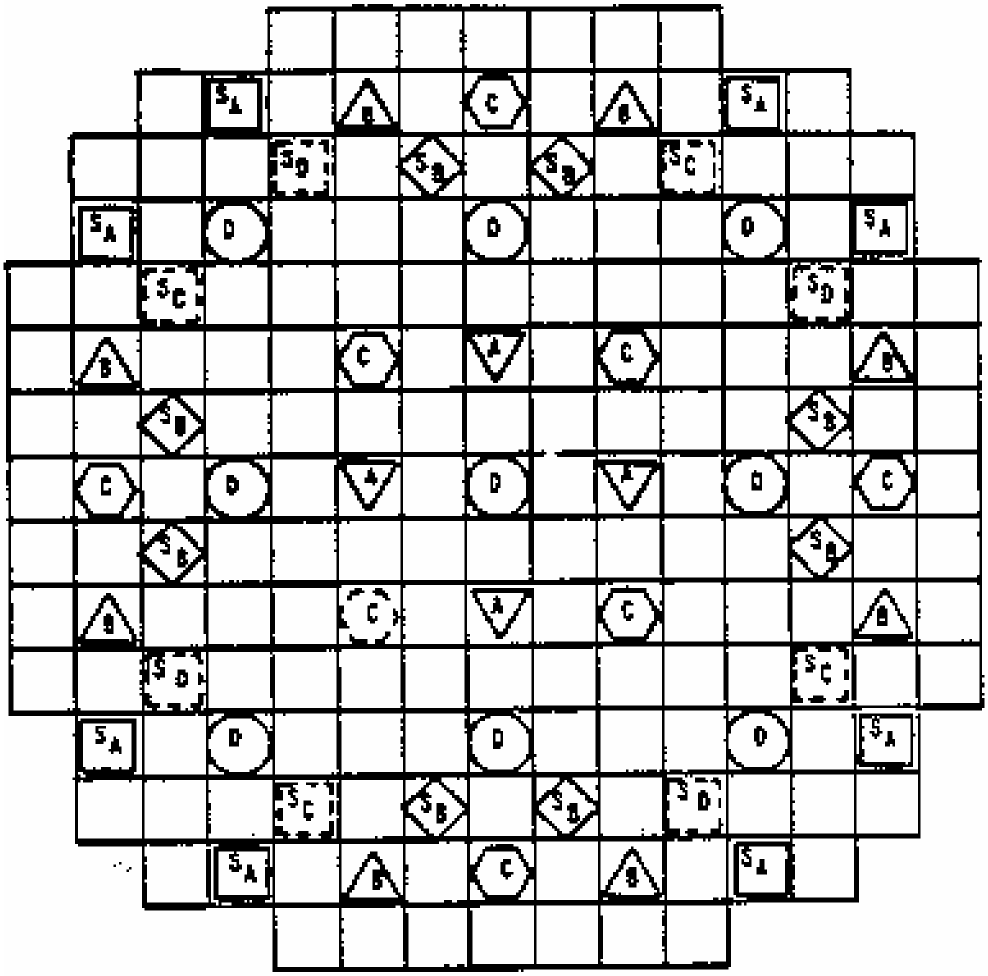
	FUNCTION	SYMBOL	NUMBER OF ROD CLUSTERS
SHUTDOWN BANK	S_A	□	8
SHUTDOWN BANK	S_B	◇	8
SHUTDOWN BANK	S_C	□	4
SHUTDOWN BANK	S_D	◇	4
CONTROL BANK	A	▽	8
CONTROL BANK	B	△	4
CONTROL BANK	C	⬡	8
CONTROL BANK	D	○	9

SP (SPARE ROD LOCATIONS)

FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

FIGURE 4.3-37
ROD CLUSTER
CONTROL ASSEMBLY PATTERN

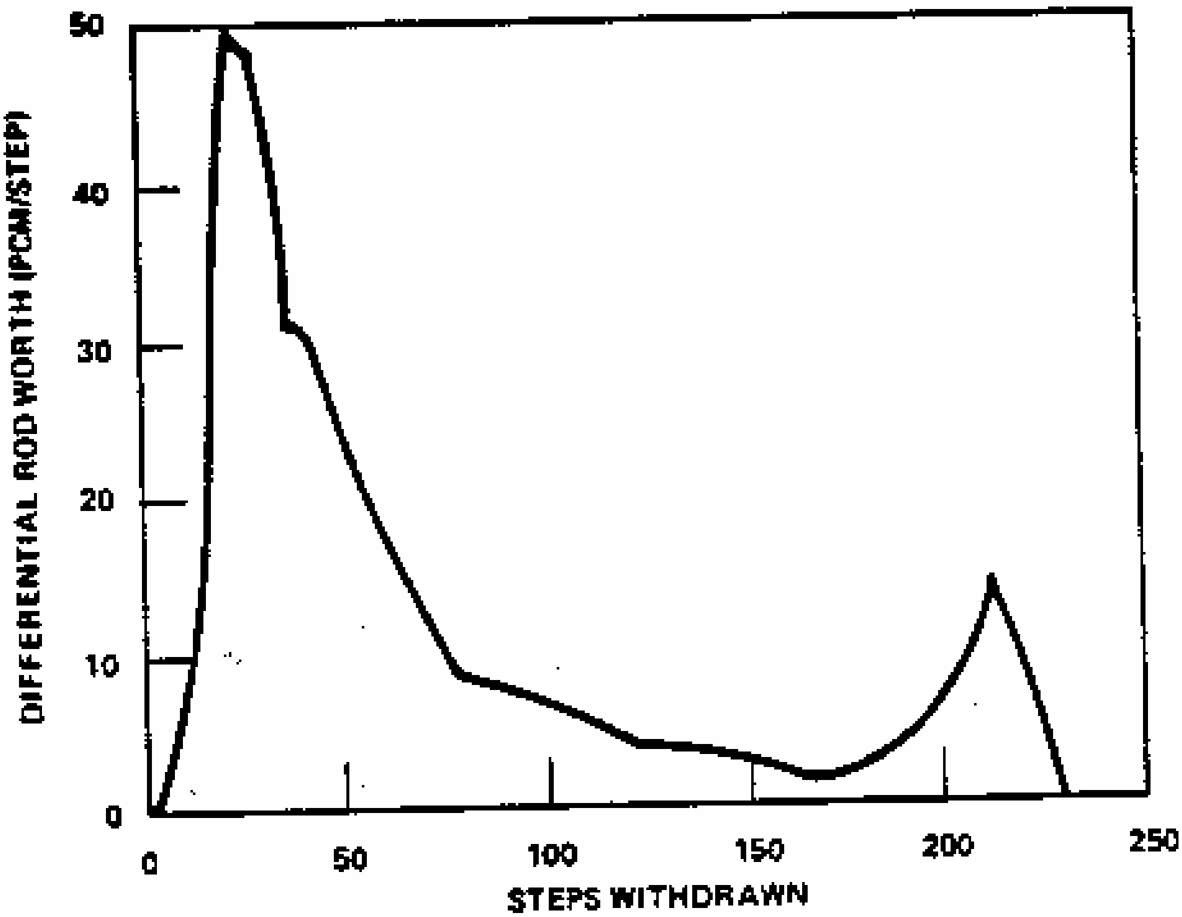


	FUNCTION	SYMBOL	NUMBER OF ROD CLUSTERS
SHUTDOWN BANK	S_A	□	8
SHUTDOWN BANK	S_B	◇	8
SHUTDOWN BANK	S_C & S_D	⬚	4 & 4
CONTROL BANK	A	▽	4
CONTROL BANK	B	△	8
CONTROL BANK	C	⬡	8
CONTROL BANK	D	○	9

FSAR UPDATE

UNIT 2
DIABLO CANYON SITE

FIGURE 4.3-38
ROD CLUSTER
CONTROL ASSEMBLY PATTERN



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-39 ACCIDENTAL SIMULTANEOUS WITHDRAWAL OF TWO CONTROL BANKS EOL, HZP BANKS B AND D MOVING IN THE SAME PLANE

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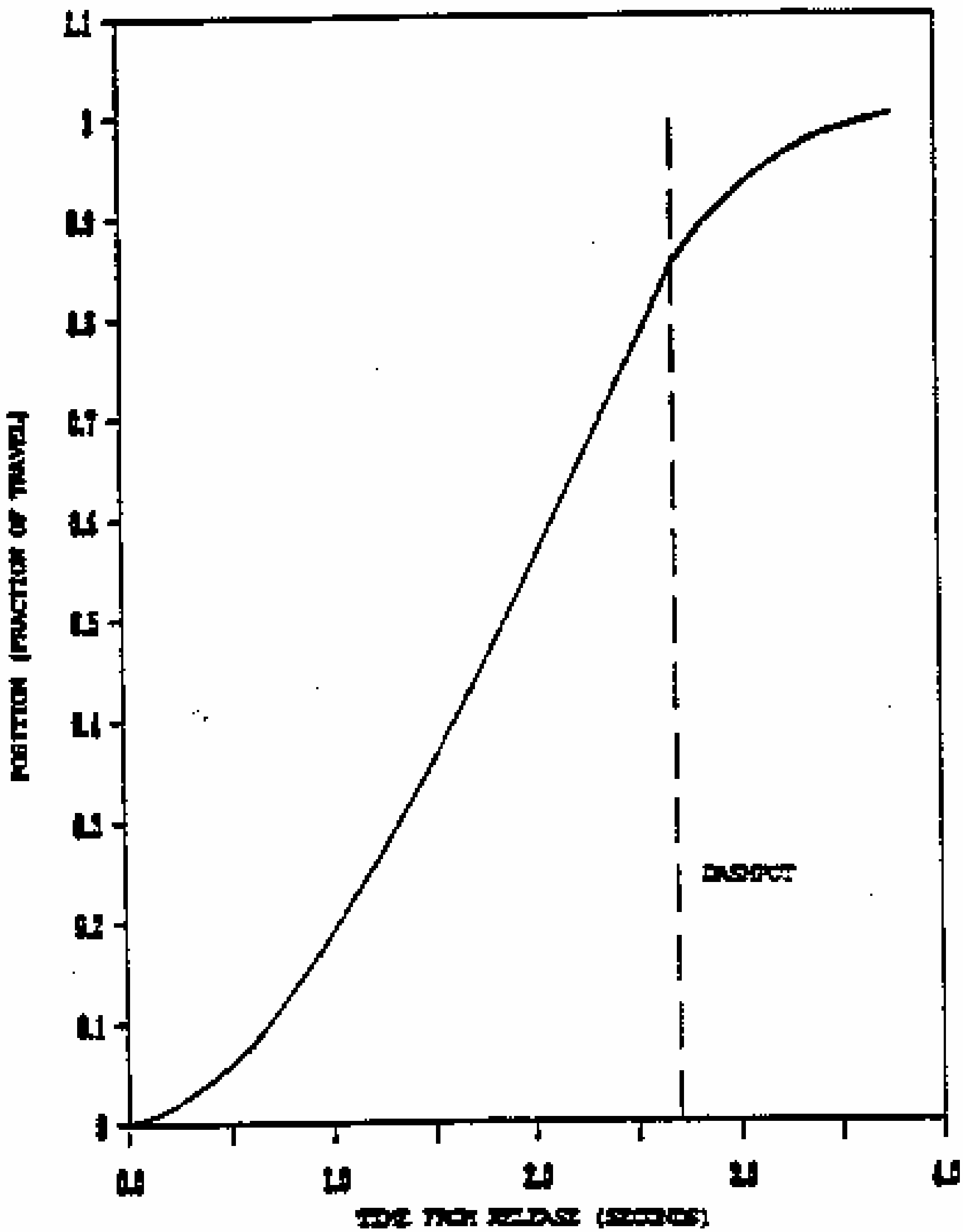
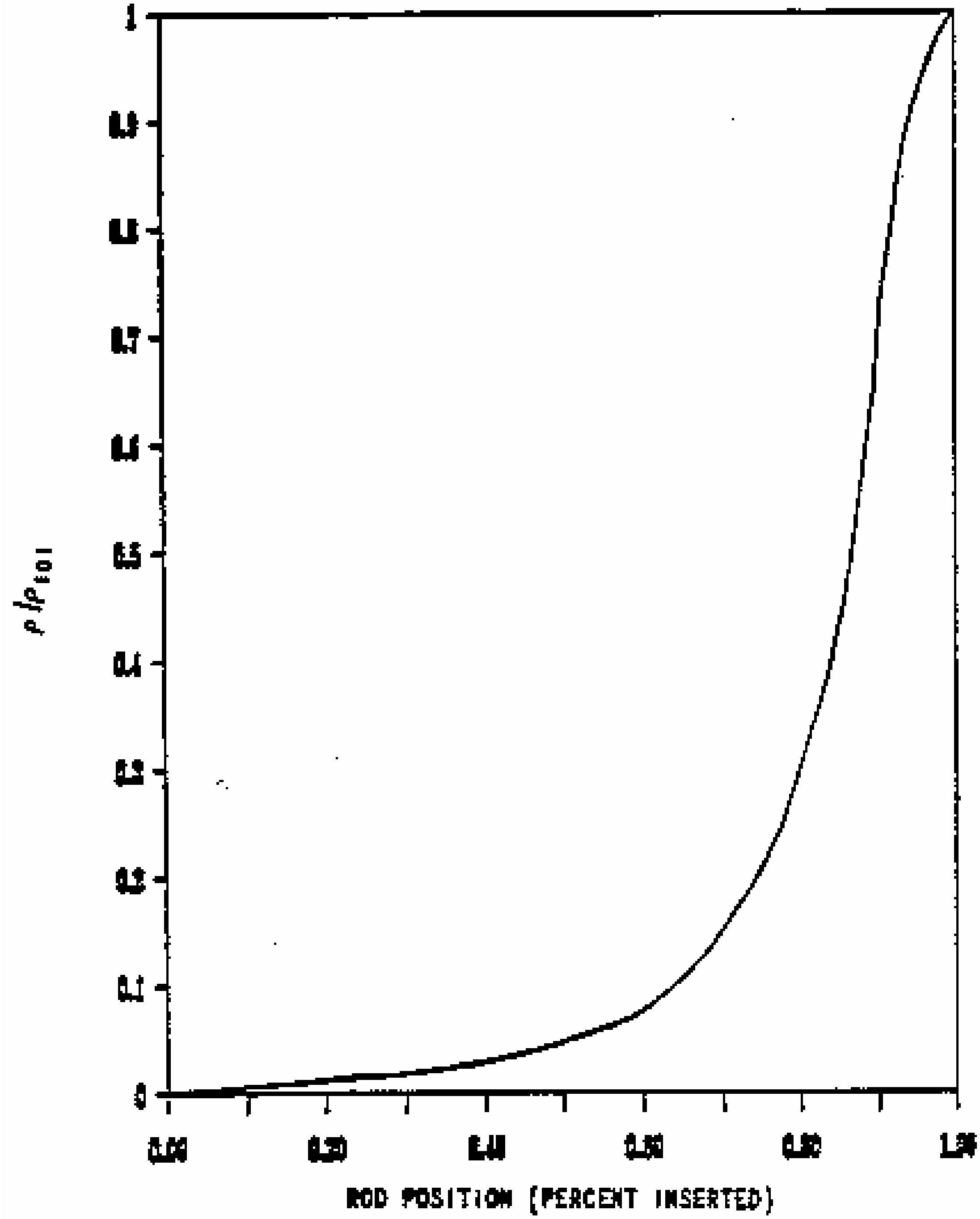


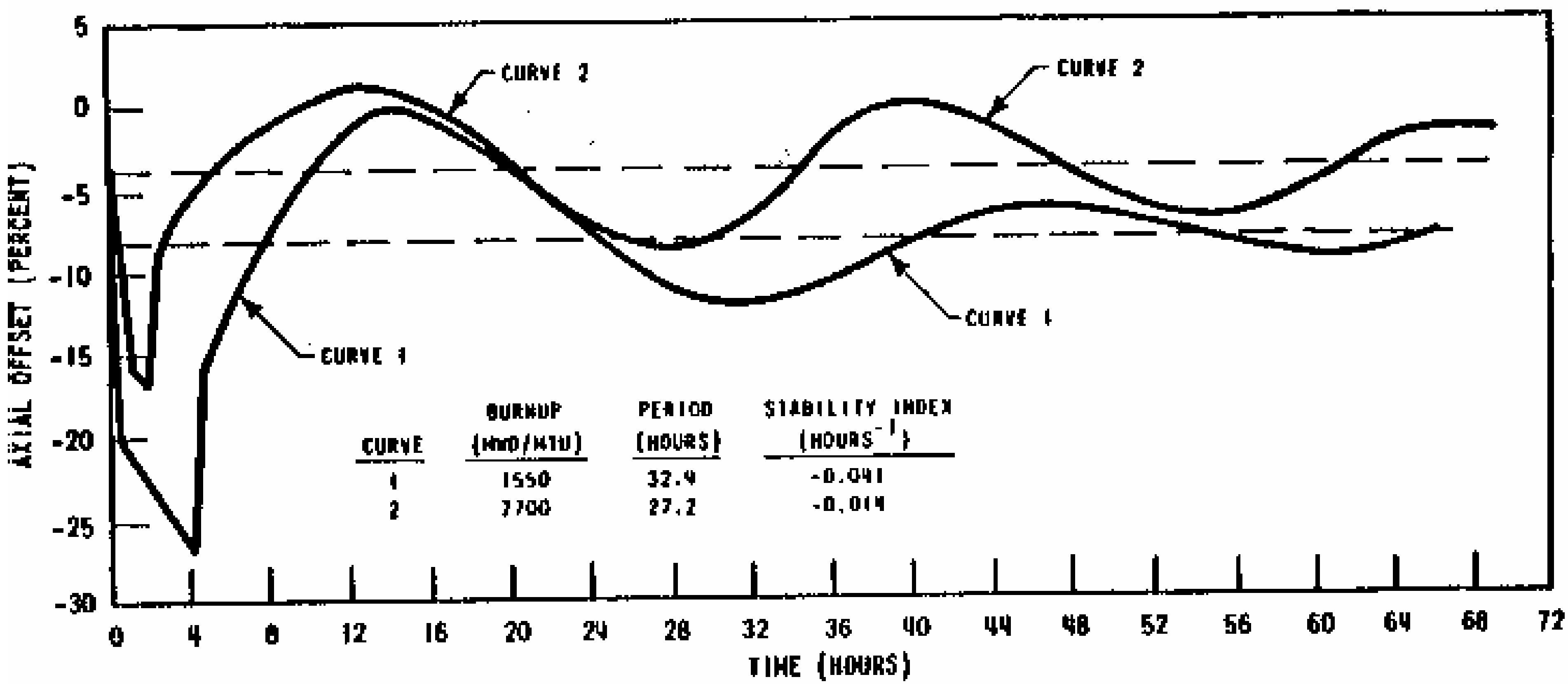
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.3-40
DESIGN – TRIP CURVE



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-41 NORMALIZED ROD WORTH vs. PERCENT INSERTION, ALL RODS BUT ONE

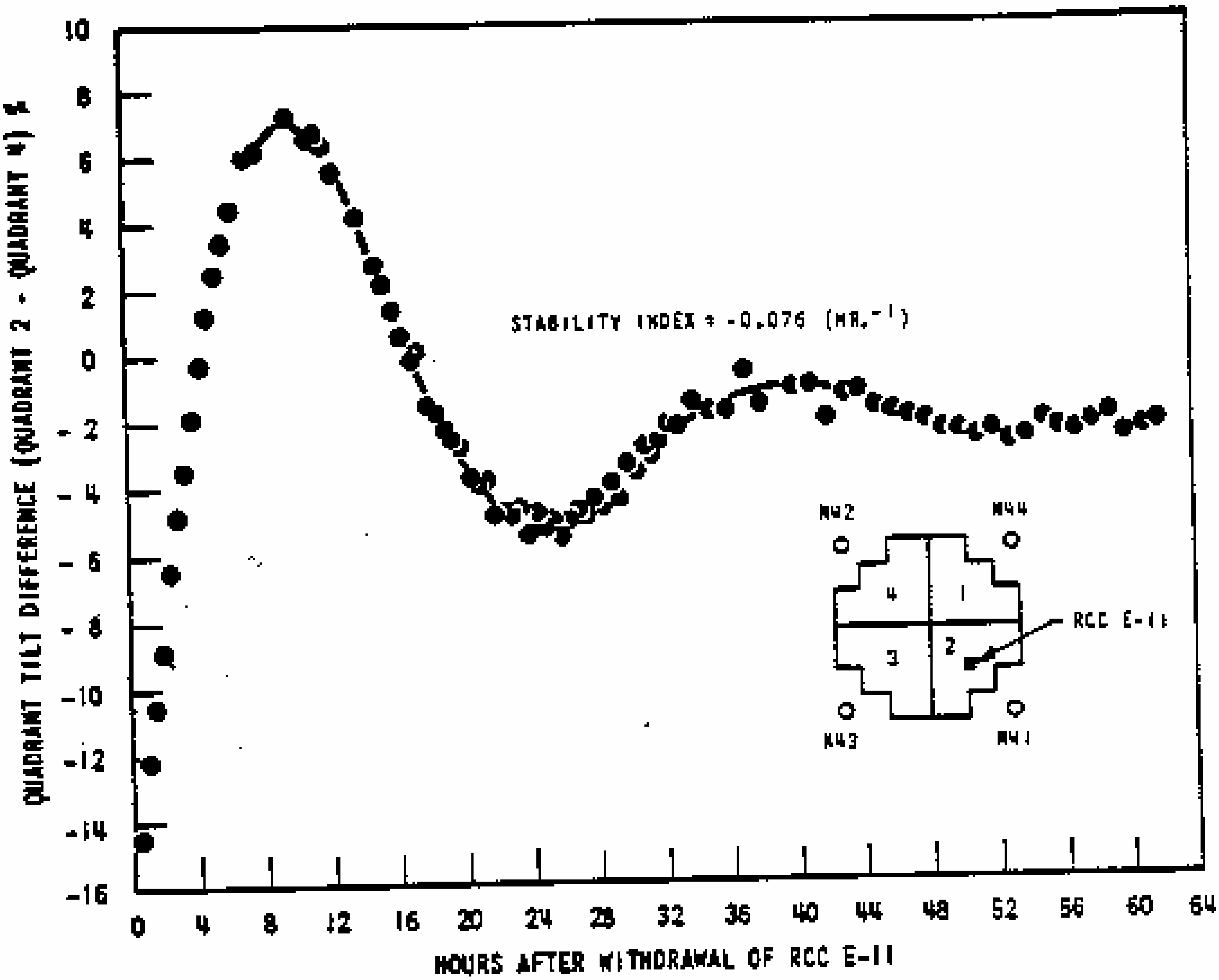


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

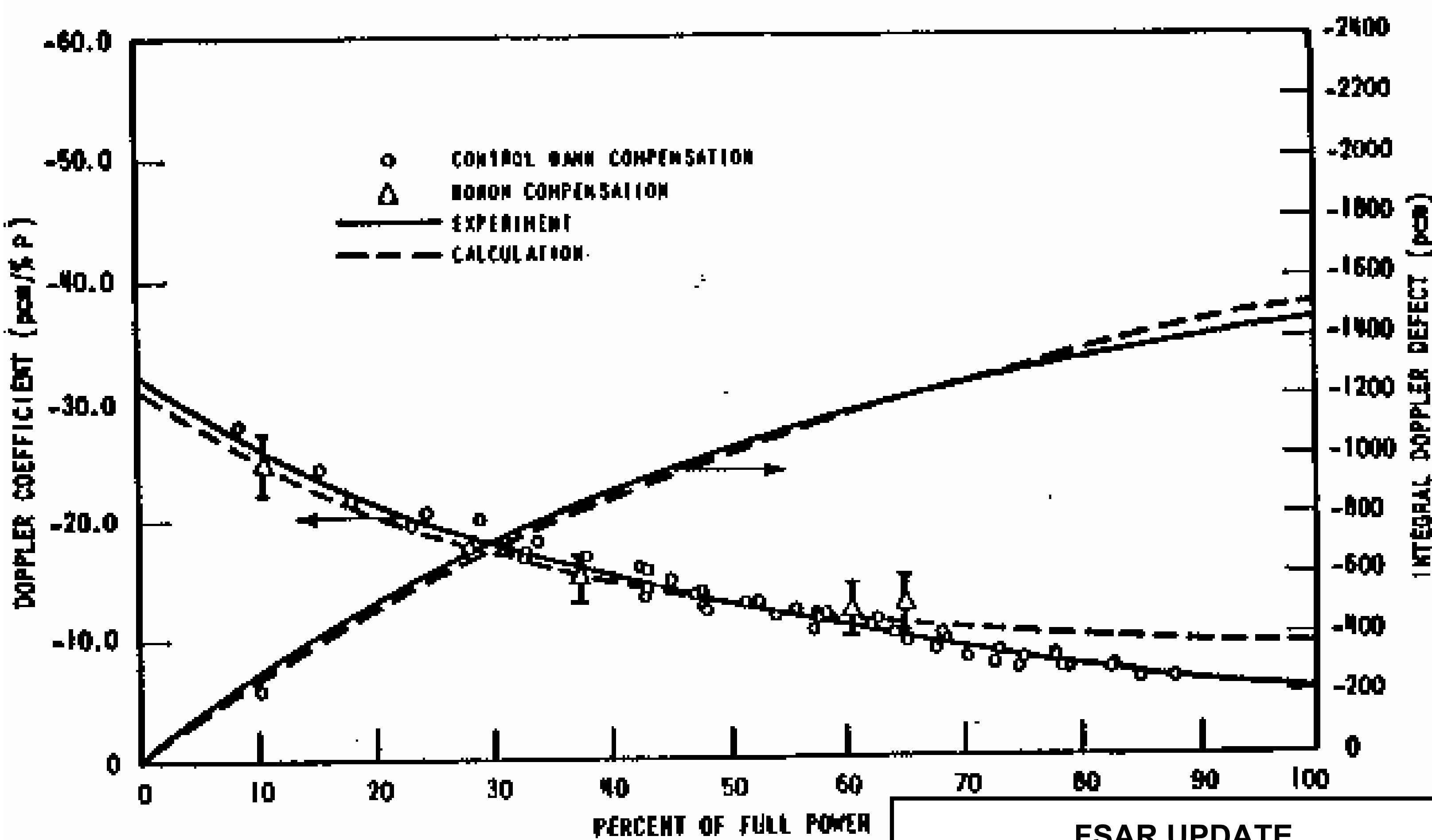
FIGURE 4.3-42

AXIAL OFFSET vs. TIME
PWR CORE WITH A 12-FT CORE HEIGHT
AND 121 ASSEMBLIES

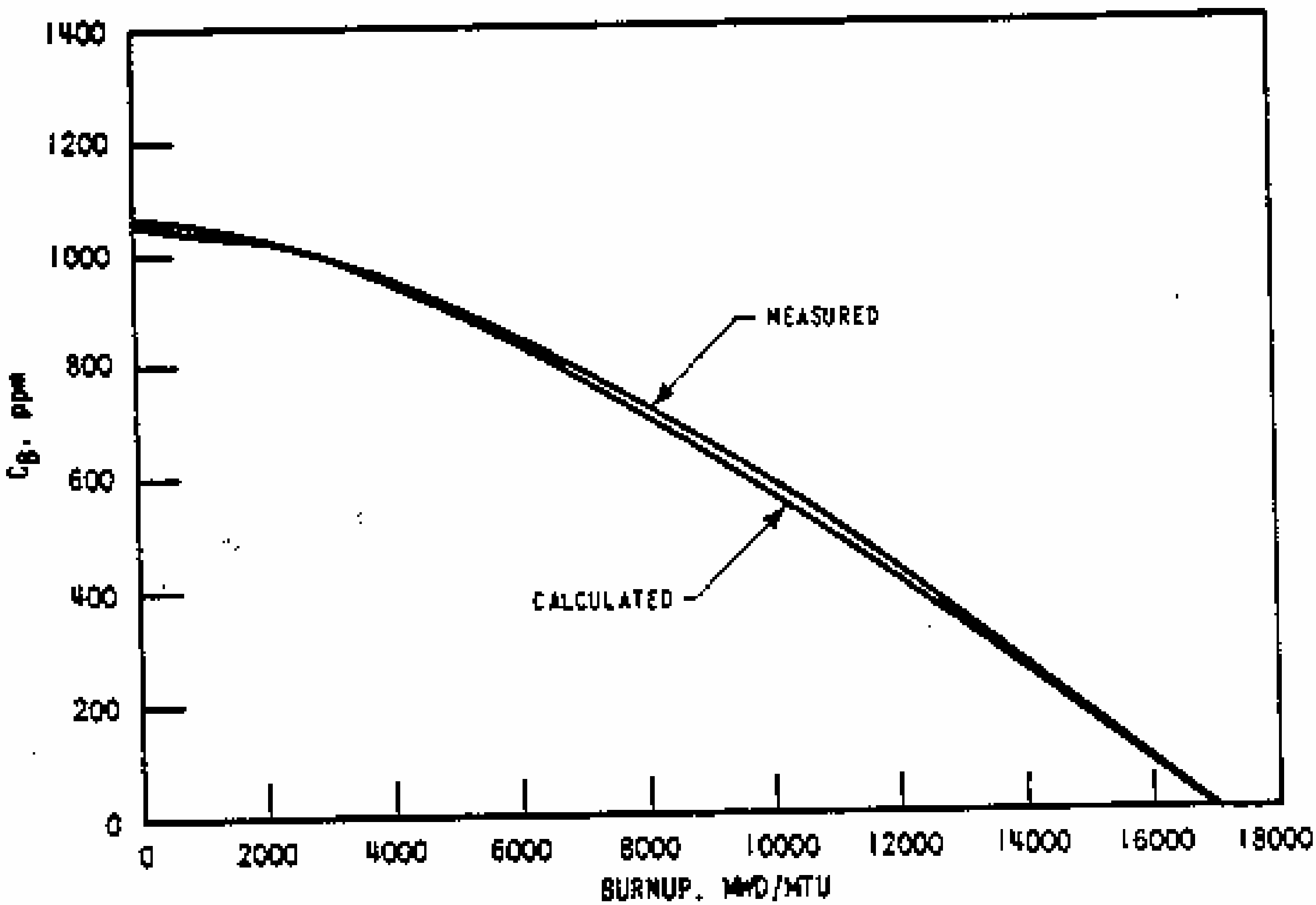


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-43 XY XENON TEST THERMOCOUPLE RESPONSE QUADRANT TILT DIFFERENCE vs. TIME

Revision 11 November 1996



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-44 CALCULATED AND MEASURED DOPPLER DEFECT AND COEFFICIENTS AT BOL, FOR A TWO-LOOP PLANT WITH A 12-FT CORE HEIGHT AND 121 ASSEMBLIES



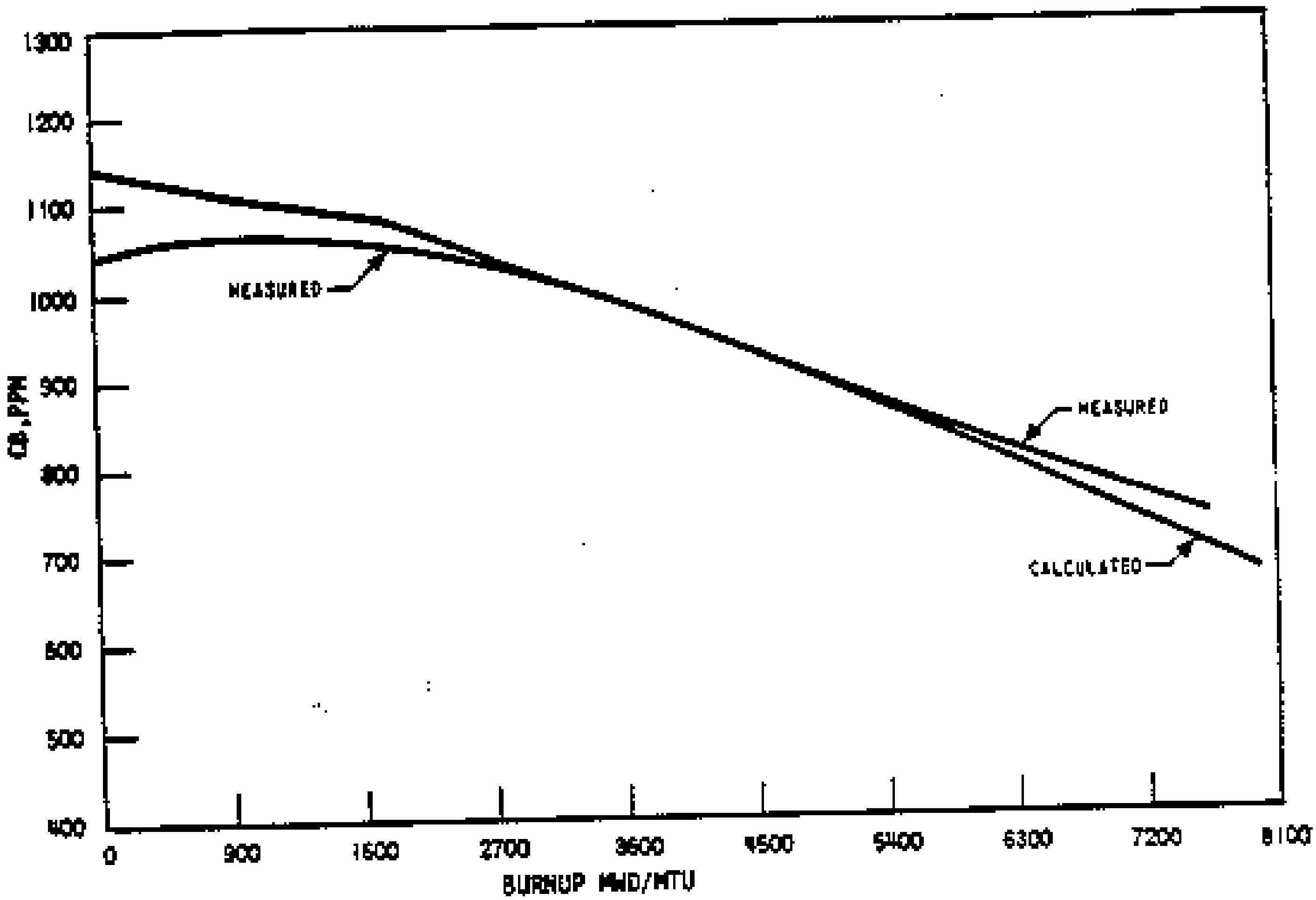
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

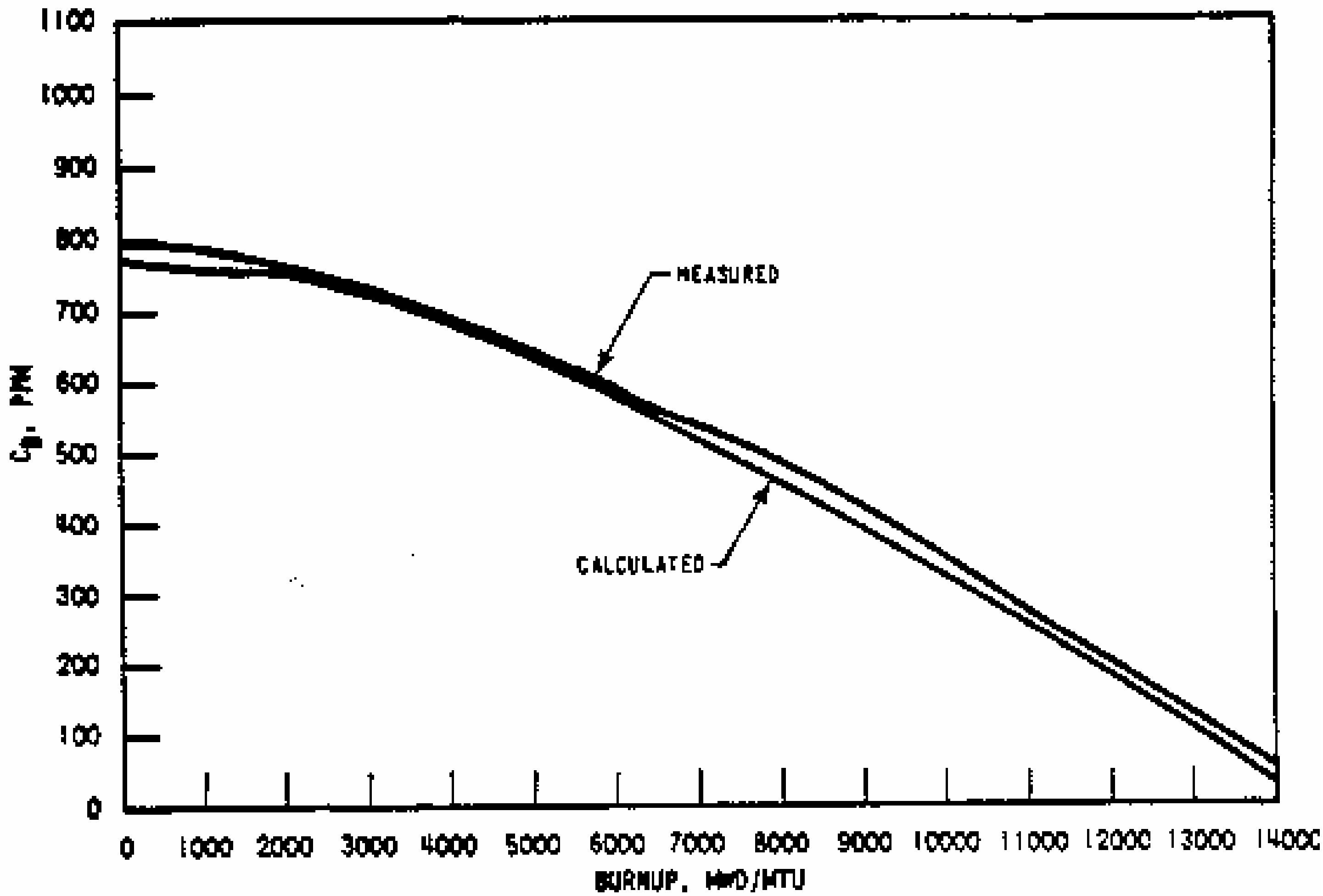
FIGURE 4.3-45

COMPARISON OF CALCULATED AND
MEASURED BORON CONCENTRATION
FOR A TWO-LOOP PLANT
WITH A 12-FT CORE HEIGHT
AND 121 ASSEMBLIES

Revision 11 November 1996



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-46 COMPARISON OF CALCULATED AND MEASURED BORON FOR A TWO LOOP PLANT WITH A 12-FT CORE HEIGHT AND 121 ASSEMBLIES

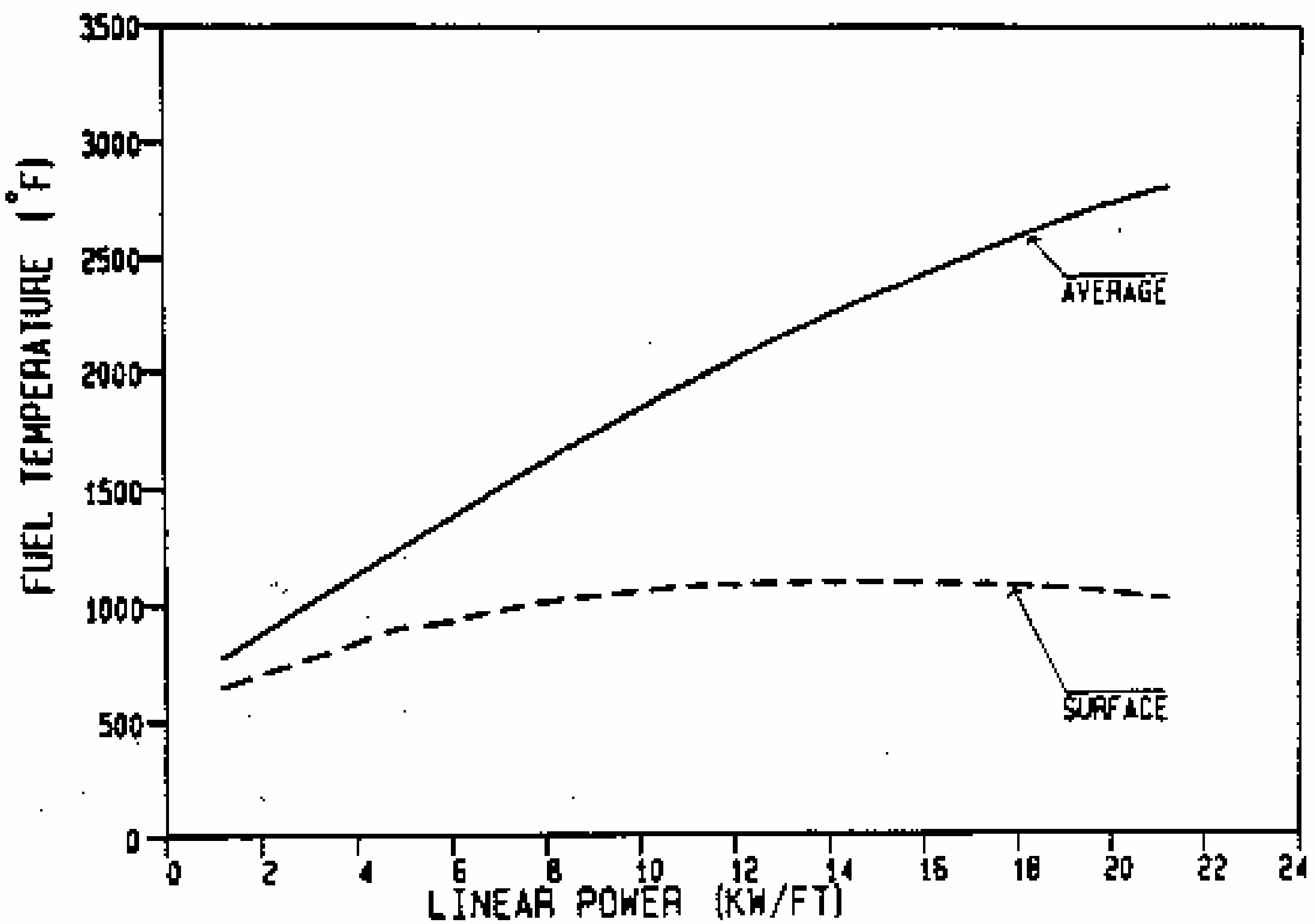


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.3-47

COMPARISON OF CALCULATED AND MEASURED BORON IN A 3-LOOP PLANT WITH A 12-FT CORE HEIGHT AND 157 ASSEMBLIES



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.4-1 PEAK FUEL AVERAGE AND SURFACE TEMPERATURES DURING FUEL ROD LIFETIME vs. LINEAR POWER DENSITY

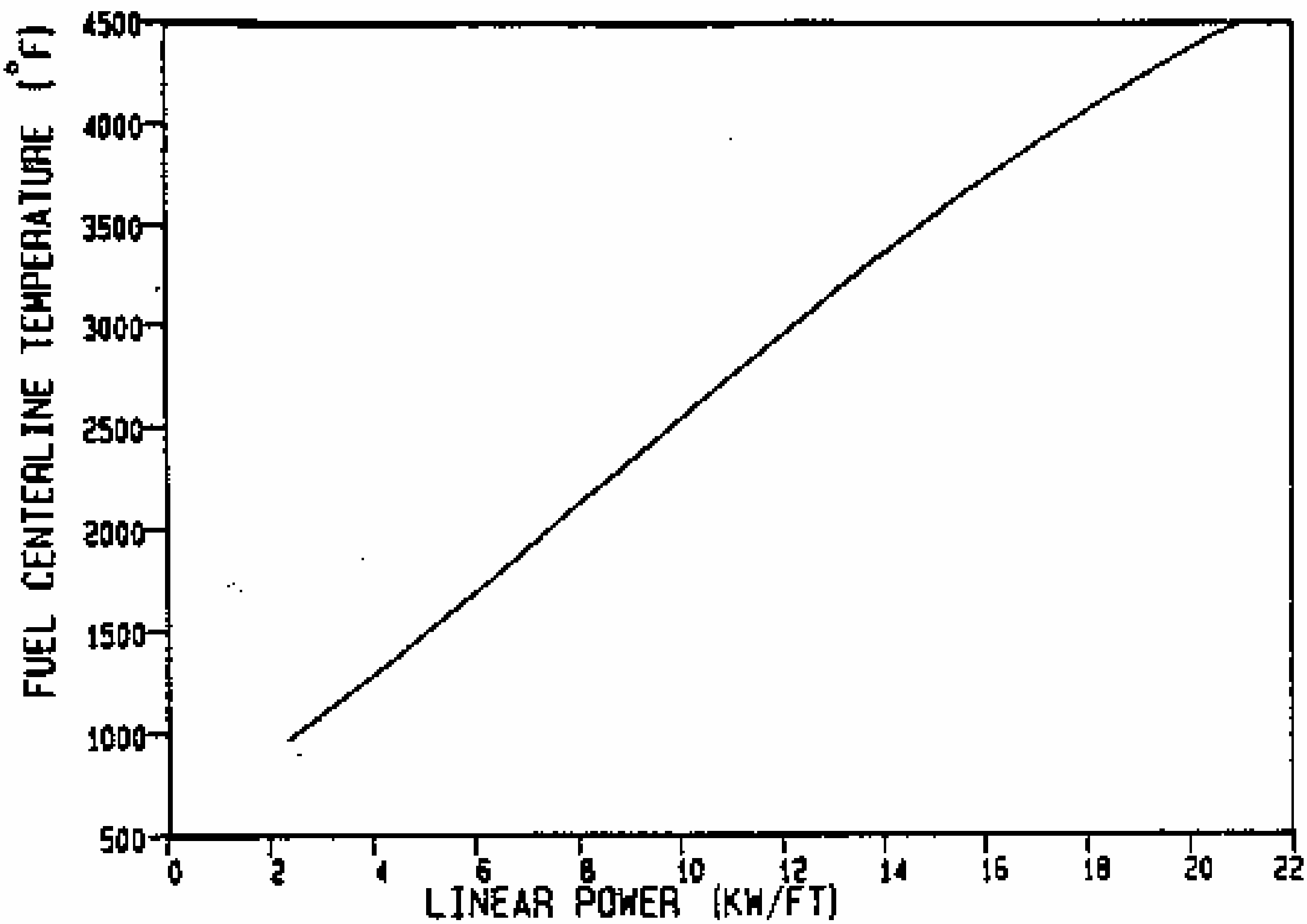


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FIGURE 4.4-2 PEAK FUEL CENTERLINE TEMPERATURE DURING FUEL ROD LIFETIME vs. LINEAR POWER DENSITY

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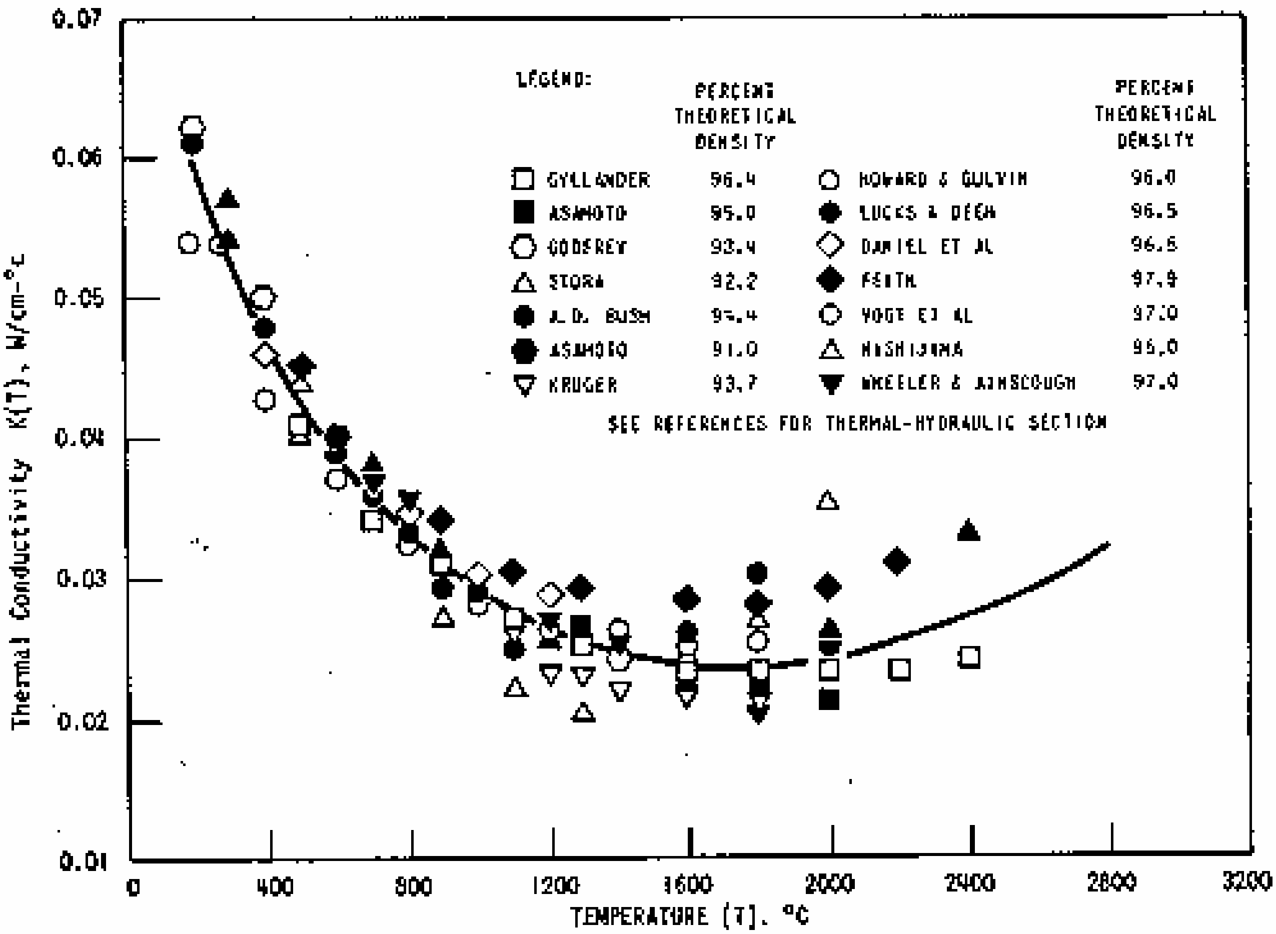

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FIGURE 4.4-3

THERMAL CONDUCTIVITY OF UO_2
(DATA CORRECTED TO 95%
THEORETICAL DENSITY)

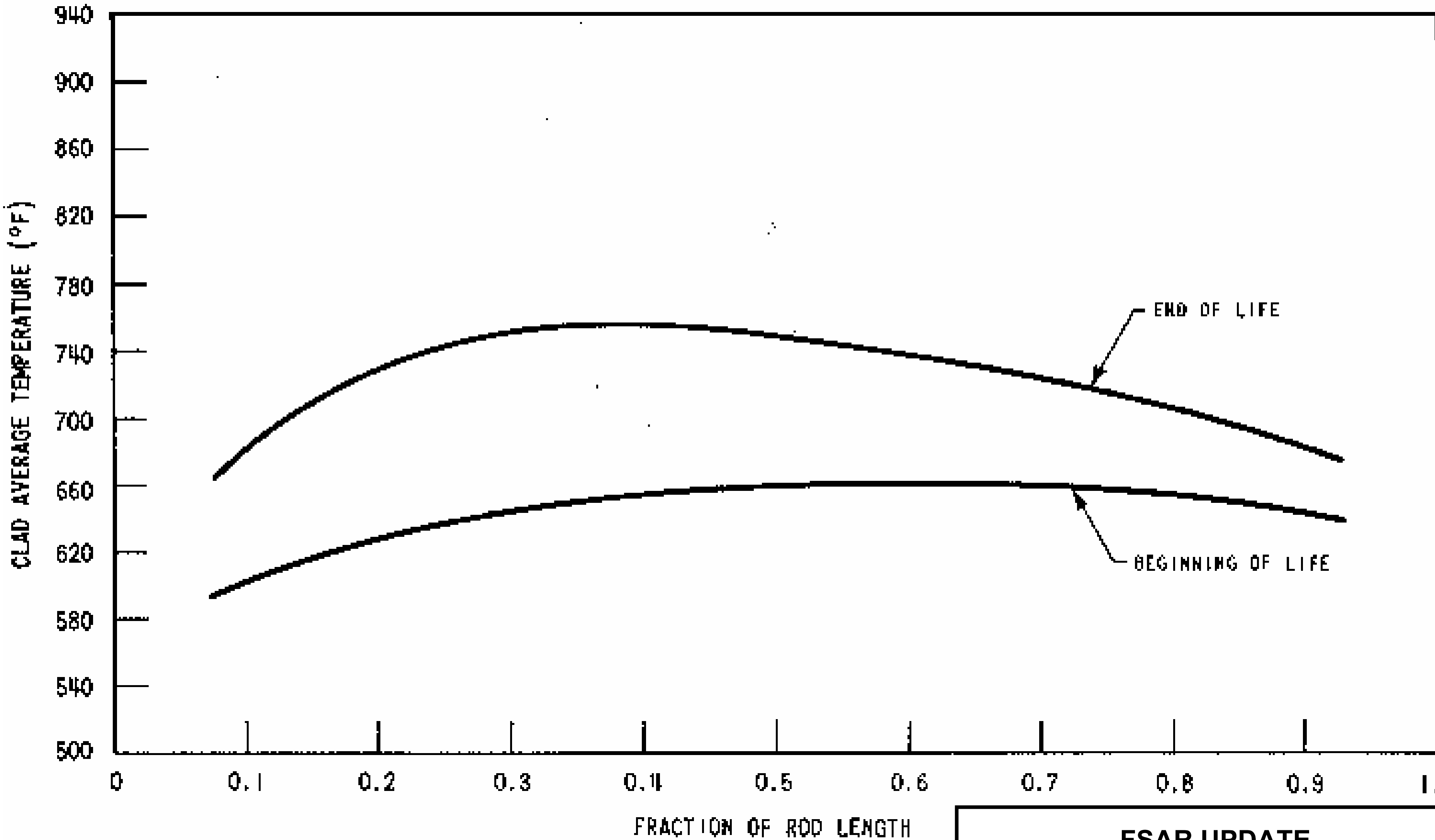

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FIGURE 4.4-4

AXIAL VARIATION OF AVERAGE CLAD TEMPERATURE FOR ROD OPERATING AT 5.43 KW/FT

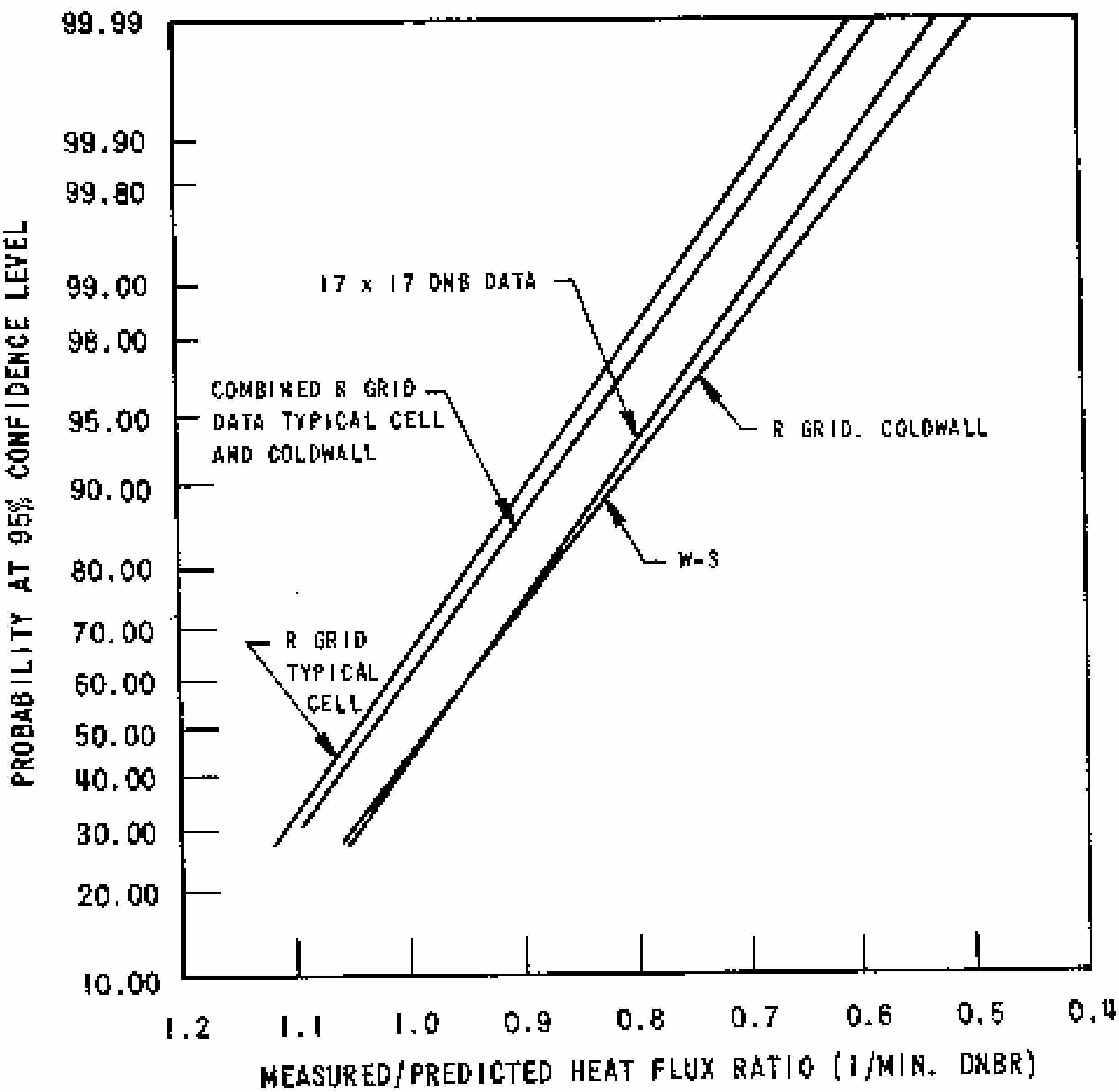

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FIGURE 4.4-5 **PROBABILITY CURVES FOR W-3 AND R GRID DNB CORRELATIONS**

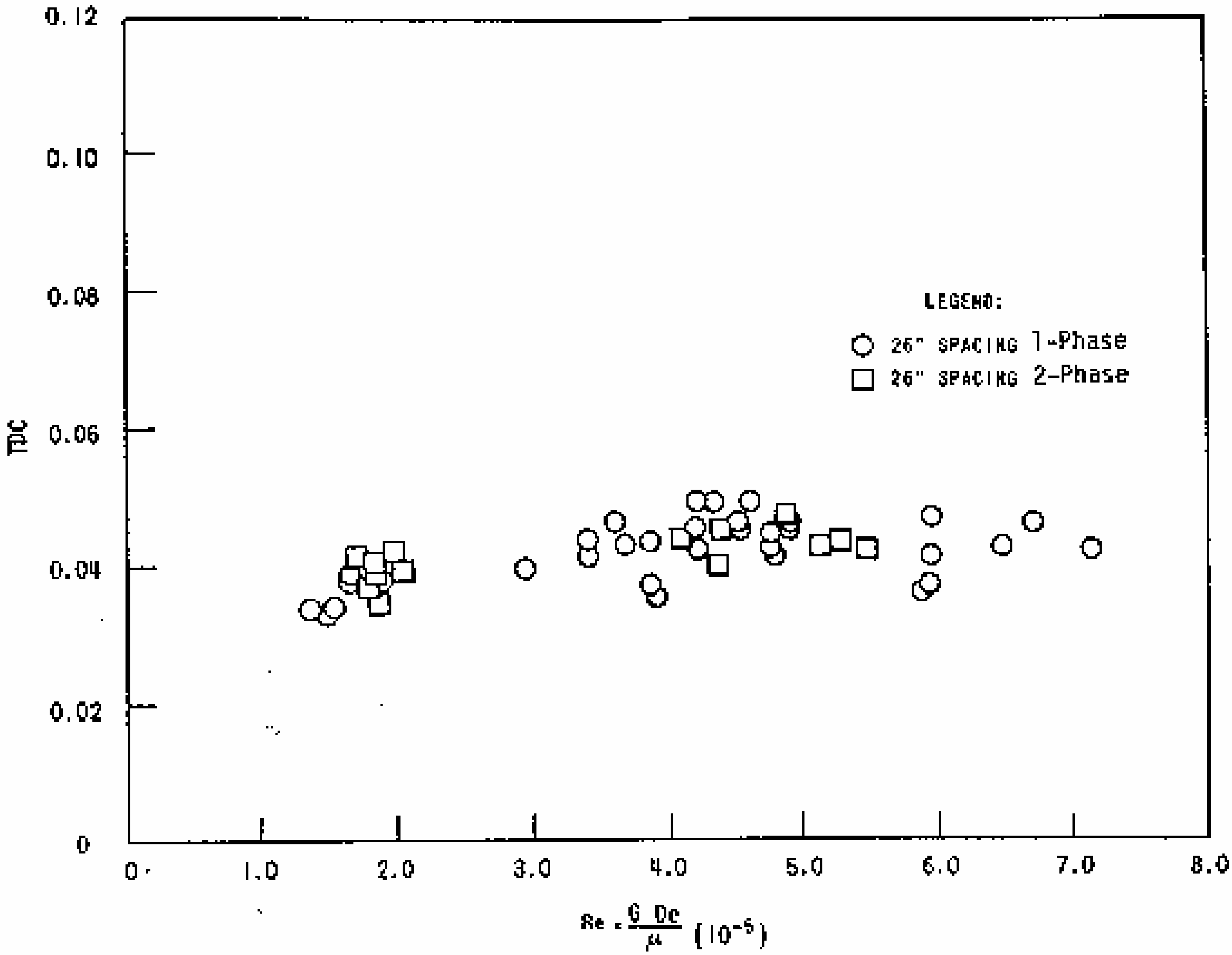

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FIGURE 4.4-6
TDC vs. REYNOLDS NUMBER
FOR 26-INCH GRID SPACING

	H	G	F	E	D	C	B	A
8	1.086 1.001							KEY: Δh/Δh G/G
9	1.020 1.001	1.111 1.001						
10	1.145 1.000	1.066 1.001	1.178 1.000					
11	1.160 1.000	1.203 1.000	1.157 1.001	1.183 1.000				
12	1.220 1.000	1.167 1.001	1.185 1.000	1.065 1.002	1.242 1.000			
13	1.125 1.001	1.161 1.001	1.094 1.002	1.088 1.002	0.921 1.001	0.975 1.001		
14	1.028 1.002	1.028 1.002	0.994 1.002	0.980 1.002	0.829 1.000	0.469 0.997		
15	0.720 0.999	0.785 0.999	0.667 0.998	0.566 0.997				

FOR RADIAL POWER DISTRIBUTION
NEAR BEGINNING OF LIFE CYCLE 1,
HOT FULL POWER, EQUILIBRIUM XENON

CALCULATED $F^{N}_{\Delta H}$ = 1.35

Note: This figure is representative of a Westinghouse Four-Loop Plant.

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FIGURE 4.4-7

NORMALIZED RADIAL FLOW AND ENTHALPY DISTRIBUTION AT 4-FT ELEVATION

	H	G	F	E	D	C	B	A
8	1.086 0.996							KEY: $\Delta h/\overline{\Delta h}$ $G/\bar{G}$
9	1.017 1.002	1.111 0.994						
10	1.147 0.991	1.064 0.998	1.181 0.988					
11	1.163 0.990	1.206 0.985	1.160 0.990	1.187 0.998				
12	1.225 0.985	1.170 0.989	1.188 0.988	1.065 0.998	1.246 0.981			
13	1.178 0.992	1.165 0.990	1.096 0.995	1.088 0.996	0.921 1.009	0.971 1.006		
14	1.027 1.000	1.078 1.000	0.993 1.003	0.978 1.004	0.825 1.018	0.471 1.018		
15	0.718 1.022	0.782 1.019	0.666 1.021	0.565 1.019				

FOR RADIAL POWER DISTRIBUTION
NEAR BEGINNING OF LIFE CYCLE 1,
HOT FULL POWER, EQUILIBRIUM XENON

CALCULATED $F^{N}_{\Delta H} = 1.35$

Note: This figure is representative of a Westinghouse Four-Loop Plant.

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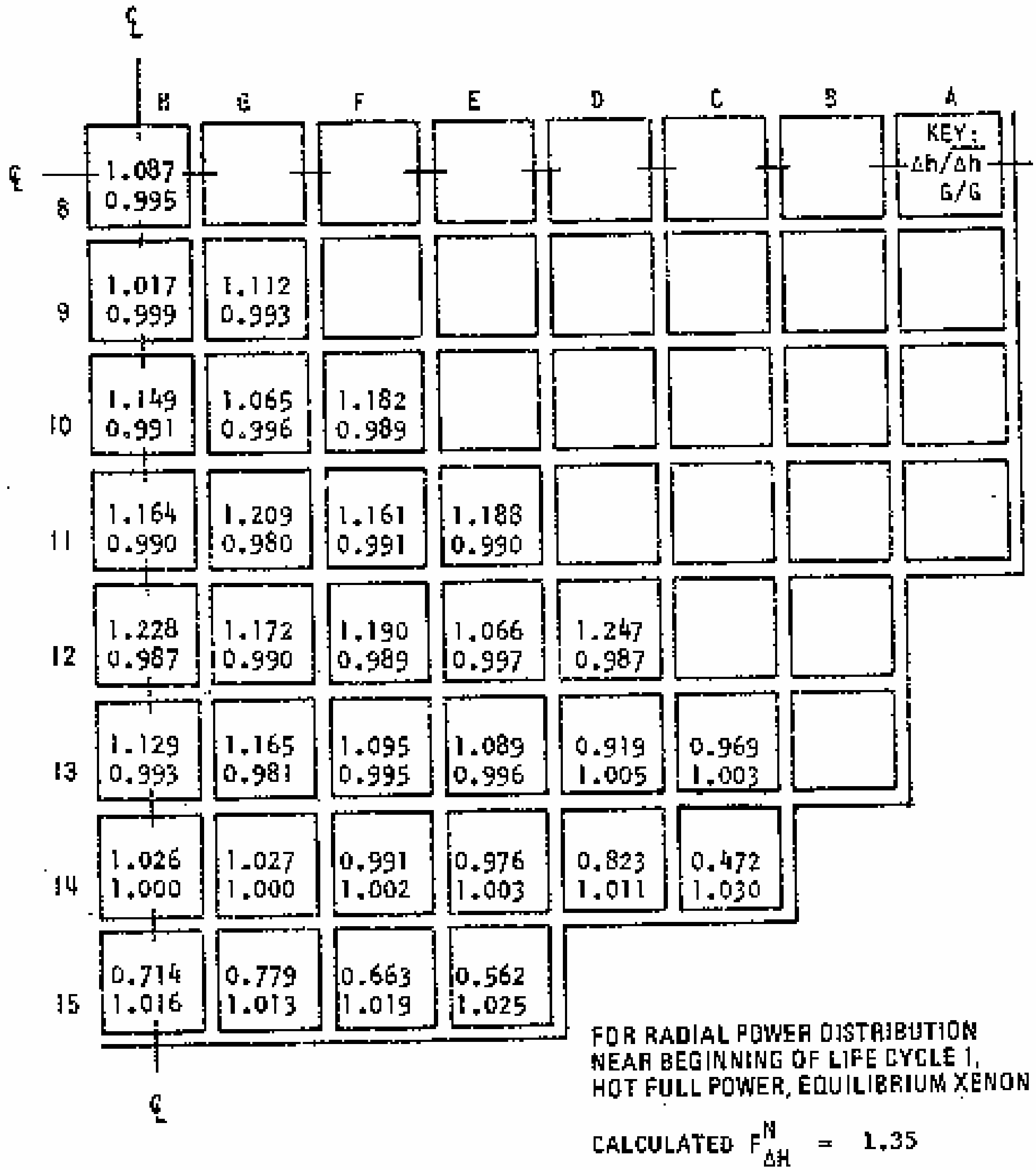
FIGURE 4.4-8

NORMALIZED RADIAL FLOW AND ENTHALPY DISTRIBUTION AT 8-FT ELEVATION



Note: This figure is representative of a Westinghouse Four-Loop Plant.

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FIGURE 4.4-9

NORMALIZED RADIAL FLOW AND ENTHALPY DISTRIBUTION AT 12-FT ELEVATION CORE EXIT

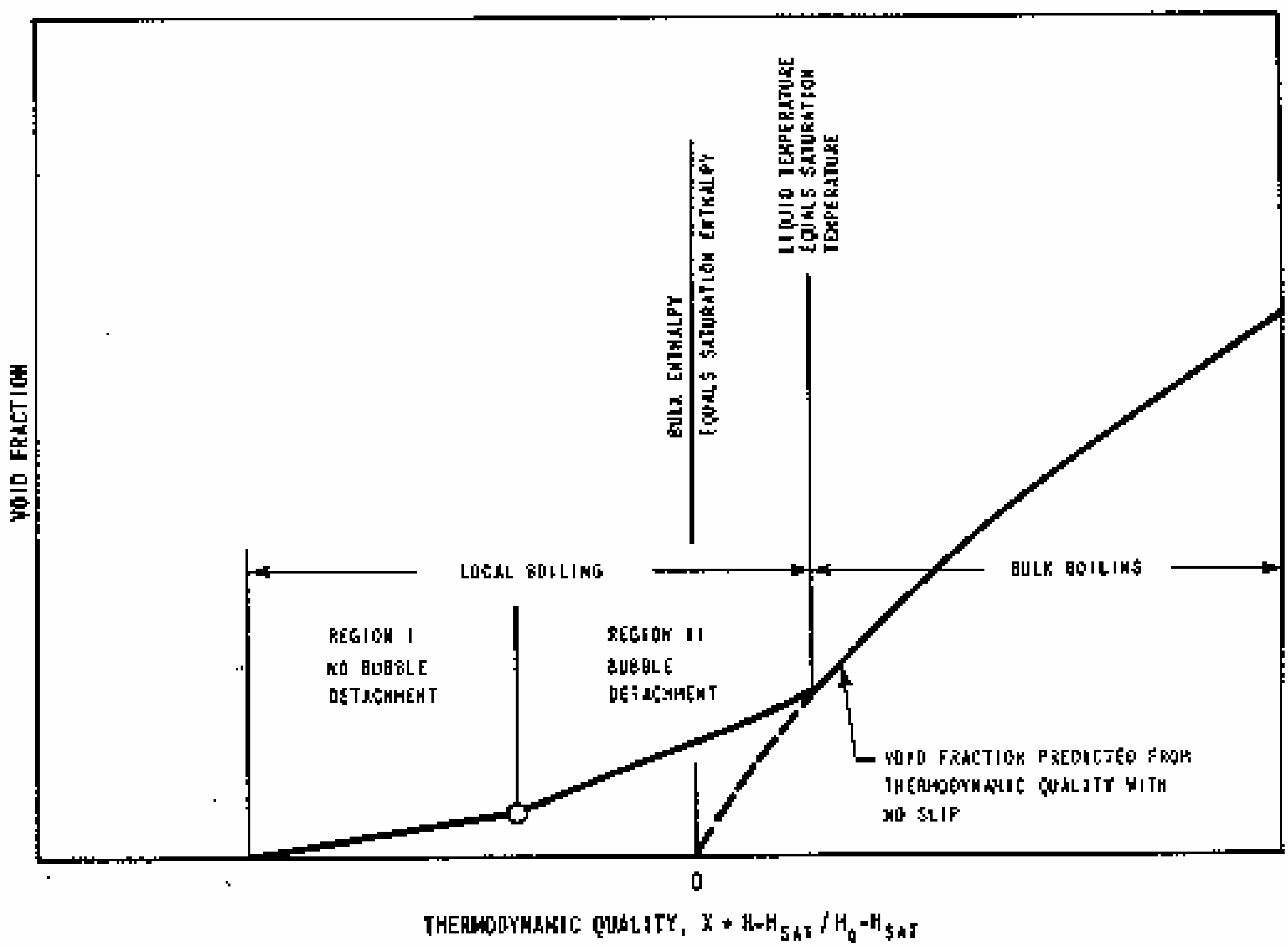

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FIGURE 4.4-10 VOID FRACTION vs. THERMODYNAMIC QUALITY $H\text{-}H_{SAT}/H_G\text{-}H_{SAT}$

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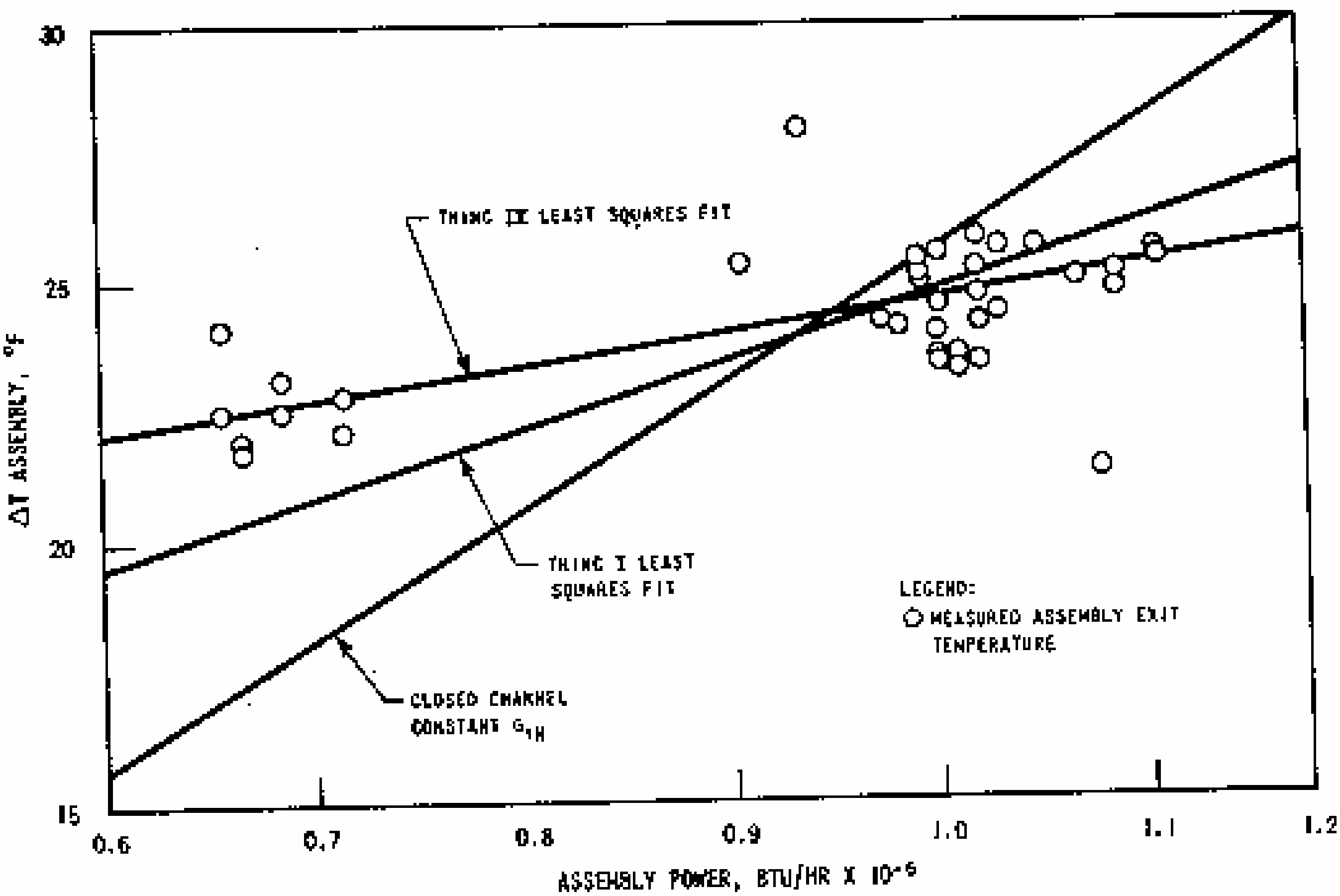

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FIGURE 4.4-11 PWR NATURAL CIRCULATION TEST

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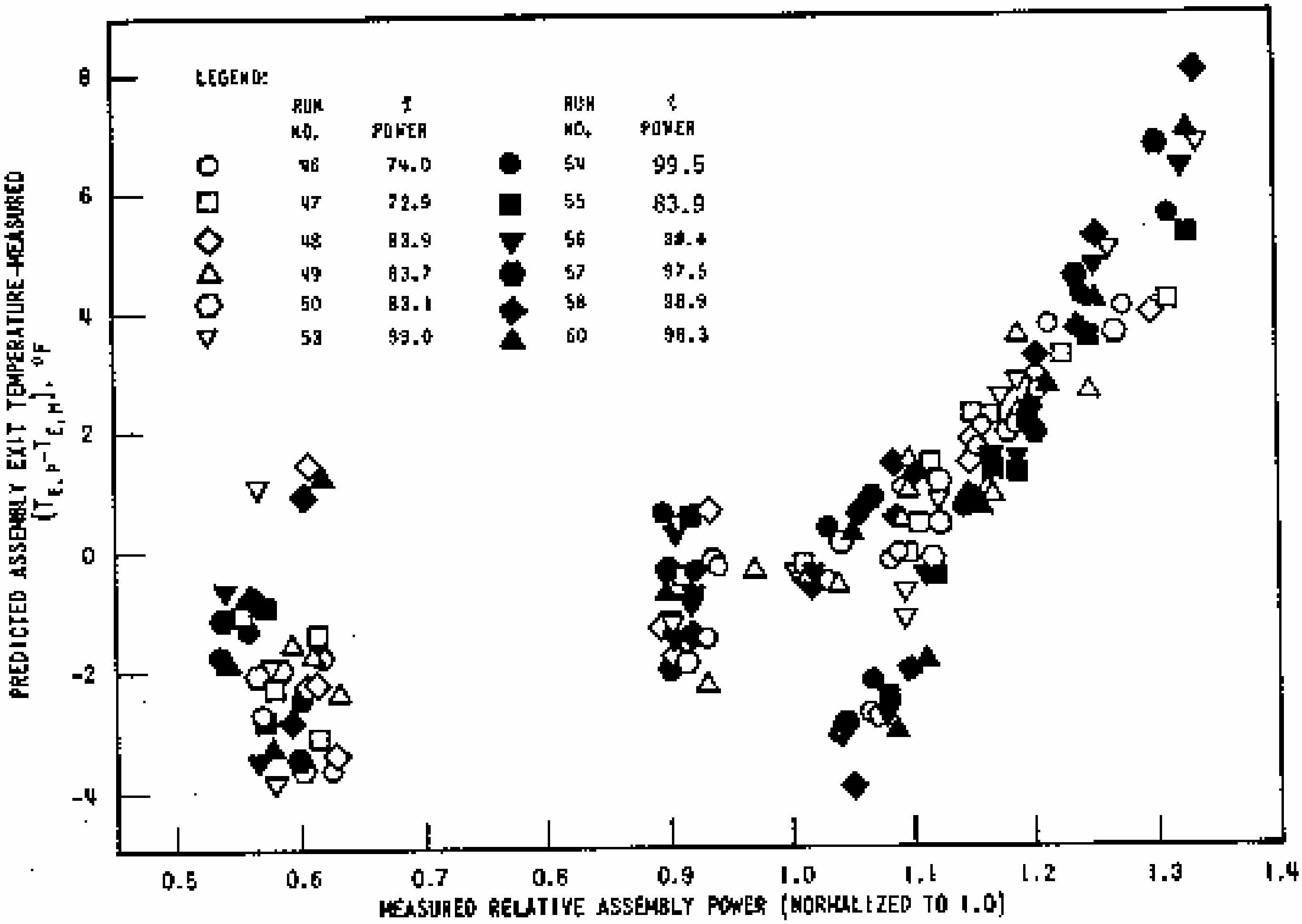

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FIGURE 4.4-12 COMPARISON OF A REPRESENTATIVE <u>W</u> TWO-LOOP REACTOR INCORE THERMOCOUPLE MEASUREMENTS WITH THINC-IV PREDICTIONS

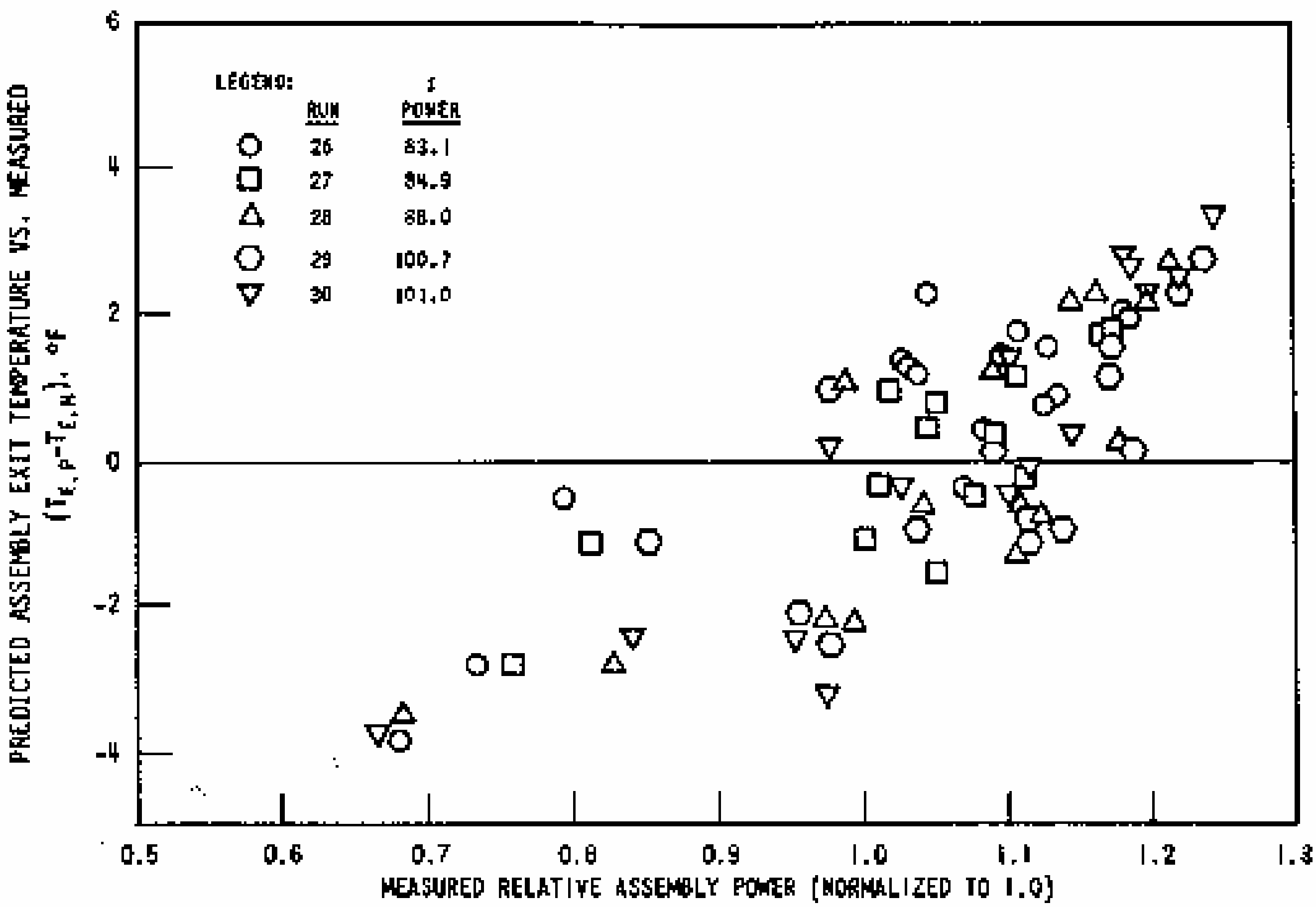

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FIGURE 4.4-13

COMPARISON OF A REPRESENTATIVE W THREE-LOOP REACTOR INCORE THERMOCOUPLE MEASUREMENTS WITH THINC-IV PREDICTIONS

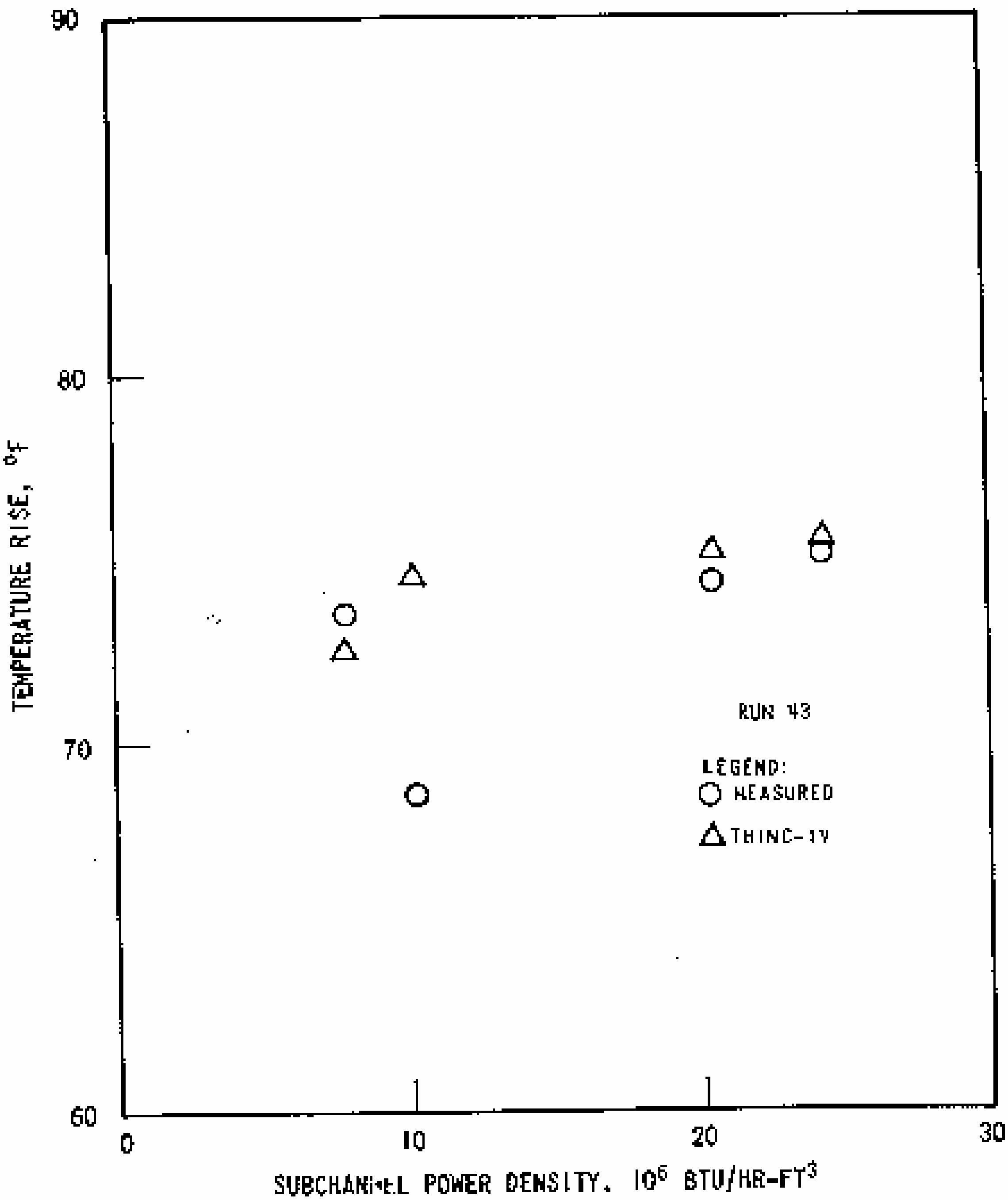

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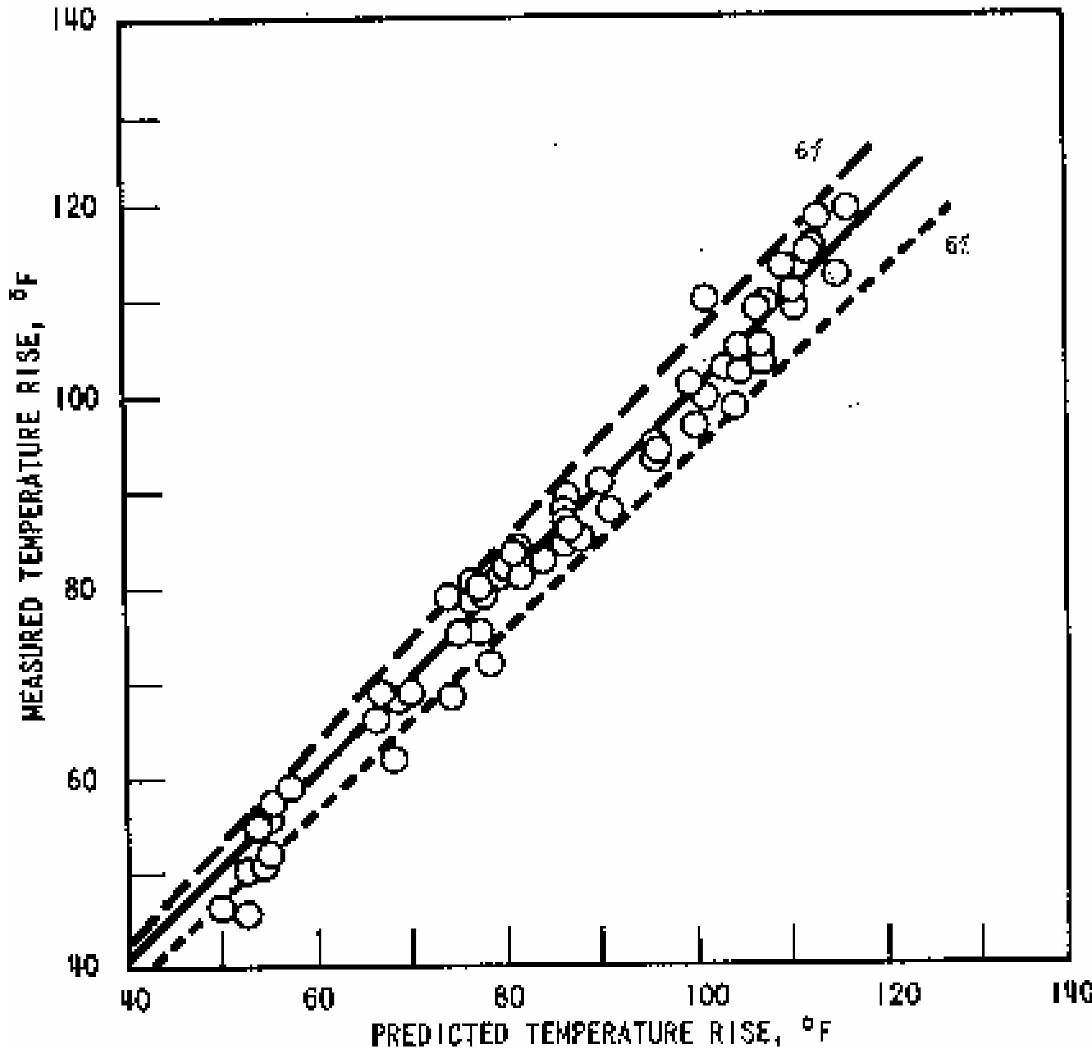
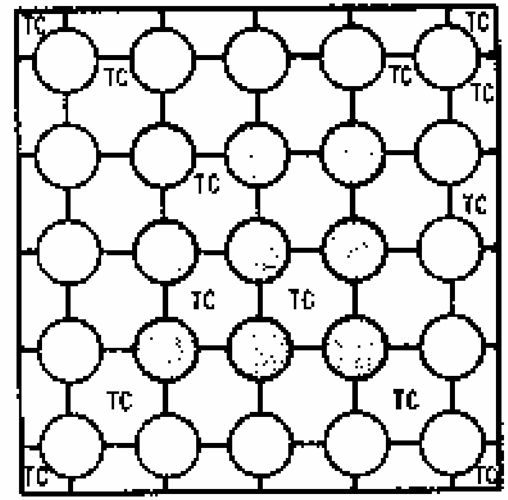
FIGURE 4.4-14

HANFORD SUBCHANNEL TEMPERATURE DATA COMPARISON WITH THINC-IV





PRESSURE	2014 PSIA
MASS FLOW	$0.5-2.2 \times 10^6 LB/_m FT^2-HR$
ROD DIAMETER	0.422 INCHES
ROD PITCH	0.555 INCHES
HEATED LENGTH	84 INCHES
HEAT FLUX DISTRIBUTION	
INNER ROD: OUTER ROD	1.204: 1.0

TC - THERMOCOUPLE LOCATION

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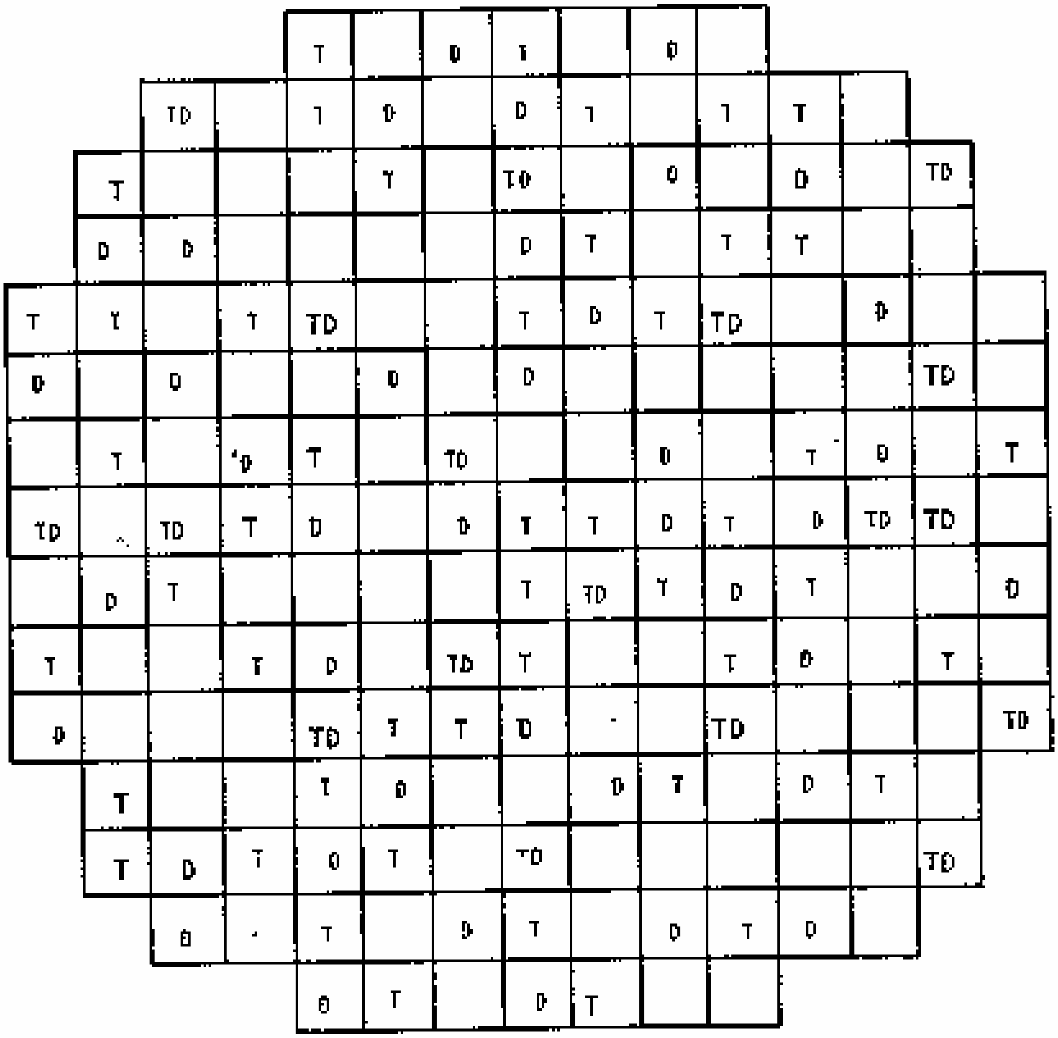
FIGURE 4.4-15

HANFORD SUBCRITICAL TEMPERATURE DATA COMPARISON WITH THINC-IV



T = THERMOCOUPLE (65)

D = MOVABLE INCORE DETECTOR (58 LOCATIONS)

SAME ORIENTATION AS FIGURE 4.3-1

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FIGURE 4.4-16 **DISTRIBUTION OF INCORE INSTRUMENTATION**

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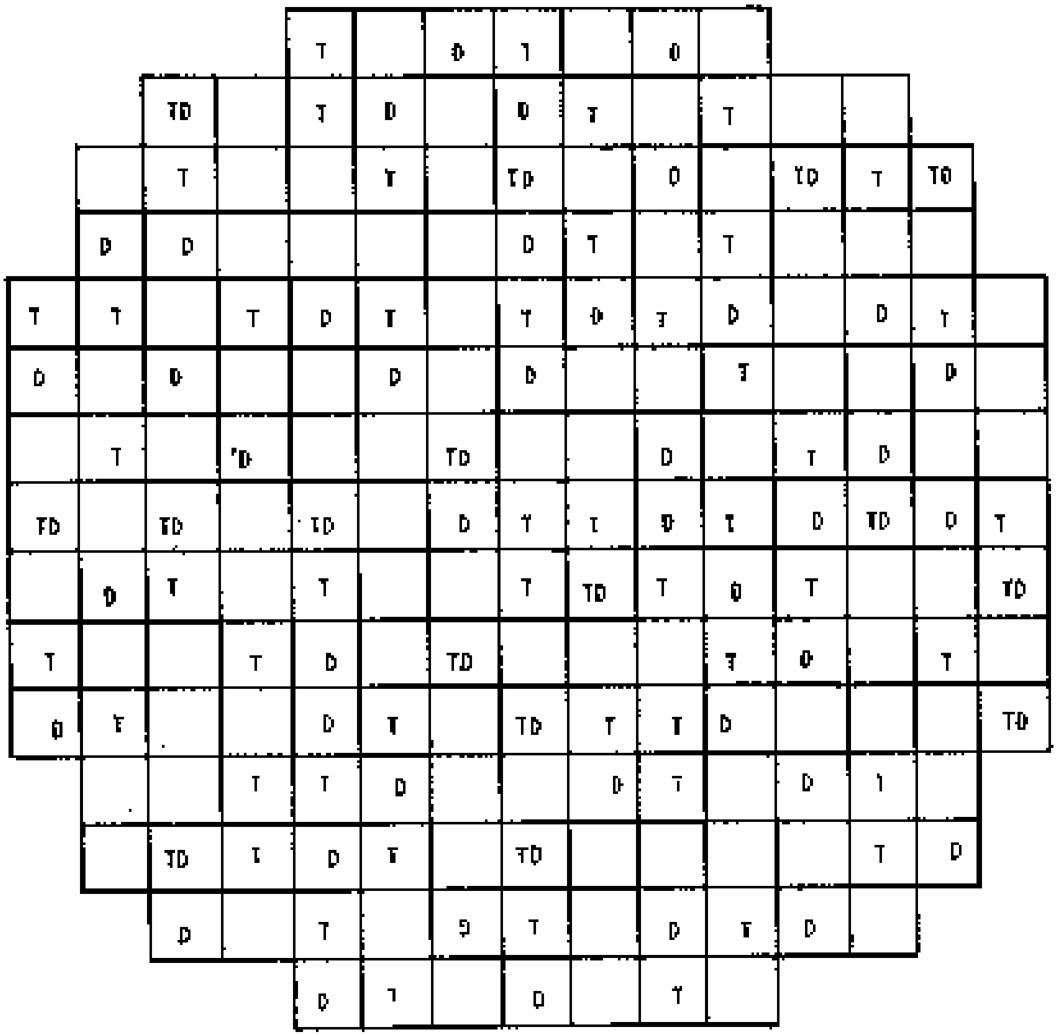

T = THERMOCOUPLE (65)

D = MOVABLE INCORE DETECTOR (58 LOCATIONS)

SAME ORIENTATION AS FIGURE 4.3-1

FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 4.4-17 DISTRIBUTION OF INCORE INSTRUMENTATION

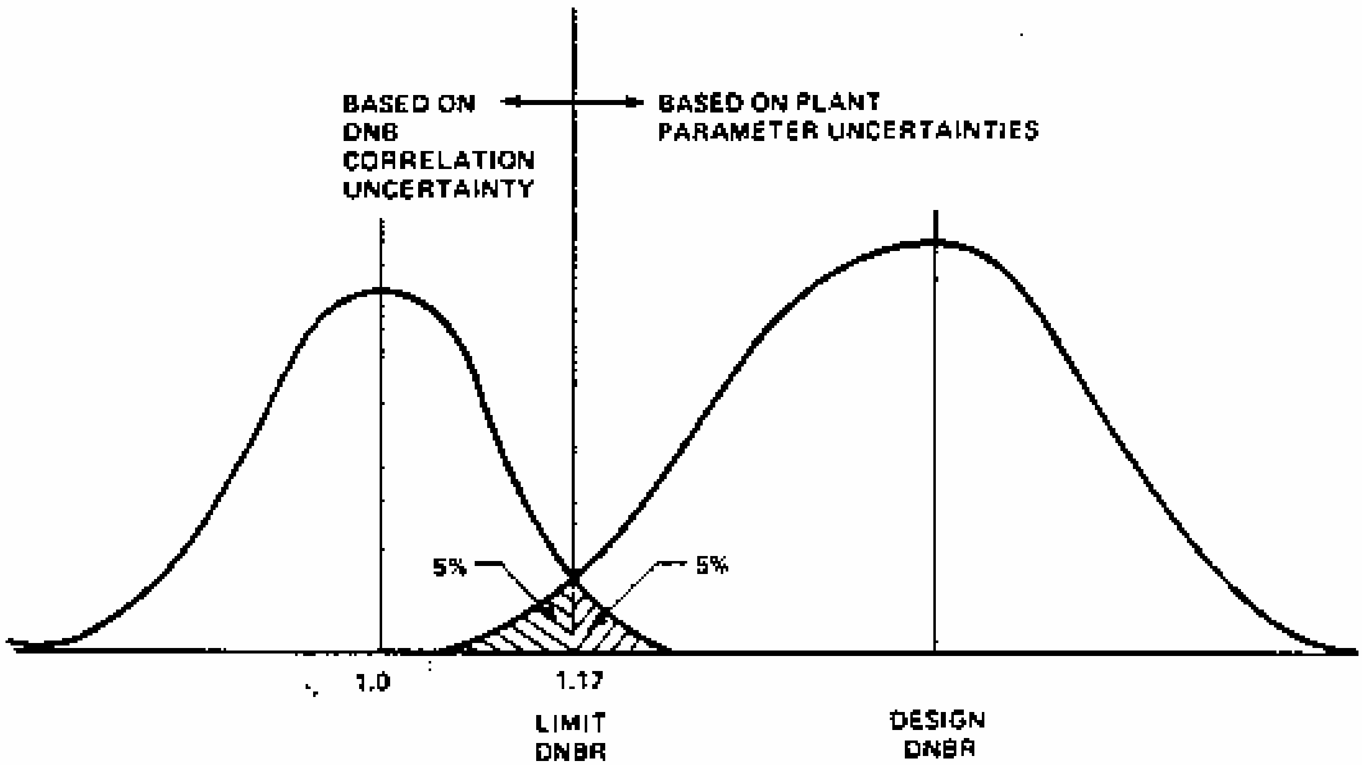

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FIGURE 4.4-18

IMPROVED THERMAL DESIGN PROCEDURE ILLUSTRATION

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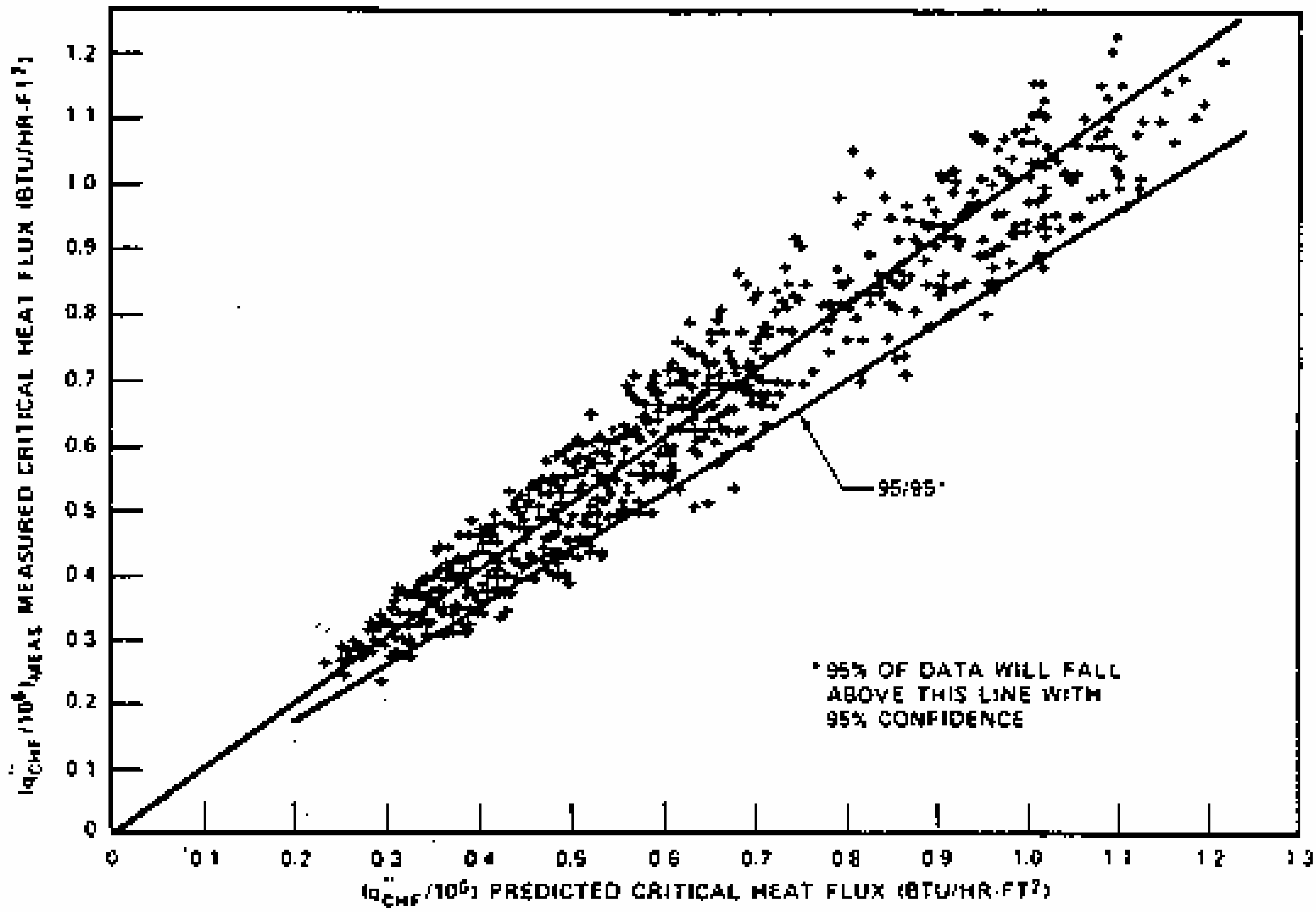

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FIGURE 4.4-19

MEASURED VERSES PREDICTED CRITICAL HEAT FLUX – WRB-1 CONNECTION

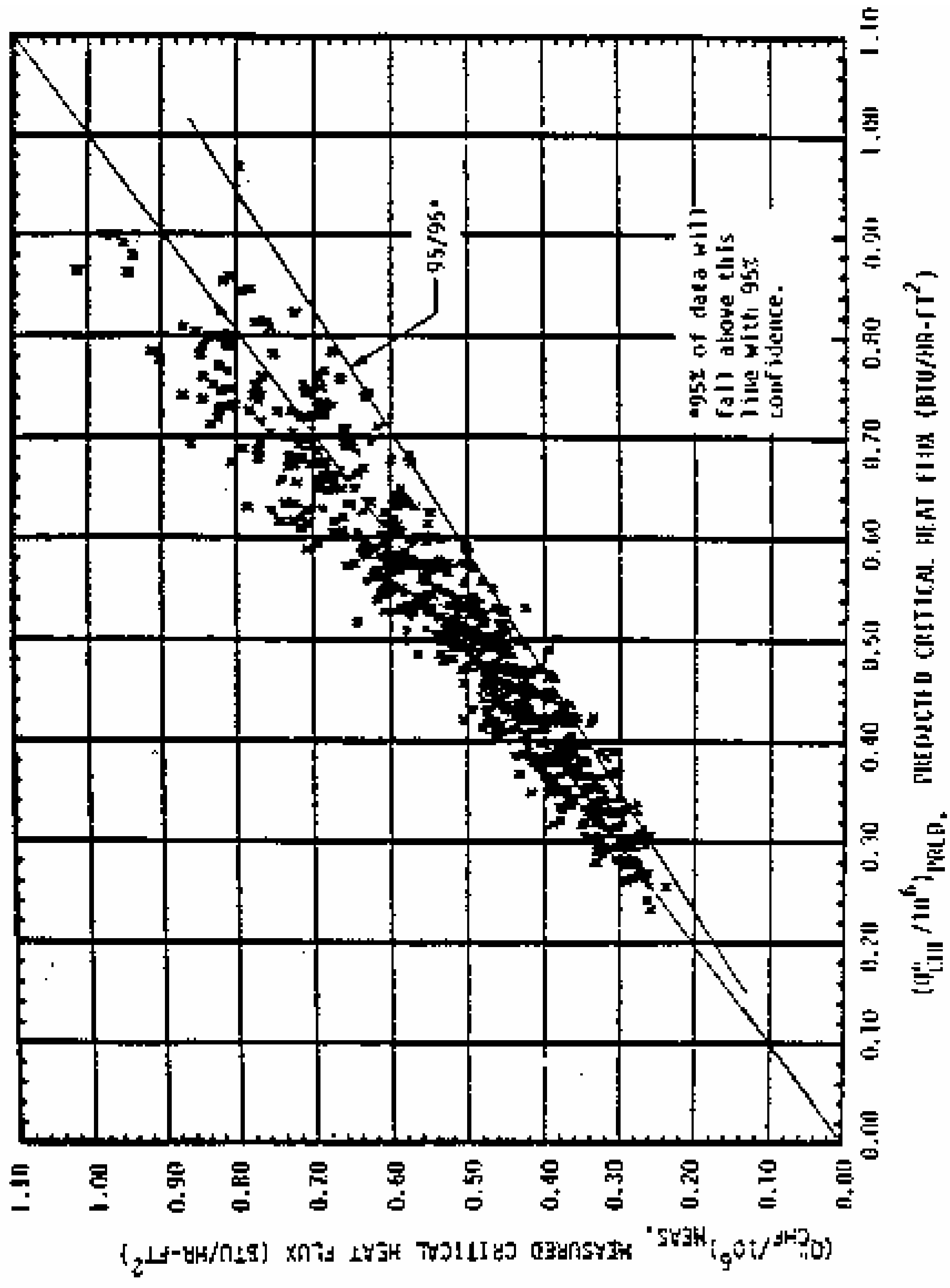

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FIGURE 4.4-20

MEASURED VERSES PREDICTED CRITICAL HEAT FLUX – WRB-2 CONNECTION

Chapter 5

REACTOR COOLANT SYSTEM

CONTENTS

CONTENTS (Continued)

CONTENTS (Continued)

CONTENTS (Continued)

CONTENTS (Continued)

CONTENTS (Continued)

TABLES (Continued)

TABLES (Continued)

TABLES (Continued)

Chapter 5

FIGURES

FIGURES (Continued)

FIGURES (Continued)

NOTE:

[a] This figure corresponds to a controlled engineering drawing that is incorporated by reference into the FSAR Update. See Table 1.6-1 for the correlation between the FSAR Update figure number and the corresponding controlled engineering drawing number.

Chapter 5

APPENDICES

Chapter 5

REACTOR COOLANT SYSTEM

5.1 SUMMARY DESCRIPTION

The reactor coolant system (RCS) consists of four similar heat transfer loops connected in parallel to the reactor pressure vessel, which are located inside the containment. Each loop contains a reactor coolant pump, steam generator, and associated piping and valves. The system also includes a pressurizer, a pressurizer relief tank, interconnecting piping, and instrumentation necessary for operation.

During operation, the RCS transfers heat generated in the core to the steam generators where the steam that drives the turbine-generator is produced. Borated pressurized water circulates in the RCS at a flowrate and temperature consistent with the reactor core thermal-hydraulic performance requirements. The water also acts as a neutron moderator and reflector, and as a solvent for the boric acid neutron absorber used as chemical shim control.

The RCS pressure boundary provides a barrier against the release of radioactivity generated within the reactor, and is designed to ensure a high degree of integrity throughout plant life.

RCS pressure is controlled by the pressurizer in which water and steam are maintained in equilibrium by electrical heaters or water sprays. Steam can be formed (by the heaters) or condensed (by the pressurizer spray) to minimize reactor coolant pressure variations. Spring-loaded safety valves and power-operated relief valves are mounted on the pressurizer, and discharge to the pressurizer relief tank where the steam is condensed and cooled by mixing with water. Noncondensable gases (primarily) or steam can be removed from the reactor vessel head by the reactor vessel head vent system (RVHVS).

5.1.1 SCHEMATIC FLOW DIAGRAM

Figure 3.2-7 is a schematic flow diagram of the reactor coolant system. Principal pressures, temperatures, flowrates, and coolant volume under normal full power operating conditions are listed in Table 5.1-1.

The RCS pressure boundary is defined as:

(1) The reactor vessel, including control rod drive mechanism housings

(2) The reactor coolant side of the steam generators

(3) Reactor coolant pump casings

(4) A pressurizer attached to one of the reactor coolant loops

(5) Safety and relief valves

(6) The interconnecting piping, valves, and fittings between the principal components listed above

(7) The piping, fittings, and valves leading to connecting auxiliary or support systems up to and including the second isolation valve (from the high-pressure side) on each line

5.1.2 PIPING AND INSTRUMENTATION DIAGRAMS

RCS piping and instrumentation are shown schematically in Figure 3.2-7.

5.1.3 ELEVATION DRAWINGS

Physical layout of the RCS is shown in the following figures:

Figures 1.2-4, 1.2-5, and 1.2-6 (plan views inside containment)
Figures 1.2-22, 1.2-24, and 1.2-28 (section views inside containment)
Figure 5.5-10 (steam generator and reactor coolant pump supports)
Figure 5.5-11 (component supports)
Figure 5.5-12 (pressurizer support)

5.1.4 REACTOR COOLANT SYSTEM COMPONENTS

The principal RCS components are described in this section.

5.1.4.1 Reactor Vessel

The reactor vessel is a cylindrical vessel with a welded hemispherical bottom head and a removable, bolted, flanged, and gasketed, hemispherical upper head. The vessel contains the core, core supporting structures, control rods, and other parts directly associated with the core. The RVHVS, consisting of four remotely operated solenoid valves in two trains, each with two valves in series, is installed on the upper head.

The vessel has inlet and outlet nozzles located in a horizontal plane just below the reactor vessel flange, but above the top of the core. Coolant enters the vessel through the inlet nozzles and most of it flows down the core barrel-vessel wall annulus, turns, and flows up through the core to the outlet nozzles (Figures 5.4-1 and 5.4-2).

5.1.4.2 Steam Generators

The steam generators are vertical shell and U-tube evaporators with integral moisture separating equipment. The reactor coolant flows through inverted U-tubes, entering and leaving through the nozzles located in the hemispherical bottom head of the steam generator. Steam is generated on the shell side and flows upward through the moisture separators to the outlet nozzle at the top of the vessel.

5.1.4.3 Reactor Coolant Pumps

The reactor coolant pumps are identical single-speed centrifugal units driven by air-cooled, three-phase induction motors. The shaft is vertical with the motor mounted above the pumps. A flywheel on the shaft above the motor provides additional rotational energy to extend pump coastdown. The inlet is at the bottom of the pump; discharge is on the side.

5.1.4.4 Piping

Sizing of reactor coolant loop piping is consistent with system requirements. RCS hot leg piping is 29 inches ID and the cold leg return line to the reactor vessel is 27-1/2 inches ID. The piping between the steam generator and the pump suction is 31 inches ID to reduce pressure drop and improve flow conditions to the pump suction. To further improve pump suction conditions, a flow splitter is provided in the pipe bend upstream of the pump suction.

5.1.4.5 Pressurizer

The pressurizer is a vertical, cylindrical vessel with hemispherical top and bottom heads. Electrical heaters are installed through the bottom head of the vessel while the spray nozzle and the relief and safety valve connections are located in the top head of the vessel. The heaters can be removed for maintenance or replacement.

5.1.4.6 Pressurizer Relief Tank

The pressurizer relief tank (PRT) is a horizontal, cylindrical vessel with elliptical ends. Steam from the pressurizer safety and relief valves is discharged into the PRT through a sparger pipe submerged below the water level. This condenses and cools the steam by mixing it with water that is near ambient temperature. The PRT is provided with 2 rupture disks set at 100 psig.

5.1.4.7 Safety and Relief Valves

The pressurizer safety valves are spring-loaded, self-activated with back-pressure compensation. The power-operated relief valves (PORVs) limit system pressure for large power mismatch and thus prevent actuation of the fixed high-pressure reactor trip. They operate automatically or by remote manual control. Remotely operated valves are

provided to isolate the inlet to the PORVs if excessive seat leakage occurs in the PORVs. Acoustic monitors are provided to monitor leaking safety valves.

5.1.5 REACTOR COOLANT SYSTEM PERFORMANCE AND SAFETY FUNCTIONS

Design and performance characteristics of the RCS are provided in Table 5.1-1 and Figures 5.1-2 and 5.1-2A.

5.1.5.1 Reactor Coolant Flow

The reactor coolant flow, a major parameter in the design of the system and its components, is established using a detailed design procedure supported by operating plant performance data, by pump model tests and analysis, and by pressure drop tests and analyses of the reactor vessel and fuel assemblies.

Evaluation of the RCS flow involves a number of parameters. RCS “Best Estimate Flow,” “Thermal Design Flow,” “Mechanical Design Flow,” “Minimum Measured Flow,” and “Minimum Required Total RCS Flow Rate,” are parameters established during original design and are evaluated in the safety analyses of record. Figure 5.1-2 and Figure 5.1-2A provide a representation of these RCS flow parameters relative to original design considerations and the current safety analyses of record.

RCS flow is measured using a precision calorimetric or cold leg elbow differential pressure taps. A cold leg elbow tap flow methodology was established using WCAP-15113, Revision 1 (Reference 2) and WCAP-14750, Revision 1 (Reference 3).

5.1.5.2 Best Estimate Flow

The best estimate flow is the most likely value for the actual plant operating condition. The best estimate flow is used in developing the thermal design flow and mechanical design flow. This flow is calculated based on the best estimate of the reactor vessel, steam generator and piping flow hydraulic resistance, and on the best estimate of the reactor coolant pump head-flow performance, with no uncertainties assigned to either the RCS component flow resistance or the pump head. The best estimate flow is calculated based on hydraulic analyses.

The best estimate flow is also used to confirm the cold leg elbow tap flow measurement while limiting the elbow flow tap measurement to a maximum value corresponding to the best estimate flow plus an allowance for the elbow tap flow repeatability uncertainty. The hydraulic analysis uncertainty is 2%, while the instrument analysis repeatability allowance is 0.4%, for a total uncertainty of 2.4%. Application of this acceptance criterion results in definition of a conservative current cycle flow, confirmed by both the elbow tap flow measurements and the best estimate hydraulic analysis.

In the event that changes are made to the plant primary side hydraulic resistance or reactor coolant pump characteristics, the best estimate flow must be recalculated.

Although the best estimate flow is the most likely value to be expected in operation, more conservative flowrates are applied in the thermal and mechanical designs, as discussed in subsections 5.1.5.3 and 5.1.5.4, below. The relationship between these parameters is reflected in Figure 5.1-2 and Figure 5.1-2A.

5.1.5.3 Thermal Design Flow

Thermal design flow is the basis for the reactor core thermal performance, the steam generator thermal performance, and the design plant parameters used throughout the design. To provide the required margin in the safety analyses, the thermal design flow accounts for the uncertainties in the reactor vessel, steam generator, and piping flow resistances, reactor coolant pump head, and the methods used to measure flowrate. The combination of these uncertainties, which includes a conservative estimate of the pump discharge weir flow resistance, is equivalent to increasing the initial plant design best estimate RCS flow resistance by approximately 19 percent. The intersection of this conservative flow resistance with the initial plant design best estimate pump curve, (an example is shown in Figure 5.1-2), established the thermal design flow. Figure 5.1-2 and Figure 5.1-2A illustrate the relationship of thermal design flow to other design and operating parameters. This procedure provides a flow margin for thermal design of approximately 4 percent from the best estimate flow. The thermal design flow is the initial flow assumed for non-Departure from Nucleate Boiling (DNB) related accident and transient analyses and DBR analyses for which the Improved Thermal Design Procedure (ITDP) is not used. The thermal design flow is maintained during plant operation by satisfying the minimum RCS flow requirements of Technical Specification Table 3.4.1-1 for Unit 1 and Table 3.4.1-2 for Unit 2.

Data from all operating plants have indicated that the actual flow has been well above the flow specified for the thermal design of the plant. Tabulations of important design and performance characteristics of the RCS, as provided in Table 5.1-1, are based on the thermal design flow, as indicated.

5.1.5.4 Mechanical Design Flow

Mechanical design flow is the flow used in the mechanical design of the reactor vessel internals and fuel assemblies. To ensure that a conservatively high flow is specified, the mechanical design flow was based on a reduced system resistance (90 percent of initial plant design best estimate) and on increased pump head capability (107 percent of initial plant design best estimate). The intersection of this flow resistance with the higher pump curve established the mechanical flow. Figure 5.1-2 and Figure 5.1-2A illustrate the relationship of mechanical design flow to other design and operating parameters.

5.1.5.5 Minimum Measured Flow

The plant Minimum Measured Flow (MMF), the RCS minimum total flow rate, is the flow used in reactor core DNB analyses for the Improved Thermal Design Procedure (ITDP). The MMF is defined as the Thermal Design flow (TDF) plus at least one flow measurement uncertainty. The RCS minimum total flow rate, reflected in Tech Spec. LCO 3.4.1(c), allows for a measurement uncertainty error of 2.4% regardless of the method used, cold leg elbow tap or precision calorimetric. The MMF for each unit is provided in Table 4.1-1 and Table 5.1-1.

5.1.5.6 Minimum Required RCS Flow Rate

The minimum required RCS flow rate is the RCS total flow rate limit provided for each unit in the Technical Specifications, Table 3.4-1 for Unit 1 and Table 3.4-2 for Unit 2, and verified under Surveillance Requirement 3.4.1.4. These RCS total flow rate limits incorporate a measurement error of no more than 2.4%. The RCS flow rate allowable values and nominal trip setpoints reflected in Technical Specifications 3.3.1, Function 10, are based on a percentage of the loop flow measured every 24 months under Technical Specification Surveillance Requirement 3.4.1.4. This is determined using either the cold leg elbow taps or by a precision calorimetric.

The RCS cold leg taps indicated total flow is continuously compared to the Reactor Coolant Flow-Low nominal trip setpoint (see also Section 7.2.1.1.4). The best estimate flow (see Section 5.1.5.2) may not be used as a substitute for the Technical Specification 3.4.1.4 Surveillance Requirement for flow measurement.

5.1.5.7 RCS Flow Determination and Safety Analyses

Reactor coolant flow is an important parameter in most of the non-LOCA safety analyses. Figure 5.1-2 provides a representation of how the Thermal Design Flow (TDF) and Mechanical Design Flow (MDF) were established for the Diablo Canyon original design. These values were generated based on the best estimate flow expected after start-up. The TDF, a conservatively low flow, and the MDF, a conservatively high flow, are used in various safety analyses, depending on whether low flow or high flow is conservative for each particular analysis. Figure 5.1-2A provides a representation of the relationship between the Best Estimate Flow, the MDF, the MMF, and the TDF. The values of these parameters are presented in Table 5.1-1.

The total RCS flow assumed in the safety analyses depends on the methodology for each specific analysis. For DNB analyses that employ the Improved Thermal Design Procedure (ITDP), the MMF value is assumed directly in the analysis. In the ITDP, a random flow uncertainty of 2.4% of flow is accounted for in a statistical square-root-of-the-sum-of-the-squares (SRSS) combination with other appropriate plant input parameter uncertainties to set the DNBR limit. For non-DNBR related events or DNB events for which the ITDP is not employed, the TDF value is used.

RCS flow is measured every cycle under Technical Specification Surveillance Requirements 3.4.1.3 and 3.4.1.4, and is compared directly to the Technical Specification flow limits to ensure continued plant operation consistent with the safety analyses. If the total RCS flow does not meet the full-power safety analysis value, Technical Specification Tables 3.4.1-1 (Unit 1) and 3.4.1-2 (Unit 2) allow a graduated trade-off between RCS flow and power level, down to 90% power.

5.1.5.8 System and Components

The interrelated performance and safety functions of the RCS and its major components are listed below:

(1) The RCS provides sufficient heat transfer capability to transfer the heat produced during power operation and the initial phase of plant cooldown, when the reactor is subcritical, to the steam system via the steam generator.

(2) The system provides sufficient heat transfer capability to transfer the heat produced during the subsequent phase of plant cooldown and cold shutdown to the residual heat removal (RHR) system.

(3) The system heat removal capability under power operation and normal operational transients, including the transition from forced to natural circulation, ensures that no fuel damage occurs within the operating bounds permitted by the reactor control and protection systems.

(4) The RCS contains the water used as the core neutron moderator and reflector and as a solvent for chemical shim control.

(5) The system, together with the chemical and volume control system (CVCS), maintains the homogeneity of soluble neutron poison concentration and controls the rate of change of coolant temperature, preventing uncontrolled reactivity changes.

(6) The reactor vessel is an integral part of the RCS pressure boundary and can accommodate the temperatures and pressures associated with operational transients. The reactor vessel supports the reactor core and control rod drive mechanisms.

(7) The pressurizer maintains system pressure during operation and limits pressure transients. During plant load reduction or increase, reactor coolant volume changes are accommodated in the pressurizer via the surge line.

(8) The reactor coolant pumps supply the coolant flow necessary to remove heat from the reactor core and transfer it to the steam generators.

(9) The steam generators provide high quality steam to the turbine. The tube and tubesheet boundary are designed to prevent the transfer of radioactivity generated within the core to the secondary system.

(10) The RCS piping constitutes a boundary to contain the coolant under operating temperature and pressure conditions and limit leakage (and radioactivity release) to the containment atmosphere. It contains pressurized water that is circulated at a flowrate and temperature, which is consistent with reactor core thermal and hydraulic performance requirements.

(11) The RVHVS can be used to remove noncondensable gases or steam from the reactor vessel head by remote-manual operation from the control room.

5.1.6 SYSTEM OPERATION

5.1.6.1 Plant Startup

Plant startup encompasses the operations which bring the reactor plant from cold shutdown to no-load power operating temperature and pressure.

Before plant startup, the reactor coolant loops and pressurizer are filled completely with reactor coolant to eliminate noncondensable gases. If the vacuum refill method of filling the RCS is performed, the vacuum process will remove noncondensable gases and the pressurizer will not need to be filled completely. The water contains the correct concentration of boron to maintain shutdown margin. The secondary side of the steam generator is filled with water to normal startup level.

The RCS is then pressurized using the low-pressure control valve and either the centrifugal charging pump (CCP3) (preferentially) or the centrifugal charging pumps (CCP1 and CCP2) to obtain the required pressure drop across the No. 1 seal of the reactor coolant pumps. The pumps may then be operated intermittently in venting operations. As an alternative, a vacuum process can be used in filling the RCS. If this method is used, operating the reactor coolant pumps intermittently to aid venting noncondensable gases may not be required.

During reactor coolant pump operation, the centrifugal charging pump (CCP3) (or a charging pump (CCP1 or CCP2)) and the low-pressure letdown path from the RHR system to the CVCS maintain the necessary RCS pressure. Reactor coolant pump operation is initiated after the required pressure differential across the No. 1 seal is achieved. The brittle fracture prevention temperature limitations of the reactor vessel impose an upper pressure limit during low temperature operation. The charging pump supplies seal injection water for the reactor coolant pump shaft seals. A nitrogen

atmosphere and normal operating temperature, pressure, and water level are established in the pressurizer relief tank.

After venting, the RCS is pressurized, all reactor coolant pumps are started, and the pressurizer heaters are energized to begin heating the reactor coolant in the pressurizer, which leads to formation of the steam bubble. If the vacuum refill method of filling the RCS is performed, a pressurizer steam bubble may be formed prior to starting the reactor coolant pumps. The pressurizer liquid level is reduced until the no-load power level volume is established. During the initial heatup phase, hydrazine is added to the reactor coolant to scavenge the oxygen in the system; the heatup is not taken beyond 180°F until the oxygen level has been reduced to the specified level.

As the reactor coolant temperature increases, the pressurizer heaters are manually controlled to maintain adequate suction pressure for the reactor coolant pumps.

5.1.6.2 Power Generation and Hot Standby

Power generation includes steady state operation, ramp changes not exceeding the rate of 5 percent of full power per minute, step changes of 10 percent of full power (not exceeding full power), and step load decreases with steam dump not exceeding 95 percent of full power.

During power generation, RCS pressure is maintained by the pressurizer controller at or near 2235 psig, while the pressurizer liquid level is controlled by the charging-letdown flow control of the CVCS.

When the reactor power level is less than 15 percent, the reactor power is controlled manually. At powers above 15 percent, the operator may select the automatic mode of operation. The rod motion is then controlled by the reactor control system that automatically maintains an average coolant temperature, which follows a program based on turbine load.

During hot standby operations, when the reactor is subcritical, the RCS temperature is maintained by steam dump to the main condenser. This is accomplished by valves in the steam line, operating in the pressure control mode, which is set to maintain the steam generator steam pressure, or manually. Residual heat from the core or operation of a reactor coolant pump provides heat to overcome RCS heat losses.

5.1.6.3 Plant Shutdown

Plant shutdown is the operation that brings the reactor plant from no-load power operating temperature and pressure to cold shutdown. During plant cooldown from hot standby to hot shutdown conditions, concentrated boric acid solution from the CVCS is added to the RCS to increase the reactor coolant boron concentration to that required for cold shutdown. If the RCS is to be opened during the shutdown, the hydrogen and

fission gas in the reactor coolant is reduced by degassing the coolant in the volume control tank.

Plant shutdown is attained in two phases: first, by the combined use of the RCS and steam systems, and, second, by the RHR system. During the first phase of shutdown, residual core and reactor coolant heat are transferred to the main steam system via the steam generator. Steam from the steam generator is dumped to the main condenser or to the atmosphere. At least one reactor coolant pump is kept running to ensure uniform RCS cooldown. Pressurizer heaters and spray flow are manually controlled to cool the pressurizer while maintaining the required reactor coolant pump suction pressure. The plant does not permit the pressurizer to go water-solid without the RHR system and low temperature overpressure protection systems in service. As the pressurizer cools, the low-pressure control valve, pressurizer spray, pressurizer heaters, and the charging pumps maintain the required RCS pressure.

When the reactor coolant temperature is below approximately 350°F and the nominal pressure is less than or equal to 390 psig, the second phase of shutdown commences with the operation of the RHR system.

Typically at least one reactor coolant pump (either of those in a loop containing a pressurizer spray line) is kept running until the coolant temperature is reduced to approximately 145°F. Pressurizer cooldown continues by initiating auxiliary spray flow from the CVCS if reactor coolant pumps are not available. Plant shutdown continues until the reactor coolant temperature is 140°F or less.

5.1.6.4 Refueling

Before removing the reactor vessel head for refueling, the system temperature is reduced to 140°F or less, and hydrogen and fission product levels are reduced. Water level is monitored to indicate when the water level is below the top of the reactor vessel head. Draining continues until the water level is below the reactor vessel flange. The vessel head is then removed and the refueling cavity is flooded. Upon completion of refueling, the system is refilled for plant startup.

5.1.6.5 Mid-Loop Operation

During refueling conditions, steam generator nozzle dams may be used in accordance with approved plant procedures to isolate the steam generator U-tubes from the reactor coolant system for inspection and maintenance. The steam generators are discussed in Section 5.5.2.

Use of steam generator nozzle dams requires lowering the water level in the RCS to a level below that necessary to remove the reactor head (i.e., partial drain or mid-loop operation). Mid-loop operation, when performed in accordance with approved plant procedures, is acceptable when core decay heat is less than or equal to 15.3 MWt

(Reference 1). During mid-loop operation, water level is closely monitored to ensure adequate decay heat removal by the RHR system.

5.1.7 REFERENCES

1. RCS Pressurization Analysis for Diablo Canyon Shutdown Scenarios, Westinghouse Technical Report, April 1997.

2. RCS Flow Measurement Using Elbow Tap Methodology at Diablo Canyon Units 1 and 2, WCAP-15113, Revision 1, Westinghouse Electric Company LLC, April 2002.

3. RCS Flow Verification Using Elbow Taps at Westinghouse 3-Loop PWRs, WCAP-14750, Revision 1, Westinghouse Electric Company, September 1999.

5.2 INTEGRITY OF THE REACTOR COOLANT PRESSURE BOUNDARY

The reactor coolant system (RCS) boundary is designed to accommodate the system pressures and temperatures attained under all expected modes of plant operation, including all anticipated transients, and to maintain the resulting stresses within allowable values. The system is protected from overpressure by means of pressure relieving devices as required by applicable codes and a special system for low temperature operation. Materials of construction are specified to minimize corrosion and erosion and to provide a structure and system pressure boundary that will maintain its integrity throughout the life of the plant. Inspections in accordance with Reference 8, and provisions for surveillance of critical areas to enable periodic assessment of the boundary integrity, are made.

5.2.1 DESIGN OF REACTOR COOLANT PRESSURE BOUNDARY COMPONENTS

The RCS transfers heat from the reactor to the steam generators under conditions of both forced and natural circulation flow. The heat transfer capability of the steam generators is sufficient to transfer to the steam and power conversion system the heat generated during normal operation and the initial phase of plant cooldown under natural circulation conditions.

During the second phase of plant cooldown and during cold shutdown and refueling, the heat exchangers of the residual heat removal (RHR) system are employed. Their capability is discussed in Section 5.5.

RCS pumps ensure heat transfer by forced circulation flow. They are also discussed in Section 5.5. Initial RCS tests are performed to determine the circulation capability of the reactor coolant pumps. Thus, adequate reactor coolant circulation is confirmed prior to plant operation.

To ensure a heat sink for the reactor under conditions of natural circulation flow, the steam generators are at a higher elevation than the reactor. The steam generators provide sufficient tube area to ensure an adequate residual heat removal rate with natural circulation flow. This was confirmed by post-TMI generic testing.

Whenever the RCS boron concentration is varied, good mixing is provided to ensure uniform boron concentration throughout the RCS. Although pressurizer mixing is not achieved to the same degree, the fraction of the total RCS volume, which is in the pressurizer is small. Pressurizer spray provides homogenization of boron concentration.

Also, the distribution of flow around the system is not subject to the degree of variation that would be required to produce nonhomogeneities in coolant temperature or boron concentration as a result of areas of low coolant flowrate.

Coolant temperature variation during normal operation is limited and the associated reactivity change is well within the capability of the rod control group movement. For design evaluation, the RCS heatup and cooldown transients are analyzed using a rate of temperature change equal to 100°F per hour. Over certain temperature ranges, fracture prevention criteria will impose a lower limit to heatup and cooldown rates.

Before plant cooldown is initiated, the boron concentration in the RCS is increased to the value required for the corresponding target temperature. Subsequent reactor coolant samples are taken to verify that the RCS boron concentration is correct. During plant cooldown, minimum shutdown margin (SDM) is maintained in accordance with requirements of the Diablo Canyon Power Plant (DCPP) Technical Specifications (Reference 19). The temperature changes imposed on the RCS during its normal modes of operation do not cause any unacceptable reactivity changes.

5.2.1.1 Performance Objectives

The performance objectives of the RCS are described in Section 5.1. Equipment codes and classification of the components within the RCS boundary are listed in Table 5.2-2. Procurement information for major RCS components is provided in Table 5.2-3.

The following five operating conditions are considered in the design of the RCS:

(1) Normal Conditions

Any condition in the course of startup, operation in the design power range, hot standby and system shutdown, other than upset, emergency, faulted, or testing conditions.

(2) Upset Conditions

Any deviations from normal conditions anticipated to occur often enough that the design should include a capability to withstand the conditions without operational impairment. The upset conditions include those transients that result from any single operator error control malfunction, transients caused by a fault in a system component requiring its isolation from the system, and transients due to loss of load or power.

Upset conditions include any abnormal incidents not resulting in a forced outage and also forced outages for which the corrective action does not include any repair of mechanical damage. The estimated duration of an upset condition was included in the design specifications.

(3) Emergency Conditions

Emergency conditions are those deviations from normal conditions that require shutdown for correction of the conditions or repair of damage in

the system. These conditions have a low probability of occurrence but are included to ensure that no gross loss of structural integrity results as a concomitant effect of any damage developed in the system. The total number of postulated occurrences for such events will not cause more than 25 stress cycles having an Sa value greater than that for 106 cycles from the applicable ASME Boiler and Pressure Vessel (ASME B&PV) Code, Section III, fatigue design curves.

(4) Faulted Conditions

Faulted conditions are those combinations of conditions associated with extremely low probability postulated events whose consequences are such that the integrity and operability of the nuclear energy system may be impaired to the extent that considerations of public health and safety are involved. Such conditions require compliance with safety criteria as may be specified by jurisdictional authorities.

(5) Testing Conditions

Testing conditions are those tests, in addition to the hydrostatic or pneumatic tests, permitted by the ASME B&PV Code, Section III, including leak tests or subsequent hydrostatic tests.

5.2.1.2 Design Parameters

The RCS, in conjunction with the reactor control and protection systems, maintains the reactor coolant at conditions of temperature, pressure, and flow adequate to protect the core from damage. The safety design requirements are to prevent conditions of high power, high reactor coolant temperature, or low reactor coolant pressure, or buildup of noncondensable gases which could interfere with core cooling, or combinations of these which could result in a departure from nucleate boiling ratio (DNBR) smaller than the applicable limit value (refer to Sections 4.4.1.1 and 4.4.2.3).

The chemical and volume control system (CVCS) is designed to avoid uncontrolled reductions in boric acid concentration or reactor coolant temperature. The reactor coolant is the core moderator, reflector, and solvent for the chemical shim. As a result, changes in coolant temperature or boric acid concentration affect the reactivity level in the core.

The following design bases have been selected to ensure that uniform RCS boron concentration and temperature are maintained:

(1) Coolant flow is provided by either a reactor coolant pump or an RHR pump to ensure uniform mixing whenever the boron concentration is varied.

(2) The RCS design arrangement eliminates dead ended sections and other areas of low coolant flow in which nonhomogeneities in coolant temperature or boron concentration could develop.

(3) The RCS is designed to operate within the coolant temperature change limitations.

The design pressure for the RCS is 2485 psig except for the pressurizer relief line between the safety valve and the pressurizer relief tank (PRT), which is designed for 600 psig, and the PRT itself, which is designed for 100 psig. Normal RCS operating pressure is 2235 psig. RCS design temperature is 650°F, except for the pressurizer and its surge line, which are designed for 680°F, and the pressurizer relief line from the safety valve to the PRT is 450°F. The PRT is designed for 340°F. Design parameters for other system components are discussed in Section 5.5.

5.2.1.3 Compliance with 10 CFR 50.55a

Codes and standards applicable to reactor coolant pressure boundary (RCPB) components are specified in 10 CFR 50.55a. They depend on when the plant was designed and constructed. Construction permits for DCPP Units 1 and 2 were issued on April 23, 1968, and December 9, 1970, respectively. Therefore, codes and standards specified in 10 CFR 50.55a for construction permits issued before January 1, 1971, are applicable to the DCPP.

The codes, standards, and component classifications used in the design and construction of the DCPP RCPB components are shown in Table 5.2-2 and are in accordance with the applicable provisions of 10 CFR 50.55a. These design codes specify applicable surveillance requirements including allowances for normal degradation.

5.2.1.4 Applicable Code Cases

Although use of the normal, upset, emergency, and faulted condition terminology was introduced in codes (ASME B&PV Code, Section III, Summer 1968 Addenda) and standards after the code applicability date for the DCPP, analyses of RCS components in accordance with the more recent ASME B&PV Code conditions (normal, upset, and faulted) have been performed for the load combinations and associated stress limits identified in Tables 5.2-5, 5.2-6, and 5.2-7. Valves have been designed in accordance with USAS B16.5, in general, and ASME B&PV Code, Section VIII, for flange connections.

Most components within the RCPB which are equivalent to PG&E Quality/Code Class I, were supplied by Westinghouse Electric Corporation. Any application, by Westinghouse or its vendors, of the code cases in Table 5.2-1 is in accordance with ASME Code guidelines. Specific application of any of these code cases to both DCPP units has not been identified since, at the time of their fabrication, there was neither

code, nor AEC requirements to maintain and update a centralized list of these code cases.

5.2.1.5 Design Transients

To ensure the high degree of integrity of RCS equipment over the design life of the plant, fatigue evaluation is based on conservative estimates of the magnitude and frequency of temperature and pressure transients resulting from various operating conditions in the plant. To a large extent, the specific transient operating conditions to be considered for equipment fatigue analyses were determined by Westinghouse. The transients selected represent operating conditions that should be prudently anticipated during plant operation and are sufficiently severe or frequent to be of possible significance to component cyclic behavior.

The design cycles discussed herein are conservative estimates for equipment design purposes only and are not intended to be an accurate representation of actual transients or to reflect operating experience. As such, the number of occurrences specified in Table 5.2-4 is not an absolute limit, but reflect design bases assumptions. The design limit requires that the cumulative fatigue usage factor (as calculated per ASME code guidance) for the equipment or component is less than 1.0. Therefore, a higher number of occurrences may be allowable based upon evaluation of actual stresses.

A program has been established and will be maintained which will include tracking the number of cyclic or transient occurrences of Table 5.2-4 to ensure that components are maintained within their design limit unless the program demonstrates by other means that the design limit will not be exceeded.

5.2.1.5.1 Normal Conditions

The following five transients are considered normal conditions:

(1) Heatup and Cooldown
For design evaluation, the heatup and cooldown cases are represented by continuous heatup or cooldown at a rate of 100°F per hour, which corresponds conceivably to a heatup or cooldown rate that could only occur under upset or emergency conditions. Heatup brings the RCS from ambient to the no-load temperature and pressure conditions. Cooldown represents the reverse situation.

Due to the practical limitations discussed below, the actual heatup rates will be lower than the limiting values, and typically will be on the order of 50°F per hour. Typical cooldown rates are approximately 80°F per hour.

The limitations on heatup reflect:

(a) Criteria for prevention of nonductile failures that establish maximum permissible temperature change rates, as a function of plant pressure and temperature.

(b) Slower initial heatup rates when using pumping energy only.

(c) Interruptions in the heatup and cooldown cycles due to such factors as drawing a pressurizer steam bubble, rod withdrawal, sampling, water chemistry, and gas adjustments.

Ideally, heatup and cooldown would occur only before and after refueling. In practice, additional unscheduled plant cooldowns may be necessary for plant maintenance.

(2) Unit Loading and Unloading

The unit loading and unloading cases under automatic reactor control are conservatively represented by a continuous and uniform ramp power change of 5 percent per minute between 15 percent load and full load. This load swing is the maximum possible consistent with operation under automatic reactor control. The reactor temperature varies with load as prescribed by the temperature control system.

(3) Step Increase and Decrease of 10 percent

The ±10 percent step change in load demand is a control transient that is assumed to be a change in turbine control valve opening that might be caused by disturbances in the outside electrical network. The reactor control system is designed to restore plant equilibrium without reactor trip following a ±10 percent step change in turbine load demand initiated from nuclear plant equilibrium conditions in the range between 15 and 100 percent of full load, the power range for automatic reactor control. During load change conditions, the reactor control system attempts to match turbine and reactor outputs in such a manner that peak reactor coolant temperature is minimized and reactor coolant temperature is restored to its programmed setpoint at a sufficiently slow rate to prevent an excessive decrease in pressurizer pressure.

Following a step load decrease in turbine load, the secondary side steam pressure and temperature initially increase since the decrease in nuclear power lags behind the step decrease in turbine load. During the same time increment, the RCS average temperature and pressurizer pressure also increase initially. Because of the power mismatch between the turbine and reactor and the increase in reactor coolant temperature, the

control system automatically inserts the control rods to reduce core power. The reactor coolant temperature is ultimately reduced from its peak value to a value below its initial equilibrium value at the beginning of the transient.

Reactor coolant average temperature setpoint changes as a function of turbine-generator load, as determined by first-stage turbine pressure measurement. The pressurizer pressure also decreases from its peak pressure value and follows the reactor coolant decreasing-temperature trend. At some point during the decreasing-pressure transient, the saturated water in the pressurizer begins to flash, reducing the rate of pressure decrease. Subsequently, the pressurizer heaters come on to restore the plant pressure to its normal value.

Following a step load increase in turbine load, the reverse situation occurs; i.e., the secondary side steam pressure and temperature initially decrease and the reactor coolant average temperature and pressure initially decrease. The control system automatically withdraws the control rods to increase core power. The decreasing pressure transient is reversed by actuation of the pressurizer heaters, and eventually the system pressure is restored to its normal value. The reactor coolant average temperature is raised to a value above its initial equilibrium value at the beginning of the transient.

(4) Large Step Decrease in Load

This transient applies to a step decrease in turbine load from full power of such magnitude that the resultant rapid increase in reactor coolant average temperature and secondary side steam pressure and temperature automatically initiates a secondary side steam dump system that prevents a reactor shutdown or lifting of steam generator safety valves. Thus, when a plant is designed to accept a step decrease of 95 percent from full power, it signifies that a steam dump system provides a heat sink to accept 85 percent of the turbine load. The remaining 10 percent of the total step change is assumed by the rod control system. If a steam dump system were not provided to cope with this transient, there would be such a large mismatch between what the turbine is demanding and what the reactor is furnishing that a reactor trip and lifting of steam generator safety valves would occur.

DCPP was originally designed to accept step load reductions from 0 to 95 percent without a reactor trip (with 85 percent steam dump capability). A 95 percent step load decrease is rarely experienced in the operation of the plant, and when it does occur, there is a large duty imposed on all operating NSSS and control systems that make recovery from this transient difficult without the occurrence of a reactor trip. Therefore, the

design basis load reduction transient for DCPP has been revised to a 50 percent step load reduction in the analyses performed for the replacement steam generators (RSGs) and Tavg range program, which is a common design basis transient for several Westinghouse plants.

The analysis for the 50 percent load reduction (References 33 and 35) shows that the DCPP control system is capable of controlling the RSG water level so that a reactor trip on steam generator low-low level or turbine trip / feedwater isolation on steam generator high-high level does not occur. Specific analysis results show that the steam generator level is maintained within +/-20 percent of the nominal setpoint and all control system responses are smooth and have no sustained oscillations or divergence. To ensure that a load reduction transient presents no hazard to the integrity of the RCS or the main steam system, the Condition II analysis presented in Section 15.2.7 continues to assume a total loss of external electrical load without an immediate reactor trip.

(5) Steady State Fluctuations

The reactor coolant average temperature, for purposes of design, is assumed to increase or decrease at a maximum rate of 6°F in 1 minute. The temperature changes are assumed to be around the programmed value of Tavg (Tavg ±3°F). Average reactor coolant pressure varies accordingly; it is controlled by the pressurizer pressure control.

5.2.1.5.2 Upset Conditions

The following six transients are considered upset conditions:

(1) Loss of Load Without Immediate Turbine or Reactor Trip

This transient applies to a step decrease in turbine load from full power occasioned by the loss of turbine load without immediately initiating a reactor trip and represents the most severe transient on the RCS. The reactor and turbine eventually trip as a consequence of a high pressurizer level trip initiated by the reactor trip system (RTS). Since redundant means of tripping the reactor are provided as a part of the reactor protection system (RPS), transients of this nature are not expected but are included to ensure a conservative design.

(2) Loss of Power

This transient involves the loss of outside electrical power to the station with a reactor and turbine trip. Under these circumstances, the reactor coolant pumps are de-energized and, following their coastdown, natural circulation builds up in the system to some equilibrium value. This

condition permits removal of core residual heat through the steam generators that are being fed by the auxiliary feedwater system (AFWS) powered either by a diesel generator or main steam. Steam is initially removed for reactor cooldown through atmospheric relief valves provided for this purpose.

(3) Loss of Flow

This transient applies to a partial loss of flow accident from full power in which a reactor coolant pump is tripped as a result of a loss of power to the pump. The consequences of such an accident are a reactor and turbine trip on reactor coolant pump bus undervoltage, followed by automatic opening of the steam dump system and flow reversal in the affected loop. The flow reversal results in a reactor coolant at cold leg temperature, being passed through the steam generator and cooled still further. This cooler water then passes through the hot leg piping and enters the reactor vessel outlet nozzles. The net result of the flow reversal is a sizable reduction in the hot leg coolant temperature of the affected loop.

(4) Reactor Trip from Full Power

A reactor trip from full power may occur for a variety of causes resulting in RCS and steam generator secondary side temperature and pressure transients. It results from continued heat transfer from the reactor coolant to the steam generator. The transient continues until the reactor coolant and steam generator secondary side temperatures are in equilibrium at zero power conditions. A continued supply of feedwater and controlled dumping of secondary steam remove the core residual heat and prevent the steam generator safety valves from lifting. The reactor coolant temperatures and pressures undergo a rapid decrease from full power values as the RTS causes the control rods to move into the core.

(5) Inadvertent Auxiliary Spray

The inadvertent pressurizer auxiliary spray transient will occur if the auxiliary spray valve is opened inadvertently during normal operation. This will introduce cold water into the pressurizer causing a very sharp pressure decrease.

Auxiliary spray water temperature depends on regenerative heat exchanger performance. The most conservative case occurs when the letdown stream is shut off and unheated charging fluid enters the pressurizer.

The design assumes a spray water temperature of 100°F and a flowrate of 200 gpm. It is also assumed that, if activated, the auxiliary spray will continue for 5 minutes until shut off.

The pressure decreases rapidly to the low-pressure reactor trip point and the pressurizer low-pressure reactor trip is assumed to be actuated. This accentuates the pressure decrease until the pressure is finally limited to the hot leg saturation pressure. After 5 minutes the spray is stopped and the pressurizer heaters return the pressure to 2250 psia.

It is finally assumed that RCS temperature changes do not occur as a result of auxiliary spray initiation except in the pressurizer.

(6) Design Earthquake (DE)

The earthquake loads are a part of the mechanical loading conditions specified in equipment specifications. The origin of their determination is separate and distinct from those transient loads resulting from fluid pressure and temperature. Their magnitude is considered in the design analysis, however, for comparison with appropriate stress limits.

5.2.1.5.3 Emergency Conditions

No transient is classified as an emergency condition.

5.2.1.5.4 Faulted Conditions

The following transients are considered faulted conditions:

(1) RCS Boundary Pipe Break

This accident involves the postulated rupture of a pipe belonging to the RCS boundary. It is conservatively assumed that system pressure is reduced rapidly and the emergency core cooling system (ECCS) is initiated to introduce water into the RCS. The safety injection signal will also initiate a turbine and reactor trip.

The criteria for locating design basis pipe ruptures for the design of RCS supports and restraints, thus ensuring continued integrity of vital components and engineered safety features (ESF), are presented in Section 3.6. They are analyzed in Reference 7. With the acceptance of the DCPP leak-before-break analysis by the NRC (Reference 31), the dynamic effects of breaks in the main reactor coolant loop piping no longer have to be considered in the design basis analyses. Only the dynamic effects from RCS branch line breaks have to be considered (see Section 3.6.2.1.1.1).

(2) Steam Line Break

For RCS component evaluation, the following conservative conditions are considered:

(a) The reactor is initially in hot, zero power subcritical condition assuming all rods in, except the most reactive rod, which is assumed to be stuck in its fully withdrawn position.

(b) A steam line break occurs inside the containment.

(c) Subsequent to the break, there is no return to power and the reactor coolant temperature cools down to 212°F.

(d) The ECCS pumps restore the reactor coolant pressure.

The above conditions result in the most severe temperature and pressure variations that the component will encounter during a steam break accident.

The dynamic reaction forces associated with circumferential steam line breaks are considered in the design of supports and restraints to ensure continued integrity of vital components and ESFs. Criteria for protection against dynamic effects associated with pipe breaks are covered in Section 3.6.

(3) Double Design Earthquake (DDE)

The mechanical stress resulting from the DDE is considered on a component basis. The design basis for the plant is the DDE. The seismic analysis is described in Section 3.7.

(4) Hosgri Earthquake

Studies subsequent to the original seismological survey of the site region have resulted in the development of a postulated earthquake of greater magnitude. The characteristics and consequences of this postulated Hosgri earthquake are discussed in Section 5.2.1.15.

The design transients and the number of cycles of each are shown in Table 5.2-4.

5.2.1.5.5 Preoperational Tests

Prior to plant startup the following tests were carried out:

(1) Turbine Roll Test

This test was imposed upon the plant during the hot functional test period for turbine cycle checkout. Reactor coolant pump power heats the reactor coolant to operating temperature and the steam generated is used to perform a turbine roll test. Plant cooldown during the test exceeds, however, the 100°F per hour maximum rate.

(2) Hydrostatic Test Conditions

Each of the major NSSS components (steam generator, reactor coolant pumps, reactor vessel, control rod drive mechanisms, and pressurizer) may be subjected to a maximum of 10 hydrostatic tests without exceeding ASME B&PV Code criteria.

The pressure tests are:

(a) Primary Side Hydrostatic Test Before Initial Startup

Pressure tests include both shop and field hydrostatic tests that occur as a result of component or system testing. This hydrostatic test was performed prior to initial fuel loading at a water temperature of at least 168°F (calculated using the methods presented in Paragraph NB2300, Section III of the 1971 ASME B&PV Code, Summer 1972 Addenda), which is compatible with reactor vessel fracture prevention criteria requirements, and a maximum test pressure. In this test, the primary side of the steam generator is pressurized to 3107 psig coincident with no pressurization of the secondary side. The reciprocating charging pump provided the means to hydrostatically test the RCS during preoperational tests, and this pump has been replaced with a centrifugal charging pump (CCP3). Hydrostatic testing of the primary side is accomplished by a temporary hydrostatic test pump.

(b) Secondary Side Hydrostatic Test Before Initial Startup

The secondary side of the steam generator is pressurized to 1356 psig (1.25 times the design pressure of the secondary side) coincident with the primary side at zero psig.

(c) Primary Side Leak Test

Each time the primary system is opened, a leak test is performed. During this test the primary system pressure is assumed, for design purposes, to be raised to 2500 psia, with the system temperature above design transition temperature, while the system is checked for leaks.

In actual practice, the primary system is pressurized to less than 2500 psia to prevent the pressurizer safety valves from lifting during the leak test. The secondary side of the steam generator is pressurized by closing off the steam lines, so that the pressure differential across the tubesheet does not exceed 1600 psi.

(d) Secondary Side Leak Test

The secondary side is pressurized to 1085 psig (the design pressure of the secondary side of the steam generator) coincident with the primary side at 0 psig.

(e) Tube Leakage Test

During the life of the plant it may be necessary to check the steam generator for tube leakage and tube-to-tube sheet leakage. This is done by visual inspection of the underside (channel head side) of the tube sheet for water leakage, with the secondary side pressurized. Tube leakage tests are performed during plant cold shutdown.

For these tests, the secondary side of the steam generators is pressurized with water, initially at a very low pressure, and the primary system remains depressurized (i.e., 0 psig). The underside of the tube sheet is examined visually for leaks. If any leaks are observed, the secondary side is depressurized and repairs made by tube plugging. The secondary side is then repressurized (to a higher pressure) and the underside of the tube sheet is again checked for leaks. The process is repeated until all the leaks are repaired. The maximum (final) secondary-side test pressure reached is 840 psig.

The total number of tube leakage tests is defined as 800 during the life of the plant. The following is a breakdown of the anticipated number of occurrences at each secondary side pressure.

Case	Test Pressure, psig	No. of Occurrences
Case 1	200	400
Case 2	400	200
Case 3	600	120
Case 4	840	80

Both the primary and secondary sides of the steam generators will be at ambient temperature during these tests.

Since the tests outlined under items (a) and (b) occur prior to plant startup, the number of cycles is independent of plant life.

5.2.1.6 Identification of Active Pumps and Valves

Pumps and valves are classified as either active or inactive components for faulted conditions. Active components are those whose operability is relied upon to perform a safety function such as a reactor shutdown. Inactive components are those whose operability (e.g., valve opening or closure, pump operation or trip) is not relied upon to perform a safety function. The reactor coolant pumps are the only pumps in the RCS boundary and are classified as "inactive" in the event of a reactor coolant loop pipe rupture.

Valves in sample lines are not considered to be part of the RCS boundary because the nozzles where these lines connect to the RCS are orificed to a 3/8-inch hole. This hole restricts the flow such that loss through a severance of one of these lines is sufficiently small to allow operators to execute an orderly plant shutdown.

Table 5.2-9 lists the active and inactive valves between major components in the main process lines of the RCPB, along with the actuation type, valve types, and location. The listed valves are those that are within the pressure boundary. Check valves are also included in Table 5.2-9. Check valves are a credited means of pressure boundary isolation for the original design per ANS 18.2. Vents, drains, test and instrument root valves are excluded from the table as they meet the isolation requirements and are not between major components of the RCPB. Manual valves are passive components and are not considered either active or inactive, therefore they are not included on Table 5.2-9.

5.2.1.7 Design of Active Pumps and Valves

The design criteria for active safety-related pumps outside the RCS boundary are discussed in Section 3.9.2. All these safety-related pumps are designated either ASME B&PV Code Class II or III.

The valves were designed to function at normal operating conditions, maximum design conditions, and DDE/Hosgri conditions. Active valves that are used for accident

mitigation only, and do not serve to support safe shutdown following a Hosgri earthquake, were qualified for active function for a Hosgri earthquake to provide increased conservatism in accordance with Reference 30. The design meets the requirements of the ANSI B31.1, ANSI B16.5, and MSS-SP-66 codes.

The stress limits for the valves in the RCS pressure boundary are indicated in Table 5.2-5. The design criteria and allowable stress limits for safety-related valves outside the RCS pressure boundary (i.e., valves considered to be ASME B&PV Code Class II or III components) are indicated in Section 3.9.2.

In addition, all valves 1 inch and larger within the RCPB were checked for wall thickness to ANSI B16.5, MSS-SP-66, or ASME B&PV Code, Section III (1968, some 1974) requirements, as applicable, and subjected to nondestructive tests in accordance with ASME and ASTM codes.

The valves were designed to the requirements of ANSI B16.5 or MSS-SP-66 pertaining to minimum wall thickness for pressure containing components. Analyses were performed to qualify active valves. These valves were subjected to a series of stringent tests prior to service and during the plant life. Prior to installation, the following tests were performed: shell hydrostatic tests to MSS-SP-61 requirements, backseat and main seat leakage tests. Cold hydrostatic tests, hot functional qualification tests, periodic inservice inspections and operability tests have been and are performed to verify and assure the functional ability of the valves. These tests assure reliability of the valves for the design life of the plant.

On all active valves, an analysis of the extended structure was performed for static equivalent seismic loads applied at the center of gravity of the extended structure. The minimum stress limits allowed in these analyses will assure that no significant permanent damage occurs in the extended structures during the earthquake.

Motor operators and other electrical appurtenances necessary for operation were qualified.

The natural frequencies of all active valves were determined by test or by analysis. If the natural frequencies of the valves were shown to be less than 33 Hz, one of the following options was employed:

(1) The valve was qualified by dynamic testing.

(2) The valve was modified to increase the minimum frequency to greater than 33 Hz.

(3) The valve was qualified conservatively using static accelerations that are sufficiently in excess of accelerations it might experience in the plant to take into account any effect due to both multifrequency excitation and multi-mode response (a factor of 1.5 times peak acceleration is generally

accepted, although lower coefficients can be used when shown to yield conservative results).

(4) A dynamic analysis of the valve was performed to determine the equivalent acceleration to be applied during the static analysis. The analysis provided the amplification of the input acceleration considering the natural frequency of the valve and the frequency content of the applicable plant floor response spectra. The adjusted accelerations were then used in the static analysis and the valve operability was assured by the methods outlined above, using the modified acceleration input.

Swing check valves are characteristically simple in design and their operation is not affected by seismic accelerations or applied nozzle loads. The check valve design is compact and there are no extended structures or masses whose motion could cause distortions which could restrict operation of the valve. The nozzle loads due to seismic excitation do not affect the functional ability of the valve since the valve disc is typically designed to be isolated from the casing wall. The clearance available around the disc prevents the disc from becoming bound or restricted due to any casing distortions caused by nozzle loads. Therefore, the design of these valves is such that once the structural integrity of the valve is assured using standard design or analysis methods, the ability of the valve to operate is assured by the design features. For the faulted condition evaluations, since piping stresses are shown to be acceptable, the check valves are qualified.

The valves have undergone the following tests: (a) in-shop hydrostatic test, (b) in-shop seat leakage test, and (c) periodic in-plant exercising and inspection to assure functional ability.

By the above methods, all active valves are qualified for operability for the faulted condition seismic loads. These methods simulate the seismic event and assure that the active valves will perform their safety-related functions when necessary.

5.2.1.8 Inadvertent Operation of Valves

The inactive valves within the reactor coolant pressure boundary listed in Table 5.2-9 are not relied upon to function after an accident. They meet redundancy requirements and will not increase the severity of any of the transients discussed in Section 5.2.1.5, if operated inadvertently during any such transient.

5.2.1.9 Stress and Pressure Limits

System hydraulic and thermal design parameters are the basis for the analysis of equipment, coolant piping, and equipment support structures for normal and upset loading conditions. The analysis uses a static model to predict deformation and stresses in the system. The analysis gives six components, three moments, and three forces. These moments and forces are resolved into pipe stresses in accordance with applicable codes. Stresses in the structural supports are determined by the material and section properties based on linear elastic small deformation theory.

In addition to the loads imposed on the system under normal and upset conditions, the design of mechanical equipment and equipment supports requires that consideration also be given to faulted loading conditions such as those experienced during seismic and pipe rupture events. With the acceptance of the DCPP leak-before-break analysis by the NRC (Reference 31), the dynamic loading conditions resulting from pipe rupture events in the main reactor coolant loop piping no longer have to be considered in the design basis analyses. Only the dynamic loads resulting from RCS branch line breaks and other high energy line breaks have to be considered (see Section 3.6.2.1.1.1).

Analysis of the reactor coolant loops and support systems for seismic loads is based on a three dimensional, multi-mass elastic dynamic model. The floor response spectra are used as input to the detailed dynamic model, which includes the effects of the supports and the supported equipment. The loads developed from the dynamic model are incorporated into a detailed loop and support model to determine the support member stresses.

The dynamic analysis employs the displacement method, lumped parameter, stiffness matrix formulations, and assumptions that all components behave in a linearly elastic manner. Seismic analyses are covered in detail in Section 3.7.

Loading combination and allowable stresses for RCS components are provided in Tables 5.2-5, 5.2-6 and 5.2-7.

5.2.1.10 Stress Analysis for Structural Adequacy

Methods and models used to determine the structural adequacy of components under the normal and upset conditions are described herewith.

5.2.1.10.1 Analysis Method for Reactor Coolant System

The load combinations considered in the design of structural steel members of component supports are summarized in Table 5.2-8. The design is described in Section 5.5.

(1) Deadweight

The deadweight loading imposed by piping on the supports consists of the dry weight of the coolant piping and weight of the water contained in the piping during normal operation. In addition, the total weight of the primary equipment components, including water, forms a deadweight loading on the individual component supports.

(2) Thermal Expansion

The free vertical thermal growth of the reactor vessel nozzle centerlines is considered to be an external anchor movement transmitted to the reactor coolant loop (RCL). The weight of the water in the steam generator and the reactor coolant pump is applied as an external force in the thermal analysis to account for equipment nozzle displacement as an external movement.

For the RSGs, the RCL piping was reanalyzed for thermal expansion. The thermal expansion reanalysis was performed in a similar manner to the original analysis except water weights were included as a part of the deadweight analysis.

(3) Earthquake Loads

The earthquake acceleration, which produces transient vibration of the equipment mounted within the containment building, is specified in terms of the floor response spectrum curves at various elevations within the containment building.

These floor response spectrum curves for earthquake motions are described in detail in Section 3.7.

(4) Pressure

The steady state hydraulic forces based on the system's initial pressure are applied as internal loads to the RCL model for determination of the RCL support system deflections and support forces.

(5) Pipe Rupture Loads

In the original RCS analysis, blowdown loads were developed in the broken and unbroken reactor coolant loops as a result of the transient flow and pressure fluctuations during a postulated loss-of-coolant accident (LOCA) in one of the reactor coolant loops. One millisecond opening time was used to simulate the instantaneous occurrence of the postulated LOCA. However, with the acceptance of the DCPP leak-before-break

analysis by the NRC (Reference 31), the dynamic blowdown loads resulting from pipe rupture events in the main reactor coolant loop piping no longer have to be considered in the design basis analyses. Only the much smaller blowdown loads resulting from RCS branch line breaks have to be considered (see Section 3.6.2.1.1.1).

For the RSGs, the RCL piping was reanalyzed for pipe rupture events. Since pipe rupture events in the main RCL piping no longer have to be considered in the design basis analyses (see Section 3.6.2.1.1.1), pipe rupture loads for the reanalysis are defined for RCL branch line breaks. The pipe rupture load analysis considered double-ended circumferential breaks in the RHR, SI (accumulator line), and pressurizer branch line connections to the RCL piping. The analysis also considered the effects of main steamline breaks on the RCL piping and the RCS equipment supports. The feedline break was not explicitly analyzed as the main steamline break is more limiting.

5.2.1.10.2 Analytical Models

The static and dynamic structural analyses assume linear elastic behavior and employ the displacement (stiffness) matrix method and the normal mode theory for lumped-parameter, multimass structural representation to formulate the solution. The complexity of the physical system to be analyzed requires the use of a computer for its solution.

(1) Reactor Coolant Loop Model

The RCL model is constructed for the WESTDYN (Reference 18) computer program. This is a special purpose program designed for the static and dynamic analysis of redundant piping systems with arbitrary loads and boundary conditions.

(2) Support Structure Models

The equipment support structure models have dual purposes since they are required:

(a) To quantitatively represent, in terms of 6 x 6 stiffness matrices, the elastic restraints which the supports impose upon the loop

(b) To evaluate the individual support member stresses due to the forces imposed upon the support by the loop.

The loadings on the component supports are obtained from the analysis of an integrated RCL support system's dynamic structural model, as shown in Figure 5.2-2.

Figure 5.2-2 shows the RCL model and component supports included in the RCL piping reanalysis performed for the RSGs. The reanalysis considered the pipe rupture restraints on the main RCL piping to be inactive. The pipe rupture restraints on the main RCL piping were made inactive by either removing shims or by removing the support.

The primary equipment supports were evaluated using the STASYS (Reference 18), STRUDL (Reference 18), and NASTRAN (Reference 18), programs.

(3) Hydraulic Models

The hydraulic model is constructed to quantitatively represent the behavior of the coolant fluid within the RCLs in terms of the concentrated time-dependent loads imposed upon the loops.

In the original analysis, in evaluating the hydraulic forcing functions during a LOCA, the pressure and the momentum flux terms are dominant. Inertia and gravitational terms were neglected although they were taken into account when evaluating the local fluid conditions.

Thrust forces resulting from a LOCA were calculated in a two-step process. First, the MULTIFLEX 3.0 (Reference 6) code calculated transient pressure, flowrates, and other coolant properties as a function of time. Second, the THRUST (Reference 18) code used the results obtained from MULTIFLEX and calculated time-history of forces at locations where there is a change in either direction or area of flow within the RCL. These locations for the broken loop are shown in Figure 5.2-3.

With the acceptance of the DCPP leak-before-break analysis by the NRC (Reference 31), the dynamic thrust forces and blowdown loads resulting from pipe rupture events in the main reactor coolant loop piping no longer have to be considered in the design basis analyses. Only the thrust forces and blowdown loads resulting from RCS branch line breaks have to be considered. (see Section 3.6.2.1.1.1)

For the RCL piping reanalysis performed for the RSGs, thrust forces and blowdown loads were determined for RCS branch line and main steamline breaks identified in Section 5.2.1.10.1.

5.2.1.10.3 Analysis and Solutions

(1) Static Load Solutions

The static solutions for deadweight, thermal expansion, and pressure load conditions are obtained by using the WESTDYN computer program.

(2) Normal Mode Response Spectral Seismic Load Solution

The stiffness matrices representing various supports for dynamic behavior are incorporated into the RCL model. The response spectra for the DE are applied along the X or Z, and Y axes simultaneously. From the input data, the overall stiffness matrix of the three-dimensional RCL is generated and the natural frequencies and normal modes are obtained by the modified Jacobi method.

The forces, moments, deflections, rotations, support structure reactions and stresses are then calculated for each significant mode. The total seismic response is computed by combining the contributions of the significant modes by the square root of the sum of the squares method.

5.2.1.10.4 Reactor Coolant Loop Stress Analysis Results

The stress for the normal and upset conditions shows that the stresses in the piping are below the code-allowable values.

(1) Normal Conditions

Stresses due to primary loading of pressure and deadweight are combined and compared with the USAS B31.1 Piping Code allowable primary stress limit. The thermal expansion stress is a secondary stress and is, therefore, not combined with stresses due to the primary loadings of pressure and deadweight. The magnitude of the thermal stress is compared with the B31.1 Piping Code allowable expansion stress limit.

The stress evaluation for the normal condition shows that the stresses in all RCL members are within the allowable stress values.

(2) Upset Conditions

The DE stresses are added to the stresses due to primary loadings of pressure and deadweight. The stress evaluation for the upset condition shows that stresses in all RCL members are within the allowable stress values.

5.2.1.10.5 Component Supports Stress Analysis Results

(1) Normal Conditions

Thermal, weight, and pressure forces (obtained from the RCL analysis) acting on the support structures are combined algebraically. The combined load component vector is multiplied by member influence coefficient matrices to obtain all force components at each end of each member in the support system.

(2) Upset Conditions

DE support forces are added algebraically to normal condition forces. The interaction and stress equations are the allowable limits specified by AISC-69.

The stress evaluation for the normal and upset conditions shows that the stresses in all members are within the allowable values.

5.2.1.11 Analysis Method for Faulted Condition

The analysis of the RCLs and support systems for blowdown loads resulting from a LOCA is based on the time-history response of simultaneously applied blowdown forcing functions on a broken and unbroken loop dynamic model. The forcing functions are defined at points in the system loop where changes in cross section or direction of flow occur such that differential loads are generated during the blowdown transient. Stresses and loads are checked and compared to the corresponding allowable stress.

The stresses in components resulting from normal sustained loads and the worst case blowdown analysis are combined with the results of seismic faulted condition analyses, using absolute sum or square root sum of the squares methodology to determine the maximum stress for the combined loading case. Combining LOCA and seismic loads is considered very conservative since it is highly improbable that both maxima will occur at the same instant. These stresses are combined to ensure that the main reactor coolant piping loops and connected primary equipment support system will not lose their intended functions under this highly improbable situation.

Combining seismic faulted condition and LOCA dynamic loads using square root sum of the squares methodology is subject to the conditions and limitations of NUREG-0484, Methodology for Combining Dynamic Reponses:

- The square root sum of the squares (SRSS) technique is acceptable contingent upon performance of a linear, elastic, dynamic analysis to meet the appropriate ASME Code, Section III, Service Limit for faulted load condition.

For components not designed to ASME Section III, a code reconciliation to ASME Section III is required to apply the above. For faulted conditions, the limits are provided in Table 5.2-7.

Further details of the stress analysis for faulted conditions are presented in Section 5.2.1.14.

Protection criteria against dynamic effects associated with pipe breaks are covered in Section 3.6. With the acceptance of the DCPP leak-before-break analysis by the NRC (Reference 31), the dynamic effects of breaks in the main reactor coolant loop piping no longer have to be considered in the design basis analysis. Only the dynamic effects from RCS branch line breaks have to be considered (see Section 3.6.2.1.1.1). For the RCL reanalysis performed for the RSGs, thrust forces and blowdown loads were determined for RCS branch line breaks identified in Section 5.2.1.10.1. Details of the stress analyses performed to evaluate the effects of the postulated Hosgri earthquake are presented in Section 5.2.1.15.

5.2.1.12 Protection Against Environmental Factors

Protection provided for the RCS against environmental factors is discussed in Sections 3.3, 3.4, and 3.5. Fire protection is discussed in Section 9.5.1.

5.2.1.13 Compliance with Code Requirements

PG&E classification of DCPP fluid systems and fluid system components, the vessels, piping, valves, pumps and their supports of the RCS pressure boundary are designated PG&E Design Class I, Quality/Code Class I. The comparison of DCPP system Design/Quality/Code classifications to non-licensing basis regulations and codes is discussed in Section 3.2 and delineated in Table 3.2-4.

For conservative fatigue evaluations of the reactor vessel, steam generator, reactor coolant pump, and pressurizer in accordance with the ASME B&PV Code, maximum stress intensity ranges are derived from combining the normal and upset condition transients discussed in Section 5.2. The stress ranges and number of occurrences are then used in conjunction with the fatigue curves in the ASME B&PV Code to get the associated cumulative usage factors.

The criterion presented in the ASME B&PV Code is used for fatigue analysis. The cumulative usage factor is less than 1, hence, the fatigue design is adequate.

The reactor vessel vendor's stress report has been reviewed by Westinghouse Electric Corporation. The stress report includes a summary of the stress analysis for regions of discontinuity analyzed in the vessel, a discussion of the results including a comparison with the corresponding code limits, a statement of the assumptions used in the analysis, descriptions of the methods of analysis and computer programs used, a presentation of the actual hand calculations, a listing of the input and output of the computer programs

used, and a tabulation of the references cited in the report. The content of the stress report is in accordance with the requirements of the ASME B&PV Code, and all information in the stress report is reviewed and approved by Westinghouse.

For the replacement RVCH, the content of the stress report is in accordance with the requirements of the ASME B&PV Code, and all information in the stress report is reviewed and approved by PG&E.

5.2.1.14 Stress Analysis for Faulted Condition Loadings (DDE and LOCA)

Stress analyses of the RCS for faulted conditions employ the displacement (stiffness) matrix method and lumped-parameter, multimass representation of the system. The analyses are based on adequate and accurate representation of the system using an idealized, mathematical model.

5.2.1.14.1 Analysis Method

(1) Reactor Coolant Loop (RCL)

The procedure for evaluation of the piping stresses due to combined loadings of weight, pressure, DDE, and LOCA is as follows:

The LOCA stress analysis yields the time-history of stresses at various cross sections in the RCL piping. Axial stress due to pressure is included.

Since the DDE results are obtained by the response spectra method, the six components of a state vector for deflection at a point or for internal member force cannot be assigned absolute and/or relative algebraic signs. Consequently, the maximum values of the DDE axial and shear stresses at a pipe cross section are calculated from the internal force state vector at that cross section by considering all possible permutations of signs of the six components of the state vector. The DDE axial and shear stresses are combined with the time-history of LOCA axial and shear stresses.

Dynamic LOCA loads resulting from pipe rupture events in the main RCL were considered in the design basis stress analyses and were included in the loading combinations. With the acceptance of the DCPP leak-before-break analysis by the NRC (Reference 31), main RCL pipe rupture events no longer need to be considered as described in Section 3.6.2.1.1.1. The resultant axial and shear stresses are combined with the hoop and radial stresses (due to pressure) to determine the principal stresses, $\sigma 1$, $\sigma 2$, and $\sigma 3$.

The previous steps are performed for various cross sections in the RCL piping. It should be emphasized that, for a given location of the pipe

cross section, the stress intensity calculation is performed at every step computed from the time-history analysis.

The state of stress for stress points in the unbroken legs of a broken loop and the unbroken loop piping are within the stress intensity limit provided in Table 5.2-7.

Reanalysis for the RSGs

Maximum resultant deadweight, DDE, and LOCA moments were determined at locations located along the RCL piping, elbows, and connections to equipment. At each location, the maximum resultant moment for DDE is the largest resultant moment from the various shock cases that were performed for the DDE load analysis. The largest resultant moment for LOCA is the largest moment from the pipe rupture analyses for RCL branch line breaks and the main steamline break.

B31.1 Code pipe stress equations were used with the resultant moments to determine deadweight DDE, and LOCA pipe stresses at locations along the RCL corresponding to the maximum resultant moment locations. At each location, the stresses were combined by absolute sum and were added to the pressure stress to determine the maximum stress at that location. This maximum stress was then verified to be within the stress limit provided in Table 5.2-7. It should be emphasized that the above analysis method is very conservative since the peak DDE and LOCA pipe stresses are considered to occur at the exact same instant in time and that the resultant moments for each load type are considered to be aligned such that the maximum pipe stress occurs at the same location around the pipe circumference for each load type.

(2) Evaluation of Support Structures

The support loads are computed by multiplying the support stiffness matrix, and the displacement vector at the support point. The support loads are used for support member evaluation.

Loads acting on the supports obtained from the RCL analysis (including time-history LOCA forces), support structure member properties, and influence coefficients at each end of each member are input into the THESSE (Reference 18) program.

The THESSE program proceeds as follows for each support:

(1) Combine the various types of support plane loads to obtain operating condition loads (normal, upset, or faulted).

(2) Multiply member influence coefficients by operating condition loads to obtain all member internal forces and moments. The output gives a complete tabulation of all worst force and stress conditions in each member in the supporting system and provides maximum loads on the supporting concrete.

(3) Solve appropriate stress or interaction equations for the specified operating condition. The AISC-69 specification is used with the limits specified in Table 5.2-8 for the operating conditions considered.

(3) Integrated Head Assembly (IHA)

The ANSYS general purpose finite element program was used to perform structural analysis of the IHA. The IHA was evaluated for stresses due to combined loadings of weight (dead load), pressure, thermal, maintenance, missile impact, seismic (DDE or Hosgri) and LOCA. The seismic loading associated with the DDE and Hosgri was developed as described in Section 3.7.3.15.4. LOCA loads were applied where the IHA is attached to the reactor head. Seismic, LOCA, and other loads were combined as shown in Table 5.2-8a. The resulting loads and stresses for the various components of the IHA were evaluated using the requirements of ASME Section III, Division I, 2001 Edition through 2003 Addenda, Subsection NF and Appendix F as shown in Table 5.2-8a. Formal analysis of the (LOCA + Hosgri) faulted load combination for the IHA is in progress. This analysis is being tracked in the DCPP corrective action program.

5.2.1.14.2 Time-history Dynamic Solution for LOCA Loading

The initial displacement configuration of the mass points is defined by applying the initial steady state hydraulic forces to the unbroken RCL model. For the dynamic solution, the unbroken RCL model is modified to simulate the physical severance of the pipe due to the postulated LOCA event. The natural frequencies and normal modes for the modified RCL dynamic model are then determined. After proper coordinate transformation to the RCL global coordinate system, the hydraulic forcing functions to be applied at each lumped mass point are then stored for later use as input to the FIXFM (Reference 18) program.

The initial displacement conditions, natural frequencies, normal modes, and the time-history hydraulic forcing functions form the input to the FIXFM program, which calculates the dynamic time-history displacement response for the dynamic degrees of freedom in the RCL model. The displacement response is plotted at all mass points. The displacement response at support points is reviewed to validate the use of the chosen support stiffness matrices for dynamic behavior. If the calculated support point response does not match the anticipated response, the dynamic solution is revised

using a new set of support stiffness matrices for dynamic behavior. This procedure is repeated until a valid dynamic solution is obtained.

The time-history displacement response from the valid solution is saved for later use to compute the support loads and to analyze the RCL piping stresses.

It is reiterated that the RCS analysis described in this section is the analysis originally performed for the RCS faulted conditions. With the acceptance of the DCPP leak-before-break analysis by the NRC (Reference 31), dynamic LOCA loads resulting from pipe rupture events in the main reactor coolant loop piping no longer have to be considered in the design basis stress analyses and included in the loading combinations; only the LOCA loads resulting from RCS branch line breaks have to be considered.

Reanalysis for the RSGs

The initial displacement configuration of the mass points is defined by applying the initial steady state hydraulic forces to the RCL model. These initial displacement conditions, natural frequencies, normal modes, the time-history hydraulic forcing functions and reactor vessel nozzle displacements are used by the WESTDYN program to calculate the time-history dynamic response for the RCL model. The time-history response is used to determine pipe moments, support forces, and pipe deflections.

5.2.1.14.3 Analysis Results

All support system elements were evaluated to verify that the supported equipment and piping remain within their respective faulted condition stress limits. Stresses in the support system elements for faulted conditions are below the limits provided in Table 5.2-8. Stresses in the piping for faulted conditions are below code-allowable values. Stresses in the PG&E Design Class I members and connections of the IHA for the specified load conditions meet the acceptance criteria provided in Table 5.2-8a.

5.2.1.15 Stress Analysis for Faulted Condition Loadings (Hosgri)

5.2.1.15.1 Integrated Reactor Coolant Loop Analysis

Analysis of the reactor coolant loop piping was performed using the response spectra method. The RCL model was constructed for the WESTDYN computer program.

The horizontal response spectrum at 140 feet in the inner containment structure, corresponding to the steam generator upper support elevation, and the horizontal spectrum at 114 feet in the inner containment structure, corresponding to the reactor coolant pump support and reactor vessel elevation, was used in the analysis. A vertical response spectrum envelope from elevation 114 ft to the base slab of elevation 87 ft was used in the analysis. With mode, the results due to the vertical shock were combined by direct addition with the results of the horizontal shock directions. The

modal contributions were then added by the square-root-sum-of-the-squares (SRSS) method.

Two seismic cases were considered; north-south plus vertical and east-west plus vertical. Each horizontal shock was combined with the vertical shock and the worst combined response was used in the evaluation of the system.

The results of the analysis are as follows: The results of the seismic evaluation were combined with the pressure and deadweight stresses. The revised piping stresses were all under the allowable of 2.4 S_h, or, for loop piping, 3.6 S_h.

5.2.1.15.2 Steam Generator Evaluation

The seismic spectra at the elevations of the steam generator upper support and vertical support were used as the seismic input. The horizontal spectra at the upper support and the vertical spectra at the vertical support were used as input. The model was used to evaluate the shell, tube bundles, upper and lower internals, and other pressure boundary components.

The nozzles and support feet of the steam generator were analyzed using static stress analysis methods with externally applied design loads. Loadings on the inlet and outlet nozzles of the steam generator for the Hosgri earthquake were calculated as part of the reactor coolant loop piping analysis. The loadings calculated by this analysis were compared with previous faulted condition loads. The new loads were shown to be lower than the loads that were used initially to evaluate the nozzles. Therefore, the stresses caused by the Hosgri spectra are within the design basis of these nozzles.

The loads on the steam generator support feet and upper seismic support were supplied for the Hosgri evaluation by the reactor coolant loop analysis. These loadings are below the loading originally calculated for the DDE analysis.

A long-term seismic program (LTSP) seismic margin assessment was performed by Westinghouse for the DCPP RSGs and associated supports. The assessment shows that the limiting LTSP seismic margin for the components affected by the RSGs is greater than the controlling value of 3.06 contained in the LTSP final report (Reference 34). In addition, the assessment confirms a minimum elastic seismic margin scale factor (FS_E) greater than 1.65 for RSG components. A lower value of FS_E (1.33) was calculated for the RSG vertical support; however, the resulting 84 percent nonexceedance high confidence, low probability of failure is greater than 3.06 (i.e., 3.22 g), when the standard ductility factor of 1.25 is applied. Details of the margin assessment are provided in Supplement 1 to Reference 33.

An LTSP seismic margin assessment was also performed for the Unit 2 RSG support anchorages. An FS_E of 1.31 corresponding to an LTSP seismic capacity of 2.6 g was determined for the RSG vertical support anchorages. Higher LTSP seismic capacities were calculated for the RSG upper and lower support anchorages.

5.2.1.15.3 Reactor Coolant Pump Evaluation

The seismic analyses of the reactor coolant pump were performed using dynamic modal methods with a finite element computer program. The seismic response spectra corresponding to the elevation of the reactor coolant pump support structure were used.

The nozzles and support feet of the reactor coolant pump were analyzed by static stress analysis methods with externally applied design loads. For the Hosgri spectra the external loads applied to the inlet and outlet nozzles of the reactor coolant pump by the reactor coolant loop piping are all below the load for which the nozzles previously were shown acceptable. No further analysis was necessary for the nozzles.

The loads resulting from piping reactions for the Hosgri spectra were lower than the DDE loads for which the reactor coolant pump support feet were analyzed. No further analysis was necessary for the support feet.

5.2.1.15.4 Reactor Vessel Evaluation

Several portions of the reactor vessel were evaluated using static stress analysis methods with externally applied design loads. The control rod drive mechanism head adapter, closure head flange, vessel flange, closure studs, inlet nozzle, outlet nozzle, vessel support, vessel wall transition, core barrel support pads, bottom head shell juncture and bottom head instrumentation penetrations were analyzed by this method. The design loads for all areas evaluated except the inlet and outlet nozzles and vessel supports were chosen to be more conservative than any actual load the component would ever experience. The design loads for the inlet and outlet nozzles and vessel supports were umbrellas of loads experienced by past plants. In cases where the actual plant loads exceed the design loads, separate analyses were performed to assure adequacy. All stresses and fatigue usage factors were found to be acceptable

The Hosgri loads calculated by the reactor coolant loop analysis were compared with the DDE seismic loads and are lower. Thus, the previous reactor vessel analysis ensures adequacy for the Hosgri seismic event.

5.2.1.15.5 Reactor Vessel Internals Evaluation

The reactor vessel internals evaluation is presented in Section 3.7.3.15.

5.2.1.15.6 Fuel Assembly Evaluation

The fuel assembly evaluation is presented in Section 3.7.3.15.

5.2.1.15.7 Control Rod Drive Mechanism (CRDM)

The SYSTUS finite element computer code was used to perform structural analysis of the replacement CRDM pressure housings. The CRDM pressure housings were evaluated for stresses due to combined loadings of deadweight, pressure, thermal, seismic, LOCA, and other pipe ruptures as shown in Table 5.2-6a. The seismic loadings were developed as described in Section 3.7.3.15.3. The combined stresses were determined at each critical location along the length of the CRDM assembly including locations along the rod travel housing, latch housing, and CRDM penetration into the RVCH. The resulting loads and stresses for the CRDM pressure housings were evaluated using the requirements of ASME Section III, Division I, 2001 Edition through 2003 Addenda, Subsection NB and Appendix F as shown in Table 5.2-6a. The results demonstrated the ASME code limits are met for the replacement CRDM pressure housings. Formal analysis of the (LOCA + Hosgri) faulted load combination for the CRDM pressure housings is in progress. This analysis is being tracked in the DCPP corrective action program

5.2.1.15.8 Primary Equipment Support Evaluation

Reactor coolant system component supports were shown adequate for the Hosgri seismic event by evaluating the supports for the loads determined in the integrated reactor coolant loops seismic analysis.

The STASYS and NASTRAN computer programs were used to obtain support stiffness matrices and member influence coefficients for the equipment supports.

Loads acting on the supports obtained from the reactor coolant loop analysis, support structure member properties, and influence coefficients at each end of each member were input to the THESSE program.

A finite element stress analysis of the steam generator upper support structure was performed with the WECAN (Reference 18) computer program. The STRUDL program was used to analyze the pressurizer support frame.

In summary, stresses in all reactor coolant system component support members are below yield and buckling values for the Hosgri seismic event. The integrity of the supports has therefore been demonstrated for this postulated event.

5.2.1.15.9 Pressurizer Evaluation

The Hosgri response spectra for 4 percent damping at the 140 ft. elevation has a peak of 5 g horizontally, well below the value used to qualify the pressurizer. Therefore, the original pressurizer analysis is conservative for the Hosgri earthquake.

A dynamic reactor coolant loop analysis, which included a surge line model and was performed with the Hosgri response spectra, produced loads (forces and moments) on

the support skirt, surge nozzle, and upper seismic lug which were less than those produced by the original surge line analysis. Therefore, the loads on these components are acceptable.

5.2.1.15.10 Reactor Vessel Closure Head

The reactor vessel closure head (RVCH) was designed and analyzed in accordance with the ASME Boiler and Pressure Vessel Code Section III, Division I, 2001 Edition through 2003 Addenda, Subsection NB and Appendix F. The RVCH is classified as ASME Code Class 1.

A finite element model of the reactor vessel closure region was used to perform the dynamic analysis of the RVCH. To adequately analyze the effects of the important structural items, a 46.67 degree circumferential segment of the RV closure region was modeled. The ANSYS general purpose finite element program was used to perform the dynamic analysis of the RVCH model. The RVCH model was evaluated for stresses due to combined loadings of dead weight, pressure, thermal, seismic (DDE or Hosgri), LOCA, and other pipe ruptures as shown in Table 5.2-6a. The seismic and LOCA loadings were developed as described in Section 3.9.1.3. The resulting loads and stresses for the RVCH were evaluated using the requirements of ASME Section III, Division I, 2001 Edition through 2003 Addenda, Subsection NB and Appendix F as shown in Table 5.2-6a. The results demonstrated the ASME code limits are met for the replacement RVCH. Formal analysis of the (LOCA + Hosgri) faulted load combination for the RVCH is in progress. This analysis is being tracked in the DCPP corrective action program.

5.2.1.16 Stress Levels in Category I Systems

Sections 5.2.1.14 and 5.2.1.15 discuss RCS Category I components and the resulting stress levels under faulted conditions.

5.2.1.17 Analytical Methods for Stresses in Pumps and Valves

The design and analysis to ensure structural integrity and operability of RCS pumps and valves used the load combinations and stress limits that reflected the AEC regulatory requirements in effect when the construction permits for DCPP were issued. As a result, the design and analysis of these components are based on the requirements of various codes and procedures that were in effect when the equipment was purchased.

These codes and procedures have been widely used by the nuclear industry and were, to a large extent, incorporated or referenced in the 1971 ASME B&PV Code, Section III (refer to Section 3.9.2). Every valve and pump is hydrostatically tested to the applicable ASME B&PV Code requirements, as listed in Table 5.2-2, to ensure the integrity of the pressure boundary parts.

5.2.1.18 Analytical Methods for Evaluation of Pump Speed and Bearing Integrity

Reactor coolant pump overspeed evaluation is covered in Section 5.5.1.

5.2.1.19 Operation of Active Valves Under Transient Loadings

Operation of active valves under transient loadings is discussed in Sections 3.9.2 and 3.10.

During plant startup testing, the preoperational piping dynamics effects test program described in Section 3.9.1 will note and correct excessive piping deflections and vibrations. Since all valves are supported as part of adjoining piping, this testing and any required corrective action, will ensure that the deflections by the pipe (and valve) supports will not impair the operability of active safety-related valves, including those in the RCS pressure boundary.

5.2.2 OVERPRESSURIZATION PROTECTION

The pressurizer is designed to accommodate pressure increases (as well as decreases) caused by load transients. The spray system condenses steam to prevent the pressurizer pressure from reaching the setpoint of the power-operated relief valves (PORVs) during a step reduction in power level of 10 percent of load. Flashing of water to steam and generation of steam by automatic actuation of the heaters keeps the pressure above the low-pressure reactor trip setpoint.

The spray nozzles are located on the top of the pressurizer. Spray is initiated when the pressure controlled spray demand signal is above a given setpoint. The spray flow increases proportionally with increasing pressure and pressure error until it reaches a maximum value. Protection against overpressurization during low temperature operation is provided by the low temperature overpressure protection (LTOP) system, which is described in Section 5.2.2.4.

5.2.2.1 Location of Pressure-Relief Devices

The pressurizer is equipped with three PORVs that limit system pressure for a large power mismatch and thus prevent actuation of the fixed high-pressure reactor trip. The relief valves are operated automatically or by remote-manual control. The operation of these valves also limits the undesirable opening of the spring-loaded safety valves. Remotely operated block valves are provided to isolate the PORVs if excessive leakage occurs. The relief valves are designed to limit the pressurizer pressure to a value below the high-pressure trip setpoint for all design transients, up to and including, the design percentage step load decrease with steam dump but without reactor trip.

Isolated output signals from the pressurizer pressure protection channels are used for pressure control. These are used to control pressurizer spray and heaters, and PORVs.

In the event of a complete loss of heat sink, protection of the RCS against overpressure (Reference 1) is afforded by pressurizer and steam generator safety valves along with any of the following reactor trip functions:

(1) Reactor trip on turbine trip

(2) Pressurizer high-pressure reactor trip

(3) Overtemperature ΔT reactor trip

(4) Steam generator low-low water level reactor trip

A detailed functional description of the process equipment associated with the high-pressure trip is provided in Reference 2.

The overpressure protection upper limit is based on the positive surge of the reactor coolant produced as a result of turbine trip under full load, assuming the core continues to produce full power and normal feedwater is maintained. The self-actuated safety valves are sized on the basis of steam flow from the pressurizer to accommodate this surge at a setpoint of 2500 psia and a total accumulation of 3 percent. Each of the safety valves is rated to carry 420,000 lb/hr, which is greater than one-third of the total rated capacity of the system. Note that no credit is taken for the relief capability provided by the PORVs during this surge.

The RCS design and operating pressures, together with the safety, power-relief, and pressurizer spray valve setpoints, and the protection system setpoint pressures are listed in Table 5.2-10. A schematic representation of the RCS showing the location of pressure-relieving devices is shown in Figure 3.2-7.

System components whose design pressure and temperature are less than the RCS design limits are provided with overpressure protection devices and redundant isolation means. System discharge from overpressure protection devices is collected in the pressurizer relief tank in the RCS. Isolation valves are provided at all connections to the RCS. Figures 3.2-8 through 3.2-10 show those systems that communicate directly with the RCS, and all pressure-relieving devices to prevent reactor coolant pressure from causing overpressure in auxiliary emergency systems in the event of leakage into those systems.

All pressurizer relief piping was manufactured, installed, tested, and analyzed in accordance with USAS B31.7. The piping from the pressurizer to the relief valves is designed to ANSI B31.1. The valve discharge piping to the pressurizer relief tank is designed to ANSI B31.7 - Class III piping.

5.2.2.2 Mounting of Pressure-Relief Devices

The pressurizer safety and relief valve piping system has undergone extensive analysis considering combined loads due to internal pressure, pipe and valve deadweight, thermal growth of the pressurizer, seismic accelerations due to earthquakes, and hydraulic hammer forces due to operation of the valve and the volume of water in the water seal at the inlet to the valve.

A vertical loop in the pipe between the pressurizer and the safety valve is provided to allow for differential thermal growth between the safety valves and the pressurizer. Previously, the loop provided a water seal against the valve seat to prevent gas and steam leakage through the valve from damaging the seat. The safety valves have been modified from a water-seated to a steam-seated design and water in the loop is continuously drained. The hydraulic hammer analysis was a dynamic time-history type of analysis taking into account the water seal volume, the valve opening time, the location and number of bends in the downstream piping, and the lengths of each piece of straight pipe on the discharge of the valves. Analyses consider combinations of all three valves open or shut to determine the most highly stressed condition. The analyses have not been revised to reflect the absence of the water seal volume, resulting in a conservative design since the loads are less severe without the water seal volume.

5.2.2.3 Report on Overpressurization Protection

The design bases for overpressurization protection of the RCS are discussed in Section 5.5. Additional information is also provided in Reference 10.

5.2.2.4 Low Temperature Overpressure Protection

RCS overpressure protection during startup and shutdown is provided by the LTOP system, which consists of two mutually redundant and independent systems. Each system receives reactor coolant pressure and temperature signals. When a low-temperature, high-pressure transient occurs, it opens a pressurizer PORV until the pressure returns to within acceptable limits. During normal operation, the system is off. If the reactor coolant temperature is below the low temperature setpoint and the enable switch on the main control board is not in the enable position, an alarm will sound on the main annunciator. The operator can then enable the circuit before a water-solid condition is reached, and the system is then ready to operate without further operator action.

During startup, at the temperature at which the steam bubble is formed, the trip circuit is automatically defeated and the operator can disable the system later in the startup sequence.

The system is completely automatic. Whenever the system is enabled and reactor coolant temperature is below the low temperature setpoint, a high-pressure signal will trip it automatically and open the PORV until the pressure drops below the reset value.

Features of the LTOP control system include: indicating lights and annunciator alarm when the system trips, indicating lights when the system is enabled, and annunciator alarm when the isolation valve for the PORV is closed and the system is enabled.

The LTOP system relieves the RCS pressure transient given a single failure. Since the two LTOP systems are mutually redundant and independent, failure of either one would not affect the remaining system.

The system is testable at all times. The pressurizer PORVs are in series with motor-operated block valves, which may be closed during testing. Test signals may be injected into the appropriate control circuits and the position of the valve monitored and timed.

All LTOP components meet Seismic Category I and IEEE-279 (Reference 21) criteria. The electrical portions of the system are powered from inverters supplied by the station's battery. The air to the valves is backed by bottled nitrogen.

5.2.3 GENERAL MATERIAL CONSIDERATIONS

This section discusses the materials used in the RCS.

5.2.3.1 Material Specifications

The reactor vessels for Units 1 and 2 were fabricated to the 1965 through Winter 1966 Addenda and 1968 Editions, respectively, of the ASME B&PV Code, Section III.

Materials of construction for the replacement RVCHs meet the requirements of the ASME B&PV Code, Section III, 2001 Edition with Addenda through 2003.

Materials of construction for the RSGs meet the requirements of the 1998 Edition of the ASME B&PV Code, Section III, with addenda through the 2000 Addenda. Steam generator pressure boundary ferritic material is procured with RT_{NDT} of 0°F.

Materials of construction for the pressurizers for Units 1 and 2 meet the requirements of the 1965 Edition of the ASME B&PV Code, Section III, and addenda through the 1966 Addenda. Charpy tests in the major working or rolling direction were performed at 10°F to ensure that the required toughness levels were obtained. The fracture toughness of these materials is considered sufficient to ensure a margin of safe operation.

Pipe is seamless forged stainless steel conforming to ASTM A376, Type 316 with weld repair limited to 3 percent of nominal wall thickness. Fittings in the main reactor coolant loops for both Unit 1 and Unit 2 are cast stainless steel conforming to ASTM A351, Gr.

CF8M. The 90-degree elbows are cast in sections and joined by electroslag welds. The cobalt content is limited to 0.20 percent.

The minimum wall thickness of the pipe and fittings is not less than that calculated using ASA B31.1, Section 1, formula of paragraph 122 with an appropriate allowable stress value provided in Nuclear ASA Code Cases N-7 (for piping) and N-10 (for fittings).

The pressurizer surge line pipe conforms to ASTM A-376, Type 316, with supplementary requirements S2 (transverse tension tests) and S6 (ultrasonic test). The S2 requirements apply to each length of pipe. The S6 requirements apply to 100 percent of the piping wall volume. The pipe wall thickness for the pressurizer surge line is Schedule 140 for Unit 1 and Schedule 160 for Unit 2. There are two 90-degree elbow fittings in the pressurizer surge line for both Unit 1 and Unit 2. The Unit 1 surge line fittings are wrought stainless steel conforming to ASTM A-403, WP316. The Unit 2 surge line fittings are forged stainless steel conforming to ASTM A-182, F316.

Branch nozzles conform to SA-182, Grade F316. Thermal sleeves for Unit 1 conform to SA-312 or SA-240, Type 316. The sample scoop conforms to SA-182, Type 316. The pressurizer spray scoop conforms to SA-403, Grade WP 316.

Stainless steel pipe conforms to ANSI B36.19 for sizes 1/2 through 12 inches and wall thickness schedules 40S through 80S. Stainless steel pipe outside of the scope of ANSI B36.19 conforms to ANSI B36.10, exclusive of the RCL piping of special sizes 27-1/2, 29, and 31 inches I.D. Flanges conform to ANSI B16.5. Socket weld fittings and socket joints conform to ANSI B16.11.

Radiographic or ultrasonic examination was performed throughout 100 percent of the wall volume of each pipe and fitting. Acceptance standards for ultrasonic testing are in accordance with ASME B&PV Code, Section III, except that the defect standard for acceptance is a Charpy-V notch not exceeding 1 inch in length and 3 percent of wall thickness in depth. Acceptance standards for radiographic examination are in accordance with ASTM E-186 Severity Level 2, except that defect categories D and E are not acceptable.

A liquid penetrant examination was performed on both the entire outside and inside surfaces of each finished hot, cold, and crossover loop fitting and pipe in accordance with the procedure of ASME B&PV Code, Section VIII, Appendix VIII, and the acceptance standards of ASA B31.1, Code Cases N-9 or N-10.

All unacceptable defects were eliminated in accordance with the requirements of ASME B&PV Code, Section III. All butt welds and nozzle welds are of a full penetration design; welds 2 inches and smaller are socket-welded joints. The mechanical properties of representative material heats in the final heat treat condition were no less than 1.20 times the allowable stress tabulated in ASA Code Case N-7 corresponding to 650°F.

Type 308 weld filler material was used for all welding applications to avoid microfissuring. As an option, Type 308L weld filler metal analysis was substituted for consumable inserts when this technique was used for the weld root closure. All welding was performed in accordance with the ASME B&PV Code, Section IX. In all welding, except for the replacement RVCH cladding operations, the interpass temperature was limited to 350°F maximum. The methodology used for the RVCH cladding was qualified in compliance with Regulatory Guide 1.43.

5.2.3.2 Compatibility with Reactor Coolant

The materials of construction of the RCPB were specified to minimize corrosion and erosion. To avoid the possibility of accelerated erosion, the internal coolant velocity is limited to about 50 fps.

The reactor vessel is constructed of carbon steel with a 0.125 inch minimum of stainless steel or Inconel cladding on all internal surfaces that are in contact with the reactor coolant. The pressurizer is also constructed of carbon steel with austenitic stainless steel cladding on all surfaces exposed to the reactor coolant. All parts of the reactor coolant pump in contact with the reactor coolant are austenitic stainless steel except for seals, bearings, and secondary seals (O-rings made of elastomer material).
The portions of the steam generator in contact with the reactor coolant water are clad with austenitic stainless steel. The steam generator tubesheet is weld clad with Inconel and the heat transfer tubes are made of Inconel. Tables 5.2-11 through 5.2-14 summarize the materials of construction of these RCS components.

The reactor coolant piping and fittings that make up the loops are austenitic stainless steel. All smaller piping that comprises part of the RCS boundary, such as the pressurizer surge line, spray and relief line, loop drains, and connecting lines to other systems, is also made of austenitic stainless steel. All valves in the RCS that are in contact with the coolant are constructed primarily of stainless steel. Other materials in contact with the coolant, such as materials for hard surfacing and packing, are special materials.

5.2.3.3 Compatibility with External Insulation and Environmental Atmosphere

The materials of construction of the RCPB were specified to ensure compatibility with the containment-operating environment. All insulation used on the RCPB, as defined by the ASME B&PV Code, Section XI, is of the reflective stainless steel type or as described in Section 6.3.3.34. Additional information on the compatibility of RCPB materials with the containment environment to which they are exposed is provided in Section 3.11.

5.2.3.4 Chemistry of Reactor Coolant

The RCS water chemistry is selected to minimize corrosion. A periodic analysis of the coolant chemical composition is performed to verify that the reactor coolant quality meets the specifications for coolant chemistry, activity level, and boron concentration.

The CVCS provides a means for adding chemicals to the RCS that control the pH of the coolant during initial startup and subsequent operation, scavenge oxygen from the coolant during startup, and control the oxygen level of the coolant due to radiolysis during all power operations subsequent to startup. To ensure thorough mixing, at least one reactor coolant pump or RHR pump is always in service when chemicals are being added to the system or when changing the boron concentration.
The chemical used for pH control is lithium hydroxide. This chemical is chosen for its compatibility with the materials and water chemistry of the borated water/stainless steel/zirconium/Inconel system. In addition, lithium is present in solution from the neutron irradiation of dissolved boron in the coolant. The lithium hydroxide is introduced into the RCS via the charging flow. The solution is prepared in the plant and poured into the chemical mixing tank. Reactor makeup water is then used to flush the solution to the suction manifold of the charging pumps.

The concentration of lithium hydroxide in the RCS is maintained in the range specified for pH control. If the concentration exceeds this range, a demineralizer is valved in to remove the excess lithium. Since the amount of lithium to be removed is small and its buildup can be readily calculated and determined by analysis, the flow through the cation bed demineralizer is not required to be full letdown flow.

During reactor startup from the cold condition, hydrazine is employed as an oxygen scavenging agent. The hydrazine solution is introduced into the RCS using the same injection flow path as the pH control agent, as described above.

Dissolved hydrogen is employed to control and scavenge oxygen produced due to radiolysis of water in the core region. Sufficient partial pressure of hydrogen is maintained in the volume control tank such that the specified equilibrium concentration of hydrogen is maintained in the reactor coolant. A self-contained pressure control valve maintains a minimum pressure in the vapor space of the volume control tank. This can be adjusted to provide the correct equilibrium hydrogen concentration. The RCS water chemistry specifications are provided in Table 5.2-15.

5.2.4 FRACTURE TOUGHNESS

This section addresses fracture toughness in the RCPB. The RCS component upon which operating limitations are based is the reactor vessel.

5.2.4.1 Compliance with Code Requirements

Assurance of adequate fracture toughness of the reactor pressure vessel is established using methods to estimate the reference nil-ductility transition (NDT) temperatures (RT_{NDT}) (Reference 5). The fracture toughness properties of the reactor vessel wall material surrounding the irradiated core region are the limiting properties. The stringent fracture toughness requirements of the ASME B&PV Code, Section III, 1971 Edition, and the 1972 Summer Addenda are complied with. The estimated RT_{NDT} uses as a guide the fracture toughness requirements of NB2300 of the Summer 1972 Addenda, which meet the intent of 10 CFR 50, Appendix G. For materials not in the beltline region, RT_{NDT} was estimated using methods identified in Section 5.3.2 of the NRC Standard Review Plan. The upper-shelf energy level of the material is established using methods (Reference 5), which are responsive to 10 CFR 50, Appendix G.

The DCPP Units 1 and 2 reactor vessels were fabricated to the 1966 and 1968 editions of the code, respectively. Thus, Charpy impact test orientation was parallel to the working or rolling direction of the base materials. Additional impact tests were performed, however, on the intermediate and lower shell course plates of both vessels. These plates surround the effective height of the fuel assemblies. Full Charpy test curves were obtained on these plates from specimens oriented normal to the principal rolling direction. Full Charpy curves for all the base material in the vessels have been obtained by the fabricator on impact specimens oriented parallel to the principal working or rolling direction. Reactor vessel fracture toughness data are provided in Tables 5.2-17A and 5.2-18A, and Tables 5.2-17B and 5.2-18B for Units 1 and 2, respectively.

The replacement reactor vessel closure head (RVCH) was manufactured to the requirements of the ASME B&PV Code, Section III, 2001 Edition with Addenda through 2003. Fracture toughness data is provided in Table 5.2-17B.

Reactor vessel beltline region weld test specimens were taken from weldments prepared from excess production plate, weld wire, and flux materials. After completion of welding, the weldments were subjected to heat treatment to obtain the metallurgical effects equivalent to those produced during fabrication of the reactor vessel. The significant properties (e.g., weld wire chemical composition and weld flux type) of the weld materials in the beltline region were representative of the actual beltline materials and their fracture toughness. The use of test specimens prepared from excess production plate, weld wire, and flux materials and subjected to heat treatment satisfies the intent of the specific requirement of Section III.C.2 of Appendix G to 10 CFR 50 and ensures an adequate margin of safety.

Two hundred forty bolting material specimens were impact tested at 10°F. The average of all the impact energy values was 50.5 ft-lb. The lateral expansion was measured on 24 specimens, and an average value of 35 mils was recorded. Fracture energy values obtained on 90 percent of the 240 specimens tested at 10°F either met or exceeded the fracture toughness requirements of Appendix G of 10 CFR 50. The lowest value of

40 ft-lb. exceeded the special mechanical property requirements of paragraph N-330 of the 1965 Edition of the ASME B&PV Code, which states that an average of 35 ft-lb. fracture energy is considered adequate for pressure vessel materials to be pressurized at ambient temperature (70°F).

5.2.4.2 Acceptable Fracture Energy Levels

The identification and location of reactor vessel beltline region materials for Units 1 and 2 are shown in Figures 5.2-1 and 5.2-4, respectively. Chemical composition, fracture toughness properties, estimates of maximum anticipated change in $RT_{NDT,}$ and upper-shelf energy at the end-of-license fluence at the vessel wall 1/4 thickness location for materials in the beltline region are provided in Tables 5.2-18A through 5.2-21B for Units 1 and 2.

The stresses due to gamma heating in the vessel walls were also calculated and combined with the other design stresses. They were compared with the code-allowable limit for mechanical plus thermal stress intensities to verify that they are acceptable. The gamma stresses are low and thus have a negligible effect on the stress intensity in the vessel.

5.2.4.3 Operating Limitations During Startup and Shutdown

Allowable pressures as a function of the rate of temperature change and the actual temperature relative to the reactor vessel RT_{NDT} are established according to the methods in the 1972 NDT Summer Addenda of the ASME B&PV Code, Section III, Appendix G. Heatup and cooldown curves are provided in the DCPP Pressure Temperature Limits Report. The heatup and cooldown curves are based on the estimated RT_{NDT} fracture toughness properties of the reactor vessel materials. Toughness data for the reactor vessel base materials are provided in Tables 5.2-17A and 5.2-17B for Units 1 and 2, respectively.

Predicted ΔRT_{NDT} values are derived for 1/4T and 3/4T (thickness) in the limiting material by using the method described in Reference 27 and the maximum fluence for the applicable service period. The limiting material in the Unit 1 reactor vessel is weld seam 3-442C with an initial RT_{NDT} conservatively estimated at -56°F, a copper content of 0.203 wt percent, and a nickel content of 1.018 wt percent. The limiting materials in the Unit 2 reactor vessel is the intermediate shell plate B5454-2 with a measured initial RT_{NDT} of 67°F, a copper content of 0.14 wt percent, and a nickel content of 0.59 wt percent.

The maximum integrated fast neutron (E > 1 MeV) exposure for the vessel at 1/4T is computed to be 7.93×10^{18} and 8.75×10^{18} n/cm^2 for 40 calendar years of operation at 3411 MWt for Units 1 and 2, respectively. The estimated end of life adjusted RT_{NDT} for Units 1 and 2 are 218°F and 180°F, respectively, at 1/4T of the above material.

5.2.4.4 Compliance with Reactor Vessel Material Surveillance Program Requirements

The toughness properties of the reactor vessel beltline material will be monitored throughout the service life with a material surveillance program that meets the requirements of 10 CFR 50, Appendix H. The original surveillance test program (Reference 11) for DCPP Unit 1 complies with ASTM E 185-70, the standard in effect when the vessel was manufactured. With three exceptions, the program also complies with ASTM E 185-73. The exceptions are the number of capsules in the program containing the limiting material, the number of Charpy specimens in each capsule, and the orientation of the base metal specimens.

A supplemental surveillance program was implemented at the Unit 1 fifth refueling outage to improve the existing program by bringing the overall surveillance program in better compliance with ASTM E 185-82, provide data for the period beyond which the original surveillance program was designed, and to provide the necessary data to demonstrate the effectiveness of reactor vessel thermal annealing. Capsule D from Unit 1, which was meant to be annealed and reinserted into the reactor vessel, was removed during 1R12 and is stored in the spent fuel pool. There are currently no industry plans to anneal reactor vessels. The Unit 1 supplemental surveillance program is described in References 28 and 29. For Unit 2, the specimen orientation, number, selection procedure, and removal schedule conform to ASTM E 185-73. The surveillance capsule program for Unit 2 is described in Reference 26.

5.2.4.4.1 Program Description

The evaluation of radiation damage is based on preirradiation testing of Charpy V-notch and tensile specimens, and postirradiation testing of Charpy V-notch, and tensile specimens; plus wedge opening loading (WOL) fracture mechanics test specimens for Unit 1 and compact tension (CT) and bend bar fracture mechanics test specimens for Unit 2. These programs are based on transition temperature and fracture mechanics approaches, and conform with ASTM E-185, Recommended Practice for Surveillance Tests for Nuclear Reactor Vessels and 10 CFR 50, Appendix H. Thermal control specimens are not required since the surveillance specimens will be exposed to the combined neutron irradiation and temperature effects, and the test results will provide the maximum transition temperature shift. The surveillance program for Unit 2 does not include correlation monitors, but the program for Unit 1 does. Neutron dosimeters included in the capsules can be used to measure exposure throughout the life of the reactor vessel.

5.2.4.4.2 Surveillance Capsules

The Unit 1 original reactor vessel surveillance program included eight specimen capsules and the supplemental surveillance program consists of four additional specimen capsules. The Unit 2 surveillance program consists of six specimen capsules. The Type II capsules in Unit 1 and all of the Unit 2 capsules utilize fissionable

materials (uranium-238 and neptunium-237) as neutron dosimeters. The fissionable materials, in the form of U_30_8 and $Np0_2$ powder, are encapsulated in metal (brass or stainless steel) capsules, which are sealed in steel blocks. The capsules are located in guide baskets welded to the outside of the thermal shield and neutron shield pads for Units 1 and 2, respectively, and are positioned directly opposite the center portion of the core. Sketches showing the location and spacing of the capsules for Unit 1 relative to the core, thermal shield, vessel, and weld seams are shown in Figures 5.2-16 and 5.2-17. Sketches showing the location and spacings of the capsules for Unit 2 are shown in Figures 5.2-18 and 5.2-19. The capsules can be removed when the vessel head and upper internals are removed and can be replaced when the lower internals are removed.

The eight capsules in the Unit 1 original surveillance program contain reactor vessel steel specimens from the intermediate shell plate or plates located in the core region of the reactor. The three Type II capsules also contain weld metal and heat affected zone specimens. All of the base material specimens are oriented parallel to the principal rolling direction. In addition, correlation monitors made from fully documented specimens of SA-533, Grade B, Class 1 material obtained through Subcommittee II of ASTM Committee E10, Radioisotopes and Radiation Effects, are inserted in the capsules of Unit 1 only. The eight capsules contain 27 tensile specimens, 256 Charpy V-notch specimens (which include weld metal and heat affected zone material), and 42 WOL specimens.

The four supplemental surveillance capsules for Unit 1 contain Charpy impact and tensile specimens machined from intermediate shell plate 4107-1, and oriented such that the specimen longitudinal axis is normal (transverse) to the plate principal rolling direction. Shell plate 4107 is the limiting base metal at 48 EFPY. These four capsules also contain surrogate weld metal specimens obtained from ABB Combustion Engineering. These surrogate weld specimens were made with the same weld wire heat (27204) and flux type (Linde 1092) as the Unit 1 reactor vessel limiting weld metal, and are representative of the Unit 1 limiting weld. The four capsules will also contain various Charpy specimens supplied by Electric Power Research Institute (EPRI) which will be used to obtain data on the effects of a reactor vessel thermal anneal. Two of the capsules will also contain previously irradiated test material from surveillance capsule S. This material consists of heat-affected zone (HAZ) and limiting weld metal broken Charpy specimens (which can be reconstituted into testable specimens), and weld metal WOL specimens. The 4 capsules contain 266 Charpy specimens, 24 tensile specimens, 20 reconstitution blanks from surveillance capsule S tested Charpy specimens, and 2 WOL specimens.

The six capsules for Unit 2 contain reactor vessel steel specimens oriented both parallel and normal (longitudinal and transverse) to the principal rolling direction of the limiting shell plate located in the core region of the reactor and associated weld metal and heat affected zone metal. The six capsules contain 54 tensile specimens, 360 Charpy V-notch specimens (which include weld metal and heat affected zone material), 72 CT specimens, and six bend bar specimens.

Dosimeters including Ni, Co, Fe (Unit 2 only), Co-Al, Cd shielded Co-Al, Cd shielded Np-237, and Cd shielded U-238 are placed in filler blocks drilled to contain the dosimeters. The dosimeters permit evaluation of the flux seen by the specimens and the vessel walls. In addition, thermal monitors made of low melting alloys are included to monitor the temperature of the specimens. The specimens are enclosed in a tight fitting stainless steel sheath to prevent corrosion and ensure good thermal conductivity. The complete capsule is helium leak tested. Vessel base material sufficient for at least two capsules will be kept in storage should the need arise for additional replacement test capsules in the program. Sufficient weld metal and heat affected zone material from Unit 2 for two additional capsules will also be stored. No additional weld metal or heat affected zone material is available for Unit 1.

As part of the surveillance program, a report of the residual elements in weight percent to the nearest 0.01 percent will be made for surveillance material and as deposited weld metal. Each of five Type I (base metal only) capsules (T, U, W, X and Z) for Unit 1 contains the following specimens:

Material	No. of Charpys	No. of Tensiles	No. of WOL
Plate No. B4106-1	8	1	2
Plate No. B4106-2	8	1	2
Plate No. B4106-3	8	1	2
ASTM Reference	8	-	-

The following dosimeters and thermal monitors are included in each of the five capsules:

<u>Dosimeters</u>

Copper
Nickel
Cobalt-aluminum (0.15% Co.)
Cobalt-aluminum (cadmium shielded)

<u>Thermal Monitors</u>

97.5% Pb, 2.5% Ag (579°F melting point)
97.5% Pb, 1.75% Ag, 0.75% Sn (590°F melting point)

Each of the three Type II capsules (S, V and Y) for Unit 1 contains the following specimens:

Material	No. of Charpys	No. of Tensiles	No. of WOL
Plate No. B4106-3	8	2	2
Weld Metal[(a)]	8	2	2
Heat Affected Zone Metal (Plate B4106-3)	8	-	-
ASTM Reference	8	-	-

The following dosimeters and thermal monitors are included in each of the three Type II capsules:

Dosimeters

Copper
Nickel
Cobalt-aluminum (0.15% Co.)
Cobalt-aluminum (cadmium shielded)
U-238 (cadmium shielded)
Np-237 (cadmium shielded)

Thermal Monitors

97.5% Pb, 2.5% Ag (579°F melting point)
97.5% Pb, 1.75% Ag, 0.75% Sn (590°F melting point)

The four supplemental capsules for Unit 1 contain the following specimens, dosimeters, and thermal monitors:

	CAPSULE A(Note i)		CAPSULE B(Note i)			CAPSULE C(Note i)		CAPSULE D(Note ii)	
	Charpy	Tension	Charpy	Tension	WOL	Charpy	Tension	Charpy	Tension
Weld Metal (Surrogate 27204)	15	3	15	3	—	30	3	15	3
Base Metal (Plate 4107-1)	15	3	15	3	—	15	3	15	3
Correlation Monitor (HSST-02 Plate)	12	—	8	—	—	—	—	—	—
Capsule S Weld Metal (Original 27204)	—	—	10 (Note iii)	—	2	—	—	10 (Note iii)	—
EPRI Specimens	—	—	30	—	—	35	—	46	—

(a) Weld fabricated from weld wire heat number 27204 using Linde 1092 Flux Lot No. 3714.

Notes:

(i) Dosimeter wires: copper, iron, nickel and aluminum-0.15% cobalt (cadmium shielded and unshielded)
Fission dosimeters: neptunium-237 (cadmium oxide shielded), and uranium 238 (cadmium oxide shielded)
Thermal monitors: 97.5% Pb, 2.5% Ag (579°F melt point), 97.5% Pb, 1.75% Ag, 0.75% Sn (590°F melt point)

(ii) Capsule D will contain the following dosimeters:
Dosimeter wires: copper, iron, nickel and aluminum-0.15% cobalt (gadolinium shielded and unshielded)
Fission dosimeters: neptunium-237 (gadolinium shielded) and uranium 238 (gadolinium shielded)
Thermal monitors: will not be provided because annealing temperature will exceed the melting point of thermal monitors

(iii) Broken weld metal and HAZ Charpy specimens from capsule S, suitable for reconstitution

Each of the six capsules for Unit 2 will contain the following specimens:

Material	No. of Charpys	No. of Tensiles	No. of Cts	No. of Bend Bars
Plate B5454-1[(a)]	15	3	4	
Plate B5454-1[(b)]	15	3	4	1
Weld Metal[(c)]	15	3	4	
Heat Affected Zone Metal (Plate B5454-1)	15			

The following dosimeters and thermal monitors are included in each of the six capsules:

Dosimeters
Iron
Copper
Nickel
Cobalt-aluminum (0.15% Co)
Cobalt-aluminum (cadmium shielded)
U-238 (cadmium shielded)
NP-237 (cadmium shielded)

Thermal Monitors
97.5% Pb, 2.5% Ag (579°F melting point)
97.5% Pb, 1.75% Ag, 0.75% Sn (590°F melting point)

(a) Specimens oriented parallel to the principal rolling direction (longitudinal).
(b) Specimens oriented normal to the principal rolling direction (transverse).
(c) Weld fabricated from weld wire heat numbers 21935 and 12008 using Linde 1092 Flux Lot No. 3869.

The fast neutron exposure of the specimens occurs at a faster rate than that experienced by the vessel wall with the specimens being located between the core and the vessel. Since these specimens experience accelerated exposure and are actual samples from the materials used in the vessel, the changes in material properties are representative of the vessel at a later time in life. Data from the fracture toughness specimens (WOL, CT, and bend bar) are expected to provide additional information for use in determining fracture toughness for irradiated material.

The reactor vessel surveillance capsules for Unit 1 are shown in Figure 5.2-16 and in Figure 5.2-18 for Unit 2.

Correlation between calculations and measurements on the irradiated samples in the capsules, assuming the same neutron spectrum at the samples and the vessel inner wall, is described in Section 5.2.4.4.5 and has indicated good agreement. The degree to which the specimens perturb the fast neutron flux and energy distribution is considered in the evaluation of the surveillance specimen data. The integrated flux calculations at the vessel wall are adjusted using the surveillance data to provide best-estimate fluence values. The calculated maximum fast neutron exposure at the vessel wall is 1.32 $x10^{19}$ n/cm^2 and 1.46 x 10^{19} n/cm^2 (E > 1 MeV) for Units 1 and 2, respectively (NUREG-1511).

5.2.4.4.3 Capsule Removal

For Units 1 and 2, the removal schedule conforms to Appendix H of 10 CFR 50. The schedule for removal of the Unit 1 and Unit 2 capsules is provided in Table 5.2-22.

5.2.4.4.4 Measurement of Integrated Fast Neutron (E > 1.0 MeV) Flux at the Irradiation Samples

The use of passive neutron sensors such as those included in the internal surveillance capsule dosimetry sets does not yield a direct measure of the energy-dependent neutron flux level at the measurement location. Rather, the activation or fission process is a measure of the integrated effect that the time-and energy-dependent neutron flux has on the target material over the course of the irradiation period. An accurate assessment of the average flux level and, hence, time integrated exposure (fluence) experienced by the sensors may be developed from the measurements only if the sensor characteristics and the parameters of the irradiation are well known.

In particular, the following variables are of interest:

(1) the measured specific activity of each sensor

(2) the physical characteristics of each sensor

(3) the operating history of the reactor

(4) the energy response of each sensor

(5) the neutron energy spectrum at the sensor location

In this section, the procedures used to determine sensor-specific activities, to develop reaction rates for individual sensors from the measured specific activities and the operating history of the reactor, and to derive key fast neutron exposure parameters from the measured reaction rates are described.

5.2.4.4.4.1 Determination of Sensor Reaction Rates

The specific activity of each of the radiometric sensors is determined using established ASTM procedures. Following sample preparation and weighing, the specific activity of each sensor is determined by means of a lithium-drifted germanium, Ge(Li), gamma spectrometer. In the case of the surveillance capsule multiple foil sensor sets, these analyses are performed by direct counting of each of the individual wires or, as in the case of U-238 and Np-237 fission monitors, by direct counting preceded by dissolution and chemical separation of cesium from the sensor.

The irradiation history of the reactor over its operating lifetime is obtained from NUREG-0020, "Licensed Operating Reactors Status Summary Report," or from other plant records. In particular, operating data are extracted on a monthly basis from reactor startup to the end of the capsule irradiation period. For the sensor sets utilized in the surveillance capsule irradiations, the half-lives of the product isotopes are long enough that a monthly histogram describing reactor operation has proven to be an adequate representation for use in radioactive decay corrections for the reactions of interest in the exposure evaluations.

Having the measured specific activities, the operating history of the reactor, and the physical characteristics of the sensors, reaction rates referenced to full power operation are determined from the following equation:

$$R = \frac{A}{N_o \; F \; Y \sum_j \frac{P_j}{P_{ref}} C_j \left[1 - e^{-\lambda t_j} \right] e^{-\lambda t_d}} \tag{5.2-1}$$

where:

A = measured specific activity (dps/gm)
R = reaction rate averaged over the irradiation period and referenced to operation at a core power level of P_{ref} (rps/nucleus)
N_o = number of target element atoms per gram of sensor
F = weight fraction of the target isotope in the sensor material
Y = number of product atoms produced per reaction
P_j = average core power level during irradiation period j (MW)
P_{ref} = maximum or reference core power level of the reactor (MW)

C_j = calculated ratio of ϕ (E > 1.0 MeV) during irradiation period j to the time weighted averaged ϕ (E > 1.0 MeV) over the entire irradiation period

λ = decay constant of the product isotope (sec^{-1})

t_j = length of irradiation period j (sec)

t_d = decay time following irradiation period j (sec)

and the summation is carried out over the total number of monthly intervals comprising the total irradiation period.

In the above equation, the ratio P_j/P_{ref} accounts for month-by-month variation of power level within a given fuel cycle. The ratio C_j is calculated for each fuel cycle and accounts for the change in sensor reaction rates caused by variations in flux level due to changes in core power spatial distributions from fuel cycle to fuel cycle. For a single cycle irradiation C_j = 1.0. However, for multiple cycle irradiations, particularly those employing low leakage fuel management, the additional C_j correction must be utilized.

5.2.4.4.4.2 Corrections to Reaction Rate Data

Prior to using the measured reaction rates in the least squares adjustment procedure discussed in Section 5.2.4.4.4.3, additional corrections are made to the U-238 measurements to account for the presence of U-235 impurities in the sensors as well as to adjust for the build-in of plutonium isotopes over the course of the irradiation.

In addition to the corrections made for the presence of U-235 in the U-238 fission sensors, corrections are also made to both the U-238 and Np-237 sensor reaction rates to account for gamma ray induced fission reactions occurring over the course of the irradiation.

5.2.4.4.4.3 Least Squares Adjustment Procedure

Values of key fast neutron exposure parameters are derived from the measured reaction rates using the FERRET least squares adjustment code (Reference 12). The FERRET approach uses the measured reaction rate data, sensor reaction cross-sections, and a calculated trial spectrum as input and proceeds to adjust the group fluxes from the trial spectrum to produce a best fit (in a least squares sense) to the measured reaction rate data. The "measured" exposure parameters along with the associated uncertainties are then obtained from the adjusted spectrum.

In the FERRET evaluations, a log-normal least squares algorithm weights both the trial values and the measured data in accordance with the assigned uncertainties and correlations. In general, the measured values f are linearly related to the flux ϕ by some response matrix A:

$$f_i^{(s,\alpha)} = \sum_g A_{ig}^{(s)} \phi_g^{(\alpha)} \qquad (5.2\text{-}2)$$

where i indexes the measured values belonging to a single data set s, g designates the energy group, and α delineates spectra that may be simultaneously adjusted. For example,

$$R_i = \sum_s \sigma_{ig} \phi_g \tag{5.2-3}$$

relates a set of measured reaction rates R_i to a single spectrum ϕ_g by the multigroup reaction cross-section σ_{ig}. The log-normal approach automatically accounts for the physical constraint of positive fluxes, even with large assigned uncertainties.

In the least squares adjustment, the continuous quantities (i.e., neutron spectra and cross-sections) are approximated in a multigroup format consisting of 53 energy groups. The trial input spectrum is converted to the FERRET 53 group structure using the SAND-II code (Reference 13). This procedure is carried out by first expanding the 47 group calculated spectrum into the SAND-II 620 group structure using a SPLINE interpolation procedure in regions where group boundaries do not coincide. The 620-point spectrum is then re-collapsed into the group structure used in FERRET.

The sensor set reaction cross-sections, obtained from the ENDF/B-VI dosimetry file (Reference 14), are also collapsed into the 53 energy group structure using the SAND-II code. In this instance, the trial spectrum, as expanded to 620 groups, is employed as a weighting function in the cross-section collapsing procedure. Reaction cross-section uncertainties in the form of a 53 x 53 covariance matrix for each sensor reaction are also constructed from the information contained on the ENDF/B-VI data files. These matrices include energy group-to-energy group uncertainty correlations for each of the individual reactions.

Due to the importance of providing a trial spectrum that exhibits a relative energy distribution close to the actual spectrum at the sensor set locations, the neutron spectrum input to the FERRET evaluation is obtained from plant-specific calculations for each dosimetry location. While the 53 x 53 group covariance matrices applicable to the sensor reaction cross-sections are developed from the cross-section data files, the covariance matrix for the input trial spectrum is constructed from the following relation:

$$M_{gg'} = R_n^2 + R_g R_{g'} P_{gg'} \tag{5.2-4}$$

where R_n specifies an overall fractional normalization uncertainty (i.e., complete correlation) for the set of values. The fractional uncertainties, R_g, specify additional random uncertainties for group g that are correlated with a correlation matrix given by:

$$P_{gg'} = [1-\theta]\ \delta_{gg'} + \theta\, e^{-H} \tag{5.2-5}$$

where:

$$H = \frac{(g - g')^2}{2\gamma^2}$$

The first term in the correlation matrix equation specifies purely random uncertainties, while the second term describes short-range correlations over a group range γ (θ specifies the strength of the latter term). The value of δ is 1 when g = g' and 0 otherwise.

5.2.4.4.5 Calculation of Integrated Fast Neutron (E > 1.0 MeV) Flux at the Irradiation Samples

Fast neutron exposure calculations for the reactor geometry are carried out using both forward and adjoint discrete ordinates transport techniques. A single forward calculation provides the relative energy distribution of neutrons for use as input to neutron dosimetry evaluations as well as for use in relating measurement results to the actual exposure at key locations in the pressure vessel wall. A series of adjoint calculations, on the other hand, establishes the means to compute absolute exposure rate values using fuel cycle-specific core power distributions, thus providing a direct comparison with all dosimetry results obtained over the operating history of the reactor.

In combination, the absolute cycle-specific data from the adjoint evaluations together with relative neutron energy spectra distributions from the forward calculation provided the means to:

(1) Evaluate neutron dosimetry from surveillance capsule locations.

(2) Enable a direct comparison of analytical prediction with measurement.

(3) Determine plant-specific bias factors to be used in the evaluation of the best estimate exposure of the reactor pressure vessel.

(4) Establish a mechanism for projection of pressure vessel exposure as the design of each new fuel cycle evolves.

5.2.4.4.5.1 Reference Forward Calculation

The forward transport calculation for the reactor is carried out in r, θ geometry using the DORT two-dimensional discrete ordinates code (Reference 15) and the BUGLE-93 cross-section library (Reference 16). The BUGLE-93 library is a 47 neutron group, ENDFB-VI based, data set produced specifically for light water reactor applications. In these analyses, anisotropic scattering is treated with a P_3 expansion of the scattering cross-sections and the angular discretization is modeled with an S_8 order of angular

quadrature. The reference forward calculation is normalized to a core midplane power density characteristic of operation at the stretch rating for the reactor.

The spatial core power distribution utilized in the reference forward calculation is derived from statistical studies of long-term operation of Westinghouse 4-loop plants. Inherent in the development of this reference core power distribution is the use of an out-in fuel management strategy, i.e., fresh fuel on the core periphery. Furthermore, for the peripheral fuel assemblies, a 2σ uncertainty derived from the statistical evaluation of plant-to-plant and cycle-to-cycle variations in peripheral power is used.

Due to the use of this bounding spatial power distribution, the results from the reference forward calculation establish conservative exposure projections for reactors of this design operating at the stretch rating. Since it is unlikely that actual reactor operation would result in the implementation of a power distribution at the nominal +2σ level for a large number of fuel cycles and, further, because of the widespread implementation of low leakage fuel management strategies, the fuel cycle-specific calculations for this reactor will result in exposure rates well below these conservative predictions.

5.2.4.4.5.2 Cycle Specific Adjoint Calculations

All adjoint analyses are also carried out using an S_8 order of angular quadrature and the P_3 cross-section approximation from the BUGLE-93 library. Adjoint source locations are chosen at several key azimuths on the pressure vessel inner radius. In addition, adjoint calculations were carried out for sources positioned at the geometric center of all surveillance capsules. Again, these calculations are run in r, θ geometry to provide neutron source distribution importance functions for the exposure parameter of interest; in this case, ϕ (E > 1.0 MeV).

The importance functions generated from these individual adjoint analyses provide the basis for all absolute exposure projections and comparison with measurement. These importance functions, when combined with cycle-specific neutron source distributions, yield absolute predictions of neutron exposure at the locations of interest for each of the operating fuel cycles, and establish the means to perform similar predictions and dosimetry evaluations for all subsequent fuel cycles.

Having the importance functions and appropriate core source distributions, the response of interest can be calculated as:

$$\phi(R_0, \theta_0) = \int_r \int_\theta \int_E I(r, \theta, E)\ S(r, \theta, E)\ r\ dr\ d\theta\ dE \qquad (5.2\text{-}6)$$

where:

$\phi(R_0, \theta_0)$ = Neutron flux (E > 1.0 MeV) at radius R_0 and azimuthal angle θ_0

$I(r, \theta, E)$ = Adjoint importance function at radius r, azimuthal angle θ, and neutron source energy E

$S(r, \theta, E)$ = Neutron source strength at core location r,θ and energy E

It is important to note that the cycle-specific neutron source distributions, $S(r,\theta,E)$, utilized with the adjoint importance functions, $I(r,\theta,E)$, permit the use not only of fuel cycle-specific spatial variations of fission rates within the reactor core, but also allow for the inclusion of the effects of the differing neutron yield per fission and the variation in fission spectrum introduced by the build-in of plutonium isotopes as the burnup of individual fuel assemblies increases.

5.2.4.5 Reactor Vessel Annealing

There are no special design features that would prohibit the onsite annealing of the vessel. In the event that an annealing operation should be required to restore the properties of the vessel material opposite the reactor core because of neutron irradiation damage, a metal temperature of approximately 850°F maximum for a period of 168 hours maximum would be applied.

The reactor vessel materials surveillance program is adequate to accommodate the reactor vessel annealing. The remaining surveillance capsules at the time of annealing would be removed and given a thermal cycle equivalent to the annealing cycle. They would then be reinserted in their normal position between the core internals assembly and the reactor vessel wall. Subsequent testing of the fracture toughness specimens from the capsules would then reflect the radiation environment both before and after any annealing operation.

5.2.4.6 LOCA Thermal Transient

In the event of a large LOCA, the RCS rapidly depressurizes and the loss of coolant may empty the reactor vessel. If the reactor is at normal operating conditions before the accident, the reactor vessel temperature is approximately 550°F, and, if the plant has been in operation for some time, part of the reactor vessel is irradiated. At an early stage in the depressurization transient, the ECCS rapidly injects cold coolant into the reactor vessel. This produces a thermal stress in the vessel wall. To evaluate the effect of the stress, three possible modes of failure are considered; ductile yielding, brittle fracture, and fatigue.

(1) Ductile Mode

The failure criterion used for this evaluation is that there shall be no gross yielding across the vessel wall using the material yield stress specified in the ASME B&PV Code, Section III. The combined pressure and thermal stresses during injection through the vessel thickness as a function of time have been compared to the material yield stress during the safety injection transient.

The results of the analyses showed that local yielding may occur only in approximately the inner 18 percent of the base metal and in the vessel cladding, complying with the above criterion.

(2) Brittle Mode

The possibility of brittle fracture of the irradiated reactor vessel core region has been considered utilizing fracture mechanics concepts. This analysis takes into account the effects of water temperature, heat transfer coefficients, and fracture toughness as a function of time, temperature, and irradiation. Both a local crack effect and a continuous crack effect have been considered, with the latter requiring the use of a rigorous finite element axisymmetric code. On the weight of this evidence, the thermal shock resulting from the LOCA will not produce instability in the vessel wall even at the end of plant life.

(3) Fatigue Mode

The failure criterion used for fatigue analysis was based on the ASME B&PV Code, Section III. In this method the piece is assumed to fail once the combined usage factor at the most critical location for all transients applied to the vessel exceeds the code-allowable usage factor of 1.

The location in the vessel below the nozzle level, which will see the emergency core cooling water and have the highest usage factor will be the incore instrumentation tube attachment welds to the vessel bottom head. As a worst case assumption, the incore instrumentation tubes and attachment penetration welds are considered to be quenched to the cooling water temperature while the vessel wall maintains its initial temperature before the start of the transient.

The maximum possible pressure stress during the transient is also taken into account. This method of analysis is quite conservative and yields calculated stresses greater than would actually be experienced. The resulting usage factor for the instrument tube welds considering all operating transients and including the safety injection transient occurring at the end of the plant life is below 0.2, which compares favorably with the code-allowable usage factor of 1.

It is concluded from the results of these analyses that the delivery of cold emergency core cooling water to the reactor vessel following a LOCA does not cause any loss of integrity of the vessel.

5.2.5 AUSTENITIC STAINLESS STEEL

The unstabilized austenitic stainless steel materials used in the RCPB, in systems required for reactor shutdown, and for emergency core cooling, are processed and fabricated using established methods and techniques to avoid partial or local sensitization. The measures taken to avoid sensitization are in general conformance with the recommendations of RG 1.44 (Reference 22).

5.2.5.1 Cleaning and Contamination Protection Procedures

All materials are cleansed and protected by procedures that guard against contaminants capable of causing stress corrosion cracking during storage, fabrication, shipment, erection, testing and operation. Contaminant concentration limits are implemented per plant approved procedures.

5.2.5.2 Solution Heat Treatment Requirements

Whenever applicable, solution heat treatment of materials prior to fabrication or assembly into components or systems is discussed in Section 5.2.5.5 below. In such cases, solution heat treatment conformed to the requirements of RG 1.44.

5.2.5.3 Material Inspection Program

Austenitic stainless steel materials are procured from raw material produced in the final heat-treated condition as required by the respective ASTM or ASME material specification for the particular type or grade of alloy.

Westinghouse-furnished wrought austenitic stainless steel alloy materials are corrosion tested in the final heat-treated condition. These tests are performed in accordance with ASTM A262.

5.2.5.4 Unstabilized Austenitic Stainless Steel

Unstabilized austenitic stainless steel used in components of the RCPB are as follows:

(1) Reactor Vessel

(a) (Unit 1) Primary nozzle safe-ends - Type 316 stainless steel forgings.

(Unit 2) Primary nozzle safe-ends - Type 316 stainless steel forgings overlaid with weld metal after final post-weld heat treatment.

(2) Steam Generators

Primary nozzle safe-ends - Grade F316LN forging.

(3)	Pressurizers	Unit 1	Unit 2
(a)	Surge nozzle safe-end	Type 316 forging	Type 316L forging
(b)	Spray nozzle safe-end	Type 316 forging	Type 316L forging
(c)	Relief nozzle safe-end	Type 316 forging	Type 316L forging
(d)	Safety valve (3) nozzle safe-end	Type 316 forging	Type 316L forging

5.2.5.5 Avoidance of Sensitization

Methods and material techniques used to avoid partial or local severe sensitization are as follows:

(1) Core Structural Components
In all cases where austenitic stainless steel must be given a stress-relieving treatment above 800°F, a high-temperature stabilizing procedure was used. This is performed in the temperature range of 1600-1900°F, with holding time sufficient to achieve chromium diffusion to the grain boundary regions. Proof that such stabilization is achieved is based on ASTM A393.

(2) Stainless Welding

(a) Nozzle safe-ends

1. Weld deposit with Ni-Cr-Fe Weld Metal F-Number 43 and attach austenitic stainless steel safe-end after final post-weld heat treatment.

2. Use of a stainless steel weld metal analysis A-7 containing less than 0.02 percent carbon or more than 5 percent ferrite, or both.

(b) All welding is conducted using procedures that are in accordance with the ASME B&PV Code, Section IX.

(c) All welding procedures and welders have been qualified to the ASME B&PV Code rules of Section IX.

When these welding procedure tests are performed on test welds made from base metal and weld metal materials that are from the same lot(s) of materials used in the fabrication of components, additional testing is frequently required to determine the metallurgical, chemical, physical, corrosion, etc., characteristics of the weldment. The additional tests conducted on a technical case

basis are as follows: light and electron microscopy, elevated temperature mechanical properties, chemical check analysis, fatigue tests, intergranular corrosion tests or static and dynamic corrosion tests within reactor water chemistry limitations.

(d) The interpass temperature of all welding methods is limited to 350°F maximum, with the exception of the replacement RVCH cladding operations. The methodology used for the RVCH cladding weld operations was qualified in compliance with Regulatory Guide 1.43.

(e) Travel speed, voltage, amperage, as well as thickness of weld metal layers, and degree of weaving (two electrode diameters or ID of gas cup maximum) are carefully controlled on all welding processes to minimize sensitization in the completed welds.

(f) All welds are nondestructively examined in accordance with code requirements.

(g) Code-authorized inspectors are required to review and sign off on all welding done both in the shop and field.

(h) For the RSGs, ferrite level is 5-18 percent, calculated by WRC sketch.

(3) Hard Facing

All hard facing procedures on austenitic stainless steel use low (less than 800°F) preheat temperatures to preclude sensitization of the base metal. Processes approved are limited to those proven by tests not to cause sensitization.

(4) Bent Pipe Sections

Bent pipe sections are solution heat-treated to produce nonsensitized conditions in the material after bending; this is done by controlling handling temperatures and water quenching time to ensure that all carbides are in solution.

5.2.5.6 Retesting Unstabilized Austenitic Stainless Steel Exposed to Sensitizing Temperatures

It is not normal Westinghouse practice to expose unstabilized austenitic stainless steels to the sensitization range of 800 to 1500°F during fabrication into components except as described in Section 5.2.5.5. If, during the course of fabrication, the steel is inadvertently exposed to the sensitization temperature range, 800 to 1500°F, the

material may be tested in accordance with A262 to verify that it is not susceptible to intergranular attack. Testing is not required for:

(1) Cast metal or weld metal with a ferrite content of 5 percent or more.

(2) Material with a carbon content of 0.03 percent or less that is subjected to temperatures in the range of 800 to 1500°F for less than 1 hour.

(3) Material exposed to special processing provided the processing is properly controlled to develop a uniform product and provided that adequate documentation exists of service experience and/or test data to demonstrate that the processing will not result in increased susceptibility to intergranular stress corrosion.

If it was verified that such material was susceptible to intergranular attack, the material would have been solution annealed again and water quenched or rejected.

5.2.5.7 Control of Delta Ferrite

Welding of austenitic stainless steel was controlled to mitigate the occurrence of microfissuring or hot cracking in the weld. Although published data and experience have not confirmed that fissuring is detrimental to the quality of the weld, it is recognized that such fissuring is undesirable in a general sense. Also, the presence of delta ferrite is one of the mechanisms for reducing the susceptibility of stainless steel welds to hot cracking.

The scope of these controls encompassed welding processes used to join stainless steel parts in components designed, fabricated, or stamped in accordance with the ASME B&PV Code, Section III, Classes 1, 2, and core support components. Delta ferrite control was appropriate for the above welding requirements except where no filler metal was used if for other reasons such control was not applicable. These exceptions included electron beam welding, autogenous gas shielded tungsten arc welding, explosive welding, and welding using fully austenitic welding materials.

In accordance with Section III, fabrication and installation specifications required welding procedure and welder qualification and included delta ferrite determinations for the austenitic stainless steel welding materials used for welding qualification testing and for production processing. Specifically, the undiluted weld deposits of the "starting" welding materials were required to contain a minimum of 5 percent delta ferrite as determined by chemical analysis and calculation using the appropriate weld metal constitution diagrams in Section III. New welding procedure qualification tests were evaluated for these applications in accordance with the requirements of Sections III and IX.

The results of all the destructive and nondestructive tests were reported in the procedure qualification record in addition to the information required by Section III.

The "starting" welding materials used for fabrication and installation welds of austenitic stainless steel materials and components meet the requirements of Section III. Welding materials were tested using the welding energy inputs to be employed in production welding.

Combinations of approved heats and lots of starting welding materials were used for all welding processes. The welding quality assurance program included identification and control of welding material by lots and heats as appropriate. All of the weld processing was monitored according to approved inspection programs, including review of starting materials, qualification records, and welding parameters. Welding systems are also subject to quality assurance audit including calibration of gauges and instruments; identification of starting and completed materials; welder and procedure qualifications; availability and use of approved welding and heat treating procedures; and documentary evidence of compliance with materials, welding parameters, and inspection requirements. Fabrication and installation welds were inspected using nondestructive examination methods according to Section III rules.

5.2.6 PUMP FLYWHEELS

Provisions for reactor coolant pump (RCP) flywheel integrity are presented in this section.

5.2.6.1 Compliance with AEC Safety Guide 14

The flywheel consists of two thick plates bolted together. The flywheel material is produced by a process that minimizes flaws in the material and improves its fracture toughness properties; i.e., an electric furnace with vacuum degassing. Each plate is fabricated from SA-533, Grade B, Class 1 steel. Supplier certification reports are available for all plates and demonstrate the acceptability of the flywheel material on the basis of the requirements of AEC Safety Guide 14 (Reference 23).

Flywheel blanks are flame cut from SA-533, Grade B, Class 1 plates with at least ½ inch of stock left on the outer and bore surfaces for machining to final dimensions. The finished machined flywheels, including bores, keyways, and drilled holes, are subjected to magnetic particle or liquid penetrant examinations in accordance with the requirements of Section III of the ASME B&PV Code. The finished flywheels, as well as the flywheel material (rolled plate), are subjected to 100 percent volumetric ultrasonic inspection using procedures and acceptance standards specified in Section III of the ASME B&PV Code.

The RCP motors are designed such that, by removing the cover to provide access, the flywheel is available to allow an inservice inspection program in accordance with the Technical Specifications.

Determining acceptability of the flywheel material involves two steps as follows:

(1) Establish a reference curve describing the lower bound fracture toughness behavior for the material in question.

(2) Use Charpy (CV) impact energy values obtained in certification tests at 10°F to fix position of the heat in question on the reference curve.

A lower bound K_{Id} reference curve (see Figure 5.2-7) has been constructed from dynamic fracture toughness data generated by Westinghouse (Reference 3) on A-533, Grade B, Class 1 steel. All data points are plotted on the temperature scale relative to the RT_{NDT} temperature. The construction of the lower-bound curve below which no single test point falls, combined with the use of dynamic data when flywheel loading is essentially static, together represent a large degree of conservatism.

The applicability of a 30 ft-lb Charpy energy reference value has been derived from sections on Special Mechanical Property Requirements and Tests in Article 3, Section III, of the ASME B&PV Code. The implication is that the low test temperature of +10°F, and the 30 ft-lb. requirement at that temperature provide assurance that RT_{NDT} is less than +10°F. Flywheel plates exhibit an average value of 30 ft-lb or greater in the weak direction and, therefore, meet the specific Safety Guide 14 requirement that RT_{NDT} must be no higher than 10°F. Making the conservative assumption that all materials in compliance with the code requirements are characterized by an RT_{NDT} temperature of 10°F, it is possible to reassign the reference temperature position RT_{NDT} in Figure 5.2-7 to a value of 10°F.

Flywheel operating temperature at the surface is 120°F. The lower bound toughness curve indicates a value of 116 ksi-in$^{1/2}$ at the (NDT + 110) position corresponding to operating temperature. Thus, the Safety Guide 14 requirement that the operating temperature be at least 100°F above RT_{NDT} is fulfilled.

At the time the flywheels were ordered, Charpy V-notch tests were required only at 10°F. However, by assuming a minimum toughness at operating temperature in excess of 100 ksi-in$^{1/2}$, it can be seen by examination of the correlation in Figure 5.2-8 that the C_V upper-shelf energy must be in excess of 50 ft-lb. Therefore, the requirement "b", that the upper-shelf energy must be at least 50 ft-lb, is satisfied.

It is concluded that flywheel plate materials are suitable for use and meet the Safety Guide 14 acceptance criteria on the bases of suppliers' certification data.

5.2.6.2 Additional Data and Analyses

The calculated stresses at operating speed are based on stresses due to centrifugal forces. The stress resulting from the interference fit of the flywheel on the shaft is less than 2000 psi at zero speed and becomes zero at approximately 600 rpm because of radial hub expansion.

The RCPs run at approximately 1190 rpm and may operate briefly at overspeeds of up to 109 percent (at 1295 rpm). For conservatism, however, 125 percent of operating speed was selected as the design speed for the RCPs. The flywheels are given a preoperational test prior to shipment at 125 percent of the operating speed.

Precautionary measures, taken to preclude missile formation from primary coolant pump components, ensure that the pumps will not produce missiles under any anticipated accident condition. Each component of the primary pump motors has been analyzed for missile generation. Any fragments of the motor rotor would be contained by the heavy stator. The same conclusion applies to the pump impeller because the small fragments that might be ejected would be contained by the heavy casing.

5.2.7 REACTOR COOLANT PRESSURE BOUNDARY LEAKAGE DETECTION SYSTEM

Means are provided to detect and, to the extent practical, identify the location of reactor coolant leakage sources. Detection systems with diverse modes of operation are used to ensure adequate surveillance with sufficient sensitivity so that increases in leakage rate can be detected before the integrated leakage rate reaches a value that could interfere with the safe operation of the plant. Section 5.2.9 discusses sources of reactor coolant leakage outside containment.

RG 1.45, Revision 0 (Reference 25), described acceptable methods for selection of leakage detection systems for the reactor coolant pressure boundary. The construction permits for DCPP Units 1 and 2 were issued prior to the guidance of RG 1.45. The RCPB leakage detection system meets the intent of RG 1.45, Revision 0, to detect and monitor reactor coolant system leakage such that operators have sufficient time to take corrective actions (References 31 and 37).

5.2.7.1 Leakage Detection Methods

Systems using diverse methods and modes of operation are provided to continuously monitor environmental conditions within the containment, and to detect the presence of radioactive and nonradioactive leakage to the containment. Once operation begins, background levels are established, thereby providing a baseline for leakage detection. Deviations from normal conditions indicate possible changes in leakage rates and are monitored in the control room and the auxiliary building. Indications of leakage include changes in containment particulate and gaseous activity, containment sump level, containment condensation, and other volumetric measurement such as increased coolant makeup demand. A list of systems available to detect these changes is provided in Table 5.2-16.

5.2.7.1.1 Containment Radioactivity Monitors

Containment radioactivity monitors continuously monitor the air particulate and gaseous activity levels in the containment during normal plant operation. Leakage to the containment from the RCPB will result in changes in airborne radioactivity levels that can be detected by this equipment. Detector sensitivity, in terms of leakage rates, depends on the radioactivity level in the reactor coolant itself.

The containment radioactivity monitors measure beta and/or gamma activity in the containment by taking continuous air samples from the containment atmosphere. This sample flow first passes through the air particulate monitor and then through the gas monitor assembly. The sample is then returned to the containment. A complete description of the containment activity monitors, including sensitivity and control, indication, and alarm, is presented in Section 11.4.

5.2.7.1.2 Containment Sump Levels and Pump Operation

Leakage from the primary system would result in reactor coolant flowing into one of the containment sumps. Sump level and sump pump integrated flow is monitored to provide a measure of the overall leakage that remains in liquid state.

5.2.7.1.3 Containment Condensation Measurements

The containment condensation measuring system provides a measure of the amount of leakage vaporized (see Section 5.2.7.4). This system collects and measures moisture condensed from the containment atmosphere by the cooling coils of the fan cooler air circulation units. Moisture from leaks up to sizes permissible for continued plant operation will partially evaporate into the containment atmosphere and will be condensed on the fan cooling coils. This system dependably and accurately measures total vaporized leakage, including leakage from the cooling coils themselves. It measures the liquid runoff flowrate from the drain pans under each containment fan cooler unit. The condensate measuring system consists of a vertical standpipe, valves, and instrumentation installed in the drain piping of the reactor containment fan cooler unit.

Depending on the number of reactor containment fan cooler units in operation, the drainage flowrate from each unit due to normal condensation can be determined. Additional or abnormal leaks will result in containment humidity and condensation runoff rate increases, and the additional leakage can then be measured.

5.2.7.1.4 Other Methods of Detection

(1) Charging Pump Operation

During normal operation only one charging pump is operating. If a gross loss of reactor coolant should occur which was not detected by the

methods previously described, the flowrate mismatch of the charging and letdown flows would indicate RCS leakage.

(2) Liquid Inventory

Gross leakage can also be detected by an increase in the makeup rate to the RCS. This is inherently a low-precision indication, because makeup to the RCS is also required due to other process variables. A quantitative measurement of leakage requires a test over a reasonable period of time to establish changes in the physical inventory.

(3) Coolant Radiation Monitors

The component cooling liquid monitor continuously monitors the component cooling water system (CCWS) for activity indicative of a leak of reactor coolant from either the RCS or the RHR system loop in the CCWS. In addition, condenser offgas monitors and steam generator blowdown radiation detectors are available to detect steam generator tube leakage.

(4) Containment Atmosphere Temperature and Pressure Measurement

Various air temperature and pressure sensors would supplement indications of RCS leakage. Containment temperature and pressure fluctuate slightly during plant operation, but a rise above the normally indicated range of values may indicate RCS leakage into the containment. The accuracy and relevance of temperature and pressure measurements is a function of containment free volume and detector location. Alarm signals from these instruments would be valuable in recognizing rapid and sizable energy releases to the containment.

Thermoswitches are installed in the leakoff piping from RCS valves with restricted access during plant operation as a means of identifying the source of leakage (i.e., the specific valve) from a packing or bellows failure. Identified indicating lights, located in a routinely inspected area, are actuated by the thermoswitches. A control room alarm is provided for valve stem leakoff.

5.2.7.1.5 Visual and Ultrasonic Inspections

Visual and ultrasonic inspections of the RCPB will be made periodically during plant shutdown periods. Limited access to the containment is possible for this purpose during normal plant operation. The design of the reactor vessel and its arrangement in the system provides accessibility during service life to the entire internal surface of the vessel (except where access is limited by control rod drive or instrument penetrations). Access is also provided to the entire primary piping system, except for the area of pipe within the concrete biological shielding.

5.2.7.1.6 Reactor Coolant System Water Inventory Balance

As prescribed by the Technical Specifications, a RCS water inventory balance shall be performed at least once every 72 hours, with exceptions as noted in the Technical Specifications. Tracking the RCS inventory in a consistent manner provides an effective means of quantifying overall system leakages.

Data on other secondary methods of leak detection, such as pressurizer liquid level, volume control tank liquid level, charging pump flowrate, and pressurizer relief tank liquid level are provided in Table 5.2-16.

5.2.7.2 Indication in Control Room

Positive indications in the control room of coolant leakage from the RCS to the containment are provided by equipment that permits continuous monitoring of containment air activity, containment sump level changes, and of runoff from the condensate collecting pans under the cooling coils of the containment fan cooler units. This equipment provides indication of normal background, which is indicative of a basic level of leakage from the RCS and components. An increase in observed parameters is an indication of leakage within the containment, and the equipment provided is capable of monitoring this change.

As indicated in Table 5.2-16, numerous other forms of RCS leakage indication are provided in the control room or auxiliary building control area. Leakage detection systems are provided and located in a manner such that for minor leakages the operator can identify the subsystem that is leaking and effectively isolate that leakage with no more than short-term interruption of the operation of the complete system. Figures 5.2-14 and 5.2-15 are examples of the correlative relationships between radioactivity leak detector indications and the corresponding volumetric leak flowrate. This information is provided to the operator for a quick and easy interpretation of leakage conditions, and forms the basis for determining operator action.

5.2.7.3 Limits for Reactor Coolant Leakage

Operational leakage limiting conditions for RCS operation are presented in the Technical Specifications.

The Technical Specifications also present leakage limitations for the Reactor Coolant System Pressure Isolation Valves (PIVs) listed in Table 5.2-23.

Reactor Coolant System PIVs protect low pressure ECCS systems such as the RHR System and the Safety Injection System (SIS) from overpressurization and rupture of their low pressure piping which could result in a LOCA that bypasses the containment. Testing of these valves at least once per refueling interval during startup ensures a low probability of gross failure. Each PIV is required to be tested prior to returning the valve to service following maintenance, repair, or replacement work.

5.2.7.4 Unidentified Leakage

The sensitivity and response time of RCPB leakage detection systems vary for different methods of detection. However, the diverse systems available are required to have the capability to detect continuous leakage rates as low as 1 gpm within 1 hour for unidentified leaks at the design conditions and assumptions, as recommended by RG 1.45 (Reference 25).

The containment particulate monitor is the most sensitive instrument of those available for detection of reactor coolant leakage into the containment. This instrument is capable of detecting particulate radioactivity concentrations as low as 10^{-11} μCi/cc. The sensitivity of the air particulate monitor to an increase in reactor coolant leakage rate is dependent on the magnitude of the normal leakage into the containment. The sensitivity is greatest where normal leakage is low, as has been demonstrated by the experience of Indian Point Unit No. 1, Yankee Rowe, and Dresden Unit 1. Based on data from these operating plants, it is expected that this unit will detect (at the 95 percent confidence level) an increase in containment air particulate activity resulting in a gross count rate equivalent to 1×10^{-9} μCi/cc during normal full power operation. As shown in Figure 5.2-9, this system has adequate response to detect a 1 gpm leak within 1 hour assuming a reactor coolant particulate activity corresponding to as low as 0.1 percent fuel defects. The assumption of 0.1 percent fuel defects used in the design calculation is less than the percentage of failed fuel assumed in the Environmental Report (Reference 36) and follows the guidance of RG 1.45 (References 25 and 37).

The containment radioactive gas monitor is inherently less sensitive (threshold at 10^{-7} μCi/cc) than the containment air particulate monitor, and would function in the event that significant reactor coolant gaseous activity results from fuel cladding defects. The sensitivity and range are such that gross count rates equivalent to from 10^{-6} to 10^{-3} μCi/cc will be detected. This system is also adequate to detect a 1 gpm leak within 1 hour assuming a reactor coolant gaseous activity corresponding to as low as 0.1 percent fuel defects as shown in Figure 5.2-9. The assumption of 0.1 percent fuel defects used in the design calculation is less than the percentage of failed fuel assumed in the Environmental Report and follows the guidance of RG 1.45 (References 25 and 37).

The containment gaseous activity will result from any fission product gases (Kr-85, Xe-135) leaking from the RCS as well as from the argon-41 produced in the air around the reactor vessel. Assuming a constant background radioactivity in the containment atmosphere due predominantly to argon-41, and reactor coolant gaseous activity of 0.03 μCi/cc (corresponding to about 0.05 percent fuel defects), a 1-gpm coolant leak would double the fission product gas background in about 2 hours. The occurrence of a leak of 2 to 4 gpm would double the background in less than 1 hour. In these circumstances, this instrument is a useful backup to the air particulate monitor.

The adequacy of the containment particulate and radioactive gas monitors to detect a change in leakage during the initial period of plant operation will be limited by low coolant activity levels. The gas detector will not be as sensitive as the other leakage detection systems during this period because the argon-41 background will mask the low level of gaseous activity from coolant leakage.

Within the containment, the average air temperature is held at 120°F or below in accordance with the Technical Specifications. The hot dry air promotes evaporation of water leakage from hot systems, and the cooling coils of the fan cooler units provide a significant surface area at or below the dewpoint temperature. Therefore, under equilibrium conditions, the quantity of condensate collected by the cooling coils of the fan cooler units should be equal to the evaporated water leakage and steam leakage from systems within the containment.

To determine abnormal leakage rate inside the containment based on condensation measurements, it will first be necessary to determine the condensation rate from the fan coolers during normal operation. With the initiation of an additional or abnormal leak, the containment atmosphere humidity will begin to increase but such an increase in humidity is reduced by additional condensation on the fan cooler tubes. (Assuming that there is no large heat addition to the containment that could cause the cooling water temperature to increase.)

With the increasing specific and relative humidity, the heat removal capacity needed to cool the air-vapor mixture to its dewpoint decreases. Therefore, increases in available heat removal capacity (i.e., increases in the number of fans in operation) will result in added condensate flow. Through accurate measurement of condensate flow from the fan coolers, a reliable estimate of evaporated leakage inside the containment can be made.

A preliminary estimate of the evaporated leakage can be obtained from the condensate flow increase rate during the transient; a better estimate can be determined from the steady state condensate flow when equilibrium has been reached. After equilibrium is attained, condensate flow from approximately 0.1 to 30 gpm per detector can be measured by this system.

Except for the condensate measuring system, the sensitivities of the RCPB leakage detection systems are not significantly affected during plant operation with concurrent leaks from other sources. Condensation of moisture on the containment air cooler coils will produce a scrubbing effect for particulate activity, but is not expected to appreciably reduce particulate detector sensitivity.

When the plant is shut down, personnel can enter the containment to check visually for leaks. The lack of escaping steam or water during hydrostatic tests has been widely used as a criterion for leaktightness of pressurized systems. Detection of the location of significant leaks would be aided by the presence of boric acid crystals near a leak. The boric acid crystals are transported outside the RCS in the leaking fluid and then

deposited by the evaporation process. Sensitivities and response times of other methods of leak detection are provided in Table 5.2-16 and in Figures 5.2-10 through 5.2-13.

5.2.7.5 Maximum Allowable Total Leakage

As discussed above, the reactor coolant leakage detection systems provide the capability for detecting extremely small leakage rates from the RCPB during normal operation. Signals from the various leak detectors are displayed in the control room and are used by the operators to determine if corrective action is required.
A limited amount of leakage is expected from the RCPB and from auxiliary systems within the containment. Although it is desirable to maintain leakage at a minimum, a maximum allowable total leakage rate is established and used as a basis for action by the reactor operator to initiate corrective measures. Allowable total leakage rates for the DCPP units are presented in the Technical Specifications. RCS identified leakage is limited to 10 gpm by Technical Specification 3.4.13.

5.2.7.6 Differentiation Between Identified and Unidentified Leaks

Generally, leakage into closed systems, or leakage into the containment atmosphere from sources that are both specifically located and known either not to interfere with the operation of the unidentified leakage monitoring systems or not to be from a flow in the RCPB, are called identified leakages. Uncontained leakage to the containment atmosphere may be the result of a variety of possible leakages that are generally classified as unidentified leakages. Unidentified leakage is eventually collected in tanks or sumps where the flowrate can be established and monitored during operation.

5.2.7.6.1 Leakage Location Capability

Leakage detection systems have been designed to aid operating personnel, to the extent possible, in differentiating between possible sources of detected leakage within the containment and in identifying the physical location of the leak. Containment entry for visual inspection will, however, remain the only method of positively identifying the source and magnitude of leakage detected by remote sensing systems.

The containment monitoring system provides the primary means of remotely identifying the source and location of leakage within the containment. Increases in containment airborne activity levels detected by any of the monitor channels will indicate the RCPB as the source of leakage. Additionally, the capability of drawing monitored samples from several containment locations will allow localization of the general area of leakage since activity levels will be somewhat higher in the vicinity of the leakage source. Conversely, if the condensate measuring system detects increased containment moisture without a corresponding increase in airborne activity level, the indicated source of leakage would be judged to be a nonradioactive system, except when the reactor coolant activity may be low.

Less sensitive methods of leakage detection, such as unexplained increases in reactor plant makeup requirements to maintain pressurizer level, will also provide positive indication of the RCPB as the leakage source. Increases in the frequency of a particular containment sump pump operation will facilitate localization of the source to components whose leakage would drain to that sump. Leakage rates of the magnitude necessary to be detectable by these latter methods are expected to be noted first by the more sensitive radiation detection equipment.

5.2.7.6.2 Adequacy of Leakage Detection System

The component cooling liquid monitor continuously monitors the component cooling loop of auxiliary coolant for activity indicative of a leak of reactor coolant from either the RCS or the RHR system.

If an accident involving gross leakage from the RCS occurred, it would be detected by the following methods:

(1) Pump Operation

During normal operation, only one charging pump is operating. If a gross loss of reactor coolant occurred which was not detected by previously described methods, the difference between charging and letdown flowrate would indicate the leakage.

(2) Liquid Inventory

Gross leaks might be detected by unscheduled increases in the amount of reactor coolant makeup water, which is required to maintain the normal level in the pressurizer. This is inherently a low-precision measurement, since makeup water is also required for leakage from systems outside the containment. Gross leakage would also be detected by a rise in the normal containment sump level.

(3) RHR Loop

The RHR loop removes residual and sensible heat from the core and reduces the temperature of the RCS during the second phase of plant shutdown. Tube leaks from the RHR heat exchangers during normal operation would be detected outside the containment by the component cooling loop radiation monitors.

Leakage detection systems are provided and located in a manner such that the operator can identify the subsystem, which is leaking and effectively isolate that leakage with no more than short-term interruption of the operation of the complete system.

5.2.7.7 Sensitivity and Operability Tests

Periodic testing of leakage detection systems will be conducted to verify the operability and sensitivity of detector equipment. These tests include installation calibrations and alignments, periodic channel calibrations, functional tests, and channel checks.
The containment monitoring system is calibrated on installation using typical isotopes of interest. Subsequent periodic calibrations using detector check sources will consist of single-point calibration to confirm detector sensitivity based on the known correlation between the detector response and the check source standard. This procedure will adequately measure instrument sensitivity since the geometry of the sampler cannot be significantly altered after the initial calibration. Channel checks to verify acceptable channel operability during normal operation and functional testing to verify proper channel response to simulated signals will also be conducted on a regular basis. A complete description of calibration and maintenance procedures and frequencies for the containment radiation monitor system is presented in Section 11.4. The condensate measuring system will also be periodically tested to ensure proper operation and verify sensitivity.

The equipment used, procedures involved, and frequency of testing, inspection surveillance and examination of the structural and leaktight integrity of RCPB components are described in detail in Section 5.2.8.

5.2.8 INSERVICE INSPECTION PROGRAM

The inservice inspection (ISI) program complies, except where relief is granted by the NRC, with the requirements of 10 CFR 50.55a(b)(2), in effect on January 1, 2005, and uses the ASME B&PV Code, Section XI, 2001 Edition with 2002 and 2003 Addenda, as the basis for the inservice examinations and tests conducted during the third 120-month inspection interval. Components that are designated ASME B&PV Code Class 1, 2, and 3 for inservice inspections are included in the Inservice Inspection (ISI) Program Plan (Reference 8). The ISI Program Plan also describes the pressure test program for pressure-retaining Code Class 1, 2, and 3 components; examination techniques; Code Cases; and compliance with ASME B&PV Code, Section XI.

The second interval Containment Inservice Inspection Program Plan implements the ASME Code Section XI, Subsections IWE and IWL, 2001 Edition with 2003 Addenda, within the limits and modifications of 10CFR50.55a. IWE exams of the metallic liner are performed on a 40-month frequency within the 10 year interval starting September 9th, 2008. Concrete shell exams occur on a 5-year frequency as specified by IWL 2410(a) with the initial examinations performed on November 2000 and August 2001, for Unit 1 and Unit 2 respectively.

As part of the inspection effort for Unit 1, a preservice inspection (PSI) program for Class 1, 2, and 3 systems was conducted in compliance with the requirements of ASME B&PV Code, Section XI, 1974 Edition including the Summer 1975 Addenda, except where relief was granted by the NRC. For PSI piping examinations in Unit 1, the

examination technique of Appendix III and the acceptance criteria of IWB-3514, both from the Winter 1975 Addenda of the ASME B&PV Code, Section XI, were used. For Unit 2, a PSI program for Class 1, 2, and 3 systems was conducted in compliance with the requirements of ASME B&PV Code, Section XI, 1977 Edition including the Summer 1978 Addenda, except where relief was granted by the NRC.

The ISI program for the first inspection interval for Units 1 and 2 met the requirements of the ASME B&PV Code, Section XI, 1977 Edition including the Summer 1978 Addenda, except where relief was granted by the NRC. The ISI program for the second inspection interval for Units 1 and 2 met the requirements of the ASMS B&PV Code, Section XI, 1989 Edition without addenda, except where relief was granted by the NRC. Where examination techniques differed due to code changes between the PSI and the ISI examinations, or between subsequent ISI examinations, the latest inservice examination data will be used as the new baseline.

Design provisions for access to the reactor vessel are described in Section 5.4.1.5. Remote access and data acquisition methods have been developed to facilitate inspection of reactor vessel areas that are not readily accessible for direct examination. Areas that are inaccessible for the remote examination equipment are detailed in PG&E requests for relief that have been submitted to the NRC.

5.2.9 LEAKAGE PREDICTION FROM PRIMARY COOLANT SOURCES OUTSIDE CONTAINMENT

NUREG-0737 (Reference 24) requires a program to reduce leakage from systems outside the containment that would or could contain highly radioactive fluids during a severe transient or accident. The systems, or portions of systems, that are included in the leakage reduction program required by NUREG-0737, and the reason for their inclusion, are as follows:

(1) The RHR and SIS that would circulate radioactive water from the RCS

(2) The containment spray system (CSS) that would circulate radioactive water from the containment sump

(3) The hydrogen purge/hydrogen recombiner systems that would purge or recirculate radioactive containment building atmosphere

(4) The nuclear steam supply (NSS) sampling system because of the highly radioactive fluids to be sampled

(5) The gaseous radwaste (GRW) system because it could be used to collect highly radioactive gases from the RCS

(6) The liquid radwaste (LRW) system for sampling the containment sump during an accident

At intervals of approximately 24 months, operating pressure leak tests will be performed on appropriate portions of the SIS, the RHR system, the NSS sampling system, the LRW system, the GRW system, the CSS and the hydrogen purge/hydrogen recombiner system. Systems that normally contain liquids will be pressurized to normal operating pressure using systems pumps or hydro pumps. Each liquid system will be visually inspected during its pressure test so that leakage from the system can be measured and corrected. Systems that normally contain gases will be pressurized with a gas, and leakage will be determined using a calibrated leakrate monitor. If gaseous systems have excessive leakage, then leaks will be located using appropriate leak detection methods such as the soap bubble. After initial criticality, leakage from the GRW system will be evaluated by monitoring the auxiliary building ventilation exhaust with radiation detectors.

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5.3 THERMAL HYDRAULIC SYSTEM DESIGN

The overall objective of the reactor core thermal and hydraulic design is to provide adequate heat transfer, compatible with the heat generation distribution in the core, such that the performance and safety criteria requirements of Chapter 4 are met under all plant operating conditions.

5.3.1 ANALYTICAL METHODS AND DATA

The thermal and hydraulic design bases of the reactor coolant system (RCS) are described in Sections 4.3 and 4.4 in terms of core heat generation rates, departure from nucleate boiling ratio (DNBR), analytical models, peaking factors, and other relevant aspects of the reactor.

5.3.2 OPERATING RESTRICTIONS ON REACTOR COOLANT PUMPS

To meet the net positive suction head (NPSH) requirements for operation of the reactor coolant pumps, the operating procedures state that the pressure differential across the No. 1 seal must be at least 200 psig before operating the reactor coolant pump. To achieve this pressure differential, the RCS pressure must be maintained at approximately 325 psig, with the volume control tank pressure high enough to provide an effective back pressure on the No. 1 seal of at least 15 psig.

5.3.3 TEMPERATURE-POWER OPERATING MAP

The programmed relationship between RCS temperature and power for Unit 1 is shown in Figure 5.3-1. A similar relationship has been programmed for Unit 2 and the corresponding temperatures are also shown in Figure 5.3-1.

The effects of reduced core flow due to inoperative pumps are discussed in Sections 5.5.1, 15.2, and 15.3.

Natural circulation capability of the system is shown in Table 15.2-2.

5.3.4 LOAD-FOLLOWING CHARACTERISTICS

The RCS is designed on the basis of steady state operation at full power heat load. The reactor coolant pumps utilize constant-speed drives as described in Section 5.5 and the average coolant temperature is controlled to have a value that is a linear function of load, as described in Section 7.7.

5.3.5 TRANSIENT EFFECTS

Evaluation of transient effects is presented as follows:

Event	FSAR Section
Complete loss of forced reactor coolant flow	15.3.4
Partial loss of forced reactor coolant flow	15.2.5
Loss of external electrical load and/or turbine trip	15.2.7
Loss of normal feedwater	15.2.8
Loss of offsite power	15.2.9
Accidental depressurization of the reactor coolant system	15.2.13

Component cyclic and transient design occurrences are contained in Table 5.2-4.

5.3.6 THERMAL AND HYDRAULIC CHARACTERISTICS SUMMARY TABLE

The thermal and hydraulic characteristics are provided in Tables 4.1-1 and 5.1-1.

5.4 REACTOR VESSEL AND APPURTENANCES

Section 5.4 discusses the design, material, fabrication, inspection, and quality provisions that apply to the reactor vessel and its appurtenances.

5.4.1 REACTOR VESSEL DESCRIPTION

5.4.1.1 Design Bases

The reactor vessel is designed to maintain its integrity under all anticipated modes of plant operation, including exposure to all foreseeable pressure and temperature transients and neutron flux during the life of the plant, by ensuring that all resulting stresses remain within allowable values.

5.4.1.2 Design Transients

Cyclic loads are introduced by normal power changes, reactor trip, startup, and shutdown operations. These design bases cycles are selected for fatigue evaluation and constitute a conservative design envelope for the projected plant life. Vessel analysis results in a usage factor that is less than 1.

Regarding the thermal and pressure transients involved in the loss-of-coolant accident (LOCA), the reactor vessel is analyzed to confirm that the delivery of cold emergency core cooling water to the vessel following a LOCA does not cause a loss of vessel integrity.

The design specifications require analysis to prove that the vessel is in compliance with the fatigue limits of Section III of ASME Boiler and Pressure Vessel Code (ASME B&PV). The loadings and transients specified for the analysis are based on the most severe conditions expected during service. The typical normal heatup and cooldown rates are less than the 100°F per hour upset or faulted condition rate used for design evaluation purposes. These rates are reflected in the vessel design specifications. (See Section 5.2)

5.4.1.3 Codes and Standards

The manufacturer of the reactor vessels for Diablo Canyon Units 1 and 2 is Combustion Engineering, Inc., Chattanooga, Tennessee. The purchase orders for the Units 1 and 2 vessels were placed on March 27, 1967, and November 20, 1968, respectively. Pursuant to 10 CFR 50.55a(c), the applicable ASME B&PV Code requirements for reactor vessel design, fabrication, and material specifications are the 1965 Edition through the Winter 1966 addenda for Unit 1 and the 1968 Edition for Unit 2.

The replacement RVCH was manufactured by AREVA and contracted on July 28, 2006. Pursuant to 10 CFR 50.55a(c), the applicable ASME B&PV Code requirements for

design, fabrication, and material specifications are the requirements of the ASME B&PV Code, 2001 Edition with Addenda through 2003.

5.4.1.4 Reactor Vessel Description

The reactor vessels are cylindrical with welded hemispherical bottom heads and removable, bolted, flanged, and gasketed hemispherical upper heads. The reactor vessel flanges and heads are each sealed by two hollow metallic O-rings. Seal leakage is detected by means of two leakoff channels: one between the inner and outer ring and one outside the outer O-ring. The vessel contains the core, core support structures, control rods, and other parts directly associated with the core.

The reactor vessel closure heads contain head adapters. These head adapters are tubular members, attached by partial penetration welds to the underside of the closure head. The upper end of the head adapters are welded to the CRDM latch housing or instrument adapters. The upper end of these items contains threads for the assembly of the rod drive housing or CET column. Inlet and outlet nozzles are spaced evenly around the vessels. Outlet nozzles are located on opposite sides of the vessel to facilitate optimum layout of the reactor coolant system (RCS) equipment. The inlet nozzles are tapered from the coolant loop vessel interfaces to the vessel inside wall to reduce loop pressure drop.

The integrated head assembly (IHA) is a multi-function structure located on top of the reactor vessel closure head (RVCH). The IHA includes the RVCH lift rig, the control rod drive mechanism (CRDM) ventilation system (including fans, shrouds, and plenum), the CRDM missile shield, radiation shielding, the reactor vessel stud tensioner hoist monorail, cable bridges, personnel access platforms, and ladders. The IHA also includes a seismic support structure, which is an integral part of the IHA that provides lateral structural support for the IHA and CRDMs. The seismic support structure assembly includes eight seismic tie-rod restraints to transfer load from the IHA and the CRDMs to the reactor cavity walls. Figure 5.4-3 shows the major components included in the seismic support structure (some items attached to the support structure are excluded for clarity).

The bottom head of the vessel contains penetration nozzles for connection and entry of the nuclear incore instrumentation. Each nozzle consists of a tubular member made of an Inconel stainless steel composite tube. Each tube is attached to the inside of the bottom head by a partial penetration weld.

Internal surfaces of the vessel that are in contact with primary coolant are weld overlaid with 5/32-inch minimum of stainless steel. The exterior of the reactor vessel is insulated with canned stainless steel reflective sheets. The insulation is 3 inches thick and contoured to enclose the top, sides, and bottom of the vessel.

A schematic of the reactor pressure vessel (RPV) is shown in Figure 5.4-1 for Unit 1 and Figure 5.4-2 for Unit 2. Reactor vessel principal design parameters for both units are provided in Table 5.4-1.

5.4.1.5 Inspection Provisions

The internal surface of the reactor vessel can be inspected using visual nondestructive techniques over the accessible areas. If necessary, the core barrel can be removed, making the entire inside vessel surface accessible.

The closure head is examined visually during each refueling. Periodic visual inspections of accessible outer control rod drive mechanism penetration tubes and the gasket seating surface are performed. The transition area between the dome and head flange, which is the area of highest stress of the closure head, is accessible on the outer surface for visual inspection, surface examination, and ultrasonic testing. The closure studs, nuts, and washers can be inspected periodically using visual, magnetic particle, and/or ultrasonic techniques.

Full-penetration welds in the following irradiated areas of the installed reactor vessel are available for visual and/or nondestructive inspection:

(1) Vessel shell

(2) Primary coolant nozzles

(3) Bottom head

(4) Field welds between the reactor vessel, nozzles, and the main coolant piping

The design considerations that have been incorporated into the system to permit the above inspections are as follows:

(1) All reactor internals are completely removable. Appropriate tools, and the storage space required to permit these inspections, are provided.

(2) The closure head is stored dry on the reactor operating deck during refueling to facilitate direct visual inspection.

(3) All reactor vessel studs, nuts, and washers are removed to dry storage during refueling.

(4) Removable plugs are provided in the primary shield. The insulation covering the nozzle welds may be removed.

(5) A removable plug is provided in the lower core support plate to allow remote access for inspection of the bottom head without removal of the lower internals.

The reactor vessel presents access problems because of the radiation levels and remote underwater accessibility to this component. Because of these limitations, several steps have been incorporated into the design and manufacturing procedures in preparation for the periodic nondestructive tests that are required by the inservice inspection (ISI) program, and in accordance with the ASME B&PV Code, Section XI. These are:

(1) Shop ultrasonic examinations were performed on all internally clad surfaces to acceptance and repair standards that ensure an adequate cladding bond to allow later ultrasonic testing of the base metal from the inside surface. The size of cladding bonding defect allowed is 3/4-inch by 3/4-inch.

(2) The design of the reactor vessel shell in the core area is a clean, uncluttered, cylindrical surface to permit positioning of the ISI test equipment without obstruction.

(3) After the shop hydrostatic testing, selected areas of the reactor vessel were ultrasonically tested and mapped to facilitate the ISI program.

5.4.2 FEATURES FOR IMPROVED RELIABILITY

Reactor pressure vessel performance reliability is based on a conservative design, adequate protection measures, proper selection of materials, appropriate fabrication processes, quality assurance program implementation, conservative operating procedures, and an adequate ISI and material surveillance program. Section 5.2 addresses RPV design, overpressure protection, material selection, pressure and temperature operating limitations, and surveillance programs. Fabrication and quality assurance measures are discussed below.

5.4.3 PROTECTION OF CLOSURE STUDS

Westinghouse refueling procedures require the studs, nuts, and washers be removed from the reactor closure and placed in storage racks during preparation for refueling. The storage racks are then removed from the refueling cavity for maintenance and inspection prior to reactor closure and refueling cavity flooding. Therefore, the reactor closure studs are never exposed to the borated refueling cavity water.

The stud holes in the reactor flange are sealed with special plugs before removing the reactor closure, thus preventing leakage of the borated refueling water into the stud holes.

5.4.4 MATERIALS AND INSPECTIONS

Reactor vessel materials are listed in Table 5.2-11. Construction, inspections and tests for the RPV and appurtenances are presented in Table 5.4-2. Inservice inspections meet the requirements of ASME Section XI, as referenced in 10 CFR 50.55a.

5.4.5 SPECIAL PROCESSES FOR FABRICATION AND INSPECTION

5.4.5.1 Fabrication Processes

(1) Minimum preheat requirements were established for pressure boundary welds using low alloy weld material. Special preheat requirements were added for stainless steel cladding of low-stressed areas. Preheat was maintained until post-weld heat treatment, except for overlay cladding. Limitations on preheat requirements (a) decrease the probabilities of weld cracking by decreasing temperature gradients, (b) lower susceptibility to brittle transformation, (c) prevent hydrogen embrittlement, and (d) reduce peak hardness.

(2) On Unit 2, the use of severely sensitized stainless steel as a pressure boundary material was prohibited and eliminated either by choice of material or by programming the assembly method. This restriction on the use of sensitized stainless steel provides the primary system with preferential materials suitable for:

  (a) Improved resistance to contaminants during shop fabrication, shipment, construction, and operation

  (b) Application of critical areas.

(3) Galling prevention is accomplished by chrome plating of the control rod drive mechanism head adapter threads and surfaces of the guide studs.

(4) Cracking prevention is accomplished by ensuring that the final joining beads are Inconel weld metal at all locations in the reactor vessel where stainless steel and Inconel are joined.

(5) Core region shells fabricated of plate material have longitudinal welds and are angularly located away from the peak neutron exposure experienced in the vessel.

5.4.5.2 Tests and Inspections

Tests and inspections for the RPV and appurtenances are listed in Table 5.4-2. They are discussed below.

5.4.5.2.1 Ultrasonic Examinations

The following ultrasonic examinations were performed:

(1) During fabrication, angle beam inspection of 100 percent of plate material is performed to detect discontinuities that may be undetected by longitudinal wave examination, in addition to the design code straight beam ultrasonic test.

(2) The reactor vessel is examined after hydrotesting to provide a baseline map for use as a reference document in relation to later inservice inspections.

5.4.5.2.2 Penetrant Examinations

The partial penetration welds for the control rod drive mechanism head adapter are inspected by dye penetrant after the first layer of weld material, after each 1/4-inch of weld metal, and the final surface. Bottom instrumentation tubes are inspected by dye penetrant after each layer of weld metal. Core support block attachment welds are inspected by dye penetrant after the first layer of weld metal and after each 1/2-inch of weld metal. This is required to detect cracks or other defects, to lower the weld surface temperatures for cleanliness, and to prevent microfissures. All austenitic steel surfaces are 100 percent dye penetrant tested after the hydrostatic test.

5.4.5.2.3 Magnetic Particle Examination

(1) All surfaces of quenched and tempered materials are inspected on the inside diameter prior to cladding and the outside diameter is 100 percent inspected after hydrotesting. This serves to detect possible defects resulting from the forming and heat treatment operations.

(2) The attachment welds for the vessel supports, lifting lugs, and refueling seal ledge are inspected after the first layer of weld metal and after each 1/2-inch of weld thickness. Where welds are back chipped, the areas are inspected prior to welding.

(3) All carbon steel surfaces are magnetic particle tested after the hydrostatic test.

5.4.6 QUALITY ASSURANCE SURVEILLANCE

The surveillance program that calls for RPV quality assurance provisi90ons to verify proper fabrication and to ensure that integrity is maintained throughout the plant's lifetime, is listed in Table 5.4-2.

5.4.7 REACTOR VESSEL DESIGN DATA

The RPV design parameters are presented in Table 5.4-1.

5.4.8 REACTOR VESSEL EVALUATION

Section 5.2 presents an assessment of the stresses induced in the RPV during normal, upset, and faulted conditions, showing that in all cases they are below the respective allowable stresses (see Tables 5.2-5, 5.2-6, and 5.2-7).

5.5 COMPONENT AND SUBSYSTEM DESIGN

This section discusses performance requirements and design features of the various components of the RCS and associated subsystems.

5.5.1 REACTOR COOLANT PUMPS

Each unit has four identical reactor coolant pumps (RCPs), one in each loop.

5.5.1.1 Design Bases

The RCP ensures an adequate core cooling flowrate, and hence sufficient heat transfer, to maintain a departure from nucleate boiling ratio (DNBR) greater than the applicable limit value (refer to Sections 4.4.1.1 and 4.4.2.3) for all modes of operation. The required net positive suction head (NPSH) is, by conservative pump design, always less than that available by system design and operation.

Sufficient pump rotation inertia is provided by a flywheel, in conjunction with the impeller and motor assembly, to provide adequate flow during coastdown. This flow provides the core with adequate cooling, following an assumed loss of pump power.

The RCP motor has been tested without mechanical damage, at overspeeds up to and including 125 percent of normal speed.

The RCP is shown in Figure 5.5-1; its design parameters are provided in Table 5.5-1.

Code applicability and material requirements are provided in Tables 5.2-2 and 5.2-13, respectively.

5.5.1.2 Design Description

The RCP is a vertical, single-stage, centrifugal, shaft seal pump designed to pump large volumes of main coolant at high temperatures and pressures.

The pump consists of, from bottom to top, the hydraulic section, the shaft seal, and the motor. Each section is described as follows:

(1) The hydraulic section consists of an impeller, diffuser, casing, thermal barrier, heat exchanger, lower radial bearing, bolting ring, motor stand, and pump shaft.

(2) The shaft seal section consists of the No. 1 controlled leakage, film riding face seal, and the No. 2 and No. 3 rubbing face seals. These seals are contained within the main flange and seal housing.

(3) The motor section consists of a vertical solid-shaft, squirrel cage induction-type motor, and oil-lubricated double Kingsbury-type thrust bearing, two oil-lubricated radial bearings, and a flywheel.

Attached to the bottom of the pump shaft is the impeller. The reactor coolant is drawn up through the impeller, discharged through passages in the diffuser, and out through the discharge nozzle in the side of the casing. A thermal barrier heat exchanger above the impeller limits heat transfer between hot system water and pump internals. A weir plate, installed in the pump discharge nozzle, prevents excessive flow of emergency core cooling system (ECCS) injection water into the casing in the event of a small loss-of-coolant accident (LOCA).

High-pressure seal injection water is introduced through the thermal barrier wall. A portion of this water flows through the seals; the remainder flows downward into the Reactor Coolant System, where it acts as a buffer to prevent system water from entering the radial bearing and seal section of the unit. The heat exchanger provides a means of cooling system water entering the pump radial bearing and seal section to an acceptable level in the event that seal injection flow is lost. The water-lubricated journal-type pump bearing, mounted above the thermal barrier heat exchanger, has a self-aligning spherical seat.

The RCP motor bearings are of conventional design. The radial bearings are the segmented- pad-type and the thrust bearings are tilting pad Kingsbury bearings. All are oil-lubricated. The lower radial bearing and the thrust bearings are submerged in oil and the upper radial bearing is fed oil from the oil flow off the outer surface of the thrust runner.

The motor is an air-cooled, Class B thermalastic epoxy-insulated, squirrel cage induction motor. The rotor and stator are of standard construction and are cooled by air. Six resistance temperature detectors are located throughout the stator to sense the winding temperature. The top of the motor consists of a flywheel and an anti-reverse rotation device.

Each RCP is equipped with a system to monitor shaft vibration. The system monitors pump shaft radial vibration, motor shaft radial vibration, and motor frame velocity. The two pump shaft radial vibration probes are mounted in a horizontal plane above the seal housing with one probe parallel to the pump discharge and the other perpendicular to the pump discharge. The two motor shaft vibration probes are mounted in a horizontal plane below the lower motor bearing with one probe parallel to the pump discharge and the other perpendicular to the pump discharge. The two velocity probes are mounted in a horizontal plane on the motor stand with one probe parallel to the pump discharge and the other perpendicular to the pump discharge. A keyphasor probe is mounted below the lower motor bearing and is used for spectral analysis and to measure pump speed. In the event that the signal from a probe becomes invalid and becomes a nuisance alarm the signal may be defeated, since the probes and cables are not accessible during power operation.

The instrumentation monitors are mounted in a common rack located on the operating deck in containment. Alarms in the control room are provided by the rack in containment. Vibration data from the instrument rack is collected and stored on a server in the control room, and analyzed at a personal computer in the administration building. The server and computer are shared by both units. The server or computer may be turned off to support maintenance or power switching, as the vibration equipment will still provide alarms and indication. If the server is off, indication requires connection of test equipment to the local rack. The RCP vibration monitoring system does not perform a safety function.

As shown in Table 5.2-13, all parts of the pump in contact with the reactor coolant are austenitic stainless steel except for seals, bearings, and special parts. Component cooling water is supplied to the two oil coolers on the pump motor and to the pump thermal barrier heat exchanger.

The pump shaft, seal housing, thermal barrier, bolting ring, and motor stand can be removed from the casing as a unit without disturbing the reactor coolant piping. The flywheel is available for inspection by removing the cover.

The performance characteristic, shown in Figure 5.5-2, is common to all of the fixed-speed mixed-flow pumps, and the "knee" at about 45 percent design flow introduces no operational restrictions since the pumps operate at full speed.

5.5.1.3 Design Evaluation

This section discusses RCP design features incorporated to ensure safe and reliable operation while maintaining RCS integrity.

5.5.1.3.1 Pump Performance

The RCPs are sized to equal or exceed the required flowrates. Initial RCS tests confirm the total delivery capability. Thus, assurance of adequate forced circulation coolant flow is provided prior to initial plant operation.

The reactor trip system (RTS) ensures that pump operation is within the assumptions used for loss-of-coolant flow analyses, which also ensures that adequate core cooling is provided to permit an orderly reduction in power if flow from an RCP is lost during operation.

An extensive test program was conducted for several years to develop the controlled leakage shaft seal for pressurized water reactor applications. Long-term tests were conducted on less than full-scale prototype seals as well as on full-size seals. Operating plants continue to demonstrate the satisfactory performance of the controlled leakage shaft seal pump design.

The support of the stationary member of the No. 1 seal (seal ring) is such as to allow large deflections, both axial and tilting, while still maintaining its controlled gap relative to the seal runner. Even if all the graphite were removed from the pump bearing, the shaft could not deflect far enough to cause opening of the controlled leakage gap. The "spring-rate" of the hydraulic forces associated with the maintenance of the gap is high enough to ensure that the ring follows the runner under very rapid shaft deflections.

Testing of pumps with the No. 1 seal entirely bypassed (full reactor pressure on the No. 2 seal) shows that relatively small leakage rates would be maintained for long periods of time. The plant operator is warned of this condition by the increase in No. 1 seal leakoff, and has time to close this line and to conduct a safe plant shutdown without significant leakage of reactor coolant to the containment. Thus, it may be concluded that gross leakage from the pump does not occur, even if seals were to suffer physical damage.

The effect of loss of offsite power on the pump itself is to cause an RCS pump trip, and temporary stoppage in the supply of injection water to the pump seals and component cooling water to the thermal barrier for seal and bearing cooling if a generator trip results. The emergency diesel generators are started automatically due to loss of offsite power, so that component cooling water flow is automatically restored to ensure cooling of the pump seals and bearings when the reactor coolant temperature is above 150°F. Seal water injection flow is subsequently restored by automatically restarting a charging pump on diesel generator electrical power.

5.5.1.3.2 Coastdown Capability

It is important to reactor operation that the reactor coolant continues to flow for a short time after reactor trip. To provide this flow after a reactor trip, each reactor coolant pump is provided with a flywheel. Thus, the rotating inertia of the pump, motor, and flywheel is employed during the coastdown period to continue the reactor coolant flow.

The pump is designed for the design earthquake (DE) at the site. Bearing integrity is maintained as discussed below. It is, therefore, concluded that the coastdown capability of the pumps is maintained even under the most adverse case of a pump trip coincident with the DE.

5.5.1.3.3 Flywheel Integrity

Integrity of the RCP flywheel is discussed in Section 5.2.6.

5.5.1.3.4 Bearing Integrity

The design requirements for the RCP bearings are primarily aimed at ensuring a long life with negligible wear, so as to give accurate alignment and smooth operation over long periods of time. To this end, the surface-bearing stresses are held at a very low

value, and, even under the most severe seismic transients, do not begin to approach loads, which cannot be adequately carried for short periods of time.

Because there are no established criteria for short-term, stress-related failures in such bearings, it is not possible to make a meaningful quantification of such parameters as margins to failure, safety factors, etc. A qualitative analysis of the bearing design, embodying such considerations, gives assurance of the adequacy of the bearing to operate without failure.

High/low oil level in the motor bearings signals an alarm in the control room. Each motor bearing contains embedded temperature detectors, and so initiation of failure, separate from loss of oil, is indicated and alarmed in the control room as a high bearing temperature. Even if these indications are ignored and the bearing proceeds to fail, the low melting point of Babbitt metal on the pad surfaces ensures that no sudden seizure of the bearing occurs. In this event, the motor continues to drive since it has sufficient reserve capacity to operate until it can be shut down.

The RCP shaft is designed so that its critical speed is well above the operating speed.

5.5.1.3.5 Locked Rotor

The postulated case in which the pump impeller severely rubs on a stationary member and then seizes, was evaluated. The analysis showed that under such conditions, assuming instantaneous seizure of the impeller, the pump shaft fails in torsion just below the coupling to the motor, disengaging the flywheel and motor from the shaft. This constitutes a loss of coolant flow in the loop. Following such a postulated seizure, the motor continues to run without any overspeed, and the flywheel maintains its integrity since it is still supported on a shaft with two bearings.

There are no credible sources of shaft seizure other than impeller rubs. Any seizure of the pump bearing is precluded by the graphite in the bearing. Any seizure in the seals results in a shearing of the anti-rotation pin in the seal ring. The motor has adequate power to continue pump operation even after the above occurrences. Indications of pump malfunction in these conditions are first, by high-temperature signals from the bearing water temperature detector, and second, by excessive No. 1 seal leakoff indications. Along with these signals, pump vibration levels are checked. When there are indications of a serious malfunction, the pump is shut down for investigation.

5.5.1.3.6 Critical Speed

The RCPs are designed to operate below first critical speed. This results in a shaft design that, even under the most severe postulated transient, gives very low stress values.

Both the damped and lateral natural frequencies are determined by establishing a number of shaft sections and applying weights and moments of inertia for each section

bearing spring and damping data. The torsional natural frequencies are similarly determined. The lateral and torsional natural frequencies are greater than 120 and 110 percent of the running speed, respectively.

5.5.1.3.7 Missile Generation

Each pump component is analyzed for missile generation. Any fragments of the motor rotor would be contained by the heavy stator. The same conclusion applies to the pump impeller because the small fragments that might be ejected would be contained by the heavy casing.

5.5.1.3.8 Pump Cavitation

The minimum NPSH required by the RCP at running speed is approximately 170 feet (approximately 74 psi). For the controlled leakage seal to operate correctly, a differential pressure of approximately 200 psi across the seal is necessary. This results in a requirement for a minimum of 325 psi pressure in the primary loop before the RCP may be operated. This 325 psi requirement is for initial fill and vent only. In normal operation, a Δp greater than 200 psi at the Number 1 seal is required for reactor coolant pump operation. This requirement is reflected in the operating instructions. At this pressure, the NPSH requirement is exceeded and no limitation on pump operation occurs from this source.

5.5.1.3.9 Pump Overspeed Considerations

The generator and the RCP remain electrically connected for 30 seconds following turbine trip actuated by either the RTS or the turbine protection system (TPS), except for certain trips caused by electrical or mechanical faults which require immediate tripping of the generator. A complete load disconnect with turbine overspeed would result in an overspeed potential for the RCP. The turbine control system and the turbine intercept valves limit the overspeed to less than 120 percent. As additional backup, the TPS has a mechanical overspeed protection trip usually set at about 110 percent.

The details of the turbine trip interface logic are shown in Figures 5.5-13 and 5.5-17. The sequence of events following a generator trip, which transfers the engineered safety features onto the emergency power system (EPS) is discussed in Section 8.3.

5.5.1.3.10 Anti-reverse Rotation Device

Each RCP is provided with an anti-reverse rotation device in the motor. This anti-reverse mechanism consists of five pawls mounted on the outside diameter of the flywheel, a serrated ratchet plate mounted on the motor frame, a spring return for the ratchet plate, and three shock absorbers.

After the motor comes to a stop, a minimum of one pawl engages the ratchet plate and, as the motor tends to rotate in the opposite direction, the ratchet plate also rotates until

stopped by the shock absorbers. The rotor remains in this position until the motor is energized again. After the motor comes up to speed, the ratchet plate is returned to its original position by the spring return.

When the motor is started, the pawls initially drag over the ratchet plate. Once the motor reaches sufficient speed, centrifugal forces acting on the pawls produce enough friction to prevent the pawls from rotating, and thus hold the pawls in the elevated position until the motor is stopped.

5.5.1.3.11 Shaft Seal Leakage

Leakage along the RCP shaft is controlled by three shaft seals arranged in series so that reactor coolant leakage to the containment is essentially zero. Charging flow is directed to each RCP via a 5-micron seal (maximum) water injection filter. It enters the pumps through the thermal barrier and is directed down to a point between the pump shaft bearing and the thermal barrier cooling coils. Here the flow splits and a portion flows down past the thermal barrier cooling cavity and labyrinth seals. The remainder flows up the pump shaft, cooling the lower bearing, and leaves the pump via the No. 1 seal bypass line or the No. 1 seal leakoff line. There is also a minor flow through the No. 2 seal.

Leakoff flow through the No. 1 seal from each pump is piped to a common manifold, and then, via a seal water return filter, through a seal water heat exchanger, to the volume control tank. The volume control tank provides a back pressure of at least 15 psig on the No. 1 seal.

A small amount of No. 1 seal leakoff passes through the No. 2 seal. No. 2 seal leakoff flows to the reactor coolant drain tank.

The No. 3 seal is a double dam seal that divides seal flow into two paths. Part of the flow is directed radially outward to join the No. 2 seal leakoff line and the second part flows radially inward to the No. 3 seal leakoff line to the containment structure sump. A standpipe is provided to ensure a back pressure of at least 7 feet of water on the No. 3 seal.

5.5.1.3.12 Spacer Couplers

The installation of a removable spool piece, shown in Figure 5.5-3, in the reactor coolant pump shaft facilitates the inspection and maintenance of the pump seal system without breaking any of the fluid, electrical, or instrumentation connections to the motor, without removal of the motor.

5.5.1.4 Tests and Inspections

Support feet are cast integral with the casing to eliminate a weld region. The design enables disassembly and removal of the pump internals for normal access to the internal surface of the pump casing.

Inservice inspection is discussed in Section 5.2.8. The RCP quality assurance program is given in Table 5.5-2.

5.5.1.4.1 Electroslag Welding

Reactor coolant pump casings fabricated by electroslag welding were qualified as follows:

(1) The electroslag welding procedure employing 2- and 3-wire technique was qualified in accordance with the requirements of the ASME Boiler and Pressure Vessel (B&PV) Code, Section IX, and Code Case 1355 (see Table 5.2-1) plus supplementary evaluations specified by Westinghouse.

(2) A separate weld test was made using the 2-wire electroslag technique to evaluate the effects of a stop and restart of welding by this process. This evaluation was performed to establish proper procedures and techniques as such an occurrence was anticipated during production applications due to equipment malfunction, power outages, etc.

(3) All of the weld test blocks in (1) and (2) above were radiographed using a 24 MeV betatron. The radiographic quality level obtained was between 0.5 and 1 percent, as defined by ASTM E-94. There were no discontinuities evident in any of the electroslag welds.

The casting segments were surface conditioned for 100 percent radiographic and penetrant inspections. The radiographic acceptance standards were ASTM E-186 Severity Level 2 except no Category D or E defectives were permitted for section thicknesses up to 4-1/2 inches and ASTM E-280, Severity Level 2, for section thicknesses greater than 4-1/2 inches. The edges of the electroslag weld preparations were machined. These surfaces were also penetrant inspected prior to welding. The penetrant acceptance standards were those of the ASME B&PV Code, Section III, Paragraph N-627.

The completed electroslag weld surfaces were ground flush with the casting surface. The electroslag weld and adjacent base material were then 100 percent radiographed in accordance with ASME B&PV Code Case 1355. Also, the electroslag weld surfaces and adjacent base material were penetrant inspected in accordance with ASME B&PV Code, Section III, Paragraph N-627. Weld metal and base metal chemical and physical properties were determined and certified. Heat treatment furnace charts were recorded

and certified, and are available at the nuclear steam supply system (NSSS) vendor's facilities.

5.5.1.4.2 In-process Control of Variables

Many variables must be controlled to maintain desired quality welds. These variables and their relative importance are as follows:

(1) Heat Input vs. Output

The heat input is determined by the product of volts and current and measured by voltmeters and ammeters, which are considered accurate and are calibrated every 30 days. During any specific weld these meters are constantly monitored by the operators.

(2) Weld Gap Configuration

The weld gap configuration is controlled by 1-1/4-inch spacer blocks. As these blocks are removed, there is the possibility of gap variation. It has been found that a variation from 1 to 1-3/4 inches is not detrimental to weld quality as long as the current is adjusted accordingly.

(3) Flux Chemistry

The flux used for welding is Arcos BV-I Vertomax. This is a neutral flux, the chemistry of which is specified by Arcos Corporation. The molten slag is kept at a nominal depth of 1-3/4 inches and may vary in depth by plus or minus 3/8 inch without affecting the weld. This is measured with a stainless steel dipstick.

(4) Weld Cross Section Configuration

The higher the current or heat input and the lower the heat output, the greater the dilution of weld metal with base metal. This causes a rounder barrel-shaped configuration compared to welding with lower heat input and higher heat output, which reduces the amount of dilution and provides a more narrow barrel-shaped configuration. Configuration is also a function of section thickness; the thinner the section, the rounder the pattern produced.

5.5.1.4.3 Welder Qualification

Welder qualification is in accordance with ASME B&PV Code, Section IX rules.

5.5.2 STEAM GENERATORS

Each RCS loop contains a vertical U-tube steam generator.

5.5.2.1 Design Bases

Steam generator design data are provided in Table 5.5-3. The design can sustain the transient conditions identified in Table 5.2-4. Estimates of radioactivity levels anticipated in the secondary side of the steam generators during normal operation and their bases for the estimates are discussed in Section 11.1. The transient analysis of a steam generator tube rupture is discussed in Section 15.4.

When operating at 100 percent power, integral moisture separating equipment reduces moisture content of the steam at the exit of the steam generators to ≤0.05 percent. Under the following transient conditions, the moisture content at the exit of the steam generators is <0.25 percent:

- loading or unloading at a rate of 5 percent of full power steam flow per minute in the range from 15 to 100 percent of full load steam flow

- a step load change of 10 percent of full power in the range from 15 to 100 percent of full load steam flow

The steam generator tubesheet complex meets the stress limitations and fatigue criteria specified in the ASME B&PV Code, Section III, as well as emergency condition limitations specified in Section 5.1 of this document. Codes and materials requirements of the steam generator are listed in Tables 5.2-2 and 5.2-14, respectively. The steam generator design maximizes integrity against hydrodynamic excitation and vibration failure of the tubes for plant life.

The water chemistry in the reactor side is selected to provide the necessary boron content for reactivity control and to minimize corrosion of RCS surfaces. Water chemistry for the primary coolant side is presented in Table 5.2-15.

5.5.2.1.1 Design Basis for the Steam Outlet Nozzle Flow Restrictor

The design criterion for the steam nozzle flow restrictors is to limit steam flow in the event of a steam line break during normal operating conditions, in order to reduce pressure drop loadings on the steam generator internal components, as well as to limit the mass and energy release rate into the containment.

5.5.2.2 Design Description

The steam generator, shown in Figure 5.5-4, is a vertical shell and U-tube design with evaporators having integral moisture separating equipment. The reactor coolant flows through the inverted U-tubes, entering and leaving through the nozzles located in the

hemispherical bottom head of the steam generator. Steam is generated on the shell side and flows upward through the moisture separators to the outlet nozzle at the top of the vessel. The head is divided into inlet and outlet chambers by a vertical partition plate extending from the head to the tubesheet. Manways are provided for access to both sides of the divided head.

The steam generator unit is primarily carbon steel. The heat transfer tubes and the divider plate are Inconel and the interior surfaces of the reactor coolant channel heads and nozzles are clad with austenitic stainless steel. The primary side of the tubesheet is weld clad with Inconel.

The feedwater enters the upper shell through an elevated feedwater ring consisting of an alloy steel header with a welded feedwater nozzle thermal liner. Water discharges from the header through debris-filtering spray nozzles located in the top of the header. This configuration reduces the potential for water hammer and thermal stratification. Feedwater then flows into the downcomer formed by the shell and the tube bundle wrapper before entering the boiler section of the steam generator.

Subsequently, the water-steam mixture flows upward through the tube bundle and into the steam drum section. A set of centrifugal moisture separators, located above the tube bundle, removes most of the entrained water from the steam. Steam dryers are employed to increase the steam quality to a minimum of 99.95 percent, which corresponds to a steam outlet moisture content of 0.05 percent. The moisture separators recirculate flow that mixes with feedwater as it enters the downcomer formed by the shell and tube bundle wrapper. The steam generator shell has two bolted and gasketed access openings for inspection and maintenance of the dryers that can be disassembled and removed through the opening.

5.5.2.2.1 Design Description of the Steam Outlet Nozzle Flow Restrictor

An integral flow restrictor is provided in each steam nozzle to limit flow in the event of a steam line break accident downstream of the steam nozzle. The flow restrictor consists of seven holes in the steam outlet nozzle forging, with Venturi type flow limiting inserts installed in each of these holes. The total minimum flow area is 1.4 ft^2 for the seven inserts. The Alloy 690 flow limiting inserts are welded to the Alloy 690 cladding at the steam nozzle bottom. Materials, welding, and inspection requirements applied in fabrication of the steam nozzle flow restrictor assemblies conform to ASME Code Section III (1998 Edition, with addenda through 2000 Addenda) requirements.

The steam outlet nozzle flow restrictor assembly is shown in Figure 5.5-18.

5.5.2.3 Design Evaluation

5.5.2.3.1 Forced Convection

The limiting case for heat transfer capability is the nominal 100 percent design thermal duty. To ensure that this thermal duty will be met, the RSGs are designed to operate with an effective fouling factor, or heat transfer resistance, that is greater than that experienced for comparable units in service. Adequate tubing area is selected to ensure that the full design heat removal rate is achieved for these conditions.

The historical best estimate fouling factor applied to Alloy 690-TT tubing is 0.00006 hr-ft^2-°F/Btu. The design fouling factor for the Diablo Canyon RSGs is 0.00018 hr-ft^2-°F/Btu. When added to the conduction resistance of the tubing, this additional resistance accounts for approximately 17 percent margin for heat transfer, i.e., a 17 percent higher heat transfer coefficient is expected compared to the design value. This margin ensures that the RSGs will provide sufficient heat transfer capability through the design life.

5.5.2.3.2 Natural Circulation Flow

The driving head created by the change in coolant density as it is heated in the core and rises to the outlet nozzle initiates convection circulation. This circulation is enhanced by the fact that the steam generators, which provide a heat sink, are at a higher elevation than the reactor core, which is the heat source. Thus, natural circulation is ensured for the removal of decay heat during hot shutdown in the unlikely event of loss of forced circulation.

5.5.2.3.3 Secondary System Fluid Flow Instability Prevention

Undesirable perturbations in secondary side flow are postulated to result from events such as water hammer and circulation loop instability. Such events can compromise the functional capability and mechanical integrity of the secondary system. The RSGs include design features intended to preclude these occurrences.

The potential for water hammer is mitigated by the inclusion of an upward-sloping section of the feedwater ring header. This reduces the volume within the feedwater ring assembly that could potentially be filled with steam, and also reduces the possibility of thermal stratification in the feed flow. The steam generators include top-discharge spray nozzles, which further reduce the possibility of steam pockets being trapped in the feedwater ring, and also serve as a means to prevent loose parts from entering the steam generator through the feedwater system.

Instability in the circulation loop for the secondary fluid can result from a distribution of pressure drops that favors two-phase flow, which is de-stabilizing and is found in the upper tube bundle and moisture separators, as opposed to single-phase flow, which is stabilizing and is found in the downcomer and lower tube bundle areas. A stability

damping factor is determined in which a negative value indicates damped, stable circulation flow. The RSGs are designed to provide damped, stable circulation over the full range of operating conditions, with sufficient margin to prevent increased two-phase pressure drop, caused by conditions such as partially blocked tube support plate flow holes, from causing instability.

5.5.2.3.4 Tube and Tubesheet Stress Analyses

Tube and tubesheet stress analyses for the RSGs confirm that the steam generator tubesheet will withstand the loading (quasi-static rather than shock loading) caused by loss of reactor coolant. With the acceptance of the DCPP leak-before-break analysis by the NRC (Reference 10), dynamic loading conditions resulting from pipe rupture events in the main reactor coolant loop piping no longer have to be considered in the design basis analyses; only the much smaller dynamic loads resulting from RCS branch line breaks have to be considered (see Section 3.6.2.1.1.1).

5.5.2.3.5 Corrosion

The RSGs include a number of key design features that enhance operation, performance, and maintenance. The design features and materials have been developed and selected to minimize the potential for tube degradation. The design features enhance steam and water flow by the tubes, which minimizes the potential for concentration of chemical species that can be detrimental to tubing material.

For the RSGs, the U-tubes are fabricated of nickel-chromium-iron (Ni-Cr-Fe) Alloy 690. The tubes undergo thermal treatment following tube-forming and annealing operations. The thermal treatment subjects the tubes to elevated temperatures for a prescribed period of time to improve the microstructure of the material. Thermally treated Alloy 690 has been shown in laboratory tests and operating nuclear power plants to be very resistant to PWSCC and ODSCC. The use of Alloy 690 does not require changes to DCPP primary or secondary water chemistry requirements or procedures.

All volatile chemistry is used in the main steam, feedwater, and condensate systems to provide improved corrosion protection and control.

The control measures exercised over the secondary water chemistry for the purpose of inhibiting steam generator tube degradation consist of a program encompassing: (a) scheduled sampling and analyses of fluid systems for the critical control parameters, (b) recording, reviewing, and management of data, (c) identification of process sampling points, (d) guidance for corrective actions for off-point chemistry, (e) identification of the authority responsible for the interpretation of data, and (f) the sequence and timing of administrative events required to initiate corrective action.

Additional control measures for secondary water chemistry come from the turbine manufacturer. The program includes the monitoring of main steam purity.

5.5.2.3.6 Design Evaluation for the Steam Outlet Nozzle Flow Restrictor

In the event of a main steam line break, steam flow rate from the steam generators is restricted by the outlet nozzle Venturi inserts, which limit the steam blowdown rate from the steam generators.

5.5.2.3.7 Flow-induced Vibration

In the design of the steam generators, the possibility of degradation of tubes due to either mechanical- or flow-induced excitation is thoroughly evaluated. This evaluation includes detailed analysis of the tube support systems as well as an extensive research program with tube vibration model tests.

In evaluating degradation due to vibration, consideration is given to sources of excitation such as those generated by primary fluid flowing within the tubes, mechanically induced vibration, and secondary fluid flow on the outside of the tubes. During normal operation, the effects of primary fluid flow within the tubes and mechanically induced vibration are considered to be negligible and should cause little concern. Thus, the primary source of tube vibrations is the hydrodynamic excitation by the secondary fluid on the outside of the tubes. In general, three vibration mechanisms have been identified:

(1) Vortex shedding

(2) Fluidelastic excitation

(3) Turbulence

Vortex shedding does not provide detectable tube bundle vibration for the following reasons:

(1) Flow turbulence in the downcomer and tube bundle inlet region inhibits the formation of Von Karman's vortex train.

(2) The spatial variations of cross flow velocities along the tube preclude vortex shedding at a single frequency.

(3) Both axial and cross flow velocity components exist on the tubes. The axial flow component disrupts the Von Karman vortices.

The steam generator design is qualified by analyses (relying on theoretical calculations based on laboratory test data and operating steam generator experience), which demonstrate that no tubes will experience unacceptable degradation or wear due to vibration over the steam generator design life.

5.5.2.4 Tests and Inspections

The steam generator quality assurance program is given in Table 5.5-5. Radiographic inspection and acceptance standards are in accordance with the requirements of the ASME B&PV Code, Section III, 1998 Edition through the 2000 Addenda.

Liquid penetrant inspection was performed on weld deposited tubesheet cladding, channel head cladding, tube-to-tubesheet weldments, and weld deposit cladding. Liquid penetrant inspection and acceptance standards are in accordance with the requirements of the ASME B&PV Code, Section III, 1998 Edition through the 2000 Addenda.

Magnetic particle inspection was performed on all pressure boundary forgings (tubesheet, shell barrels, channel head, transition cone, elliptical head, and secondary-side nozzles), and the following weldments:

- Nozzle to shell
- Upper lateral support lugs
- Instrument connections
- Temporary attachments after removal
- All accessible pressure-retaining welds after hydrostatic testing.

Magnetic particle inspection and acceptance standards were in accordance with the requirements of the ASME B&PV Code, Section III, 1998 Edition through the 2000 Addenda.

Ultrasonic examination was performed on all pressure boundary forgings (tubesheet, shell barrels, channel head, transition cone, elliptical head, primary nozzle safe ends, and secondary-side nozzles.

Manways provide access to both the primary and secondary sides of the steam generators. Primary side inspection and maintenance is described in Section 5.5.2.5 and is typically performed with nozzle dams in place to isolate the steam generator bowl from the reactor coolant system.

5.5.2.4.1 Tests and Inspections for the Steam Outlet Nozzle Flow Restrictor

The flow restrictor Venturi inserts at the steam outlet are located inside the steam outlet nozzle and welded to the cladding. Therefore, the flow restrictor inserts are not a pressure boundary component. However, component integrity is ensured by compliance with ASME Code requirements.

5.5.2.5 Steam Generator Tube Surveillance Program

5.5.2.5.1 Inservice Inspection

Steam generator tube inspection is performed in accordance with the Technical Specifications (Reference 6) and the DCPP surveillance test procedure. Eddy current non-destructive testing is used to perform tube inspections. The steam generator tube surveillance program ensures that the structural and leakage integrity of this portion of the RCS will be maintained. The program for inservice inspection of steam generator tubes is based on NEI 97-06 (Reference 5). Inservice inspection of SG tubing is essential in order to maintain surveillance of the conditions of the tubes in the event there is evidence of mechanical damage or progressive degradation due to design, manufacturing errors, or inservice conditions that lead to corrosion. Inservice inspection of SG tubing also provides a means of characterizing the nature and cause of any tube degradation so that corrective measures can be taken.

Tube degradation will be detected during scheduled inservice SG tube examinations. Steam generator tube inspections of operating plants have demonstrated the capability to reliably detect degradation that has penetrated 20 percent of the original tube wall thickness. Plugging is required for all tubes with imperfections exceeding the plugging limit defined in the Technical Specifications. Degradation may be left in service if qualified non-destructive examination sizing techniques verify that the imperfection is less than the plugging limit (reference PG&E response to NRC Generic Letter 97-05).

5.5.2.5.2 Primary-to-Secondary Leakage

The plant is expected to be operated in a manner such that the secondary coolant will be maintained within those chemistry limits found to result in negligible corrosion of the SG tubes. The extent of cracking during plant operation is limited by the limitation on SG tube leakage between the Reactor Coolant System and the Secondary Coolant System (primary-to-secondary leakage = 150 gallons per day per SG). Cracks having a primary-to-secondary leakage less than this limit during operation will have an adequate margin of safety to withstand the loads imposed during normal operation and by postulated accidents. DCPP has demonstrated that primary-to-secondary leakage of 150 gallons per day per SG can readily be detected during power operation. Leakage in excess of this limit will require plant shutdown and an unscheduled inspection, during which the leaking tubes will be located and plugged.

Section 15.5.18.1 provides the radiological assessment for accident-induced leakage up to 10.5 gpm at room temperature conditions in any one SG following an SLB.

5.5.3 REACTOR COOLANT PIPING

Reactor coolant piping provides a flowpath connecting the major components of each RCS loop.

5.5.3.1 Design Bases

The RCS piping was designed and fabricated to accommodate the stresses due to the pressures and temperatures attained under all expected modes of plant operation or system interactions. Code and material requirements are provided in Table 5.2-2 and Section 5.2.3.

Materials of construction are specified to minimize corrosion/erosion and ensure compatibility with the operating environment.

The reactor coolant loop and pressurizer surge line piping for both units are designed and fabricated in accordance with ASA Standard B31.1. It was installed in accordance with ASME B&PV Code, Section III, 1971.

5.5.3.2 Design Description

Principal design data for the reactor coolant system (RCS) piping for both units are provided in Table 5.5-6. The RCS piping was specified in the smallest sizes consistent with system requirements. In general, high fluid velocities are used to reduce piping sizes. This design philosophy results in the reactor inlet and outlet piping diameters listed in Table 5.5-6. The line between the steam generator and the pump suction is larger to reduce pressure drop and improve flow conditions to the pump suction.

The reactor coolant piping is seamless forged, and fittings are cast. Cast sections of large 90° elbows are joined by electroslag welds. All materials are austenitic stainless steel. All smaller piping that is part of the RCS boundary, such as the pressurizer surge line, spray and relief line, loop drains, and connecting lines to other systems are also austenitic stainless steel. The nitrogen supply line for the pressurizer relief tank is carbon steel. All joints and connections are welded, except for the pressurizer relief and the pressurizer safety valves, where flanged joints are used. Thermal sleeves are installed at points in the system where high thermal stresses could develop due to rapid changes in fluid temperature during normal operational transients. These points include:

(1) Charging connections at the primary loop from the chemical and volume control system (CVCS)

(2) Both ends of the pressurizer surge line

(3) Pressurizer spray line connection at the pressurizer

Thermal sleeves were not provided for the remaining injection connections of the ECCS since these connections are not in normal use.

All piping connections from auxiliary systems were made above the horizontal centerline of the reactor coolant piping, with the exception of:

(1) Residual heat removal (RHR) pump suction, which is 45° down from the horizontal centerline. This enables the water level in the RCS to be lowered in the reactor coolant pipe while continuing to operate the RHR system, should this be required for maintenance.

(2) Loop drain lines and the connection for temporary level measurement of water in the RCS during refueling and maintenance operation.

(3) The differential pressure taps for flow measurement are downstream of the steam generators on the first 90° elbow. There are three flow transmitters at each elbow. The transmitters at each elbow are arranged so that they use a common high-pressure tap (on the outside of the elbow) and separate low pressure taps (on the inside of the elbow). Additional discussion is included in Section 7.2.2.1.4.

Penetrations into the coolant flowpath were limited to the following:

(1) The spray line inlet connections extend into the cold leg piping in the form of a scoop so that the velocity head of the reactor coolant loop flow adds to the spray driving force.

(2) The reactor coolant sample system taps protrude into the main stream to obtain a representative sample of the reactor coolant.

(3) The narrow range RCS temperature sensors (RTDs) are mounted in thermowells that extend into the hot and cold legs. The RTD bypass scoops and nozzles have been capped.

(4) The wide range RCS temperature sensors (RTDs) are mounted in thermowells that protrude into the hot legs and cold legs.

Signals from these instruments are used to compute the reactor coolant ΔT (temperature of the hot leg, T_{hot}, minus the temperature of the cold leg, T_{cold}) and an average reactor coolant temperature (T_{avg}). The T_{avg} and ΔT for each loop are indicated on the main control board. Section 7 further describes the temperature sensor arrangement.

The RCS pressure boundary piping includes those sections of piping interconnecting the reactor vessel, steam generator, and RCP. It also includes the following:

(1) Charging line and alternate charging line from the isolation valve up to the branch connections on the reactor coolant loop

(2) Letdown line and excess letdown line from the branch connections on the reactor coolant loop to the isolation valve

(3) Pressurizer spray lines from the reactor coolant cold legs to the spray nozzle on the pressurizer vessel

(4) RHR lines to or from the reactor coolant loops up to the designated isolation or check valve

(5) Safety injection lines from the designated isolation or check valve to the reactor coolant loops

(6) Accumulator lines from the designated isolation or check valve to the reactor coolant loops

(7) Loop fill, loop drain, sample, and instrument lines to or from the designated isolation valve to or from the reactor coolant loops

(8) Pressurizer surge line from one reactor coolant loop hot leg to the pressurizer vessel inlet nozzle

(9) Abandoned resistance temperature detector scoop element, pressurizer spray scoop, sample connection with scoop, reactor coolant temperature element installation boss, and the temperature element thermowell itself

(10) All branch connection nozzles attached to reactor coolant loops

(11) Pressure relief lines from nozzles on top of the pressurizer vessel up to and through the power-operated pressurizer relief valves and pressurizer safety valves

(12) Seal injection water and labyrinth differential pressure lines to or from the RCP inside reactor containment

(13) Auxiliary spray line from the isolation valve to the pressurizer spray line header

(14) Sample lines from pressurizer to the isolation valve

(15) Pressurizer loop seal drain lines to the pressurizer.

Details of the materials of construction and codes used in the fabrication of reactor coolant piping and fittings are discussed in Section 5.2.

5.5.3.3 Design Evaluation

5.5.3.3.1 Piping Load and Stress Evaluation

Piping loads and stress evaluation methodology for normal, upset, and faulted conditions are described in Section 5.2.1.

5.5.3.3.2 Material Corrosion/Erosion Evaluation

The water chemistry is selected to minimize corrosion. A periodic analysis of the coolant chemical composition is performed to verify that the reactor coolant quality meets the specifications. The RCS water chemistry is presented in Section 5.2.3.4 and Table 5.2-15.

An upper limit of about 50 feet per second is specified for internal coolant velocity to avoid the possibility of accelerated erosion. All pressure-containing welds within the reactor coolant pressure boundary are available for examination and have removable insulation.

5.5.3.4 Tests and Inspections

5.5.3.4.1 Inservice Inspection

Inservice inspection is discussed in Section 5.2.8.

5.5.3.4.2 Piping Quality Assurance

The RCS piping quality assurance program is given in Table 5.5-7.

5.5.3.4.3 Electroslag Weld Quality Assurance

The 90° elbows used in the reactor coolant loop piping were electroslag welded. A description of this procedure is contained in Section 5.5.1.

The following quality assurance actions for RCS piping were undertaken:

(1) The electroslag welding procedure employing 1-wire technique was qualified in accordance with the requirements of ASME B&PV Code, Section IX, and Code Case 1355 plus supplementary evaluation.

(2) The casting segments were surface conditioned for 100 percent radiographic and penetrant inspections. The acceptance standards were USAS Code Case N-10, and ASTM E-186, Severity Level 2, except no Category D or E defectives were permitted.

5.5.4 MAIN STEAM LINE FLOW RESTRICTORS

As described in Section 5.5.2.2.1, each steam generator has a flow restrictor located in the steam outlet nozzle to limit the steam blowdown from the steam generators in the event of a main steam line rupture. The flow restrictor consists of seven 6.03-inch ID venturi nozzles. In addition, a 16-inch flow restrictor is installed in each main steam line outlet to measure steam flow.

The main steam line flow restrictors are welded into the inside of a length of main steam pipe. Therefore, the 16-inch flow restrictors are not a pressure boundary component. However, component integrity is ensured by compliance with ASME Code requirements.

5.5.5 MAIN STEAM LINE ISOLATION SYSTEM

Each main steam line has one isolation valve and one check valve, both of the swing check type, located outside the containment. The isolation valves are held open by a pneumatic actuator until a trip signal is received, as discussed in Section 6.2.4. For analysis of the ability of these valves to close under pipe break conditions, refer to Appendix 5.5A to this Chapter.

5.5.6 RESIDUAL HEAT REMOVAL SYSTEM

A separate RHR system is provided for each unit. This section describes one system with the second being identical unless otherwise noted.

The RHR system transfers heat from the RCS to the component cooling water system (CCWS) to reduce reactor coolant temperature to the cold shutdown temperature at a controlled rate during the latter part of normal plant cooldown, and maintains this temperature until the plant is started up again.

As a secondary function, the RHR system also serves as part of the ECCS during the injection and recirculation phases of a LOCA.

The RHR system can also be used to transfer refueling water between the refueling water storage tank and the refueling cavity before and after the refueling operations.

5.5.6.1 Design Bases

RHR system design parameters are listed in Table 5.5-8. A schematic diagram of the RHR system is shown in Figure 3.2-10.

The RHR system is designed to remove heat from the core and reduce the temperature of the RCS during the second phase of plant cooldown. During the first phase of cooldown, the temperature of the RCS is reduced by transferring heat from the RCS to the steam and power conversion system (SPCS) via the steam generators.

The RHR system is placed in operation when the nominal temperature and pressure of the RCS are ≤ 350°F and ≤ 390 psig, respectively. The cooldown calculation of Reference 12 assumes the RHR is placed in service no sooner than 4 hours after reactor shutdown. Assuming that two RHR heat exchangers and two RHR pumps are in service and that each heat exchanger is supplied with component cooling water at design flow and temperature, the analysis shows that the RHR system design is capable of reducing the temperature of the reactor coolant to 140°F in less than 20 hours after reactor shutdown. The heat load handled by the RHR system during the cooldown transient includes sensible and decay heat from the core and RCP heat.

5.5.6.2 System Description

The RHR system consists of two RHR heat exchangers, two RHR pumps, and the associated piping, valves, and instrumentation necessary for operational control. The inlet line to the RHR system is connected to the hot leg of reactor coolant loop 4, while the return lines are connected to the cold legs of each of the reactor coolant loops. These normal return lines are also the ECCS low-head injection lines (see Figure 6.3-4).

The RHR system suction line is isolated from the RCS by two motor-operated valves in series while the discharge lines are isolated by two check valves in each line. These check valves are not a part of the RHR system; they are shown as part of the ECCS. The isolation valves inlet line pressure-relief valve and associated piping are located inside the containment. The remainder of the system is located outside the containment.

During system operation, reactor coolant flows from the RCS to the RHR pumps, through the tube side of the RHR exchangers, and back to the RCS. The heat is transferred in the RHR heat exchangers to the component cooling water circulating through the shell side of the heat exchangers.

Coincident with RHR operations, a portion of the reactor coolant flow may be diverted from downstream of the RHR heat exchangers to the CVCS low-pressure letdown line for cleanup and/or pressure control. By regulating the diverted flowrate and the charging flow, the RCS pressure can be controlled. Pressure regulation is necessary to maintain the pressure range dictated by the fracture prevention criteria requirements of the reactor vessel and by the No. 1 seal differential pressure and NPSH requirements of the RCPs.

The RCS cooldown rate is manually controlled by regulating the reactor coolant flow through the tube side of the RHR heat exchangers. A line containing a flow control valve bypasses the RHR heat exchangers and is used to maintain a constant return flow to the RCS. Instrumentation is provided to monitor system pressure, temperature, and total flow, and to activate an alarm on system low flow.

The RHR system is also used for filling the refueling cavity before refueling. After refueling operations, water is pumped back to the refueling water storage tank until the water level is brought down to the desired level below the flange of the reactor vessel. The remainder is removed via a drain connection at the bottom of the refueling canal.

When the RHR system is in operation, the water chemistry is the same as that of the reactor coolant. Provision is made for the sampling system to extract samples from the flow of reactor coolant downstream of the RHR heat exchangers. A local sampling point is also provided on each RHR train between the pump and heat exchanger.

The RHR system functions in conjunction with the high-head and intermediate portions of the ECCS to provide injection of borated water from the refueling water storage tank into the RCS cold legs during the injection phase following a LOCA. During normal operation, the RHR system is lined up to perform this emergency function.

In its capacity as the low-head portion of the ECCS, the RHR system provides long-term recirculation capability for core cooling following the injection phase of the LOCA. This function is accomplished by aligning the RHR system to take suction from the containment sump.

For a more complete discussion of the use of the RHR system as part of the ECCS, see Section 6.3.

5.5.6.2.1 Component Description

The materials used to fabricate RHR system components are in accordance with applicable code requirements. All parts of components in contact with borated water are fabricated or clad with austenitic stainless steel or equivalent corrosion resistant material.

RHR component applicable codes and classification are provided in Table 5.5-9. Component parameters are listed in Table 5.5-10.

5.5.6.2.1.1 Residual Heat Removal Pumps

Two pumps are installed in the RHR system. The pumps are sized to deliver sufficient reactor coolant flow through the RHR heat exchangers to meet the plant cooldown requirements. The use of two pumps ensures that cooling capacity is only partially lost should one pump become inoperative.

The RHR pumps are protected from overheating and loss of suction flow by miniflow bypass lines that provide flow to the pump suction at all times. A control valve located in each miniflow line is regulated by a signal from the flow transmitters located in each pump discharge header. The control valves open on low RHR pump discharge flow and close when RHR flow has been established. To prevent pump to pump interaction as a result of differences between pump flow characteristics, check valves were installed

downstream of the RHR heat exchangers. During minimum flow operation the check valve will prevent the stronger pump from dead heading or reversing flow into the weaker pump, thereby maintaining minimum required recirculation flow.

A pressure sensor in each pump discharge header provides a signal for an indicator in the control room. A high pressure alarm is also actuated by the pressure sensor.

The two pumps are vertical, centrifugal units with mechanical shaft seals. All pump surfaces in contact with reactor coolant are austenitic stainless steel or equivalent corrosion resistant material.

5.5.6.2.1.2 Residual Heat Removal Heat Exchangers

Two RHR heat exchangers are installed in the system. The heat exchanger design is based on heat load and temperature differences between reactor coolant and component cooling water existing 20 hours after reactor shutdown when the temperature difference between the two systems is small. The decay heat removal used in the cooldown analysis is given in Table 5.5-8.

The RHR heat exchangers are part of the emergency core cooling supporting the recirculation mode in which long-term core cooling is provided during the accident recovery period. During the emergency core cooling recirculation phase, water from the containment sump flows through the tube side of the RHR heat exchangers, transferring heat from containment to the CCW system. Further discussion of the RHR heat exchangers in this mode is found in Section 6.3.2.4.4.

The most limiting RHR system heat exchanger design requirement is to remove decay heat, sensible heat and reactor coolant pump heat at the design flow rates starting four hours following reactor shutdown. Less limiting, the initial heat removal provided by the RHR heat exchangers after a design basis loss-of-coolant accident (LOCA) occurs after the refueling water storage tank (RWST) inventory has been injected into the reactor. Under these conditions, the RHR heat exchangers are in service with a containment sump temperature well below the limiting condition. In addition to RHR heat exchangers, heat removal from containment following a LOCA is shared with the containment fan cooler units (CFCUs).

The installation of two heat exchangers ensures that the heat removal capacity of the system is only partially lost if one heat exchanger becomes inoperative.

The RHR heat exchangers are of the shell and U-tube type. Reactor coolant circulates through the tubes, while component cooling water circulates through the shell. The tubes and other surfaces in contact with reactor coolant are austenitic stainless steel or equivalent corrosion resistant material. The shell is carbon steel. The tubes are welded to the tubesheet to prevent leakage of reactor coolant.

5.5.6.2.1.3 Residual Heat Removal System Valves

Valves that perform a modulating function are equipped with two sets of packings and an intermediate leakoff connection that discharges to the drain header.

Some manual and motor-operated valves have backseats to facilitate repacking and to limit stem leakage when the valves are open. Leakoff connections are provided where required by valve size and fluid conditions.

5.5.6.2.2 System Operation

A discussion of RHR system operation during various reactor operating modes follows.

5.5.6.2.2.1 Reactor Startup

Generally, during cold shutdown, residual heat from the reactor core is being removed by the RHR system. The number of pumps and heat exchangers in service depends on the RHR load at the time.

At initiation of plant startup, the RCS is completely filled, and the pressurizer heaters are energized. The RHR pumps are operating, but a portion of the discharge is directed to the CVCS via a line that is connected to the common header downstream of the RHR heat exchanger. After the RCPs are running and the pressurizer steam bubble has formed, the RHR pumps are stopped. Indication of steam bubble formation is provided in the control room by the damping out of the RCS pressure fluctuations and by pressurizer level indication. The RHR system is then isolated from the RCS and the system pressure is controlled by normal letdown and the pressurizer spray and pressurizer heaters. An alternative to this startup process is a vacuum refill method of filling the RCS, described in Section 5.1.6.1. This may result in starting the RCPs after the pressurizer steam bubble is formed.

5.5.6.2.2.2 Power Generation and Hot Standby Operation

During power generation and hot standby operation, the RHR system is not in service but is aligned for operation as part of the ECCS.

5.5.6.2.2.3 Reactor Shutdown

The initial phase of reactor cooldown is accomplished by transferring heat from the RCS to the SPCS through the use of the steam generators.

When the reactor coolant nominal temperature and pressure are reduced to ≤ 350°F and ≤ 390 psig, respectively, the second phase of cooldown starts with the RHR system being placed in operation. Data and procedure reviews indicate it will require more than 4 hours after reactor shutdown to initiate RHR cooldown (Reference 12).

Startup of the RHR system includes a warmup period during which time reactor coolant flow through the heat exchangers is limited to minimize thermal shock. The rate of heat removal from the reactor coolant is manually controlled by regulating the coolant flow through the RHR heat exchangers. By adjusting the control valves downstream of the RHR heat exchangers, the mixed mean temperature of the return flows is controlled. Coincident with the manual adjustment, the heat exchanger bypass valve contained in the common bypass line is regulated to give the required total flow.

The reactor cooldown rate is limited by RCS equipment cooling rates based on allowable stress limits, as well as the operating temperature limits of the CCWS. As the reactor coolant temperature decreases, the reactor coolant flow through the RHR heat exchangers is increased.

As cooldown continues, the pressurizer is filled with water and the RCS is operated in the water-solid condition.

At this stage, pressure is controlled by regulating the charging flow rate and the alternate letdown rate to the CVCS from the RHR system.

After the reactor coolant pressure is reduced and the temperature is 140°F or lower, the RCS may be opened for refueling or maintenance.

5.5.6.2.2.4 Refueling

Several systems may be used during refueling to provide borated water from the refueling water storage tank to the refueling cavity. These include the RHR system, containment spray system, safety injection system, refueling water purification system, and the charging system (which includes the LHUTs). During this operation, the isolation valves to the refueling water storage tank are opened.

The reactor vessel head is removed. The refueling water is then pumped into the reactor vessel and into the refueling cavity through the open reactor vessel.

After the water level reaches the desired level, the refueling water storage tank supply valves are closed, and RHR operation continues.

During refueling, the RHR system is maintained in service with the number of pumps and heat exchangers in operation as required by the heat load.

Following refueling, the RHR pumps are used to drain the refueling cavity to the desired level below the top of the reactor vessel flange by pumping water from the RCS to the refueling water storage tank.

5.5.6.3 Design Evaluation

Design features of the RHR system ensure safe and reliable system performance as discussed below.

5.5.6.3.1 System Availability and Reliability

The system is provided with two RHR pumps and two RHR heat exchangers arranged in separate flowpaths. If one of the two pumps or one of the two heat exchangers is not operable, safe cooldown of the plant is not compromised, although the time required for cooldown is extended.

The two separate heat exchanger and pump flowpaths provide redundant capability of meeting the engineered safety function of the RHR system. The loss of one of these RHR system flowpaths would not negate the capability of the ECCS since the two flowpaths provide full redundancy for engineered safety requirements. The injection flow paths to loops one and two and to loops three and four are not redundant. Both of these flowpaths must be available with the heat exchanger discharge cross tie open to meet the engineered safety function of the RHR system.

To ensure reliability, the two RHR pumps are connected to two separate electrical buses so that each pump receives power from a different source. If a total loss of offsite power occurs while the system is in service, each bus is automatically transferred to a separate emergency diesel power supply.

5.5.6.3.2 Leakage Provisions and Flooding Protection

In the event of a LOCA, fission products may be recirculated via the RHR system exterior to the containment. If an RHR pump seal should fail, water would spill onto the floor of the pump compartment. Each RHR pump is in a separate, shielded compartment that drains to a sump containing two pumps that can pump the spillage to the waste disposal system. Each sump pump is capable of removing the spillage that would result from the failure of one RHR pump seal.

If flooding occurred, overflow from one pump compartment would drain through a 14 inch line to the pipe trench rather than flood the adjacent compartment. Added sump pump reliability is achieved by elevating the drive motors above the compartment overflow drain so that the pump motors would not be flooded. Gross leakage from the RHR system can be accommodated in the pump compartments, each of which has a capacity of 9450 gallons.

The RHR heat exchangers and pumps can also be isolated, in the event of gross leakage, through appropriate isolation valves. The isolation valves are operated manually by means of remote valve reach-rod operators located in a shielded valve gallery. Radiation levels in the vicinity of the recirculation loop are discussed in Chapter 12.

Recirculation loop component leakage is detected by means of a radiation monitor that samples the air in the ventilation exhaust ducts from each compartment. Supplemental radiation monitoring is provided by the plant vent gas monitoring system. Alarms in the control room alert the operator when the activity exceeds a preset level, and the capability exists to detect small leaks within a short period of time. Operation of the sump pumps is a less sensitive indication of leakage. Recirculation loop components that are potential sources of leaks are described in Table 5.5-11. The table lists conservative estimates of the maximum leakage expected from each leak source during normal operation. However, the design basis for sizing auxiliary building sump pumps that will be required to dispose of this leakage employs a conservative value of 35 gpm, as described above.

The consequences of a leak through an RHR heat exchanger to the CCWS are discussed in Section 9.2.

5.5.6.3.3 Overpressurization Protection

The inlet line to the RHR system is equipped with a pressure relief valve sized to relieve the combined flow of both charging pumps into the RCS and thus prevents exceeding the RHR system design pressure.

Each discharge line to the RCS is equipped with a pressure relief valve located in the ECCS (see Figure 3.2-9, Sheet 3). They relieve the maximum possible back-leakage through the valves separating the RHR system from the RCS.
The design of the RHR system includes the following features for valves on the inlet line between the high-pressure RCS and the lower pressure RHR system:

(1) To prevent both RHR suction line isolation valves from opening as a result of fire damage to electrical cables, ac power is removed from the operators of the indicated motor-operated valves for plant conditions during which the RHR system is isolated.

(2) The isolation valve adjoining the RCS is interlocked with a pressure signal to prevent its being opened whenever the RCS pressure is greater than a set value.

(3) The second isolation valve, the one adjoining the RHR system, is similarly interlocked with a pressure signal to prevent opening if RCS pressure is above a set value, and a pressurizer temperature signal to prevent opening if it exceeds a set value.

(4) The RHR suction valves interlock relays are powered from the SSPS output cabinets. To maintain the ability to open the RHR suction valve(s) when the SSPS output cabinet(s) are de-energized in Mode 6 or defueled, a jumper(s) is used to lock-in the RHR suction valve(s) open permissive.

This defeats the applicable RHR system overpressurization/temperature protection. Jumper installation is limited to Mode 6 and defueled only.

See Section 7.6 for a more complete discussion of the permissive interlocks on these isolation valves.

5.5.6.3.4 Shared Function

The safety function performed by the RHR system is not compromised by its normal function during plant cooldown. The valves associated with the RHR system are normally aligned to allow immediate use of this system in its engineered safety feature mode of operation. The system has been designed in such a manner that two redundant flow circuits are available, ensuring the availability of at least one train for safety purposes.

The normal plant cooldown function of the RHR system is accomplished through a suction line arrangement that is independent of any safety function. The normal cooldown return lines are arranged in parallel redundant circuits and are utilized also as the low-head safety injection lines to the RCS. Utilization of the same return circuits for the safety function as well as for normal cooldown, lends assurance to the proper functioning of these lines for safety purposes.

5.5.6.3.5 Radiological Considerations

The highest radiation levels experienced by the RHR system are those that would result from a LOCA. Following a LOCA, the RHR system is used as part of the ECCS. During the recirculation phase of emergency core cooling, the RHR system is designed to operate for up to a year pumping water from the containment sump, cooling it, and returning it to the containment to cool the core.

Since the RHR system is located outside the containment, except for some valves and piping, most of the system is not subjected to the high levels of radioactivity in the containment postaccident environment. To ensure continued operation of the RHR system components, the valve motor operators, the RHR pump motors, and the RHR pump seals have been evaluated for operation in postaccident environments. See Section 3.11 for details of the evaluation.

The operation of the RHR system does not involve a radiation hazard for the operators since the system is controlled remotely from the control room. If maintenance of the system is necessary, the portion of the system requiring maintenance is isolated by remotely operated valves and/or manual valves with stem extensions, which allow operation of the valves from a shielded location. The isolated piping is drained and flushed before maintenance is performed.

5.5.6.4 Tests and Inspections

Periodic visual inspections and preventive maintenance are conducted during plant operation according to normal industrial practice.

The instrumentation channels for the RHR pump flow instrumentation devices are calibrated on a nominal 36-month frequency.

The RHR pumps are tested by starting them periodically.

5.5.7 REACTOR COOLANT CLEANUP SYSTEM

The CVCS provides reactor coolant cleanup and is discussed in Section 9.3. The radiological considerations are discussed in Chapter 11.

5.5.8 MAIN STEAM LINE AND FEEDWATER PIPING

Main steam line piping is covered in Section 10.3. Feedwater piping is covered in Section 10.4.

5.5.9 PRESSURIZER

The pressurizer provides a point in the RCS where liquid and vapor are maintained at equilibrium temperature and pressure under saturated conditions for pressure control purposes.

During an insurge, the spray system, fed from two cold legs, condenses steam in the vessel to prevent the pressurizer pressure from reaching the setpoint of the power-operated relief valves. During an outsurge, flashing of water to steam and generation of steam by automatic actuation of the heaters helps keep the pressure above the low-pressure reactor trip setpoint. Heaters are also energized, on high water level during insurges, to heat the subcooled surge water entering the pressurizer from the reactor coolant loop.

5.5.9.1 Design Bases

The general configuration of the pressurizer is shown in Figure 5.5-8. The design data of the pressurizer are provided in Table 5.5-12. Codes and material requirements are provided in Section 5.2.

5.5.9.1.1 Pressurizer Surge Line

The surge line is sized to limit the pressure drop between the RCS and the safety valves with maximum allowable discharge flow from the safety valves. Overpressure of the RCS does not exceed 110 percent of the design pressure. The surge line and the thermal sleeves at each end are designed to withstand the thermal stresses resulting from volume surges, which occur during operation.

5.5.9.1.2 Pressurizer

The pressurizer volume (see Table 5.5-12) satisfies the following requirements:

(1) The combined saturated water volume and steam expansion volume is sufficient to provide the desired pressure response to system volume changes.

(2) The water volume is sufficient to prevent the heaters from being uncovered during a step load increase of 10 percent of full power.

(3) The steam volume is large enough to accommodate the surge resulting from the design step load reduction from full load with reactor control and steam dump without the water level reaching the high level reactor trip point.

(4) The steam volume is large enough to prevent water relief through the safety valves following a loss of load with the high water level initiating a reactor trip.

(5) The pressurizer does not empty following reactor and turbine trip.

(6) The emergency core cooling signal is not activated during reactor trip and turbine trip.

5.5.9.2 Design Description

The pressurizer is designed to accommodate positive and negative reactor coolant surges caused by RCS transients.

5.5.9.2.1 Pressurizer Surge Line

The pressurizer surge line connects the pressurizer to one reactor hot leg. The line enables continuous coolant volume/pressure adjustments between the RCS and the pressurizer.

5.5.9.2.2 Pressurizer

The pressurizer is a vertical, cylindrical vessel with essentially hemispherical top and bottom heads constructed of carbon steel, with austenitic stainless steel cladding on all surfaces exposed to the reactor coolant.

The surge line nozzle and removable electric heaters are installed in the bottom head. The heaters are removable for maintenance or replacement. A thermal sleeve is provided to minimize stresses in the surge line nozzle. A screen at the surge line nozzle and baffles in the lower section of the pressurizer prevent a cold insurge of water from flowing directly to the steam/water interface and assist mixing.

Spray line nozzles and relief and safety valve connections are located in the top head of the vessel. Spray flow is modulated by automatically controlled air-operated valves. The spray valves can also be operated manually by a switch in the control room.

A small continuous spray flow is provided through a manual bypass valve around the power-operated spray valves to ensure that the pressurizer liquid is homogeneous with the coolant and to prevent excessive cooling of the spray piping. During an outsurge from the pressurizer, flashing of water to steam and generating of steam by automatic actuation of the heaters keep the pressure above the minimum allowable limit. During an insurge from the RCS, the spray system, which is fed from two cold legs, condenses steam in the vessel to prevent the pressurizer pressure from reaching the setpoint of the power-operated relief valves for normal design transients. Heaters are energized on high water level during insurge to heat the subcooled surge water that enters the pressurizer from the reactor coolant loop. The heaters are further discussed in Section 8.3.

5.5.9.2.2.1 Pressurizer Support

The skirt-type support, shown in Figure 5.5-12, is attached to the lower head and extends for a full 360° around the vessel. The lower part of the skirt terminates in a bolting flange with bolt holes to secure the vessel to its structural steel framework. The skirt-type support is provided with ventilation holes around its upper perimeter to ensure free convection of ambient air past the heater plus connector ends for cooling.

5.5.9.2.2.2 Pressurizer Instrumentation

Refer to Chapter 7 for details of the instrumentation associated with pressurizer pressure, level, and temperature.

5.5.9.2.2.3 Spray Line Temperatures

Temperatures in the spray lines from two loops are measured and indicated. Alarms from these signals are actuated by low spray water temperature. Low temperature conditions indicate insufficient flow in the spray lines.

5.5.9.2.2.4 Safety and Relief Valve Discharge Temperatures

Temperatures in the pressurizer safety and relief valve discharge lines are measured and indicated. An increase in a discharge line temperature is an indication of leakage through the associated valve.

5.5.9.3 Design Evaluation

The pressurizer is designed to provide safe and reliable reactor coolant system pressure control.

5.5.9.3.1 System Pressure

RCS pressure is maintained by the steam bubble in the pressurizer. During normal operation, the pressurizer maintains RCS pressure by automatic operation of pressurizer heaters and spray. When the pressurizer is filled with water (i.e., near the end of the second phase of plant cooldown and during initial system heatup, if the vacuum refill method of filling the RCS is not used as described in section 5.1.6.1), RCS pressure is maintained by the RHR, CVCS, and LTOP systems. Safety limits are established to control the rate of temperature change in the pressurizer. These safety limits are administratively controlled to ensure that RCS pressure and temperature do not exceed the maximum transient value allowed under ASME B&PV Code, Section III, and thereby ensure continued integrity of the RCS boundary.

5.5.9.3.2 Pressurizer Performance

The pressurizer has a minimum free internal volume. The normal operating water volume at full load conditions is 60 percent of the minimum free internal vessel volume. Under part load conditions, the water volume in the vessel is reduced for proportional reductions in plant load to 22 percent of free vessel volume at zero power level. During shutdown modes 3, 4, and 5, the pressurizer water volume is controlled between ≥22 percent and ≤90 percent of the indicated level. Whenever the LTOP system is enabled as described in Section 5.2.2.4, the administrative controls and requirements of the Pressure and Temperature Limits Report (PTLR) take precedence. Pressurizer performance has been analyzed for the various plant operating transients discussed in Section 5.2.1. The design pressure was not exceeded with the pressurizer design parameters listed in Table 5.5-12.

5.5.9.3.3 Pressure Setpoints

The RCS design and operating pressure together with the safety, power relief, and pressurizer spray valves setpoints, and the protection system setpoint pressures are listed in Section 5.2.2. The design pressure allows for operating transient pressure changes. The selected design margin considers core thermal lag, coolant transport times and pressure drops, instrumentation and control response characteristics, and system relief valve characteristics.

5.5.9.3.4 Pressurizer Spray

Two separate, automatically controlled spray valves with remote-manual overrides are used to initiate pressurizer spray. In parallel with each spray valve is a manual throttle valve that permits a small, continuous flow through both spray lines to reduce thermal stresses and thermal shock when the spray valves open, and to help maintain uniform water chemistry and temperature in the pressurizer. Spray flow is not normally initiated if the temperature difference between the pressurizer and spray fluid exceeds 320°F. Temperature sensors with low alarms are provided in each spray line to alert the operator to insufficient bypass flow. The layout of the common spray line piping to the pressurizer forms a water seal that prevents the steam buildup back to the control valves. The spray rate is selected to prevent the pressurizer pressure from reaching the operating setpoint of the power relief valves during a step reduction in power level of 10 percent of full load.

The pressurizer spray lines and valves are large enough to provide adequate spray using as the driving force the differential pressure between the surge line connection in the hot leg and the spray line connection in the cold leg. The spray line inlet connections extend into the cold leg piping in the form of a scoop so that the velocity head of the reactor coolant loop flow adds to the spray driving force. The spray valves and spray line connections are arranged so that the spray will operate when one RCP is not operating. The line may also be used to assist in equalizing the boron concentration between the reactor coolant loops and the pressurizer.

A flowpath from the CVCS to the pressurizer spray line is also provided. This additional facility provides auxiliary spray to the vapor space of the pressurizer during cooldown if the RCPs are not operating. The thermal sleeves on the pressurizer spray connection and the spray piping are designed to withstand the thermal stresses resulting from the introduction of cold spray water.

5.5.9.3.5 Pressurizer Design Analysis

The occurrences for pressurizer design cycle analysis are defined as follows:

(1) For design purposes, the temperature in the pressurizer vessel is always assumed to equal saturation temperature for the existing RCS pressure, except in the pressurizer steam space subsequent to a pressure increase.

In this case, the temperature of the steam space will exceed the saturation temperature since an isentropic compression of the steam is assumed.

(2) The temperature shock on the spray nozzle is assumed to equal the temperature of the nozzle minus the cold leg temperature, and the temperature shock on the surge nozzle is assumed to equal the pressurizer water space temperature minus the hot leg temperature.

(3) Pressurizer spray is assumed to be initiated instantaneously reaching its design value as soon as the RCS pressure increases 40 psi above the nominal operating pressure. Spray is assumed to be terminated as soon as the RCS pressure falls below the normal operating pressure-plus 40 psi-level.

(4) Unless otherwise noted, pressurizer spray is assumed to be initiated once during each transient condition. The pressurizer surge nozzle is also assumed to be subject to one temperature transient per transient condition, unless otherwise noted.

(5) At the end of each transient, except the faulted conditions, the RCS is assumed to return to a load condition consistent with the plant heatup transient.

(6) Temperature changes occurring as a result of pressurizer spray are assumed to be instantaneous. Temperature changes occurring on the surge nozzle are also assumed to be instantaneous.

(7) Whenever spray is initiated in the pressurizer, the pressurizer water level is assumed to be at the no-load level.

5.5.9.4 Tests and Inspections

The pressurizer is designed and constructed in accordance with ASME B&PV Code, Section III, 1965 Edition with addenda through the summer of 1966. Peripheral support rings are furnished for the insulation modules. The pressurizer quality assurance program is given in Table 5.5-13.

5.5.10 PRESSURIZER RELIEF TANK

The pressurizer relief tank (PRT) accommodates the pressurizer and other relief valve discharges.

5.5.10.1 Design Bases

Design data for the PRT are provided in Table 5.5-14. Codes and materials applicable to the tank are discussed in Section 5.2.

The tank design is based on the requirement to condense and cool a discharge of pressurizer steam equal to 110 percent of the volume above the full power pressurizer water level setpoint. The tank is not designed to accept a continuous discharge from the pressurizer. The volume of water in the tank (see Table 5.1-1) is capable of absorbing the heat from the assumed discharge, with an initial temperature of 120°F and increasing to a final temperature of 200°F. The tank is cooled, when necessary, by manual spraying of cool water into the tank and draining the warm mixture to the waste disposal system (WDS).

5.5.10.2 Design Description

The PRT condenses and cools the discharge from the pressurizer safety and relief valves. Discharge from smaller relief valves located inside and outside the containment is also piped to the relief tank. The tank normally contains water and a predominantly nitrogen or hydrogen (temporary modification (TMOD) for Unit 2 only per TMOD 60076719) atmosphere. The atmosphere inside the tank is controlled to avoid a combustible mixture. Provision is made to permit the gas in the tank to be periodically monitored for hydrogen and/or oxygen concentrations. Through its connection to the WDS, the PRT provides a means for removing any noncondensable gases from the RCS that might collect in the pressurizer vessel.

Steam is discharged through a sparger pipe under the water level. This condenses and cools the steam by mixing it with water that is near ambient temperature. The tank is equipped with an internal spray and a drain that are used to cool the tank following a discharge. A flanged nozzle is provided on the tank for the pressurizer discharge line connection. The tank is protected against a discharge exceeding its design pressure by two rupture disks that discharge into the reactor containment.

5.5.10.2.1 Pressurizer Relief Tank Pressure

The PRT pressure transmitter supplies a signal for an indicator with a high-pressure alarm. Also, the PRT pressure transmitter provides a signal to close the air-operated valve to the WDS vent header on high pressure.

5.5.10.2.2 Pressurizer Relief Tank Level

The PRT level transmitter supplies a signal for an indicator with high and low level alarms.

5.5.10.2.3 Pressurizer Relief Tank Water Temperature

The temperature of the water in the PRT is indicated in the control room. An alarm actuated by high temperature informs the operator that cooling of the tank contents is required.

5.5.10.3 Design Evaluation

The volume of water in the tank is capable of absorbing heat from the pressurizer discharge during a step load decrease of 10 percent. Water temperature in the tank is maintained at the nominal containment temperature.

The rupture disks on the relief tank have a relief capacity equal to the combined capacity of the pressurizer safety valves. The tank design pressure is twice the calculated pressure resulting from the maximum design safety valve discharge described above. The tank and rupture disks holders are also designed for full vacuum to prevent tank collapse if the contents cool following a discharge without nitrogen being added. The discharge piping from the safety and relief valves to the PRT is sufficiently large to prevent back pressure at the safety valves from exceeding 20 percent of the setpoint pressure at full flow.

5.5.11 VALVES

The safety-related function of the valves within the reactor coolant pressure boundary listed on Table 5.2-9 is to act as pressure-retaining components and leaktight barriers during normal plant operation and accidents.

5.5.11.1 Design Bases

As noted in Section 5.2, all RCS valves including those in connected systems, out to and including the second isolation valve, are normally closed or capable of automatic or remote manual closure. Valve closure time must be such that for any postulated component failure outside the system boundary, the loss of reactor coolant event would not prevent orderly reactor shutdown and cooldown assuming makeup is provided by normal makeup systems. Normal makeup systems are those systems normally used to maintain reactor coolant inventory under startup, hot standby, operation, or cooldown conditions. If the second of two normally open check valves is considered as the pressure boundary, means are provided to periodically assess back-flow leakage of the first valve when closed. For a check valve to qualify as the system pressure boundary, it must be located inside the containment.

Reactor coolant pressure boundary valves are listed in Table 5.2-9. Materials of construction are specified to minimize corrosion/erosion and to ensure compatibility with the environment. Design parameters are provided in Table 5.5-15.

Valves are designed and fabricated in accordance with ASA B16.5, MSS-SP-66, and ASME B&PV Code, Section III, 1968 Edition. To the extent practicable, valve leakage is minimized by design.

5.5.11.2 Design Description

All valves in the RCS that are in contact with the coolant are constructed primarily of stainless steel. Other materials in contact with the coolant, such as for hard surfacing and packing, are special materials.

All RCS pressure boundary manual and motor-operated valves that are 3 inches and larger are provided with double-packed stuffing boxes and stem intermediate lantern gland leakoff connections. Some of the throttling control valves, regardless of size, are provided with double-packed stuffing boxes and with stem leakoff connections. All leakoff connections are piped to a closed collection system. Leakage to the atmosphere is essentially zero for these valves.

Gate valves are either wedge design or parallel disk and are essentially straight through. The wedge may be either split or solid. All gate valves have a backseat, outside screw and yoke. Globe valves, "T" and "Y" style, are full-ported with outside screw and yoke construction. Ball valves are V-notch design for equal percentage flow characteristics. Check valves are spring-loaded lift piston types for sizes 2 inches and smaller, and swing type for sizes 2-1/2 inches and larger. All check valves containing radioactive fluid are stainless steel and do not have body penetrations other than the inlet, outlet, and bonnet. The check hinge is serviced through the bonnet. The RHR heat exchanger outlet check valves have hinge pin covers.

Each accumulator check valve is designed with a low-pressure drop configuration with all operating parts contained within the body. The disk has unlimited rotation to provide a change of seating surface and alignment after each valve opening.

Valves at the RHR system interface are provided with interlocks that meet the intent of IEEE-Std-279 (Reference 1). These interlocks are discussed in detail in Section 5.5.6 above and Section 7.6.

5.5.11.3 Design Evaluation

Stress analysis of the reactor coolant loop/support system, discussed in Sections 3.7 and 5.2, ensure acceptable stresses for all valves in the reactor coolant pressure boundary under every condition expected. Reactor coolant chemistry parameters are specified to minimize corrosion. Periodic analyses of coolant chemical composition, discussed in the DCPP Equipment Control Guidelines, ensure that the reactor coolant meets these specifications. The upper-limit coolant velocity of about 50 feet per second minimizes erosion. Valve leakage is minimized by design features as discussed above.

5.5.11.4 Tests and Inspections

Hydrostatic, seat leakage, and operation tests are performed on RCS boundary valves in accordance with ASME B&PV Code, Section XI, Subsection IWV, as required by the Technical Specifications and 10 CFR 50.55a. No further test program is considered necessary. Inservice inspection is discussed in Section 5.2.8.

There are no full-penetration welds within valve body walls. Valves are accessible for disassembly and internal visual inspection.

5.5.12 SAFETY AND RELIEF VALVES

The pressurizer is equipped with safety and relief valves for overpressure protection and control. Their use is described in Section 5.2.2.

5.5.12.1 Design Bases

The combined capacity of the pressurizer safety valves is designed to accommodate the maximum surge resulting from complete loss of load. This objective is met without reactor trip or any operator action, provided the steam safety valves open as designed when steam pressure reaches the steam-side safety valve setting. The power-operated pressurizer relief valves are designed to limit pressurizer pressure to a value below the fixed high-pressure reactor trip setpoint.

5.5.12.2 Design Description

The pressurizer safety valves are totally enclosed pop type. The valves are spring loaded, self-actuated, and have back pressure compensation features.

The pressurizer is equipped with three power-operated relief valves (PORVs), each with a corresponding PORV block valve. The PORVs are air-operated and actuated by 125 Vdc solenoid valves that are energized-to-open, spring-to-close. The circuits to the solenoid valves are supplied with redundant interlocks that prevent energization below normal operating pressure. Control power is vital 125 Vdc from the station batteries (see Section 8.3.2). Indication is powered from 120 V instrument ac. The PORV block valves are shown schematically in Figure 3.2-7. Each of the three valves is powered from a separate 480 V vital bus.

Positive indication of PORV position is obtained by a direct, stem-mounted indicator, which mechanically actuates limit switches at the full-open and full-closed valve stem positions. Acoustic monitors located in the downstream piping provide indication of safety valve positions. The acoustic position indication is both seismically and environmentally qualified. Sections 3.10 and 3.11 discuss equipment qualification. An alarm is provided in the control room to signal if a PORV is not fully closed.

The 6-inch pipes connecting the pressurizer nozzles to their respective safety valves are shaped in the form of a loop seal. This arrangement is necessary to accommodate thermal movement and the collection of condensate for the water loop seal. However, the pressurizer safety valves have been converted from water-seated to steam-seated, and the water loop seal was eliminated by continuously draining the condensate back to the pressurizer liquid space. With the elimination of the water loop seal, hydraulic loading due to the presence of water in the loop seal is no longer a concern.

The relief valves are quick-opening, operated automatically or by remote control. Remotely operated stop valves are provided to isolate the PORVs if excessive leakage develops.

Temperatures in the pressurizer safety and relief valve discharge lines are measured and indicated. An increase in a discharge line temperature is an indication of leakage through the associated valve. Design parameters for the pressurizer spray control, safety, and power relief valves are provided in Table 5.5-16.

5.5.12.3 Design Evaluation

The pressurizer safety valves prevent RCS pressure from exceeding 110 percent of design pressure. The pressurizer power relief valves prevent actuation of the fixed high-pressure trip for all design transients up to and including the design step load decrease, with steam dump but without reactor trip. The relief valves also limit undesirable opening of the spring-loaded safety valves.

The mounting of these valves is designed to accommodate the magnitude and direction of thrust of the safety valve discharges. In addition, the physical layout is such as to limit the piping reaction loads on these valves. The adequacy of the design has been checked by Westinghouse.

5.5.12.4 Tests and Inspections

Safety and relief valves, as well as the corresponding block valves, were tested on a prototypical basis to demonstrate their ability to open and close under expected operating conditions for design basis transients and accidents. Qualification criteria include provisions for the associated circuitry, piping, and supports as well as the valves themselves.

In addition to the requirements of the Technical Specifications, each pressurizer power operated relief valve will be demonstrated operable at least once per 24 months by performing a channel calibration of the actuation instrumentation. This frequency interval is subject to SR 3.0.2 of the Technical Specifications.

The only other testing performed on safety and relief valves, other than operational tests and inspections, is the required hydrostatic, seat leakage, and operation tests. These

tests ensure that the valves will operate as designed. No further test program is considered necessary.

There are no full-penetration welds within the valve body walls. Valves are accessible for disassembly and internal visual inspection.

5.5.13 COMPONENT SUPPORTS

RCS component supports are designed to maintain safe and reliable component and system operation.

5.5.13.1 Design Bases

Component supports allow virtually unrestrained lateral thermal movement of the loop during plant operation and provide restraint to the loops and components during accident conditions. The loading combinations and stress limits are discussed in Section 5.2 and listed in Table 5.2-8. The design maintains the integrity of the RCS boundary for normal and accident conditions and satisfies the requirements of the piping code. Results of piping and supports stress evaluation are presented in Sections 5.2.1.10.4 and 5.2.1.10.5, respectively.

5.5.13.2 Design Description

The support structures for the steam generator lower supports and the RCP supports are welded structural steel sections. The steam generator upper supports consist of a steel ring with lateral bumpers and four snubbers per steam generator. Linear-type structures (tension and compression struts, columns, and beams) are used in all cases except for the reactor vessel supports, which consist of a closed, steel box ring-type structure.

Attachments to the supported equipment are the nonintegral type that are bolted to or bear against the components. The supports-to-concrete attachments are either embedded anchor bolts or fabricated assemblies. The supports permit virtually unrestrained thermal growth of the supported systems but restrain vertical, lateral, and rotational movement resulting from seismic and pipe break loadings. This is accomplished using spherical bushings in the columns for vertical support and structural frames, hydraulic snubbers, and struts for lateral support.

The principal support material is welded and bolted structural steel that is subjected to Charpy V-notch impact tests in accordance with ASTM Standard Method A370. Material properties are discussed in Section 5.2.3. The supports for the various components are described in the following paragraphs.

5.5.13.2.1 Reactor Support

The reactor is supported on a massive concrete structure that also serves as a biological shield. Forces are transmitted from the reactor to the concrete support structure by an octagonal closed steel box that provides support at four of the eight reactor nozzles as shown in Figure 5.5-9. The bearing plates below the reactor nozzle support shoes contain cooling water passages to control the temperature of the supporting concrete. The reactor support resists seismic loads and coolant loop (hot and cold leg) piping reactions. The reactor support system allows the reactor to expand radially over the supports but resists translational and torsional movement by the combined tangential restraining action of each nozzle support.

5.5.13.2.2 Steam Generator Supports

The steam generators are supported by two independent upper and lower structural systems as shown in Figures 5.5-10 and 5.5-11 and described below:

(1) Vertical Supports

Four vertical pipe columns for each steam generator provide full vertical restraint while allowing free movement radially with respect to the reactor. These are bolted at the top to the steam generator and at the bottom to the concrete structure. Spherical ball bushings at the top and bottom of each of column allow unrestrained lateral movement of the steam generator during heatup and cooldown.

(2) Horizontal Supports

Horizontal supports restrain the steam generators at two levels:

(a) At elevation 140 feet, where the reinforced concrete slab acts as a rigid diaphragm supporting horizontal forces (predominantly seismic) generated at this level.

(b) At elevation 111 feet (the channel head), where support pads are provided on the vessel.

The horizontal supports permit slow radial movement due to thermal expansion while maintaining a positive restraint against sudden loads such as an earthquake or pipe rupture. This is accomplished through the use of four 1300 kip rated hydraulic snubbers at elevation 140 feet attached to a ring shimmed to the steam generator at 20 locations around the circumference. Each hydraulic snubber was tested to 1-1/3 times the rated load and is capable of supporting twice the rated load at yield.

The support pads at elevation 111 feet are keyed and shimmed to a sliding frame that is sandwiched between two rigid stationary frames anchored to massive concrete walls.

The sliding frame is provided with a bumper system to transfer load to the stationary frames. The frame system for each of two sets of steam generators is interconnected so that pipe rupture loads in one loop are distributed between two frame systems.

5.5.13.2.3 Reactor Coolant Pump Supports

The RCPs are supported on structural steel frames restrained horizontally at elevation 106 feet 5-1/2 inches by a system of steel struts anchored to rigid concrete walls as shown in Figures 5.5-10 and 5.5-11. Thermal expansion is permitted by low friction support pads and oversized mounting holes. The support pads are keyed and shimmed to the frame. This support system resists vertical and lateral loads due to all plant operating conditions.

5.5.13.2.4 Pressurizer Support

The pressurizer is bolted to a structural steel frame, providing vertical and lateral support at its base at elevation 113 feet 2 inches as shown in Figure 5.5-12. Additional lateral support is provided by rigid guides embedded in the concrete slab near the center of gravity of the vessel at elevation 139 feet, in conjunction with lugs projecting from the vessel shell. The upper support allows the pressurizer to expand radially and vertically, but resists torsional and translational horizontal movements.

5.5.13.2.5 Crossover Pipe Restraint

The crossover leg is restrained at elevation 96 feet by a system of two sets of steel bumpers located at the elbows of the pipe as shown in Figure 5.5-10. Each set consists of a bumper strapped to the pipe, which bears on a rigid bumper anchored to a concrete pad at elevation 94 feet. The restraint resists blowdown loads from a rupture of the crossover pipe. The crossover pipe restraints were deactivated by removing shims. The bumpers strapped to the pipe and the rigid bumpers were left intact and are abandoned in place.

5.5.13.3 Design Evaluation

Detailed evaluation ensures the design adequacy and structural integrity of the reactor coolant loop and the primary equipment supports system. The detailed evaluation is made by comparing the analytical results with established criteria for acceptability. Structural analyses are performed to demonstrate design adequacy for safety and reliability of the plant in case of a large or small seismic disturbance and/or LOCA conditions. However, with the acceptance of the DCPP leak-before-break analysis by the NRC (Reference 10), dynamic LOCA loads resulting from pipe rupture events in the main reactor coolant loop piping no longer have to be considered in the design basis structural analyses and included in the loading combinations; only the LOCA loads resulting from RCS branch line breaks have to be considered (see Section 3.6.2.1.1.1). Since the breaks postulated for the original analyses are more severe than the breaks now required to be considered, the original analyses are conservative. Loads (thermal,

weight and pressure) that the system is expected to encounter often during its lifetime are applied and stresses are compared to allowable values, as described in Section 5.2. The stress limits for component supports are provided in Table 5.2-8.

For the RCL piping reanalysis performed for the RSGs in Unit 2, thrust forces and blowdown loads were determined for RCS branch line breaks identified in Section 5.2.1.10.1.

5.5.14 REACTOR VESSEL HEAD VENT SYSTEM

5.5.14.1 Design Bases

The basic function of the reactor vessel head vent system (RVHVS) is to remove noncondensable gases from the reactor vessel head. This system is designed to mitigate a possible condition of inadequate core cooling or impaired natural circulation resulting from the accumulation of noncondensable gases in the RCS. The design of the RVHVS is in accordance with the requirements of NUREG-0578 (Reference 7) and the subsequent definitions and clarifications in NUREG-0737 (Reference 8).

5.5.14.2 Design Description

The RVHVS removes noncondensable gases or steam from the RCS via remote-manual operations from the control room. The system discharges at the reactor vessel head, into a well-ventilated area of the containment, to ensure optimum dilution of combustible gases. The RVHVS is designed to vent a volume of hydrogen at system design pressure and temperature approximately equivalent to one-half of the RCS volume in 1 hour.

The flow diagram of the RVHVS is shown in Figure 5.5-14. The RVHVS consists of two parallel flowpaths with redundant isolation valves in each flowpath. The venting operation uses only one of these flowpaths at any time. Equipment design parameters are listed in Table 5.5-17. Isolation valve limit switch position indication is provided in the control room.

The active portion of the system consists of four 1 inch open/close solenoid operated isolation valves connected to a dedicated RVCH penetration, located near the center of the reactor vessel head. The use of two valves in series in each flowpath minimizes the possibility of reactor coolant pressure boundary leakage. The isolation valves in one flowpath are powered by one vital power supply, and the valves in the second flowpath are powered by a second vital power supply. The isolation valves are fail closed, normally closed, active valves. Device qualification is described in Sections 3.10 and 3.11.

If one single active failure prevents a venting operation through one flowpath, the redundant path is available for venting. Similarly, the two isolation valves in each flowpath provide a single failure method of isolating the venting system. With

two valves in series, the failure of any one valve or power supply will not inadvertently open a vent path. These valves are energized-to-open, spring-to-close. Thus, the combination of safety-grade train assignments and valve failure modes will not prevent vessel head venting or venting isolation with any single active failure.

The RVHVS has two normally deenergized valves in series in each flowpath. This arrangement eliminates the possibility of a spuriously opened flowpath due to the spurious movement of one valve. As such, power lockout to any valve is not considered necessary.

The RVHCS is connected to a reactor vessel closure head vent nozzle penetration. The reactor vent piping utilizes a 3/8-inch orifice prior to branching into two redundant flowpaths. The system is designed to limit the blowdown from a break downstream of the orifices such that loss through a severance of one of these lines is sufficiently small to allow operators to execute an orderly plant shutdown.

A break of the RVHVS line upstream of the orifices would result in a small LOCA of not greater than 1 inch diameter. Such a break is similar to those analyzed in WCAP-9600 (Reference 2). Since a break in the head vent line would behave similarly to the hot leg break case presented in WCAP-9600, the results presented therein are applicable to a RVHVS line break. This postulated vent line break results, therefore, in no calculated core uncovery.

All piping and equipment from the housing to second isolation valve are designed and fabricated in accordance with ASME B&PV Code, Section III, Class 1 requirements. The remainder of the piping is nonsafety related.

5.5.14.3 Supports

The vent system piping is supported to ensure that the resulting loads and stresses on the piping and on the vent connection to the housing are acceptable. All supports and support structures comply with the requirements of the ASME B&PV Code, Section III, Subsection NF.

5.5.15 REFERENCES

1. IEEE-Std-279, Criteria for Protection Systems for Nuclear Power Generating Station, 1971.

2. Report on Small Break Accidents for Westinghouse NSSS System, WCAP-9600, June 1979.

3. Deleted in Revision 18.

4. Deleted in Revision 19.

5. NEI 97-06, Steam Generator Program Guidelines, latest revision.

6. Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.

7. Nuclear Regulatory Commission, TMI Short-Term Lessons Learned Requirements, NUREG-0578, 1979.

8. Nuclear Regulatory Commission, Clarification of TMI Plan Requirements, NUREG-0737, November 1980.

9. Deleted in Revision 19.

10. Letter from Sheri R. Peterson (NRC) to Gregory M. Rueger (PG&E), "Leak-Before-Break Evaluation of Reactor Coolant System Piping for DCPP Units 1 and 2," March 2, 1993,

11. Deleted in Revision 19.

12. Westinghouse Calculation SE/FSE-C-PGE-0013, "RHRS Cooldown Performance at Uprated Conditions," Rev. 0, June 5, 1996.

5.5.16 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

5.6 INSTRUMENTATION REQUIREMENTS

5.6.1 PRESSURIZER AND COOLANT LOOPS

The pressurizer and each of the reactor coolant loops are monitored by process control instrumentation. This instrumentation provides the input signals to the following control and protection functions that are described in Chapter 7:

(1) Reactor trip (Section 7.2)

(2) Engineered safety features actuation (Sections 7.3 and 7.6)

(3) Nonsafety related systems (Section 7.7)

The reactor coolant system (RCS) design and operating pressure together with the safety, power relief and pressurizer spray valves nominal setpoints, and the protection system nominal setpoint pressures are listed in Table 5.2-10. The design pressure allows for operating transient pressure changes. The selected design margin considers core thermal lag, coolant transport times and pressure drops, instrumentation and control response characteristics, and system relief valve characteristics.

To meet the requirements of NUREG-0578[(1)] for supplementing existing instrumentation to unambiguously indicate inadequate core cooling, a subcooling meter and a reactor vessel water level measurement are provided. Inadequate core cooling detection instrumentation is discussed in more detail in Section 7.5.2.2. The subcooling meters are a subset of RVLIS and provide the operator with on-line indication of the core coolant temperature and pressure margins to saturation conditions. The reactor vessel water level is determined by the reactor vessel head level system by measuring the pressure drop between the upper and lower plena in the vessel.

Each subcooling meter (train A or B) has wide range temperature inputs from two each of the RCS hot legs and the hottest incore thermocouple associated with that train. Two pressure measurements (one per train) are input from the hot legs. The subcooling meter displays consist of a digital meter on the main control board (train B), a recorder to provide a redundant display (train A/PAM1), and the indication on each RVLIS display (PAM3 and PAM4). All the indications provide the temperature margin to saturation of the RCS. In addition to temperature margin, the RVLIS displays also provide the pressure margin.

The reactor vessel level measurement is used in combination with the existing core exit thermocouples and the subcooling meter. Differential pressure between the top of the reactor vessel and the bottom of the reactor vessel on two narrow-range and two wide-range instruments is measured. The system functions as follows: with the reactor coolant pumps off, the pressure drop between the top and the bottom of the vessel indicates the collapsed liquid level (the equivalent liquid level without voids in the two-phase region) in the vessel. This is read on the narrow-range instrument in terms

of feet of liquid. With the reactor coolant pumps running, the pressure drop (in feet of liquid) from the top to the bottom of the vessel when compared to the measurement with the same combination of running pumps during normal, single phase RCS condition, provides an approximate indication of the void fraction in the vessel. This is read on the wide-range instrument as percent of full flow differential pressure with the vessel filled with water.

5.6.2 RESIDUAL HEAT REMOVAL (RHR) SYSTEM

Process control instrumentation for the RHR system is provided for the following purposes:

(1) Furnish input signals for monitoring and/or alarming purposes for:

   (a) Temperature indications

   (b) Pressure indications

   (c) Flow indications

(2) Furnish input signals for control purposes of such processes as follows:

   (a) Control valve in the RHR pump bypass line so that it opens at flows below a preset limit and closes at flows above a preset limit

   (b) RHR isolation valves control circuitry (See Section 7.6 for the description of the interlocks)

   (c) Control valve in the RHR heat exchanger bypass line to control temperature of reactor coolant returning to reactor loops during plant cooldown

   (d) RHR pump circuitry for starting RHR pumps on "S" signal

   (e) RHR pump trip on low reactor water storage tank level

5.6.3 REFERENCES

1. NUREG-0578, TMI Short-Term Lessons Learned Requirements, USNRC, 1979.

TABLE 5.1-1

SYSTEM DESIGN AND OPERATING PARAMETERS[c]

	Unit 1	Unit 2
Plant design life, years[a]	50	50
Nominal operating pressure, psig	2,235	2,235
Total system volume, including pressurizer and surge line, ft^3	12,064 +/- 100	12,169 +/- 100
System liquid volume, including pressurizer water, ft^3 (nominal)	11,082 - 11,337[f]	11,187 - 11,448[d]
Total heat output , Btu/hr	11,687 x10^6	11,687x 10^6
System thermal and hydraulic data [f]		
Minimum Measured Flow (RCS total flow), gpm	359,200	362,500
Core Bypass Flow, %	7.5	9.0
Mechanical Design Flow (MDF), gpm/loop	99,600	102,000
Thermal Design Flow, lb/hr	132.9 x 10^6 – 135.1 x 10^6 [f]	134.0 x 10^6 – 136.3 x 10^6 [d]
Reactor vessel		
Inlet temp, °F	531.7 - 544.5[f]	531.9 - 545.1[d]
Outlet temp, °F	598.3 - 610.1[f]	598.1 - 610.1[d]
Steam generator		
Inlet temp, °F	598.3 - 610.1[f]	598.1 - 610.1[d]
Outlet temp, °F	531.4 - 544.2[f]	531.6 - 544.8[d]
Design Fouling Factor, hr-ft^2-°F/BTU	0.00018	0.00018
Reactor coolant pump		
Inlet temp, °F	531.4 - 544.2[f]	531.6 - 544.8[d]
Outlet temp, °F	531.7 - 544.5[f]	531.9 - 545.1[d]
Steam pressure, psia	730 - 821[f] [g]	731 - 825[d] [h]

TABLE 5.1-1 Sheet 2 of 2

Steam flow, lb/hr (total)	14.64×10^6 – 14.89×10^6 (f)(g)	14.64×10^6 - 14.90×10^6 (d)(h)
Feedwater inlet temp, °F	425.0 - 435.0	425.0 - 435.0
Pressurizer spray rate, maximum, gpm	800	800
Pressurizer heater capacity, kW(b)	1800	1800
Pressurizer relief tank volume, ft^3	1800	1800
Best Estimate Operating Data(c)		
NSSS Power, MWt	3425	3425
(a) Primary System Flows and ΔP(e):		
Reactor Vessel Avg. Temp., °F	565.0	565.0
RCS Flow, gpm/loop	94,900	95,500
Reactor Coolant Pump developed head, ft	282.3	266.6
Component ΔP, psia		
Reactor Vessel ΔP, psi	48.2	42.4~~6~~
Steam Generator ΔP, psi	38.5	38.9
RCS Piping ΔP, psi	7.2	7.3
(b) Secondary Side Performance Parameters:		
Reactor Vessel Avg. Temp., °F	577.3	577.6
RCS Flow, gpm/loop	94,900	95,500
Steam Generators		
Steam pressure, psia	874	878
Steam flow, lb/hr x 10^6	14.920	14.924
Best Estimate Fouling Factor, hr-ft^2-°F/BTU	0.00006	0.00006

(a) Although DCPP useful life is expected to be 40 years, the RCS design conservatively assumes that integrity must be maintained during 50 years.
(b) See Table 5.5-12.
(c) 0% SGTP, NSSS rated power
(d) Design value corresponding to full power, 565.0 - 577.6°F vessel average temperature.
(e) Best Estimate calculations were performed to maximize Best Estimate Flow and system/component pressure drops.
(f) Design value corresponding to full power, 565.0 - 577.3°F vessel average coolant temperature.
(g) If a high steam pressure is more limiting for analysis purposes, a greater steam pressure of 881 psia, steam temperature of 529.4°F, and steam flow of 14.93×10^6 lb/hr total should be assumed for Unit 1. This is to envelop the possibility that the plant could operate with better than expected steam generator performance.
(h) If a high steam pressure is more limiting for analysis purposes, a greater steam pressure of 885 psia, steam temperature of 530.0°F, and steam flow of 14.93×10^6 lb/hr total should be assumed for Unit 2. This is to envelop the possibility that the plant could operate with better than expected steam generator performance.

TABLE 5.2-1 Sheet 1 of 2

ASME CODE CASES
FOR WESTINGHOUSE PWR CLASS A COMPONENTS

Code Case[b]	Title
1141	Foreign Produced Steel
1332	Requirements for Steel Forgings
1334	Requirements for Corrosion Resistant Steel Bars
1335	Requirements for Bolting Material
1337	Requirements for Special Type 403 Modified Forgings or Bars (Section III)
1344	Requirements for Nickel-Chromium Age-Hardenable Alloys
1345	Requirements for Nickel-Molybdenum-Chromium-Iron Alloys
1355	Electroslag Welding
1358[a]	High Yield Strength Steel for Section III Construction
1360[a]	Explosive Welding
1361	Socket Welds
1364	Ultrasonic Transducers SA-435 (Section II)
1384	Requirements for Precipitation Hardening Alloy Bars & Forgings
1388	Requirements for Stainless Steel – Precipitation Hardening
1390	Requirements for Nickel-Chromium Age-Hardenable Alloys for Bolting
1395	SA-508, Class 2 Forgings – Modified Manganese Content
1401	Welding Repair to Cladding
1407	Time of Examination
1412[a]	Modified High Yield Strength Steel
1414[a]	High Yield Strength Cr-Mo
1423	Plate: Wrought Type 304 with Nitrogen Added
1433	Forgings: SA-387
1434	Class BN Steel Casting (Postweld Heat Treatment for SA-487)
1448	Use of Case Interpretations of ANSI B31 Code for Pressure Piping
1456	Substitution of Ultrasonic Examination
1459	Welding Repairs to Base Metal
1461	Electron Beam Welding
1470	External Pressure Charts for Low Alloy Steel
1471	Vacuum Electron Beam Welding of Tube Sheet Joints
1474	Integrally Finned Tubes (Section III)
1477	B-31.7, ANSI 1970 Addenda
N-20-4	SB-163 Nickel-Chromium-Iron Tubing at a Specified Minimum Yield Strength of 40,000 psi
1487	Evaluation of Nuclear Piping for Faulted Conditions
1492	Postweld Heat Treatment
1493	Postweld Heat Treatment
1494	Weld Procedure Qualification Test
1498	SA-508, Class 2, Minimum Tempering Temperature
1501	Use of SA-453 Bolts in Service Below 800 degrees F without Stress Rupture Tests
1504	Electrical and Mechanical Penetration Assemblies
1505[a]	Use of 26 Cr, 1 Mo Steel
1508	Allowable Stresses, Design Stress Intensity and/or Yield Strength Values
1514	Fracture Toughness Requirements
1515	Ultrasonic Examination of Ring Forgings for Shell Section of Section III – Class I Vessels
1516	Welding of Non-Integral Seats in Valves for Section III Application
1517	Material Used in Pipe Fittings
1519	Use of A-105-71 in lieu of SA-105
1521	Use of H. Grades SA-240, SA-479, SA-336, and SA-358

TABLE 5.2-1 Sheet 2 of 2

Code Case[b]	Title
1522	ASTM Material Specifications
1523	Plate Steel Refined by Electroslag Remelting
1524	Piping 2" NPS and Smaller
1525	Pipe Descaled by Other Than Pickling
1526	Elimination of Surface Defects
1527	Integrally Finned Tubes
1528	High Strength SA-508 Class 2 and SA-541 Class 2 Forgings for Section III Construction of Class I Components
1529	Material for Instrument Line Fittings
1531	Electrical Penetrations, Special Alloys for Electrical Penetrations Seals
1534	Overpressurization of Valves
1535	Hydrostatic Test of Class I Nuclear Valves
1539	Metal Bellows and Metal Diaphragm Steam Sealed Valves, Class 1, 2, and 3
1542	Requirements for Type 403 Modified Forgings of Bars for Bolting Material
1544	Radiographic Acceptance Standards for Repair Welds
1545	Test Specimens from Separate Forgings for Class 1, 2, 3, and MC.
1546	Fracture Toughness Test for Weld Metal Section
1547	Weld Procedure Qualification Tests; Impact Testing Requirements, Class I
1522	Design by Analysis of Section III Class I Valves
1556[a]	Penetrameters for Film Side Radiographs in Table T-320 of Section V
1567	Test Lots for Low Alloy Steel Electrodes
1568	Test Lots for Low Alloy Steel Electrodes
1571	Materials for Instrument Line Fittings; For SA-234 Carbon Steel Fittings
1573	Vacuum Relief Valves
1574	Hydrostatic Test Pressure for Safety Relief Valves

(a) Westinghouse has performed a review of these specific code cases and knows of no specific application made to components for Diablo Canyon Units 1 and 2.

(b) Code cases adopted for use at DCPP are specified in the introduction to the Inservice Inspection Program Plan.

TABLE 5.2-2

EQUIPMENT CODE AND CLASSIFICATION LIST

	Code	Unit 1		Unit 2	
Component	Class[d]	Code	Addenda	Code	Addenda
Reactor Coolant System					
Reactor vessel	A	ASME III 65	thru winter 66	ASME III 68	none
Reactor vessel closure head	A	ASME III 2001	thru 2003	ASME III 2001	thru 2003
Control rod drive					
mechanism housing	A	ASME III 2001	thru 2003	ASME III 2001	thru 2003
Steam generator (tube side)	A	ASME III 98	thru 2000	ASME III 98	thru 2000
shell side)	C[a]	ASME III 65	thru winter 65	ASME III 65	thru summer 66
Pressurizer	A	ASME III 65	thru summer 66	ASME III 65	thru summer 66
Reactor coolant piping[b][c],					
fittings	N/A	ASA B31.1	none	ASA B31.1.0	1971
Surge pipe, fittings	N/A	ASA B31.1	none	ASA B31.1.0	1971
Reactor coolant thermowells	N/A	ASA B31.1	none	ASA B31.1	none
Safety valves	N/A	ASME III 65	Article 9	ASME III 65	Article 9
Relief valves	N/A	USAS B16.5	none	USAS B16.5	none
Valves to reactor coolant					
system boundary	N/A	USAS B16.5 or MSS-SP-66 or ASME III 68 or 74[e]	None	USAS B16.5 or MSS-SP-66 or ASME III 68 or 74[e]	None
Piping to reactor coolant					
system boundary	A	ANSI B31.7 69	1971 Addenda	ANSI B31.7 69	1971
Pressurizer relief tank	C	ASME III 68	thru summer 68	ASME III 68	thru summer 68
Reactor coolant pump standpipe					
orifice	N/A	No Code		No Code	
Reactor coolant pump standpipe	N/A	ASME VIII 68	None	ASME VIII 68	None
Reactor coolant pump					
Casing	A	ASME III 65	thru summer 66	ASME III 65	thru summer 66
Main flange	A	ASME III 65	thru summer 66	ASME III 65	thru summer 66
Thermal barrier	A	ASME III 65	thru summer 66	ASME III 65	thru summer 66
#1 seal housing	A	ASME III 65	thru summer 66	ASME III 65	thru summer 66
#2 seal housing	A	ASME III 65	thru summer 66	ASME III 65	thru summer 66

TABLE 5.2-2

Component	Code Class[d]	Unit 1 Code	Unit 1 Addenda	Unit 2 Code	Unit 2 Addenda
Pressure retaining bolting	A	ASME III 65	thru summer 66	ASME III 65	thru summer 66
Remaining parts	N/A	ASME III 65	thru summer 66	ASME III 65	thru summer 66
Reactor coolant pump motor oil coolers	B	ASME III 65	thru summer 66	ASME III 65	thru summer 66

(a) Code design requirements are in excess of the requirement dictated by the applicable Safety Class.

(b) Reactor Coolant System piping subassemblies inspected to ASME I as required by California law.

(c) Classification for other piping and associated valves in the Reactor Coolant System boundary shall be as defined by the Systems Engineering Flow Diagrams for the appropriate Safety Class.

(d) See Section 3.2.

(e) A small number of valves were purchased to ASME Section III, 1974 requirements.

TABLE 5.2-3

PROCUREMENT INFORMATION
COMPONENTS WITHIN REACTOR COOLANT SYSTEM BOUNDARY

Component	Purchase Order Dates	
	Unit 1	Unit 2
Reactor vessel	3/27/67	12/27/68
Replacement RVCH	7/28/06	7/28/06
CRDM housing	7/28/06	7/28/06
Original steam generator	11/22/66	4/6/67
Replacement steam generator	8/12/04	8/12/04
Pressurizer	4/24/67	4/24/67
Reactor coolant pump	3/29/67	3/29/67
Reactor coolant pipe, fittings, and fabrication	5/2/67[a] 1/16/68[b]	10/7/68[a] 11/20/69[b]
Surge pipe, fittings, and fabrication	5/2/67[a]	10/7/68[a]
Piping to reactor coolant system boundary fabrication and installation	5/25/70	5/25/70

(a) Purchase of pipe.
(b) Fabrication of pipe.

TABLE 5.2-4

SUMMARY OF REACTOR COOLANT SYSTEM DESIGN TRANSIENTS

Normal Conditions	Occurrences
1. RCS heatup and cooldown at ≤ 100°F/hr	250 (each)[(e)]
2. Pressurizer heatup at ≤ 100°F/hr and cooldown at ≤ 200°F/hr	250 (each)[(e)]
3. Unit loading and unloading at 5% of full power/min	18,300 (each)
4. Step load increase and decrease of 10% of full power	2,500 (each)
5. Hot standby operation/feedwater cycling [(f)]	18,300
6. Large step load decrease	250
7. Steady state fluctuations	infinite
8. Tavg/power coastdown from nominal to reduced temperature	Note (c)
Upset Conditions	
1. Loss of load (above 15% full power), without immediate turbine or reactor trip	100[(e)]
2. Loss of all offsite power	50[(e)]
3. Partial loss of flow	100[(e)]
4. Reactor trip from full power	500[(e)]
5. Inadvertent auxiliary spray (differential temperature > 320°F	12[(e)]
6. Design earthquake	20
Faulted Conditions[(a)]	
1. Main reactor coolant pipe break[(d)]	1
2. Steam pipe break	1
3. Double design earthquake	1
4. 7.5M Hosgri earthquake[(b)]	1
Test Conditions	
1. Turbine roll test	10[(e)]
2. Hydrostatic test conditions	
a. Primary side	10[(e)]
b. Secondary side	10[(e)]
3. Leak tests (for closures)	
a. Primary side	60[(e)]
b. Secondary side	10
4. Tube leak tests (secondary side pressurized as follows)	
200 psig	400
400 psig	200
600 psig	120
840 psig	80

(a) In accordance with the ASME Boiler and Pressure Vessel Code, faulted conditions are not included in fatigue evaluations.

(b) See Section 3.7.

TABLE 5.2-4 Sheet 2 of 2

(c) The Tavg operating range conditions bound the Tavg/power coastdown conditions of 565°F and steam pressure of 750 psia. No special or separate Tavg/power coastdown transients are required.

(d) With the acceptance of the DCPP leak-before-break analysis by the NRC, dynamic loading conditions resulting from pipe rupture events in the main reactor coolant loop piping no longer have to be considered in the design basis analyses; only the loads resulting from RCS branch line breaks have to be considered.

(e) These limits were contained in Technical Specifications (Table 5.7-1) prior to License Amendment 135 (Improved Technical Specifications)

(f) Applies to steam generator only.

TABLE 5.2-5

STRESS LIMITS FOR CLASS A COMPONENTS

Loading Combinations	Piping[a]	Valves
1. Normal	$P \leq S_h$	See Section 3.9.2
2. Upset (Normal + DE loads)	$P \leq 1.2\ S_h$	See Section 3.9.2
3. Faulted (Normal + DDE loads)	$P \leq 1.8\ S_h$	See Section 3.9.2
4. Faulted (Normal + Hosgri)	$P \leq 2.4\ S_h$	See Section 3.9.2

(a) S_h = allowable stress from USAS B31.1 Code for power piping
P = piping stress calculated per USAS B31.1 Code requirements.

TABLE 5.2-6

LOAD COMBINATIONS AND STRESS CRITERIA FOR WESTINGHOUSE PRIMARY EQUIPMENT [(a)]

CONDITION	LOAD COMBINATION	STRESS CRITERIA[(e)]
Design	Deadweight + Pressure ± DE	$P_m \leq S_m$ $P_L + P_b \leq 1.5\ S_m$
Normal	Deadweight + Pressure + Thermal	$P_L + P_b + P_e + Q \leq 3\ S_m$[(b)]
Upset - 1	Deadweight + Pressure + Thermal ± DE	$U_T \leq 1.0$[(b)] $P_L + P_b + P_e + Q \leq 3\ S_m$
	Deadweight + Pressure + Thermal	$U_T \leq 1.0$[(b)] $P_L + P_b + P_e + Q \leq 3\ S_m$
Faulted - 1	Deadweight + Pressure ± DDE	Table 5.2-7
Faulted - 2	Deadweight + Pressure ± (DDE or HE)+LPR[(c, d, g)]	Table 5.2-7
Faulted - 3	Deadweight + Pressure ± Hosgri	Table 5.2-7
Faulted - 4	Deadweight + Pressure + Other Pipe Rupture[(f)]	Table 5.2-7

(a) Steam generators, reactor coolant pumps, pressurizer.
(b) Based on elastic analysis. For simplified elastic-plastic analysis, the stress limits of the 1971 ASME Code Section III, NB-3228.3 apply.
(c) LPR = reactor coolant loop pipe rupture
(d) Seismic faulted conditions (DDE or HE) and LPR combined by ABSUM or SRSS method (SRSS subject to the conditions and limitations of NUREG-0484).
(e) For definition of stress criteria terms, see Additional Notes.
(f) Pipe rupture other than LPR.
(g) While the original stress analysis considered this load combination, with the acceptance of the DCPP leak-before-break analysis by the NRC, loads resulting from ruptures in the main reactor coolant loop no longer have to be considered in the design basis structural analyses and included in the loading combinations, only the loads resulting from RCS branch line breaks have to be considered.

P_m = General membrane; average primary stress across solid section. Excludes discontinuities and concentrations. Produced only by mechanical loads.
P_L = Local membrane; average stress across any solid section. Considers discontinuities, but not concentrations. Produced only by mechanical loads.
P_b = Bending; component of primary stress proportional to distance from centroid of solid section. Excludes discontinuities and concentrations. Produced only by mechanical loads.
P_e = Expansions; stresses which result from the constraint of "free end displacement" and the effect of anchor point motions resulting from earthquakes. Considers effects of discontinuities, but not local stress concentration. (Not applicable to vessels).
Q = Membrane Plus Bending; self-equilibrating stress necessary to satisfy continuity of structure. Occurs at structural discontinuities. Can be caused by mechanical loads or by differential thermal expansion. Excludes local stress concentrations.
U_T = Cumulative usage factor.

TABLE 5.2-6a

LOAD COMBINATIONS AND ACCEPTANCE CRITERIA FOR REPLACEMENT PRIMARY EQUIPMENT(Note 1)

LOAD CONDITION	LOAD COMBINATION(Note 2 & 6)	ACCEPTANCE CRITERIA
Design	DL + P ± DE	ASME Boiler and Pressure Vessel (B&PV) Code, Section III, Division 1, 2001 Edition through 2003 Addenda – Subsections NCA and NB
Normal (ASME Service Level A)	DL + P ± I(Note 3) + T	
Upset (ASME Service Level B)	DL + P + T ± DE DL + P + T	
Faulted (ASME Service Level D)	DL + P ± (HE or DDE) DL + P ± DDE + LOCA(Note 4 & 5) DL + P ± HE + LOCA(Note 4, 5, 7)	ASME B&PV Code, Section III, Division 1, 2001 Edition through 2003 Addenda - Appendix F

NOTES:

1. RVCH, CRDM pressure housings (pressure retaining components), CETNA, and Vent/RVLIS nozzle
2. Load Case Description

   DL Dead Load (or Dead Weight)
   I Impulse
   P Pressure
   T Thermal Expansion (considered if applicable)
   DE Design Earthquake
   DDE Double Design Earthquake
   HE Hosgri Earthquake
   LOCA Loss of Coolant Accident Load(Note 4)
3. Impulse loads apply only to CRDMs
4. For CRDMs, LOCA loads are applied where the CRDM attaches to the RVCH.
5. Seismic faulted conditions (DDE or HE) and LOCA combined by ABSUM or SRSS method (SRSS subject to the conditions and limitations of NUREG-0484).
6. Other pipe ruptures; i.e., main steam line break and feedwater line break, do not impact these components and, therefore, are not included in the load combinations.
7. Formal analysis of the (LOCA + Hosgri) faulted load combination for the affected equipment is in progress. This analysis is being tracked in the DCPP corrective action program.

TABLE 5.2-7

FAULTED CONDITION STRESS LIMITS FOR CLASS A COMPONENTS

System (or Subsystem) Analysis	Component Analysis	Stress Limits for Vessels and Pumps (f)		Stress Limits for Loop Piping	Test
		P_m	$P_m + P_b$	P	
Elastic	Elastic	Smaller of 2.4 S_m and 0.70 S_u (e)	Smaller of 3.6 Sm and 1.05 S_u (b)	$3.6S_h$	$0.8\ L_T$ (c)(d)
	Plastic	Larger of 0.70 S_u or S_y + 1/3 (S_u - S_y) (c)	Larger of 0.70 S_{ut} or S_y + 1/3 (S_{ut} - S_y) (c)	Larger of 0.70 S_{ut} or S_y + 1/3 (S_{ut} - S_y) (c)	$0.8\ L_T$ (c)(d)
	Limit Analysis	$0.9L_1$ (a)(c)	$0.9L_1$ (a)(c)	$0.9L_1$ (a)(c)	$0.8\ L_T$ (c)(d)
Plastic	Plastic or Elastic	Larger of 0.70 S_u or S_y + 1/3 (S_u - S_y)	Larger of 0.70 S_{ut} or S_y + 1/3 (S_{ut} - S_y)	Larger of 0.70 S_{ut} or S_y + 1/3 (S_{ut} - S_y)	$0.8\ L_T$ (c)(d)

(a) L_1 = Lower bound limit load with an assumed yield point equal to 2.3 S_m or 1.5 S_y, as applicable.
(b) These limits are based on a bending shape factor of 1.5 for simple bending cases with different shape factors; the limits will be changed proportionally.
(c) When elastic system analysis is performed, the effect of component deformation on the dynamic system response should be checked.
(d) L_T = The limits established for the analysis need not be satisfied if it can be shown from the test of a prototype or model that the specified loads (dynamic or static equivalent) do not exceed 80% of L_T, where L_T is the ultimate load or load combination used in the test. In using this method, account shall be taken of the size effect and dimensional tolerances (similitude relationships) that may exist between the actual component and the tested models to ensure that the loads obtained from the test are a conservative representation of the load carrying capability of the actual component under postulated loading for faulted conditions.
(e) S_y = Yield stress at temperature
S_u = Ultimate stress from engineering stress strain curve at temperature
S_h = Allowable stress from USAS B31.1 Code
S_{ut} = ultimate stress from true stress-strain curve at temperature
S_m = stress intensity from ASME Section III at temperature
(f) For steam generators, stress limits are taken from Appendix F of ASME Section III.

TABLE 5.2-8

LOADING COMBINATIONS AND ACCEPTANCE CRITERIA FOR PRIMARY EQUIPMENT SUPPORTS

CONDITION	LOADING COMBINATIONS	STRESS LIMITS
Normal	Deadweight + Temperature + Pressure	1969 AISC Specification, Part 1
Upset	Deadweight + Temperature + Pressure ± DE	1969 AISC Specification, Part 1
Faulted - 1	Deadweight + Pressure ± (DDE or HE)+LPR[a, b, f]	1969 AISC Specification, Part 2[c] or S_y after load redistribution, whichever is higher
Faulted - 2	Deadweight + Pressure ± HOSGRI	1969 AISC Specification, Part 2[c] or S_y[e] after load redistribution, whichever is higher
Faulted - 3	Deadweight + Pressure + Other Pipe Rupture[d]	1969 AISC Specification, Part 2[c] or S_y after load redistribution, whichever is higher

(a) LPR = Reactor coolant loop pipe rupture.
(b) Seismic faulted conditions (DDE or HE) and LPR combined by ABSUM or SRSS method (SRSS subject to the conditions and limitations of NUREG-0484).
(c) For supports qualified by load test, allowable loads = 0.8 times L_t per Table 5.2-7.
(d) Pipe rupture other than LPR.
(e) For the pressurizer upper lateral supports and the reactor vessel supports, the allowable S_y is based on average value of actual yield stress of the material.
(f) While the original stress analysis considered this load combination, with the acceptance of the DCPP leak-before-break analysis by the NRC, loads resulting from ruptures in the main reactor coolant loop no longer have to be considered in the design basis structural analyses and included in the loading combinations, only the loads resulting from RCS branch line breaks have to be considered.

TABLE 5.2-8a

LOAD COMBINATIONS AND ACCEPTANCE CRITERIA
FOR INTEGRATED HEAD ASSEMBLY (IHA)

[PG&E Design Class I Support Structure Components]

LOAD CONDITION	LOAD COMBINATION(Notes 1 &,2)	ACCEPTANCE CRITERIA
Design	DL + P	ASME Boiler and Pressure Vessel (B&PV) Code, Section III, Division 1, 2001 Edition through 2003 Addenda - Subsection NF
Normal (ASME Service Level A)	DL + ML DL + P + T	
Upset (ASME Service Level B)	DL + P ± DE DL + P + T ± DE	
Faulted (ASME Service Level D)	DL + P + T ± (HE or DDE) DL + P + T ± $(DDE^2+LOCA^2)^{1/2}$ DL + P + T ± $(HE^2+LOCA^2)^{1/2}$(Note 4)	ASME B&PV Code, Section III, Division 1, 2001 Edition through 2003 Addenda - Appendix F
Faulted (Missile Shield and Support)	DL + P + T ± $(DDE^2+MI^2)^{1/2}$	

NOTES:

1. Load Case Description

DL	Dead Load
P	Pressure
T	Thermal(Note 2)
ML	Maintenance Load (live loads on walkways during maintenance activities)
MI	Missile impact load (missile shield and support only)
DE	Design Earthquake
DDE	Double Design Earthquake
HE	Hosgri Earthquake
LOCA	Loss of Coolant Accident Load(Note 3)

2. The IHA offers no resistance to reactor vessel thermal growth and, therefore, sustains no stress due to such growth. The temperature load symbol is included in the above table since this load was considered as part of the IHA design criteria. Applicable service and accident temperatures are considered when determining material properties and material allowable stress values.

3. The response spectra input used for the IHA LOCA analysis is the envelope of the Unit 1 and 2 LOCA response spectra associated with a pressurizer surge line break, residual heat removal (RHR) line break, and accumulator line break. LOCA motions are at the reactor head and were therefore applied where the IHA is attached to the reactor head.

4. Formal analysis of the (LOCA + Hosgri) faulted load combination for the IHA is in progress. This analysis is being tracked in the DCPP corrective action program.

TABLE 5.2-9

ACTIVE AND INACTIVE VALVES IN THE REACTOR COOLANT PRESSURE BOUNDARY[(a)]

System	Valves I.D. Number	Location and Figure Number	Type	Valve Size, in.	Valve Actuation	Type A-Active I-Inactive
RCS	8000 A, B, C	Pressurizer Figure 3.2-7, Sheets 3 & 4	Gate	3	Motor	A
RCS	8010 A, B, C	Pressurizer Figure 3.2-7, Sheets 3 & 4	Relief	6	ΔP	A
RCS	8078 A,B,C,D	Reactor vessel head vent Figure 5.5-14	Globe	1	Solenoid	A
RCS	PCV-455 A,B	Pressurizer spray Figure 3.2-7, Sheets 3 & 4	Ball	4	Air	I
RCS	PCV-455 C PCV-456	Pressurizer Figure 3.2-7, Sheets 3 & 4	Globe	3	Air	A
RCS	PCV-474	Pressurizer Figure 3.2-7, Sheets 3 & 4	Globe	3	Air	I
CVCS	LCV-459	RCS cold leg loop 2 Figure 3.2-8, Sheets 5 & 6	Globe	3	Air	A
CVCS	LCV-460	RCS cold leg loop 2 Figure 3.2-8, Sheets 5 & 6	Globe	3	Air	A
CVCS	8145 8148	CVCS pressurizer auxiliary spray Figure 3.2-8, Sheets 5 & 6	Globe	2	Air	A
CVCS	8166 8167	RCS excess letdown Figure 3.2-8, Sheets 1B & 2	Globe	1	Air	I

TABLE 5.2-9

System	Valves I.D. Number	Location and Figure Number	Type	Valve Size, in.	Valve Actuation	Type A-Active I-Inactive
CVCS	8367 A, B, C, D	CVCS seal water injection Figure 3.2-8, Sheets 1, 1A, 1B, 1C & 2	Check	2	ΔP	I
CVCS	8372 A, B, C, D	CVCS seal water injection Figure 3.2-8, Sheets 1, 1A, 1B, 1C & 2	Check	2	ΔP	I
CVCS	8377	CVCS pressurizer auxiliary spray Figure 3.2-8, Sheets 5 & 6	Check	2	ΔP	I
CVCS	8378 A 8379 A	CVCS charging line to loop 3 Figure 3.2-8, Sheets 5 & 6	Check	3	ΔP	I
CVCS	8378 B 8379 B	CVCS charging line to loop 4 Figure 3.2-8, Sheet 5 & 6	Check	3	ΔP	I
RHR	8701	RHR isol. hot leg loop 4 Figure 3.2-10, Sheets 1 & 2	Gate	14	Motor	I(b)
RHR	8702	RHR isol. hot leg loop 4 Figure 3.2-10, Sheets 1 & 2	Gate	14	Motor	I(b)
RHR	8740 A, B	RCS hot leg Figure 3.2-10, Sheets 1 & 2	Check	8	ΔP	I
SIS	8818 A, B, C, D	SIS cold leg Figure 3.2-9, Sheets 5 & 6	Check	6	ΔP	I
SIS	8819 A, B, C, D	SIS cold legs Figure 3.2-9, Sheets 5 & 6	Check	2	ΔP	I

TABLE 5.2-9

System	Valves I.D. Number	Location and Figure Number	Type	Valve Size, in.	Valve Actuation	Type A-Active I-Inactive
SIS	8820	SIS boron injection containment isolation, Figure 3.2-9, Sheets 3 & 4	Check	3	ΔP	I
SIS	8900 A, B, C, D	SIS cold leg Figure 3.2-9, Sheets 3 & 4	Check	1 1/2	ΔP	I
SIS	8905 A, B, C, D	RCS hot legs Figure 3.2-9, Sheets 5 & 6	Check	2	ΔP	I
SIS	8948 A, B, C, D	RCS cold leg Figure 3.2-9, Sheets 1 & 2	Check	10	ΔP	I
SIS	8949 A, B, C, D	RCS hot legs Figure 3.2-9, Sheets 5 & 6	Check	6	ΔP	I
SIS	8956 A, B, C, D	RCS cold leg Figure 3.2-9, Sheets 1 & 2	Check	10	ΔP	I

(a) As defined in 10 CFR 50.2, valves are listed first by system (RCS, CVCS, RHR, and SIS) and then by valve I.D. number.

(b) For the postulated Hosgri earthquake this valve is considered active.

TABLE 5.2-10

REACTOR COOLANT SYSTEM NOMINAL PRESSURE SETPOINTS (PSIG)

Design pressure	2485
Operating pressure	2235
Safety valves	2485
Power relief valves	2335
Pressurizer spray valves (begin to open)	2260
Pressurizer spray valves (full open)	2310
High-pressure reactor trip	2385
High-pressure alarm	2310
Low-pressure reactor trip (typical, but variable)	1950
Low-pressure alarm	2210
Hydrostatic test pressure	3107
Backup heaters on (pressurizer)	2210
Proportional heaters (begin to operate)	2250
Proportional heaters (full operation) pressurizer	2220
Pressurizer power relief valve interlock	2185

TABLE 5.2-11

REACTOR VESSEL MATERIALS

Section	Materials
Pressure plate	Unit 1: A-533 Grade B Class 1 Unit 2: SA-533 Grade B Class 1
Pressure forgings	Unit 1: A-508 Class 2 Unit 2: SA-508 Class 2
Replacement RVCH Forging	SA-508 Grade 3 Class 1
Primary nozzle safe ends	Stainless steel Type 316 Forging
Cladding, stainless	Type 304 or equivalent (Combination of Types 308, 308L, 309, 309L, and 312)
Stainless weld rod	Types 308L, 308, and 309
O-ring head seals	Inconel 718
CRDM housings	Inconel 690 and stainless Type 304
Lower tube	SB-167
Studs	SA-540 Grade B-23 and B-24
Instrumentation nozzles	Inconel 600
Thermal insulation	Stainless steel

TABLE 5.2-12 Sheet 1 of 2

PRESSURIZER, PRESSURIZER RELIEF TANKS, AND SURGE LINE MATERIALS

Pressurizer	Unit 1	Unit 2
Shell	SA-533, Grade A (Class 1)	SA-533, Grade A (Class 2)
Heads	SA-216, Grade WCC (Class 2)	SA-533, Grade A
Support skirt	SA-516, Grade 70	SA-516, Grade 70
Nozzle weld ends	SA-182, F316	SA-182, F316L
Inst. tube coupling	SA-182, F316	SA-182, F316
Cladding, stainless	Type 304 or equivalent	Type 304 or equivalent
Nozzle forgings		SA-508, Class 2 Mn-Mo
Nozzle Weld Overlay	N/A	
First pass		309L, ERNiCr-3 over dissimilar metal weld
Remainder of overlay		ERNiCrFe-7 (Automatic GTAW) ERNiCrFe-7A (Manual GTAW)
Internal plate	SA-240, Type 304	SA-240, Type 304
Inst. tubing	SA-213, Type 304 316	SA-213, Type 304 316
Heater well tubing	SA-213, Type 316 seamless	SA-213, Type 316 seamless
Heater well adaptor	SA-182, F316	SA-182, F316
Pressurizer Relief Tank		
Shell	ASTM A-285, Grade C	ASTM A-285, Grade C
Heads	ASTM A-285, Grade C	ASTM A-285, Grade C
Internal coating	Amercoat 55	Amercoat 55
Surge Line		
Pipes	ASTM A-376, Type 316	ASTM A-376, Type 316
Fittings	ASTM A-403, WP316	ASTM A-182, F316
Nozzles	ASTM A-182, Grade F316	ASTM A-182, Grade F316

TABLE 5.2-12

Valves	Unit 1	Unit 2
Pressure-containing parts	ASTM A-351, Grade CF8M ASTM A-182, Grade F and ASME SA-351, Grade CF3 (for RCS-8029)	ASTM A-351, Grade CF8M ASTM A-182, Grade F and ASME SA-351, Grade CF3 (for RCS-8029)

TABLE 5.2-13

REACTOR COOLANT PUMP MATERIALS

Shaft	ASTM A-182, Grade F347
Impeller	ASTM A-351, Grade CF8
Casing	ASTM A-351, Grade CF8
Flywheel	ASTM A-533, Grade B, Class I

TABLE 5.2-14

STEAM GENERATOR MATERIALS

Pressure forgings	ASME SA 508, Grade 3, Class 2
Cladding	Stainless steel Types 309L, 308L
Tubesheet cladding	Alloy 690 weld material
Tubes	Alloy 690 TT

TABLE 5.2-15

REACTOR COOLANT WATER CHEMISTRY SPECIFICATION

Parameter	Steady State	Transient Limit
Conductivity, μMho/cm @ 25°C	(a)(c)	----
pH @ 25°C	(a)(c)	----
Oxygen, ppm(b)	≤ 0.10	≤ 1.0
Chloride, ppm	≤ 0.15	≤ 1.5
Fluoride, ppm	≤ 0.15	≤ 1.5
Hydrogen, cc(STP)/kg		
power > 1 MWt	(c)	----
normal target band	(c)	----
Total suspended solids, ppm	(c)	----
Li-7, ppm as Li	(c)	----
Boric acid, ppm as B	(c)	----
Silica, ppm	(c)	----
Aluminum, ppm	(c)	----
Calcium, ppm	(c)	----
Magnesium, ppm	(c)	----
Sulfur compounds, ppm	(c)	----

(a) Varies with boric acid and lithium hydroxide concentration.

(b) Limit is not applicable with Tavg ≤ 250°F. During startup, hydrazine may be used to achieve RCS concentrations of up to 10 ppm when the coolant temperature is between 150 and 180°F and the oxygen exceeds 0.1 ppm.

(c) Chemical Control Limits and Actions Guidelines for the Primary Systems are listed in plant procedures.

TABLE 5.2-16

REACTOR COOLANT BOUNDARY LEAKAGE DETECTION SYSTEMS

Radioactivity Detection Systems

Detector Location or Process	Medium	Type	Range	Approximate Time to Detect 1-gpm Leak	Identified[c] Leak Detection	Seismic[a] Category	Indicator in Control Room
Containment	Air	G-M	10^{-1} to 10^{4} mR/hr	Less responsive than other detection systems	No	II	Yes
Incore inst area	Air	G-M	10^{-1} to 10^{4} mR/hr	Less responsive than other detection systems	No	II	Yes
Containment air particulate	Air	NaI Scintillator	10 to 10^{6} cpm	See Fig. 5.2-9	No	II[b]	Yes
Containment radiogas	Air	G-M	10 to 10^{6} cpm	See Fig. 5.2-9	No	II[b]	Yes
Plant vent radiogas	Air	Beta Scintillator	10 to 5E6 cpm	Less responsive than other detection systems	No	II	Yes
Condenser air ejector	Air	Beta Scintillator	10 to 5E6 cpm	See Fig. 5.2-10	Yes	II	Yes
Component cooling liquid	Liquid	NaI Scintillator	10 to 10^{6} cpm	See Fig. 5.2-12	No	IC	Yes
Steam generator blowdown	Liquid	NaI Scintillator	10 to 10^{6} cpm	See Fig. 5.2-11	Yes	II	Yes

TABLE 5.2-16

Other Detection Systems

Detector Location or Process	Medium	Type	Range and Repeatability[e]	Approximate Time to Detect 1-gpm Leak[q]	Identified[c] Leak Detection	Seismic[a] Category	Indicator in Control Room
Containment[d] condensation	Liquid	Change in time required to accumulate fixed volume	see note (m)	1 hr [g][h][l]	No	II	Yes
Containment sumps	Liquid	Liquid level and quantity of liquid	1 to 48 in. W.C. [n] 1 to 35 in. W.C. [p] ±1 in.	<1 hr [h]	No	II	Yes
Reactor vessel flange leakoff	Liquid	Temperature	50 to 300 °F ±5 °F	<30 sec [f]	Yes	II	Yes
Reactor coolant drain tank	Liquid	Liquid level and quantity of liquid	0-100% ±2%	<20 min [h]	Yes	II	No
Pressurizer relief valve discharge	Liquid	Temperature	50 to 400 °F ±7 °F	<30 sec [f]	Yes	II	Yes
Pressurizer relief tank	Liquid				Yes	II	Yes
		Liquid level	0 to 100 % ±2%	<12 hrs [h]			

Systems Used to Quantify Leakage [i]

Detector System	Medium	Type	Range/Sensitivity	Seismic Category	Indicated in Control Room
Pressurizer level	Liquid	Liquid level	0 to 100% [g][j] ~125 gal/% level	I	Yes
Volume control tank level	Liquid	Liquid level	0 to 100% [g][j] ~19 gal/% level	II	Yes
Charging pump flow	Liquid	Flow	0 to 200 gpm [k] ± 10% span when flow >60 gpm (channel uncertainty value)	II	Yes
Pressurizer relief tank level	Liquid	Liquid level	0 to 100% [h] min. 127, max. 154 gal/% level (20 < % level < 80)	II	Yes

(a) Seismic Category I systems are designed to perform required safety functions following a DDE. Category II instrument systems were designed to function under conditions up to DE. Class IC instrument systems refer to maintenance of pressure boundary integrity of Category I fluid systems. Also refer to Section 3.2.

(b) These units were not constructed to withstand DDE accelerations; however, they will be housed in a Seismic Category I structure and protected from external damage associated with a seismic event. Therefore, it is considered that these units can be returned to operational status within 36 hours of a DDE.

(c) Leakage is defined as identified or unidentified in accordance with Regulatory Guide 1.45.

(d) Containment condensation measures moisture condensed by the fan cooler drip collection system.

(e) Repeatability, including the operators ability to read the same value at another time, is included in this column; this is a true measure of ability to detect a change in system conditions over a period of time.

(f) Automatically alarmed.

TABLE 5.2-16

(g) Requires operator action - (i.e., close valve, start-stop pump, etc., and operator monitoring and logging).

(h) Requires operator monitoring and logging to note changes in rate, level, flow, etc.

(i) Systems listed here would be used to quantify true leakage rate in the event systems listed on Sheets 1 & 2 above detected an unidentified leak. These systems also provide additional capability for detecting leak rates of 1-gpm within short periods of time.

(j) Normal variations in process variable or automatic control systems will mask this change. Operator must take action as in (g) above to detect leakage.

(k) Insufficient accuracy/repeatability to ever detect a 1-gpm change in flowrate.

(l) Dependent on initial conditions. May take longer for fan cooler drip level if humidity is initially low.

(m) Level switches (HI and HI-HI) are provided in each CFCU drain line. The level switches have a fixed location in each drain line providing a repeatable alarm. The time intervals between the receipt of the HI level and HI-HI level alarms are monitored and logged by the operator. Alarm intervals less than a conservative pre-defined value directs the operator to perform an RCS water inventory balance to quantify the RCS leakage rate.

(n) This range refers to the containment structure sumps.

(o) Not used.

(p) This range refers to the reactor cavity sump.

(q) This column refers to the capability of the detection system to sense a leak.

TABLE 5.2-17A

DCPP UNIT 1 REACTOR VESSEL TOUGHNESS DATA

Component	Plate No.	Material Type	Cu (Wt%)	Ni (Wt%)	P (Wt%)	NDTT °F	Minimum 50 Ft-lb/35 Mil Tempt °F Long	Minimum 50 Ft-lb/35 Mil Tempt °F Trans	RT_{NDT} °F	Average Upper Shelf Ft-lb Long	Average Upper Shelf Ft-lb Trans
Repl. Cl. Hd.	06W255-1	SA508,CL1	0.05	0.82	0.005	-40	-	20	-40	-	211
Ves. Sh. Flg.	B4101	A508,CL2	--	0.75	0.010	35(a)	-5	15(a)	35		99(a)
Inlet Noz.	B4103-1	A508,CL2	--	0.66	0.013	60(a)	17	37(a)	60		77(a)
Inlet Noz.	B4103-2	A508,CL2	--	0.67	0.013	60(a)	27	47(a)	60		75(a)
Inlet Noz.	B4103-3	A508,CL2	--	0.68	0.010	43(a)	10	30(a)	43		108(a)
Inlet Noz.	B4103-4	A508,CL2	--	0.66	0.010	48(a)	2	22(a)	48		106(a)
Outlet Noz.	B4104-1	A508,CL2	--	0.74	0.011	60(a)	-13	7(a)	60		77(a)
Outlet Noz.	B4104-2	A508,CL2	--	0.76	0.006	43(a)	-3	17(a)	43		74(a)
Outlet Noz.	B4104-3	A508,CL2	--	0.71	0.012	54(a)	-12	8(a)	54		86(a)
Outlet Noz.	B4104-4	A508,CL2	--	0.68	0.008	60(a)	30	50(a)	60		84(a)
Upper Shl.	B4105-1	A533B,CL1	0.12	0.56	0.010	10	68	88(a)	28		80(a)
Upper Shl.	B4105-2	A533B,CL1	0.12	0.57	0.008	0	49	69(a)	9		74(a)
Upper Shl.	B4105-3	A533B,CL1	0.14	0.56	0.010	0	54	74(a)	14		81(a)
Inter. Shl.	B4106-1	A533B,CL1	0.125	0.53	0.013	-10	57	40	-10	134	116
Inter. Shl.	B4106-2	A533B,CL1	0.120	0.50	0.013	-10	36	57	-3	132	114
Inter.Shl.	B4106-3	A533B,CL1	0.086	0.476	0.011	10	70	90(a)	30	119	77(a)
Lower Shl.	B4107-1	A533B,CL1	0.13	0.56	0.011	-10	59	75	15	127	110
Lower Shl.	B4107-2	A533B,CL1	0.12	0.56	0.010	-10	64	80	20	127	103
Lower Shl.	B4107-3	A533B,CL1	0.12	0.52	0.010	-50	52	38	-22	135	116
Bot. Hd. Seg.	B4111-1	A533B,CL1	0.15	0.51	0.014	-20	33	53(a)	-7		82(a)
Bot. Hd. Seg.	B4111-2	A533B,CL1	0.12	0.63	0.009	-40	16	36(a)	-24		90(a)
Bot. Hd. Seg.	B4111-3	A533B,CL1	0.13	0.50	0.009	-40	21	41(a)	-19		85(a)
Bot. Hd. Seg.	B4110	A553B,CL1	0.06	0.44	0.010	-10	60	80(a)	20		75(a)

(a) Estimated per NRC Standard Review Plan Section 5.3.2.

TABLE 5.2-17B

DCPP UNIT 2 REACTOR VESSEL TOUGHNESS DATA

							Minimum			Average	
							50 Ft-lb/35 Mil Tempt °F			Upper Shelf Ft-lb	
Component	Plate No.	Material Type	Cu (Wt%)	Ni (Wt%)	P (Wt%)	NDTT °F	Long	Trans	RT_{NDT} °F	Long	Trans
Repl. Cl. Hd.	06W255-1	SA508,CL1	0.05	0.82	0.005	-40	--	20	-40	--	211
Inlet Noz.	B5461-1	SA508,CL2	0.09	0.70	0.012	-20	23	43[a]	-17	116	75
Inlet Noz.	B5461-2	SA508,CL2	0.09	0.70	0.012	-20	-2	18[a]	-20	119	77[a]
Inlet Noz.	B5461-3	SA508,CL2	0.10	0.82	0.013	-40	-45	-25[a]	-40	127	83[a]
Inlet Noz.	B5461-4	SA508,CL2	0.10	0.81	0.013	-40	-48	-28[a]	-40	129	84[a]
Outlet Noz.	B5462-1	SA508,CL2	0.11	0.67	0.010	-50	-4	16[a]	-44	145	94
Outlet Noz.	B5462-4	SA508,CL2	0.11	0.67	0.009	-40	-10	10[a]	-40	137.5	89[a]
Outlet Noz.	B5462-2	SA508,CL2	0.11	0.67	0.009	-40	14	34[a]	-26	135.5	88[a]
Outlet Noz.	B5462-3	SA508,CL2	0.11	0.67	0.009	-50	17	37[a]	-23	131.5	85[a]
Upper Shl.	B5453-1	SA533B,CL1	0.11	0.60	0.014	0	85	88	28	92	82
Upper Shl.	B5453-3	SA533B,CL1	0.11	0.60	0.012	10	45	65[a]	5	136.5	86.5[ab]
Upper Shl.	B5011-1R	SA533B,CL1	0.11	0.65	0.015	10	40	60[a]	0	110	72[a]
Inter. Shl.	B5454-1	SA533B,CL1	0.14	0.65	0.010	-40	14	112	52	128	91
Inter. Shl.	B5454-2	SA533B,CL1	0.14	0.59	0.012	0	60	127	67	113	99
Inter. Shl.	B5454-3	SA533B,CL1	0.15	0.62	0.013	-40	30	93	33	129	90
Lower Shl.	B5455-1	SA533B,CL1	0.14	0.56	0.010	-20	42	45	-15	134	112
Lower Shl.	B5455-2	SA5338,CL1	0.14	0.56	0.011	0	25	45	0	137	122
Lower Shl.	B5455-3	SA533B,CL1	0.10	0.62	0.010	0	55	75	15	128	100
Bot. Hd. Seg.	B5009-2	SA533B,CL1	0.13	0.57	0.011	-10	110	130[a]	70	85	55[a]
Bot. Hd. Seg.	B5009-3	SA533B,CL1	0.13	0.60	0.009	-20	-12	8[a]	-20	131	84
Bot. Hd. Seg.	B5009-1	SA533B,CL1	0.13	0.58	0.010	0	88	108[a]	48	95	62[a]
Bot. Hd. Seg.	B5010	SA533B,CL1	0.14	0.63	0.011	-30	20	40[a]	-20	114	74

(a) Estimated per NRC Standard Review Plan Section 5.3.2.
(b) Westinghouse Letter LTR-PCAM-09-26, Revision 1, "Diablo Canyon Units 1 and 2 Reactor Vessel Extended Beltline Material Properties Search," June 3, 2009

TABLE 5.2-18A

IDENTIFICATION OF UNIT 1 REACTOR VESSEL BELTLINE REGION BASE MATERIAL

			Material	Composition, Wt.%							
Component	Plate No.	Heat No.	Spec. No.	C	Mn	P	S	Si	Ni	Mo	Cu
Inter shell	B4106-1	C2884-1	A533B,CL1	0.25	1.34	0.013	0.015	0.21	0.53	0.45	0.125
Inter shell	B4106-2	C2854-2	A533B,CL1	0.18	1.32	0.013	0.015	0.23	0.50	0.46	0.120
Inter shell	B4106-3	C2793-1	A533B,CL1	0.20	1.33	0.011	0.012	0.25	0.476	0.46	0.086
Lower shell	B4107-1	C3121-1	A533B,CL1	0.25	1.36	0.011	0.014	0.24	0.56	0.48	0.13
Lower shell	B4107-2	C3131-2	A533B,CL1	0.24	1.32	0.010	0.013	0.23	0.56	0.46	0.12
Lower shell	B4107-3	C3131-1	A533B,CL1	0.19	1.38	0.010	0.013	0.26	0.52	0.46	0.12

TABLE 5.2-18B

IDENTIFICATION OF UNIT 2 REACTOR VESSEL BELTLINE REGION BASE MATERIAL

			Material	Composition, Wt.%							
Component	Plate No.	Heat No.	Spec. No.	C	Mn	P	S	Si	Ni	Mo	Cu
Inter shell	B5454-1	C5161-1	SA533B,CL1	0.21	1.30	0.010	0.015	0.19	0.65	0.46	0.14
Inter shell	B5454-2	C5168-2	SA533B,CL1	0.25	1.38	0.012	0.016	0.21	0.59	0.55	0.14
Inter shell	B5454-3	C5161-2	SA533B,CL1	0.23	1.32	0.013	0.015	0.20	0.62	0.45	0.15
Lower shell	B5455-1	C5175-1	SA533B,CL1	0.21	1.38	0.010	0.018	0.19	0.56	0.56	0.14
Lower shell	B5455-2	C5175-2	SA533B,CL1	0.22	1.40	0.011	0.018	0.19	0.56	0.56	0.14
Lower shell	B5455-3	C5176-1	SA533B,CL1	0.23	1.34	0.010	0.014	0.20	0.62	0.56	0.10

TABLE 5.2-19A

FRACTURE TOUGHNESS PROPERTIES OF UNIT 1 REACTOR VESSEL BELTLINE REGION BASE MATERIAL

Material		Initial		EOL[a]		
	T_{NDT} (°F)	RT_{NDT} (°F)	USE[b] (ft-lb)	Fluence[c] (N/cm^2)	RT_{NDT}[d] (°F)	USE[d] (ft-lb)
Upper Shell Plate						
B4105-1	10	28[e]	80[e]	1.64E+17	89	74
B4105-2	0	9[e]	74[e]	1.64E+17	70	68
B4105-3	0	14[e]	81[e]	1.64E+17	77	74
Inter Shell Plate						
B4106-1	-10	-10	116	7.93E+18	115	90
B4106-2	-10	-3	114	7.93E+18	113	90
B4106-3	10	30[e]	77[e]	7.93E+18	139	63
Lower Shell Plate						
B4107-1	-10	15	110	7.93E+18	133	87
B4107-2	-10	20	103	7.93E+18	131	82
B4107-3	-50	-22	116	7.93E+18	88	93

(a) End of license for 40 operating years, September 2021.
(b) Upper shelf energy.
(c) Fluence at vessel wall 1/4 thickness location.
(d) Per Regulatory Guide 1.99, Revision 2.
(e) Estimated from data in the longitudinal direction per NRC Standard Review Plan Section 5.3.2.

TABLE 5.2-19B

FRACTURE TOUGHNESS PROPERTIES OF UNIT 2 REACTOR VESSEL BELTLINE REGION BASE MATERIAL

Material	T_{NDT} (°F)	Initial RT_{NDT} (°F)	Initial USE[b] (ft-lb)	EOL[a] Fluence[c] (N/cm^2)	EOL[a] RT_{NDT}[d] (°F)	EOL[a] USE[d] (ft-lb)
Upper Shell Plate						
B5453-1	0	28	82	1.81E+17	74	75
B5453-3	-10	5[e]	86.5[f]	1.81E+17	65	82
B5011-1R	10	0[e]	72[e]	1.81E+17	60	66
Inter Shell Plate						
B5454-1	-40	52	91	8.75E+18	166	69
B5454-2	0	67	99	8.75E+18	180	76
B5454-3	40	33	90	8.75E+18	173	68
Lower Shell Plate						
B5455-1	-20	-15	112	8.75E+18	114	86
B5455-2	0	0	122	8.75E+18	129	94
B5455-3	0	15	100	8.75E+18	112	81

(a) End of license for 40 operating years, April 2025.
(b) Upper shelf energy.
(c) Fluence at vessel wall 1/4 thickness location.
(d) Per Regulatory Guide 1.99, Revision 2.
(e) Estimated from data in the longitudinal direction per NRC Standard Review Plan Section 5.3.2.
(f) Westinghouse Letter LTR-PCAM-09-26, Revision 1, "Diablo Canyon Units 1 and 2 Reactor Vessel Extended Beltline Material Properties Search," June 3, 2009

TABLE 5.2-20A

IDENTIFICATION OF UNIT 1 REACTOR VESSEL BELTLINE REGION WELD METAL

	Weld	Weld Wire		Flux		Average Deposit Composition, Wt.%								
Weld Location	Process	Type	Heat No.	Type	Lot No.	C	Mn	P	S	Si	Mo	Ni	CR	Cu
Upper shell to inter shell circle seam 8-442	Sub-Arc	B-4 Mod.	13253	Linde 1092	3774	0.18	1.30	0.020	0.013	0.24	0.45	0.73	0.19	0.25
Inter shell long seams 2-442 A, B, & C	Sub-Arc	B-4 Mod.	27204	Linde 1092	3724	0.14	1.36	0.016	0.025	0.45	0.48	1.018	0.06	0.203
Inter shell to lower shell circle seam 9-442	Sub-Arc	B-4 Mod.	21935	Linde1092	3869	0.14	1.38	0.015	0.010	0.15	0.54	0.704	--	0.183
Lower shell long seams 3-442 A, B, & C	Sub-Arc	B-4 Mod.	27204	Linde 1092	3774	0.14	1.36	0.016	0.025	0.45	0.48	1.018	0.06	0.203

TABLE 5.2-20B

IDENTIFICATION OF UNIT 2 REACTOR VESSEL BELTLINE REGION WELD METAL

	Weld	Weld Wire		Flux		Average Deposit Composition, Wt.%								
Weld Location	Process	Type	Heat No.	Type	Lot No.	C	Mn	P	S	Si	Mo	Ni	CR	Cu
Nozzle shell to inter shell circle seam 8-201	Sub-Arc	B-4 Mod.	21935	Linde 1092	3889	0.14	1.38	0.015	0.010	0.15	0.54	0.704	—	0.183
Inter shell long seams 2-201 A, B, & C	Sub-Arc (Tandem)	B-4 Mod. B-4 Mod.	21935 12008	Linde 1092	3869	0.13	1.41	0.018	0.010	0.16	0.55	0.87	0.03	0.22
Inter shell to lower shell circle seam 9-201	Sub-Arc	B-4	10120	Linde 0091	3458	0.14	1.12	0.011	0.008	0.18	0.48	0.082	—	0.046
Lower shell long seams 3-201 A, B, & C	Sub-Arc	B-4	33A277	Linde 124	3878	0.11	1.17	0.015	0.011	0.26	0.50	0.165	0.06	0.258

TABLE 5.2-21A

FRACTURE TOUGHNESS PROPERTIES OF UNIT 1 REACTOR VESSEL BELTLINE REGION WELD METAL

Material	Initial		EOL[a]		
	RT_{NDT} (°F)	USE[b] (ft-lb)	Fluence[c] (N/cm^2)	RT_{NDT}[d] (°F)	USE[d] (ft-lb)
Upper Shell Long. Welds 1-442 A,B,C	-20	86[f]	<1.64+17	69	74
Upper Shell to Inter. Shell Weld 8-442	-56[e]	111[g]	<1.64E+17	40	93
Inter. Shell Long. Welds 2-442 A,B	-56[e]	91[h]	5.35E+18	194	66
2-442 C	-56[e]	91[h]	2.87E+18	157	69
Inter. Shell to Lower Shell Weld 9-442	-56[e]	109[I]	7.93E+18	166	75
Lower Shell Long. Welds 3-442 A,B	-56[e]	91[h]	4.46E+18	182	67
3-442 C	-56[e]	91[h]	7.93E+18	218	63

(a) End of license for 40 operating years, September 2021.
(b) Upper shelf energy.
(c) Fluence at vessel wall 1/4 thickness location.
(d) Per Regulatory Guide 1.99, Revision 2.
(e) Generic value per 10 CFR 50.61.
(f) CE Vessel Weld Test Report, April 9, 1968.
(g) WCAP 10492, Analysis of Capsule T, Salem 2 Surveillance Program, March 1984.
(h) WCAP 15958, Rev. 0, "Analysis of Capsule V from PG&E Diablo Canyon Unit 1 Reactor Vessel Radiation Surveillance Program," January 2003.
(i) PG&E Letter DCL-95-176, August 16, 1995, and PG&E Letter DCL-98-094, July 6, 1998.

TABLE 5.2-21B

FRACTURE TOUGHNESS PROPERTIES OF UNIT 2 REACTOR VESSEL BELTLINE REGION WELD METAL

Material	Initial		EOL[a]		
	RT_{NDT} (°F)	USE[b] (ft-lb)	Fluence[c] (N/cm^2)	RT_{NDT}[d] (°F)	USE[d] (ft-lb)
Upper Shell Long. Welds 1-201 A,B,C	-50	118[f]	<1.81E+17	14	97
Upper Shell to Inter. Shell Weld 8-201	-56[e]	109[g]	<1.81E+17	37	95
Inter. Shell Long. Welds 2-201 A,B	-50	118[f]	5.61E+18	165	78
2-201 C	-50	118[f]	6.08E+18	170	76
Inter. Shell to Lower Shell Weld 9-201	-56[e]	125[h]	8.75E+18	35	102
Lower Shell Long. Welds 3-201 A,B	-56[e]	88[h]	6.08E+18	121	56
3-201 B	-56[e]	88[h]	5.61E+18	118	57

(a) End of license for 40 operating years, April 2025.
(b) Upper shelf energy.
(c) Fluence at vessel wall 1/4 thickness location.
(d) Per Regulatory Guide 1.99, Revision 2.
(e) Generic value per 10 CFR 50.61.
(f) WCAP 15423, "Analysis of Capsule V from PG&E Diablo Canyon Unit 2 Reactor Vessel Radiation Surveillance Program," September 2000.
(g) PG&E Letter DCL-95-176, August 16, 1995.
(h) Average of three Charpy tests at +10°F, CD weld wire/flux qualification test.

TABLE 5.2-22

REACTOR VESSEL MATERIAL SURVEILLANCE PROGRAM
WITHDRAWAL SCHEDULE

UNIT 1

Capsule[f][g]	Location	Lead Factor[d]	Fluence at Capsule Center (n/cm^2)[d]	Removal Time (Plant EFPY)[a]
S	320°	3.48	2.83E+18	1.25 (Tested,1R1)
Y	40°	3.45	1.05E+19	5.86 (Tested, 1R5)
T	140°	3.45	1.05E+19	5.86 (Removed, 1R5)
Z	220°	3.45	1.05E+19	5.86 (Removed, 1R5)
V	320°	2.26	1.36E+19	14.3 (Tested 1R11)
C[b]	140°	3.47	1.22E+19	15.9 (Removed 1R12)
D[b]	220°	3.47	1.22E+19	15.9 (Removed 1R12)
B[b]	40°	3.47	3.44E+19 (projected)	33.0 (Planned 1R23)
A[b]	184°	1.32	Standby	Standby
U	356°	1.24	Standby	Standby
X	176°	1.24	Standby	Standby
W	4°	1.24	Standby	Standby

UNIT 2

Capsule	Location	Lead Factor[d]	Fluence at Capsule Center (n/cm^2)[d]	Removal Time (EFPY)[a]
U	56°	5.20	3.30E+18	1.02 (Tested, 2R1)
X	236°	5.39	9.06E+18	3.16 (Tested, 2R3)
Y	238.5°	4.56	1.53E+19	7.08 (Tested, 2R6)
W[e]	124°	5.35	2.78E+19	11.49 (Removed, 2R9)
V[e]	58.5°	4.57	2.38E+19	11.49 (Tested, 2R9)
Z[e]	304°	5.35	2.78E+19	11.49 (Removed, 2R9)

(a) Approximate full power years from plant startup.
(b) Four supplemental capsules installed at 5.86 EFPY (EOC5).
(c) Deleted in Revision 16.
(d) Approximate values taken from WCAP-17299-NP (Rev. 0) for Units 1 and 2.
(e) Capsule EFPY for Unit 2 capsules removed in 2R9; W = 61.5, V = 52.5, and Z = 61.5
(f) Unit 1 capsules T, U, W, X, and Z are Type 1 (base metal only)
(g) Unit 1 capsules S, V, and Y are Type 2 (base metal and weld)

TABLE 5.2-23

REACTOR COOLANT SYSTEM PRESSURE BOUNDARY ISOLATION VALVES

VALVE NUMBER	FUNCTION
1. 8948 A, B, C, and D	Accumulator, RHR, and SIS first off check valves from RCS cold legs
2. 8819 A, B, C, and D	SIS second off check valves from RCS cold legs
3. 8818 A, B, C, and D	RHR second off check valves from RCS cold legs
4. 8956 A, B, C, and D	Accumulator second off check valves from RCS cold legs
5. 8701 and 8702	RHR suction isolation valves
6. 8949 A, B, C, and D	RHR and SIS first off check valves from RCS hot legs
7. 8905 A, B, C, and D	SIS second off check valves from RCS hot legs
8. 8740[a] A and B	RHR second off check valves from RCS hot legs

[a] 8703 may be used to satisfy Technical Specification 3.4.14 Required Actions A.1 or A.2.1 when in Condition A for valves 8740A and 8740B.

TABLE 5.4-1

REACTOR VESSEL DESIGN PARAMETERS (BOTH UNITS)

Design/operating pressure, psig	2485/2235
Design temperature, °F	650
Overall height of vessel and closure head, ft-in. (bottom head OD to top of control rod mechanism adapter)	43-10
Thickness of insulation, min, in.	3
Number of reactor closure head studs	54
Diameter of reactor closure head/studs, in.	7
ID of flange, in.	167
OD of flange, in.	205
ID at shell, in.	173
Inlet nozzle ID, in.	27-1/2
Outlet nozzle ID, in.	29
Cladding thickness, min, in.	5/32
Lower head thickness, min, in.	5-1/4
Vessel beltline thickness, min, in.	8-1/2
Closure head thickness, in.	7

TABLE 5.4-2

REACTOR VESSEL CONSTRUCTION QUALITY ASSURANCE PROGRAM

Forgings	RT[(a)]	UT[(a)]	PT[(a)]	MT[(a)]
1. Flanges	-	Yes	-	Yes
2. Studs	-	Yes	-	Yes
3. Instrumentation tubes	-	Yes	Yes	-
4. Main nozzles	-	Yes	-	Yes
5. Nozzles safe ends	-	Yes	Yes	-
6. CRDM and Thermocouple Nozzles	-	Yes	Yes	-
7. RVHVS and RVLIS Nozzles	Yes	-	Yes	-
Plates	-	Yes	-	Yes
Weldments				
1. Main seam	Yes	Yes[(c)]	-	Yes
2. Instrumentation tube connection	-	-	Yes	-
3. Main nozzles	Yes	Yes[(c)]	-	Yes
4. Cladding	-	Yes[(b)]	Yes	-
5. Nozzle to safe ends weld	Yes	-	-	Yes
6. Nozzle to safe ends weld overlay (Unit 2)	Yes	Yes[(c)]	Yes	-
7. All ferritic welds accessible after hydrotest	-	-	-	Yes
8. All nonferritic welds accessible after hydrotest	-	-	Yes	-
9. Seal ledge	-	-	-	Yes
10. Head lift lugs	-	-	-	Yes
11. Core pads welds	-	Yes	Yes	Yes
12. CRDM and Thermocouple Nozzle Connections	-	-	Yes	-
13. RVHVS and RVLIS Nozzle Connections	-	-	Yes	-
14. CRDM Nozzle to Integrated Latch Housing Weld	Yes	-	Yes	-

(a) RT - Radiographic; UT - Ultrasonic; PT - Dye penetrant; MT - Magnetic particle
(b) UT of cladding bond-to-base metal
(c) UT after hydrotest

TABLE 5.5-1

REACTOR COOLANT PUMP DESIGN PARAMETERS (BOTH UNITS)

Design pressure, psig	2,485
Design temperature, °F	650
Capacity per pump, gpm	88,500
Developed head, ft	277
NPSH required, ft	170
Suction temperature, °F	545
RPM nameplate rating	1,180
Discharge nozzle, ID, in.	27-1/2
Suction nozzle, ID, in.	31
Overall unit height, ft-in.	28-6.7
Water volume, ft^3	56
Moment of inertia, ft-lb	82,000
Weight, dry, lb	188,200
Motor	
Type	AC induction single-speed, air-cooled
Power, HP	6,000
Voltage, volts	11,500
Insulation class	B or H Thermalastic Epoxy
Phase	3
Starting	
Current, amps	1,700
Input (hot reactor coolant), kW	4,371
Input (cold reactor coolant), kW	5,790
Seal water injection, gpm	8
Seal water return, gpm	3

TABLE 5.5-2

REACTOR COOLANT PUMP QUALITY ASSURANCE PROGRAM

	RT[a]	UT[a]	PT[a]	MT[a]
Castings	Yes	-	Yes	-
Forgings				
1. Main shaft	-	Yes	Yes	-
2. Main studs	-	Yes	Yes	-
3. Flywheel (rolled plate)	-	Yes	Yes (for the bore)	
Weldments				
1. Circumferential	Yes	-	Yes	-
2. Instrument connections	-	-	Yes	-

(a) RT - Radiographic
UT - Ultrasonic
PT - Dye penetrant
MT - Magnetic particle

TABLE 5.5-3 Sheet 1 of 2

STEAM GENERATOR DESIGN DATA[(a)]

	Unit 1	Unit 2
Number of steam generators	4	4
Design pressure, reactor coolant/steam, psig	2,485/1085	2,485/1085
Reactor coolant hydrostatic test pressure (tube side-cold), psig	3,106	3,106
Design temperature, reactor coolant/steam, °F	650/600	650/600
Reactor coolant flow, (per SG) lb/hr	33.2×10^6	33.5×10^6
Total heat transfer surface area, ft^2	54,240	54,240
Heat transferred, Btu/hr	$2,920 \times 10^6$	$2,920 \times 10^6$
Steam conditions at full load		
Outlet nozzle:		
Steam flow, lb/hr	3.64×10^6	3.7×10^6
Steam temperature, °F	519	519
Steam pressure, psia	805[(c)]	805[(c)]
Maximum moisture carryover, wt %	0.05	0.05
Feedwater, temperature, °F	435	435
Overall height, ft-in.	68-2	68-2
Shell OD, upper/lower, in.	175-3/8 /135-3/8	175-3/8/135-3/8
Number of U-tubes[(b)]	4,444	4,444
U-tube outer diameter, in.	0.75	0.75
Tube wall thickness, (minimum), in.	0.043	0.043
Number of manways/ID, in.	4/18	4/18
Number of handholes/ID, in.	4/6	4/6
Number of inspection ports/ID, in.	8/2.5	8/2.5
Number of tube upper bundle inspection ports/ID, in.	2/4	2/4

TABLE 5.5-3

	Rated Load	
	Unit 1	Unit 2
Reactor coolant water volume, ft^3	1016	1016
Primary side fluid heat content, Btu	26.0×10^7	26.0×10^7
Secondary side water volume, ft^3	2100	2100
Secondary side steam volume, ft^3	3700	3700
Secondary side fluid heat content, Btu	6.0×10^7	6.0×10^7

(a) Quantities are for each steam generator.

(b) The actual number of “active” tubes (i.e., those contributing to the heat transfer surface area) may be less than the number given due to the plugging and/or removal of some tubes.

(c) Warranted exit pressure at SG end-of-life (e.g., 10% SGTP and design fouling conditions).

TABLE 5.5-5

STEAM GENERATOR QUALITY ASSURANCE PROGRAM
(BOTH UNITS)

	RT[a]	UT[a]	PT[a]	MT[a]	ET[a]
Tubesheet					
1. Forging	-	Yes	-	Yes	-
2. Cladding	-	Yes[b]	Yes	-	-
Channel Head					
1. Forging		Yes	-	Yes	-
2. Cladding	-	Yes	Yes	-	-
Secondary Shell and Head					
1. Forgings	-	Yes	-	Yes	-
Tubes	-	Yes	-	-	Yes
Nozzles (Forging)	-	Yes	-	Yes	-
Weldments					
1. Shell, circumferential	Yes	Yes [d]	-	Yes	-
2. Cladding, (channel head-tubesheet joint cladding restoration)	-	Yes	Yes	-	-
3. Feedwater nozzle to shell	Yes	-	-	Yes	-
4. Support brackets	-	-	-	Yes	-
5. Tube to tubesheet	-	-	Yes	-	-
6. Instrument connections (primary and secondary)	-	-	-	Yes	-
7. Temporary attachments after removal	-	-	-	Yes	-

TABLE 5.5-5 Sheet 2 of 2

	RT[(a)]	UT[(a)]	PT[(a)]	MT[(a)]	ET[(a)]
Weldments (Cont'd)					
8. After hydrostatic test (all welds where accessible)	-	-	-	Yes	-
9. Primary nozzle safe ends	Yes	Yes	Yes	-	-
10. Steam nozzle safe ends	Yes	-	-		-
11. Feedwater nozzle safe ends	Yes	Yes	Yes	-	-

(a) RT - Radiographic
UT - Ultrasonic
PT - Dyepenetrant
MT - Magnetic particle
ET - Eddy current

(b) Flat surfaces only

(c) Weld deposit areas only

(d) Welds subject to ASME Section XI ISI

TABLE 5.5-6

REACTOR COOLANT PIPING DESIGN PARAMETERS (BOTH UNITS)

Reactor inlet piping, ID, in.	27.5
Reactor inlet piping, nominal/min wall thickness, in.	2.38/2.22
Reactor outlet piping, ID, in.	29
Reactor outlet piping, nominal/min wall thickness, in.	2.50/2.33
Coolant pump suction piping, ID, in.	31
Coolant pump suction piping, nominal/min wall thickness, in.	2.66/2.50
Pressurizer surge line piping, Unit 1/Unit 2 ID, in.	11.50/11.19
Pressurizer surge line piping, Unit 1/Unit 2 nominal wall thickness, in.	1.25/1.41
Water volume, all loops and surge line, ft^3	1500
Design/operating pressure, psig	2485/2235
Design temperature, °F	650
Design temperature (pressurizer surge line) °F	680
Design pressure, pressurizer relief line	From pressurizer to safety valve, 2485 psig, 650° F
Design temperature, pressurizer relief lines	From safety valve to pressurizer relief tank, 600 psig, 450°F

TABLE 5.5-7

REACTOR COOLANT PIPING QUALITY ASSURANCE PROGRAM (BOTH UNITS)

	RT[a]	UT[a]	PT[a]
Fittings and Pipe (Castings)	Yes	-	Yes
Fittings and Pipe (Forgings)	-	Yes	Yes
Weldments			
1. Circumferential	Yes	-	Yes
2. Nozzle to piperun (except no RT for nozzles less than 4 inches)	Yes	-	Yes
3. Instrument connections	-	-	Yes

(a) RT - Radiographic
UT - Ultrasonic
PT - Dye penetrant

TABLE 5.5-8

DESIGN BASES FOR RESIDUAL HEAT REMOVAL SYSTEM OPERATION
(BOTH UNITS)

Residual heat removal system startup	No sooner than 4 hours after reactor shutdown
Number of Trains in Operation	2
Reactor coolant system initial pressure, psig	390
Reactor coolant system initial temperature, °F	350
Component cooling water design temperature, °F	95
Cooldown time, hours after reactor shutdown	<20
Reactor coolant system temperature at end of cooldown, °F	140
Decay heat generation used in cooldown analysis, Btu/hr	75.5×10^6

TABLE 5.5-9

RESIDUAL HEAT REMOVAL SYSTEM CODES AND CLASSIFICATIONS
(BOTH UNITS)

Components		Code
Residual heat removal pump		ASME P&V[(a)], Class II
Residual heat exchanger	(tube side)	ASME III[(b)], Class C
	(shell side)	ASME VIII[(c)]
Piping[(d)]		ANSI B31.7 ANSI B31.1
Valves		ANSI B16.5[(e)]

(a) Draft ASME Code for Pumps and Valves for Nuclear Power, November 1968 Edition.

(b) ASME III - American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section VIII, Pressure Vessels, 1968 Edition.

(c) ASME VIII - American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section VIII, Pressure Vessels, 1968 Edition.

(d) American National Standards Institute, B31.7 Class II - 1969 with 1970 Addendum for safety-related portions. American National Standards Institute, B31.1-1967 with 1970 Addendum for nonsafety- related portions.

(e) American National Standards Institute, B16.5, Steel Pipe Flanges and Flanged Fittings, 1968 Edition.

TABLE 5.5-10 Sheet 1 of 2

RESIDUAL HEAT REMOVAL SYSTEM COMPONENT DATA
(BOTH UNITS)

Residual Heat Removal Pump

Number	2 (per unit)	
Design pressure, psig	700	
Design temperature, °F	400	
Design flow, gpm	3000	
Design head, ft	350	
Net positive suction head, ft		
Available	36.3	
Required	11.0	
Residual Heat Exchanger		
Number	2 (per unit)	
Design heat removal capacity, Btu/hr	34.15×10^6	
	Tube-side	Shell-side
Design pressure, psig	630	150
Design temperature, °F	400	250
Design flow, lb/hr	1.48×10^6	2.48×10^6
Inlet temperature, °F	137	95
Outlet temperature, °F	114	108.8
Material	Austenitic stainless steel	Carbon steel
Fluid	Reactor coolant	Component cooling water

Piping and Valves

Design pressure, psig	2485[a]
Design temperature, °F	650[a]
Design pressure, psig	700
Design temperature, °F	400
Suction side relief valve	
Relief pressure, psig	450
Relief capacity, gpm	900
Discharge side relief valve	
Relief pressure, psig	600
Relief capacity, gpm	20
Material	Austenitic stainless steel

(a) Valves and piping that are part of the reactor coolant pressure boundary.

TABLE 5.5-11

RECIRCULATION LOOP LEAKAGE

Items	No. of Units	Type of Leakage Control and Unit Leakage Rate Used in the Analysis	Leakage to Atmosphere, cc/hr	Leakage to Drain Tank, cc/hr
Residual heat removal pumps (low-head safety injection)	2	Mechanical seal with leakoff of one drop/min	20	0
Centrifugal charging pump (CCP1 and CCP2)	2	Same as residual heat removal pump	40	0
Safety injection	2	Same as residual heat removal pump	40	0
Flanges:				
a. Pump	12	Gasket-adjusted to zero leakage following any test	0	0
b. Valves bonnet body (larger than 2 in.)	40	10 drops/min/flange used in analysis (30 cc/hr)	1200	0
c. Control valves	6		180	0
d. Heat exchangers	2		240	0
Valves - stem leakoffs	40	Backseated, double packing with leak-off of 1 cc/hr/in. stem diameter	0	40
Miscellaneous small valves	50	Flanged body packed stems - 1 drop/min used	50	0
Miscellaneous large valves (larger than 2 in.)		Double-packing 1 cc/hr/in. stem diameter	40	0
		TOTALS	1910	40

TABLE 5.5-12

PRESSURIZER DESIGN DATA

Design/operating pressure, psig	2485/2235
Hydrostatic test pressure (cold), psig	3107
Design/operating temperature, °F	680/653
Water volume, full power, ft^3	1080
Steam volume, full power, ft^3	720
Surge line nozzle diameter, in.	14
Shell ID, in.	84
Electric heaters capacity, kW[(a)]	1800
Heatup rate of pressurizer using heaters only, °F/hr	55
Maximum spray rate, gpm	800

(a) Initial heater capacity limit; 150 kW is the minimum required capacity for each backup group that can be supplied by emergency vital power (2 groups).

TABLE 5.5-13

PRESSURIZER QUALITY ASSURANCE PROGRAM (BOTH UNITS)

Heads	RT[a]	UT[a]	PT[a]	MT[a]	ET[a]
1. Plates	Yes	-	-	Yes	-
2. Cladding	-	-	Yes	-	-
Shell					
1. Plates	-	Yes	-	Yes	-
2. Cladding	-	-	Yes	-	-
Heaters					
1. Tubing[b]	-	Yes	Yes	-	-
2. Center of element	-	-	-	-	Yes
Nozzle	-	Yes	Yes	-	-
Weldments					
1. Shell, longitudinal	Yes	-	-	Yes	-
2. Shell, circumferential	Yes	-	-	Yes	-
3. Cladding	-	-	Yes	-	-
4. Nozzle safe end (forging)	Yes	-	Yes	-	-
5. Instrument connections	-	-	Yes	-	-
6. Support skirt	-	-	-	Yes	-
7. Temporary attachments after removal	-	-	-	Yes	-
8. All welds and plate heads after hydrostatic test	-	-	-	Yes	-
Final Assembly					
1. All accessible exterior surfaces after hydrostatic test	-	-	-	Yes	-

(a) RT - Radiographic; UT - Ultrasonic; PT - Dye penetrant; MT - Magnetic particle; ET - Eddy current
(b) Or a UT and ET

TABLE 5.5-14

PRESSURIZER RELIEF TANK DESIGN DATA

Design pressure, psig	100
Rupture disk release pressure, psig	100 ± 5%
Design temperature, °F	340
Total rupture disk relief capacity lb/hr at 100 psig	1.6×10^6

TABLE 5.5-15

REACTOR COOLANT SYSTEM BOUNDARY VALVE DESIGN PARAMETERS

Design pressure, psig	2485
Nominal operating pressure, psig	2235
Preoperational plant hydrotest, psig	3107
Design temperature, °F	650

TABLE 5.5-16

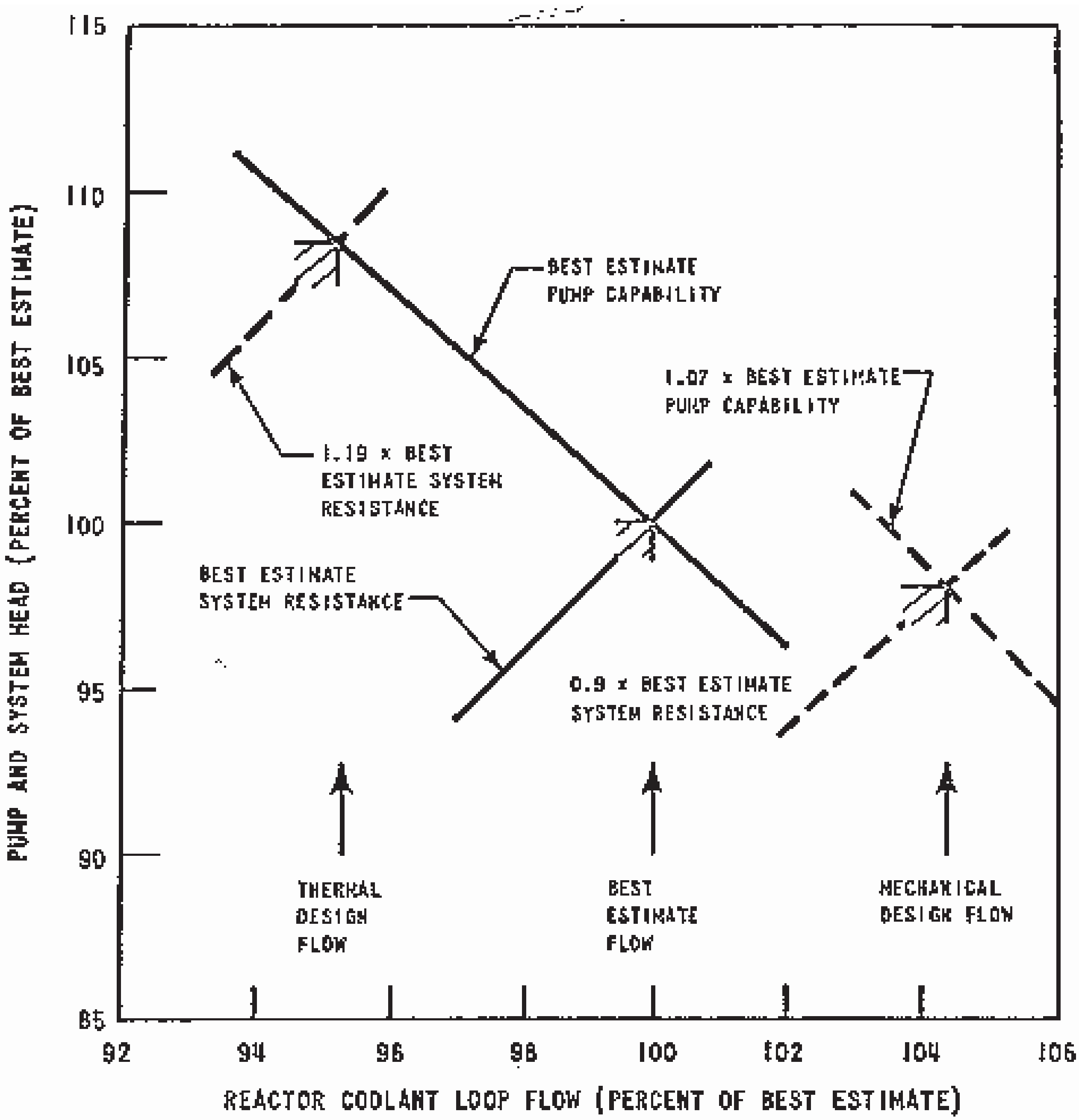
PRESSURIZER VALVES DESIGN PARAMETERS

Pressurizer Spray Control Valves	
Number	2
Design pressure	2485
Design temperature, °F	650
Design flow for valves full open, each, gpm	400
Pressurizer Safety Valves	
Number	3
Maximum relieving capacity, ASME rated flow, lb/hr (per valve)	420,000
Set pressure, psig	2485
Fluid	Saturated steam
Backpressure:	
Normal, psig	3 to 5
Expected during discharge, psig	350
Pressurizer Power Relief Valves	
Number	3
Design pressure, psig	2485
Design temperature, °F	650
Relieving capacity at 2,350 psig, lb/hr (per valve)	210,000
Fluid	Saturated steam

TABLE 5.5-17

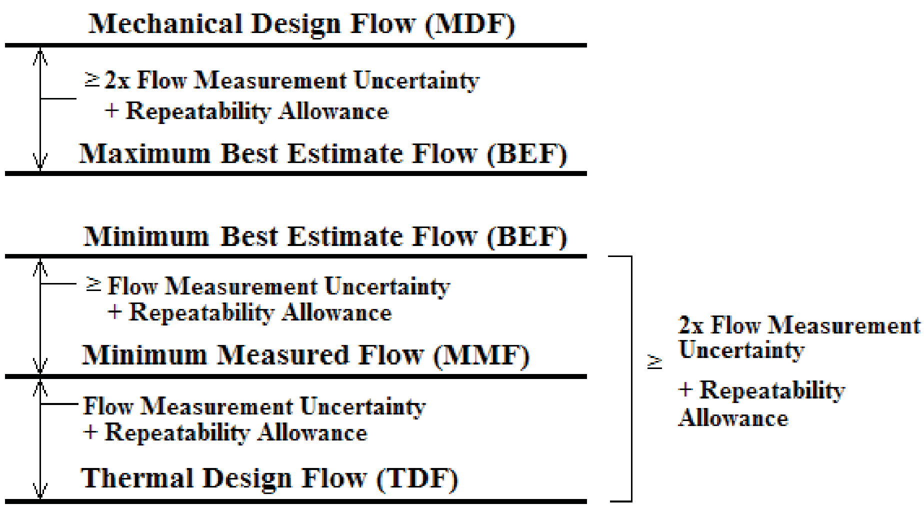
REACTOR VESSEL HEAD VENT SYSTEM EQUIPMENT DESIGN PARAMETERS

Valves	
Number (includes six manual valves)	10
Design pressure, psig	2485
Design temperature, °F	650
Piping	
Vent line, nominal diameter, in.	1
Design pressure, psig	2485
Design temperature, °F	620



This figure depicts information utilized in the original plant design and is not intended to be updated. For current plant information, refer to Figure 5.1-2A.

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 5.1-2 PUMP HEAD - FLOW CHARACTERISTICS



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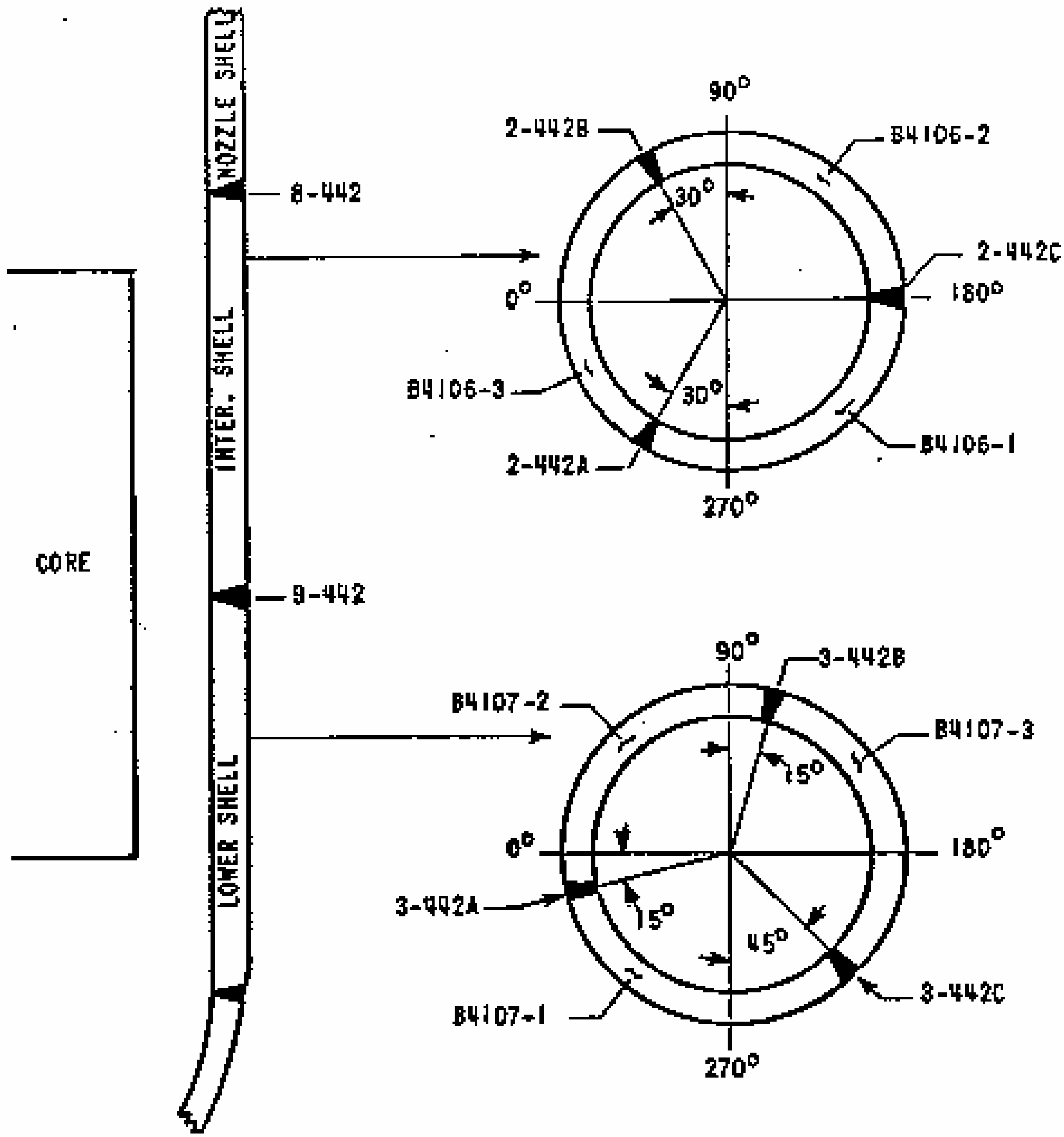
UNITS 1 and 2
DIABLO CANYON SITE

FIGURE 5.1-2A
SAFETY ANALYSIS-
RCS FLOW PARAMETERS



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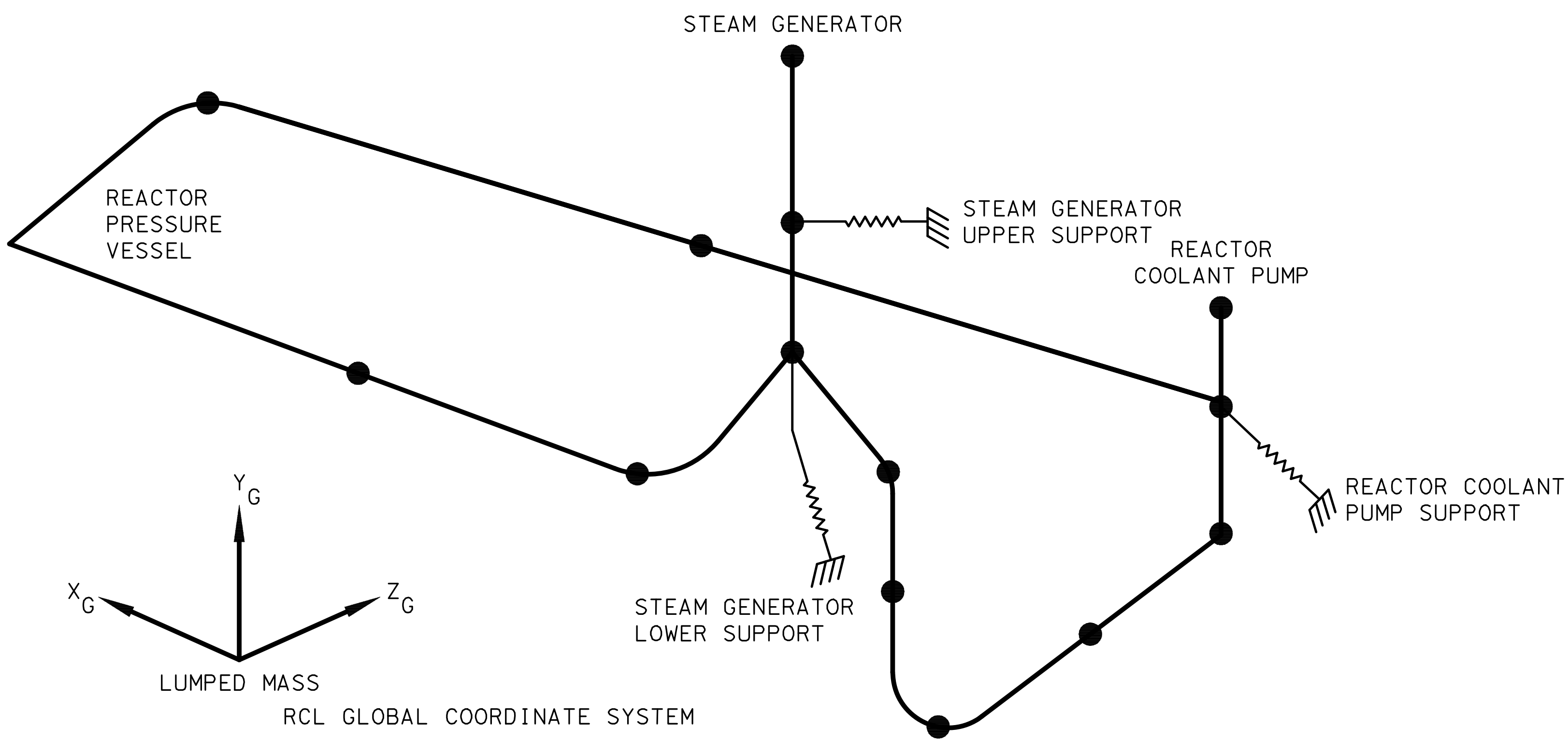
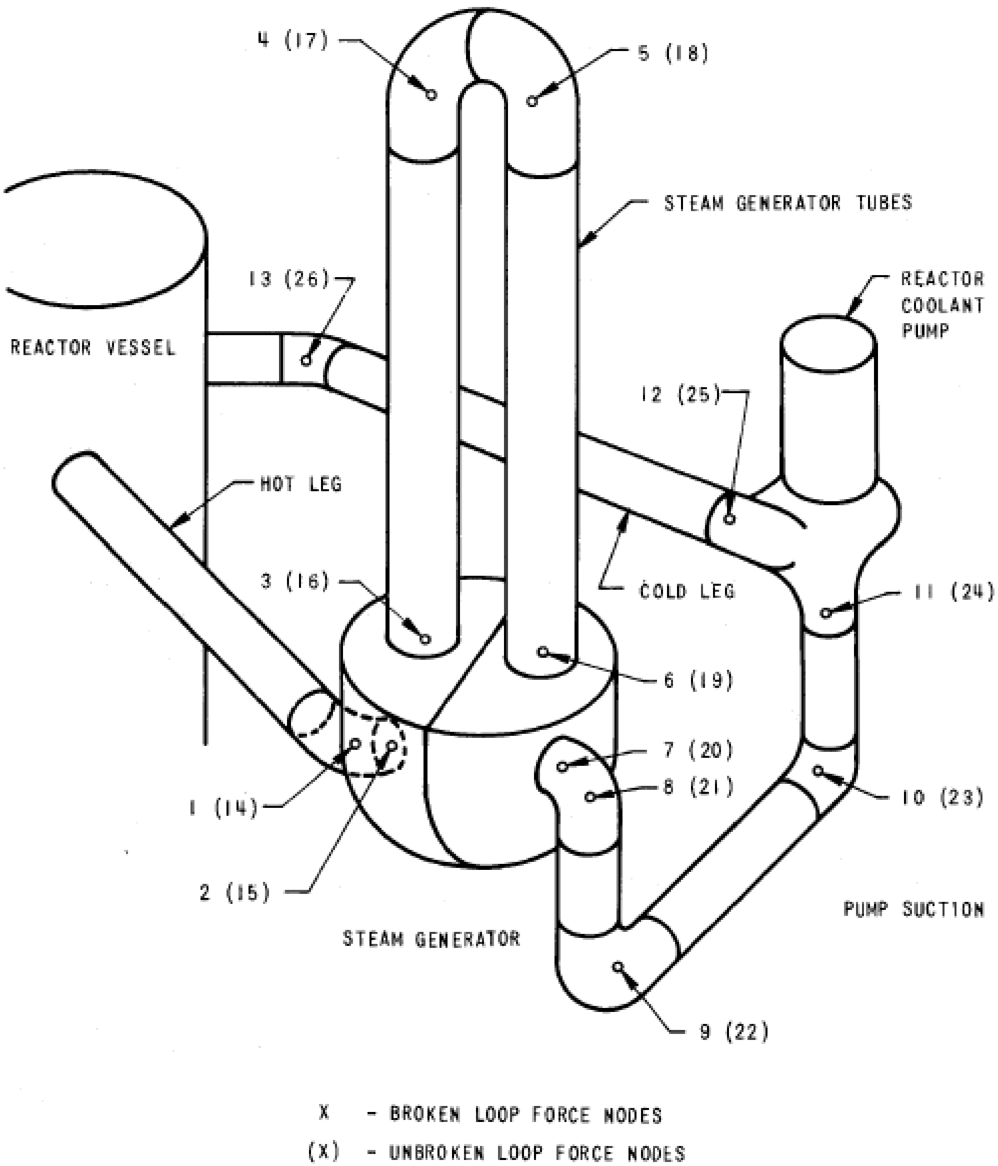
UNIT 1
DIABLO CANYON SITE

FIGURE 5.2-1
IDENTIFICATION AND LOCATION OF BELTLINE REGION MATERIALS FOR THE REACTOR VESSEL



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 5.2-2 REACTOR COOLANT LOOP MODEL

Revision 19 May 2010



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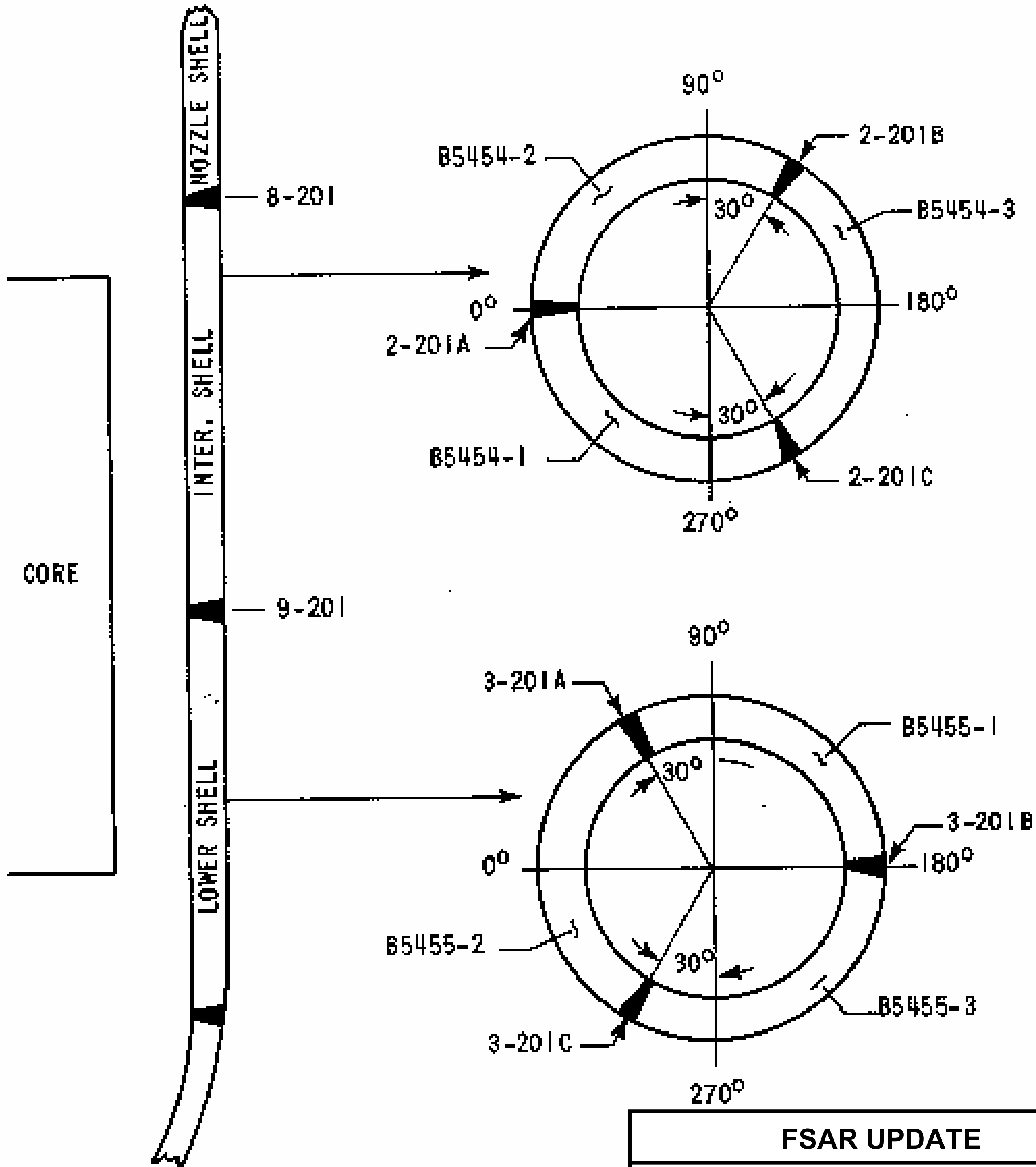
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 5.2-3 **THRUST RCL MODEL SHOWING HYDRAULIC FORCE LOCATIONS**



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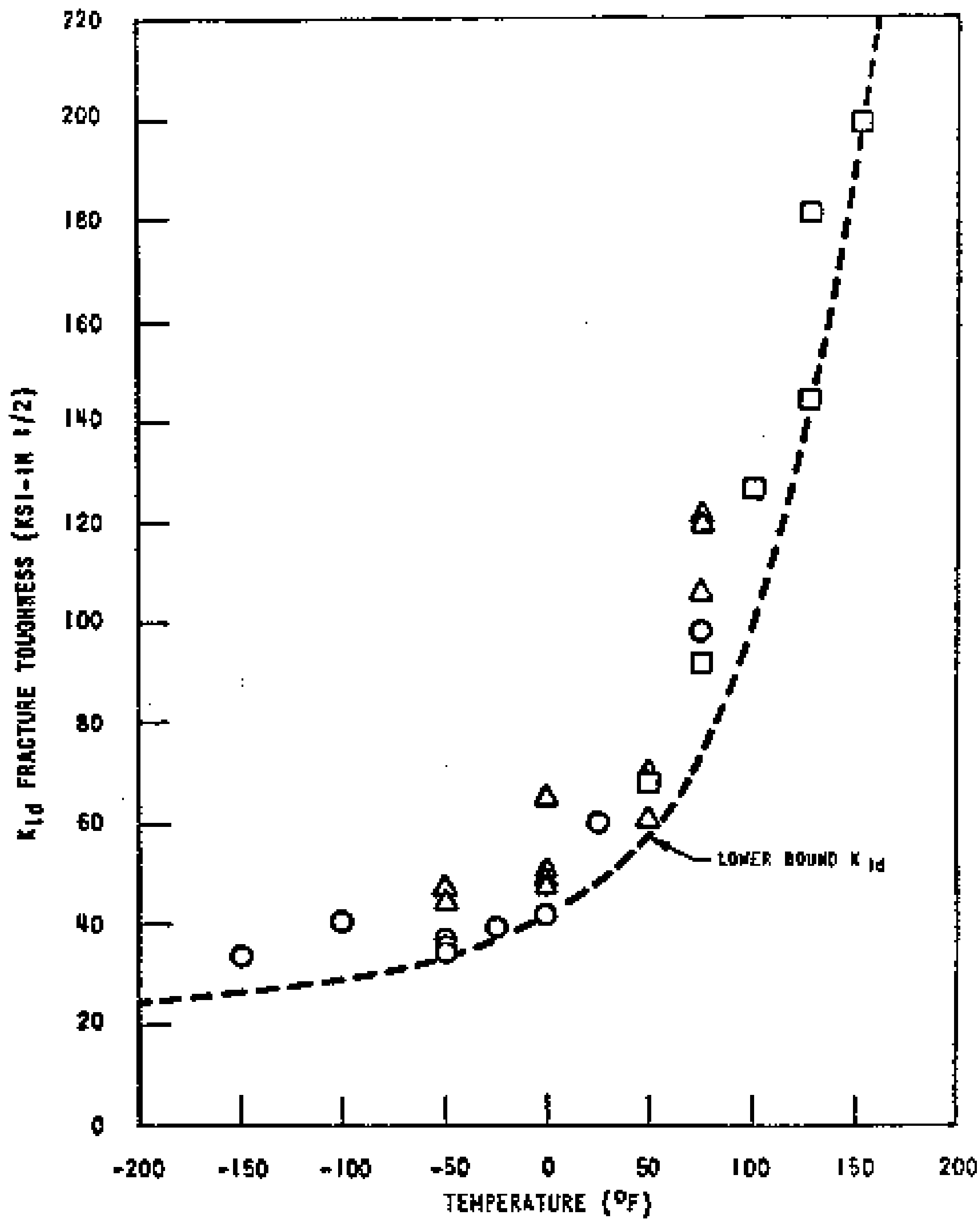
UNIT 2
DIABLO CANYON SITE

FIGURE 5.2-4
IDENTIFICATION AND LOCATION OF BELTLINE REGION MATERIAL FOR THE REACTOR VESSEL



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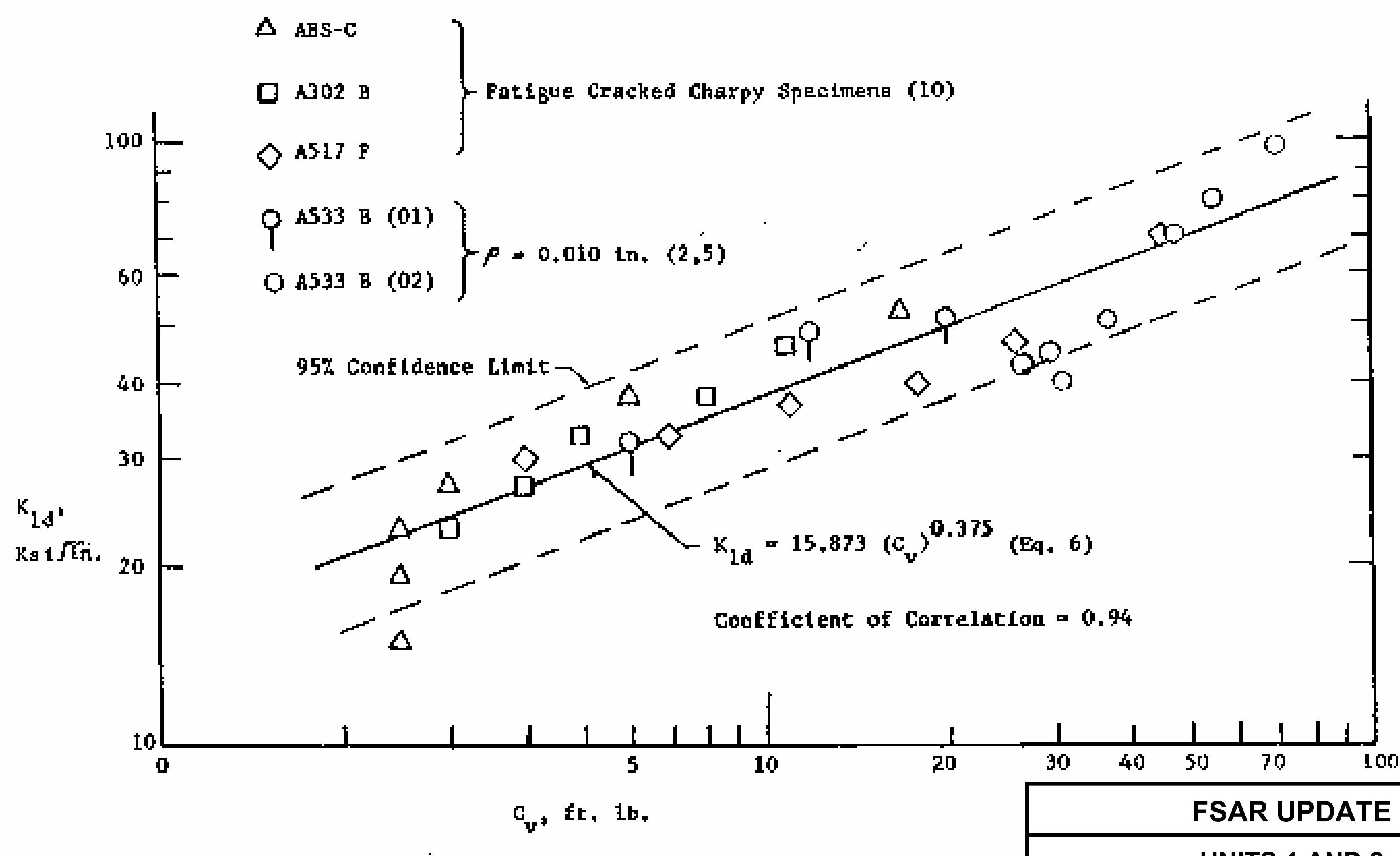
UNIT 1
DIABLO CANYON SITE

FIGURE 5.2-7
LOWER BOUND FRACTURE TOUGHNESS
A533 GRADE B CLASS 1 (REF WCAP-7623)



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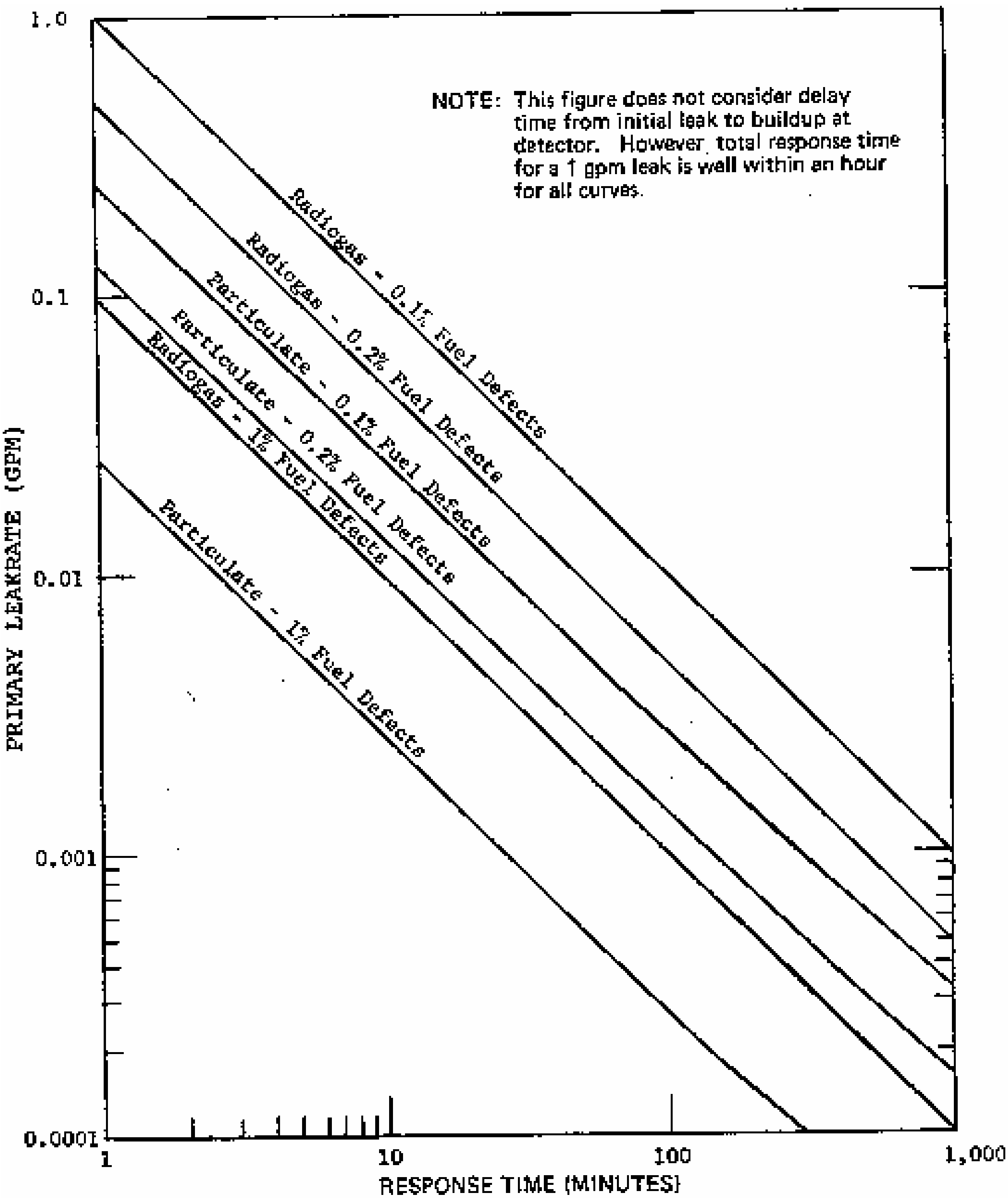
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 5.2-8 TRANSITION TEMPERATURE CORRELATION BETWEEN K_{Id} (DYNAMIC) AND C_v FOR A SERIES OF UNIRRADIAYED STEELS



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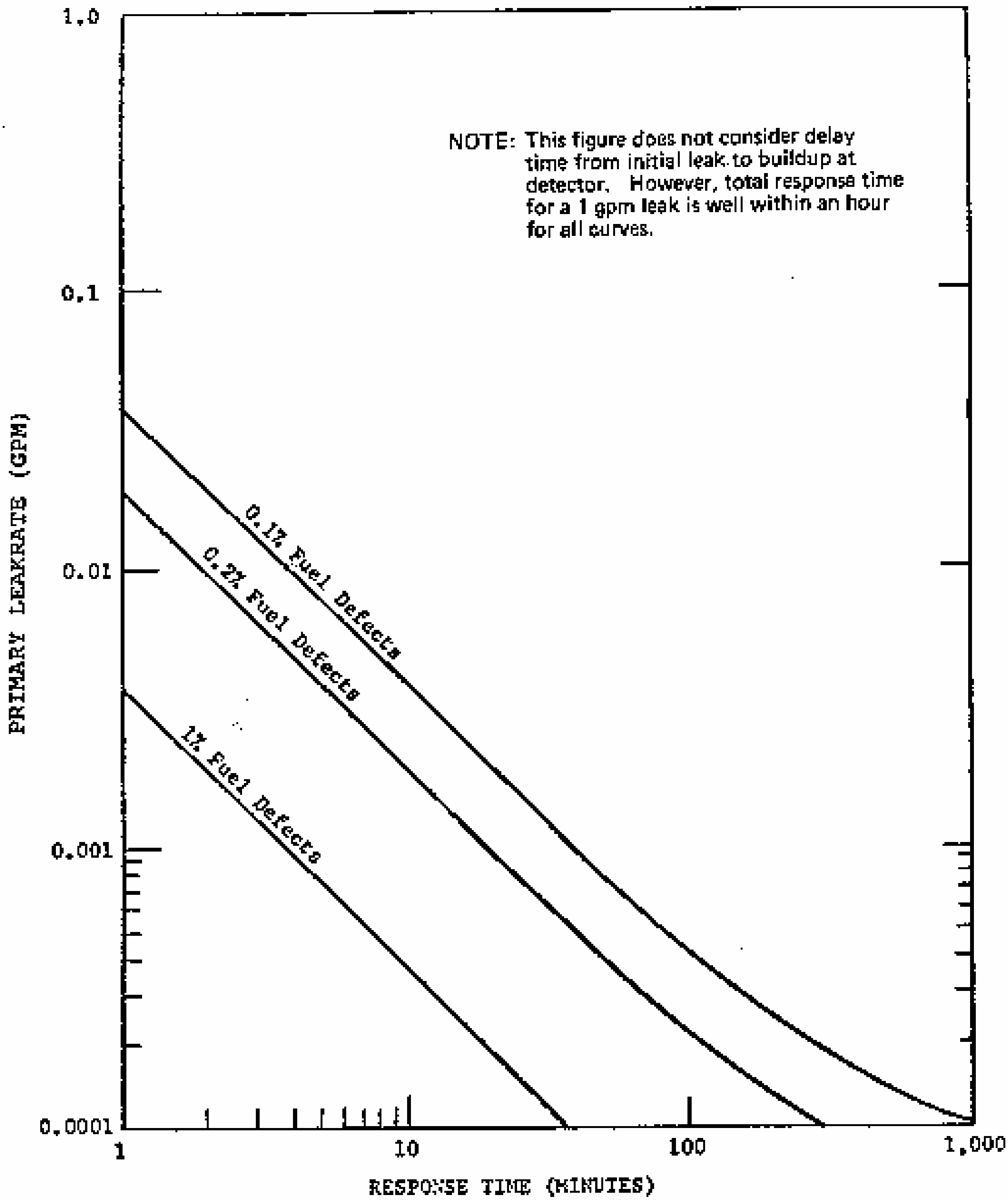
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 5.2-9
CONTAINMENT MONITOR RESPONSE TIME VERSUS PRIMARY LEAKRATE



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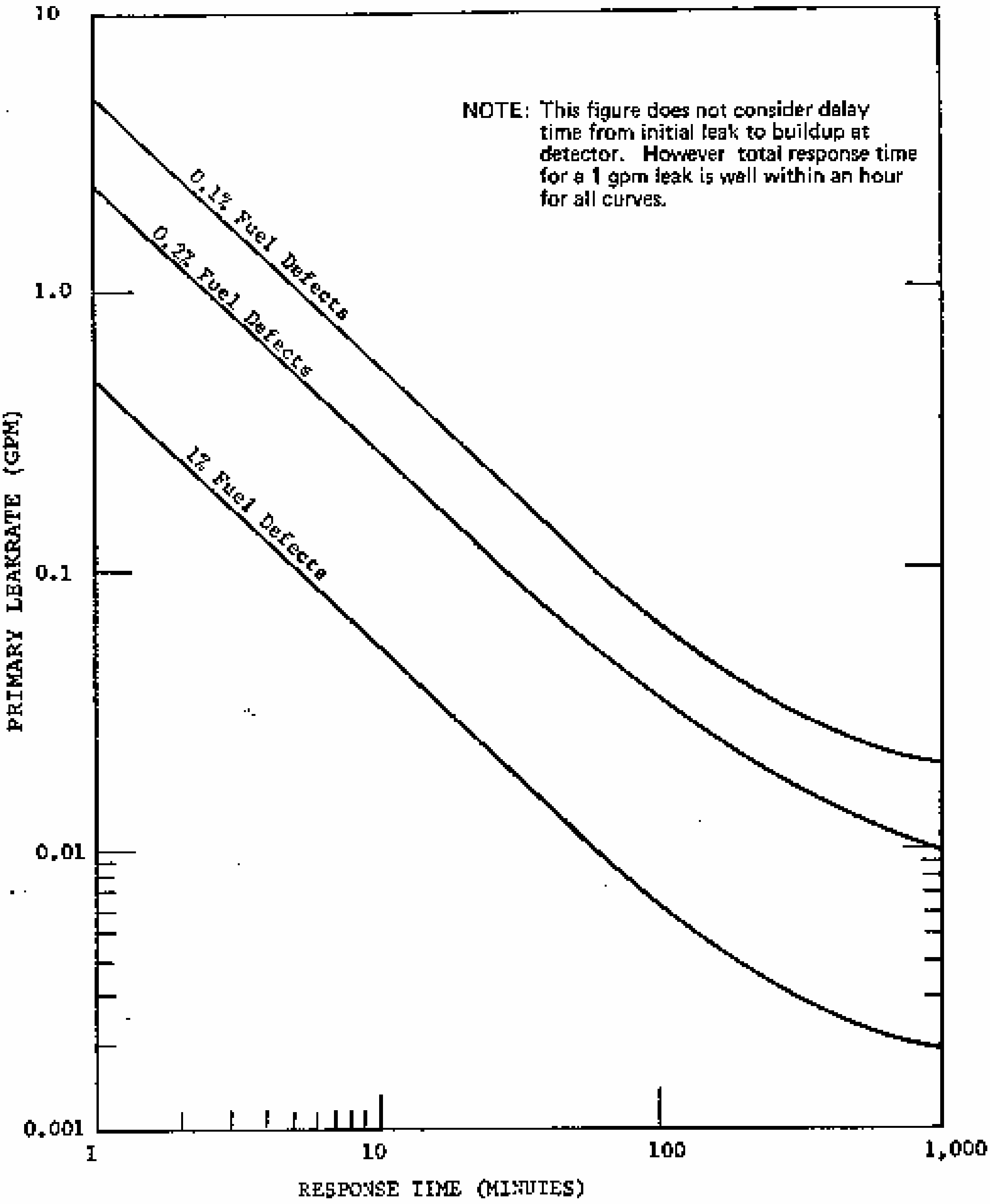
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 5.2-10
AIR EJECTOR RADIOGAS MONITOR RESPONSE TIME VERSUS PRIMARY LEAKRATE



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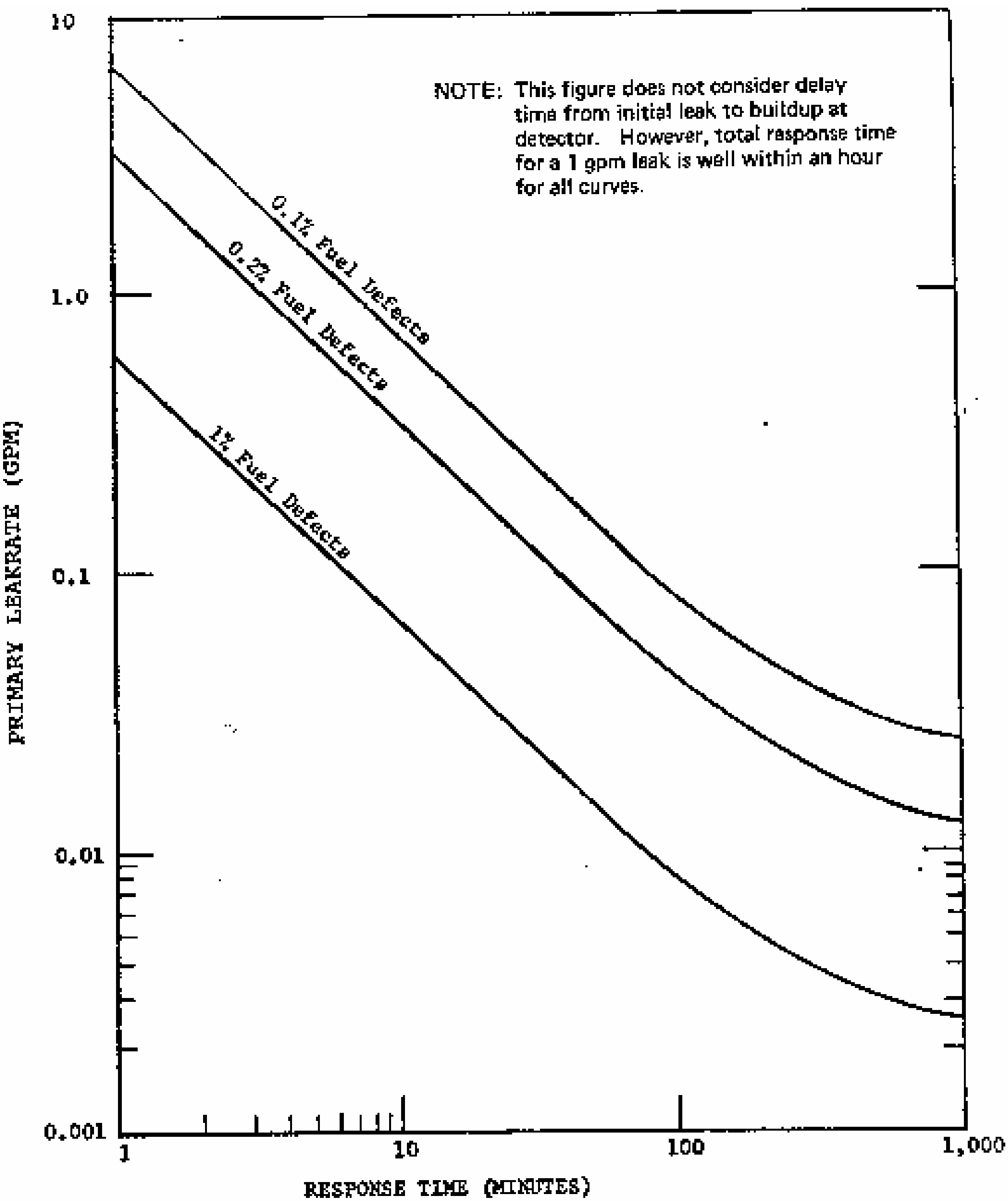
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 5.2-11 BLOWDOWN LIQUID MONITOR RESPONSE TIME VERSUS PRIMARY LEAKRATE



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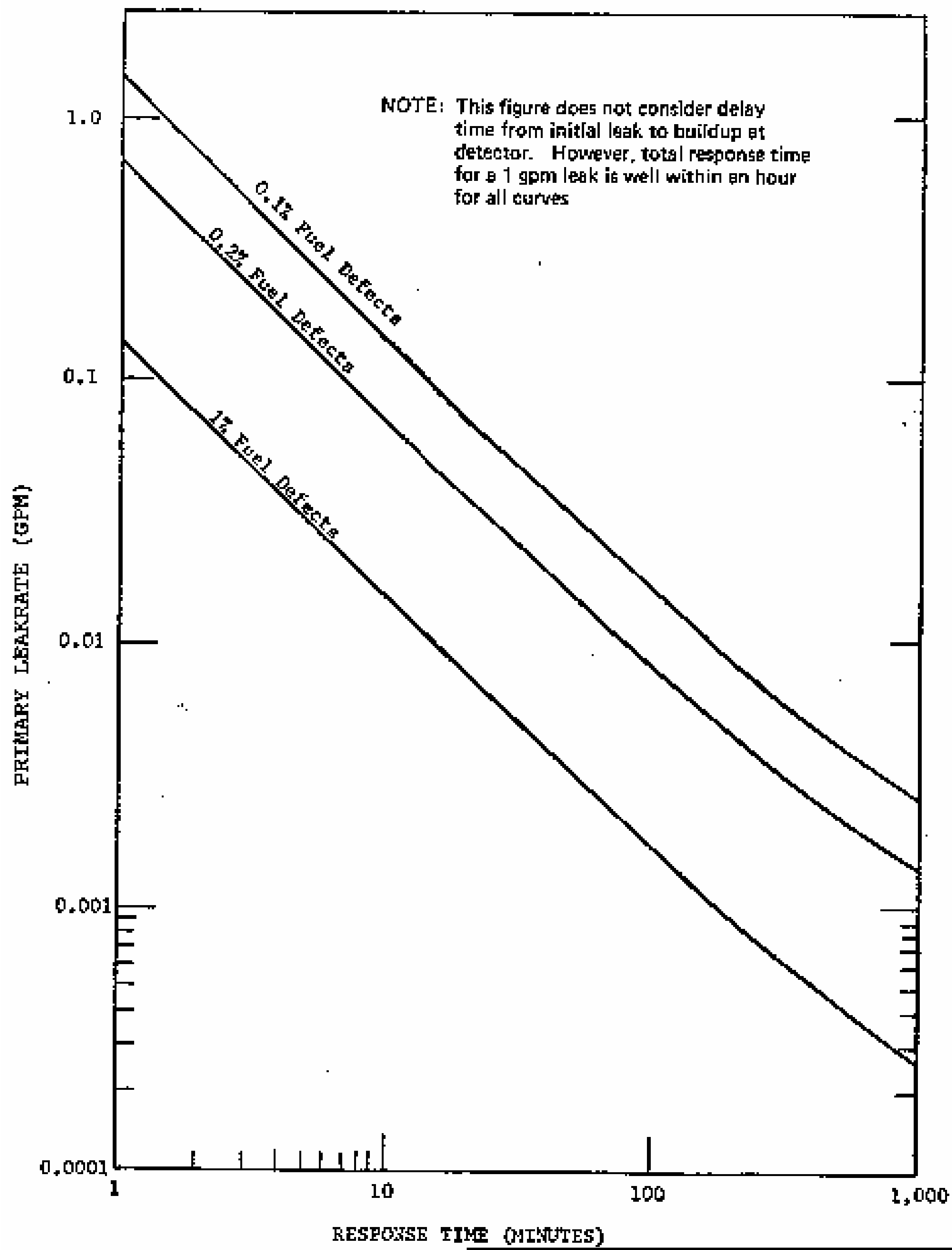
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 5.2-12 CONTAINMENT COOLING WATER LIQUID MONITOR RESPONSE TIME VERSUS PRIMARY LEAKRATE



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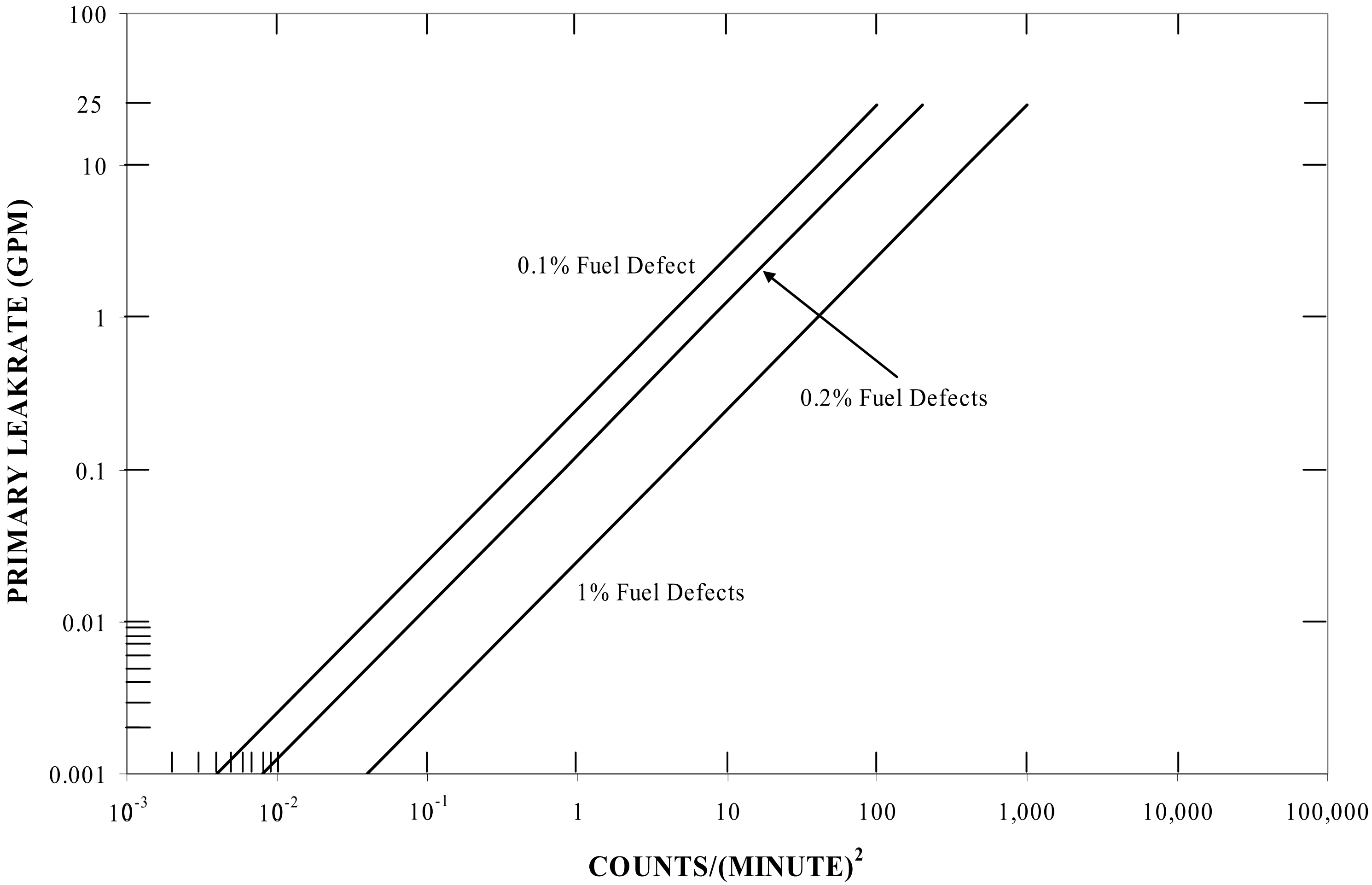
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 5.2-13
CONTAINMENT AREA MONITOR RESPONSE TIME VERSUS PRIMARY LEAKRATE



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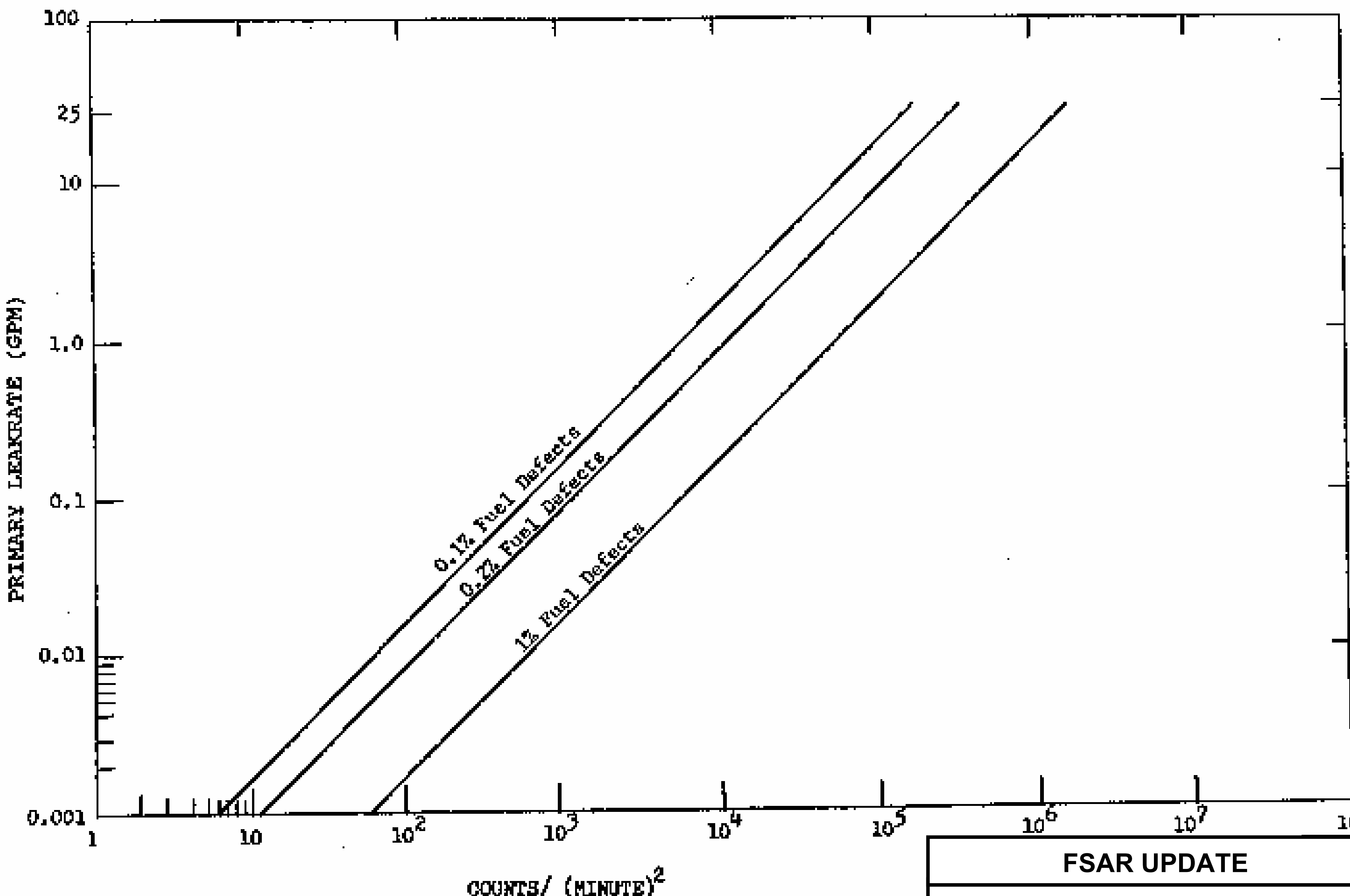
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 5.2-14 CONTAINMENT RADIOGAS MONITOR COUNT RATE VERSES PRIMARY LEAKRATE AFTER EQUILIBRIUM



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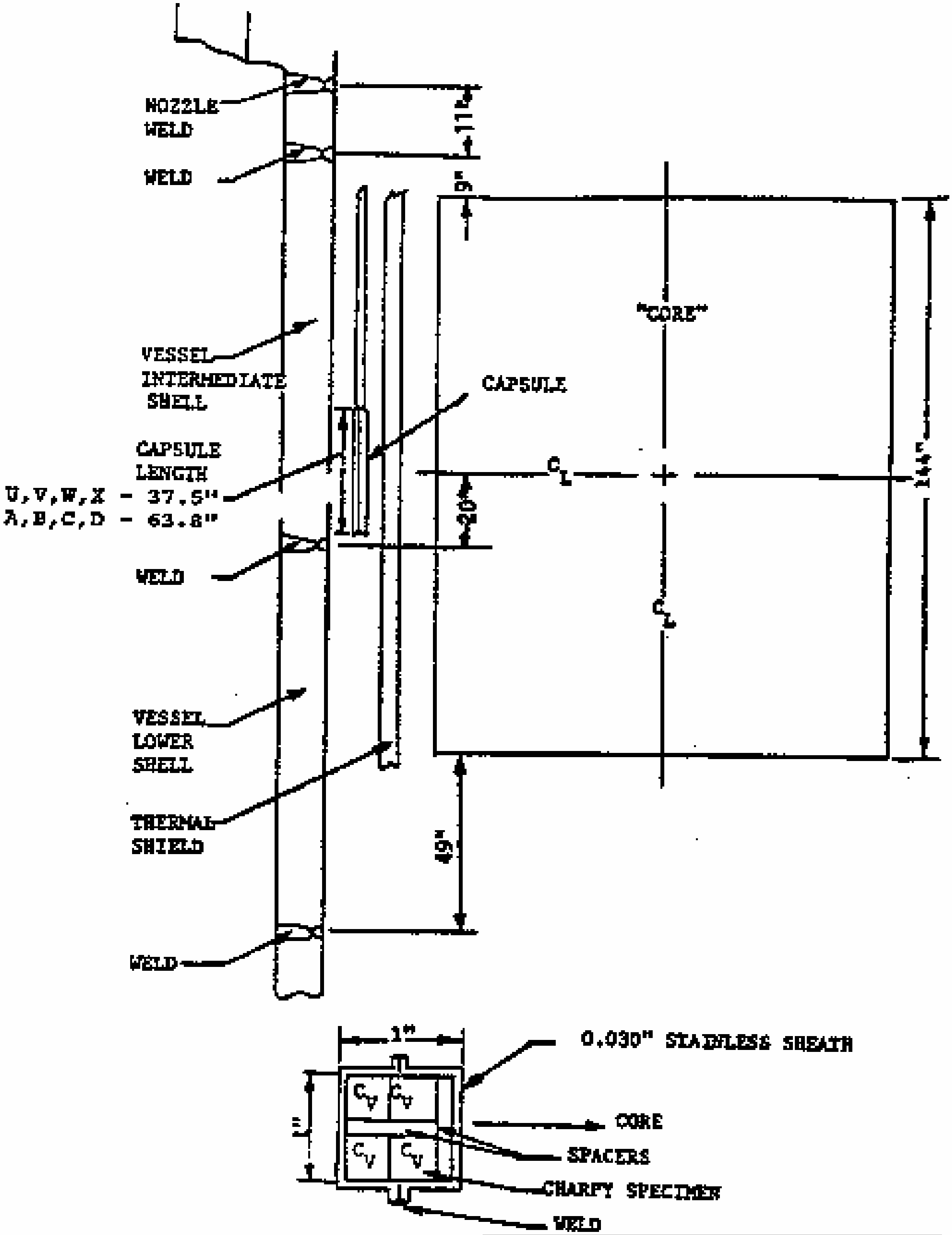
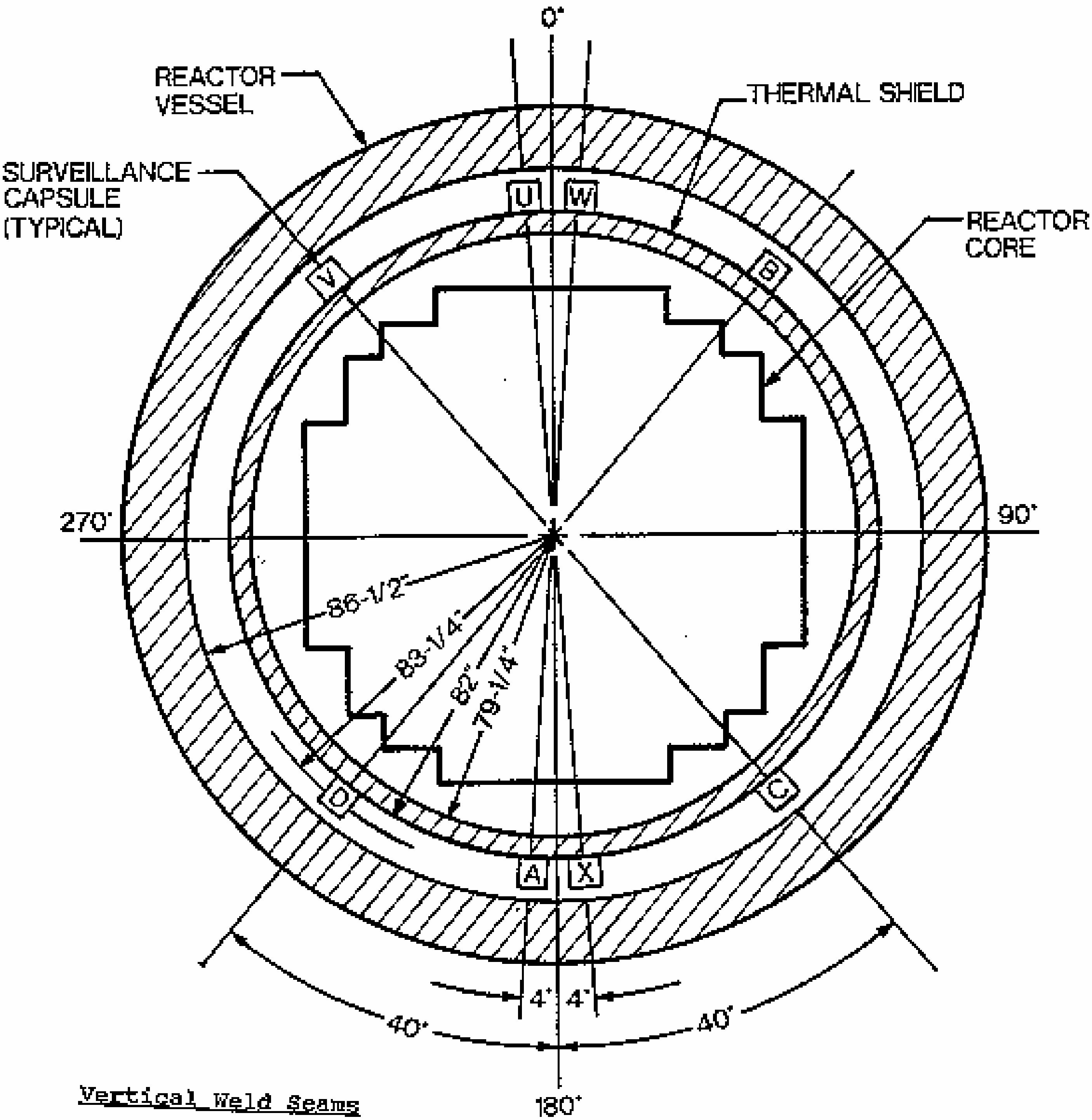
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 5.2-15 CONTAINMENT PARTICULATE MONITOR COUNT RATE VERSUS PRIMARY LEAKRATE AFTER EQUILIBRIUM



FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 5.2-16 SURVEILLANCE CAPSULE ELEVATION VIEW



Vertical Weld Seams

Int. Shell	0°,	120°,	240°
Lower Shell	60°,	180°,	300°

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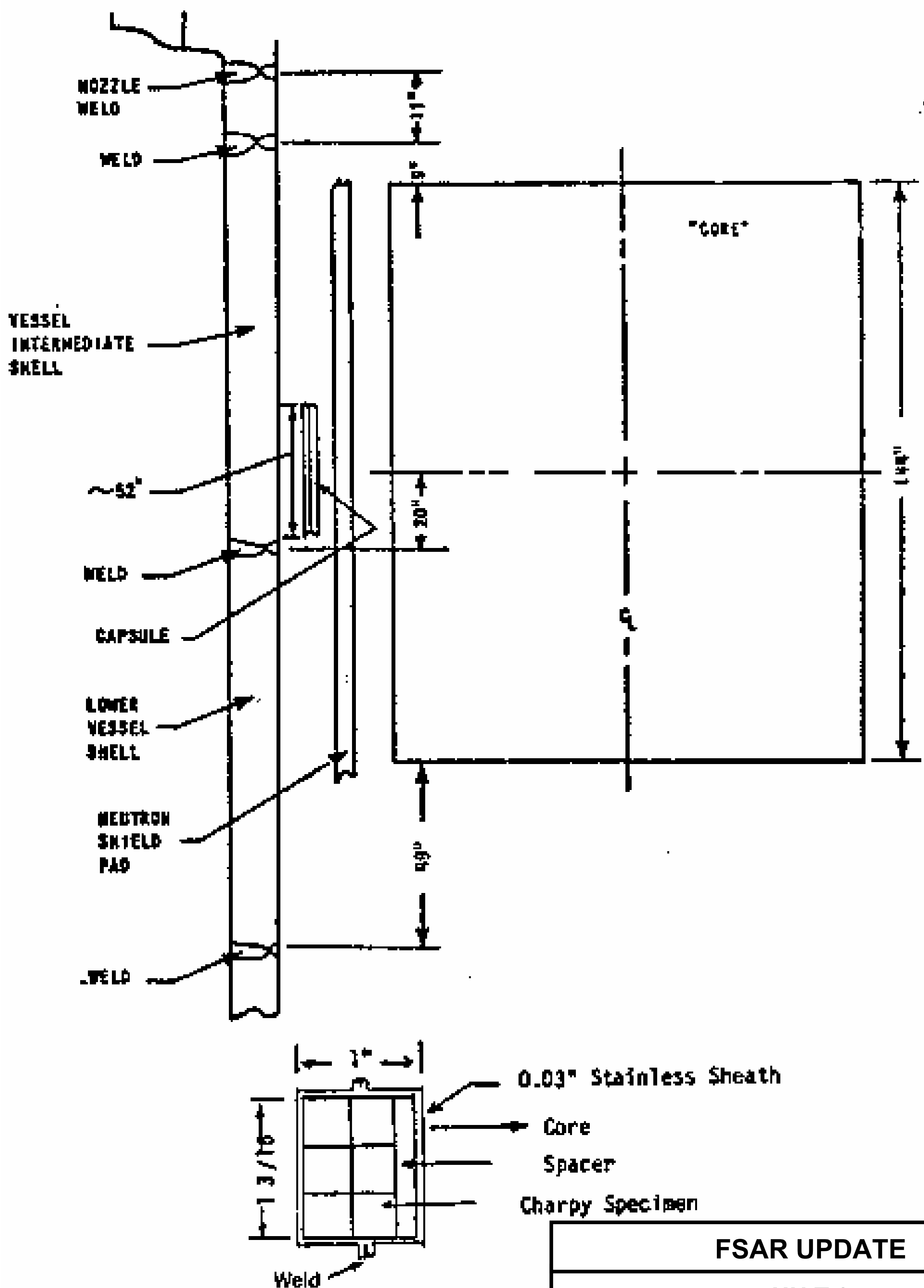
UNIT 1
DIABLO CANYON SITE

FIGURE 5.2-17
SURVEILLANCE CAPSULE
PLAN VIEW



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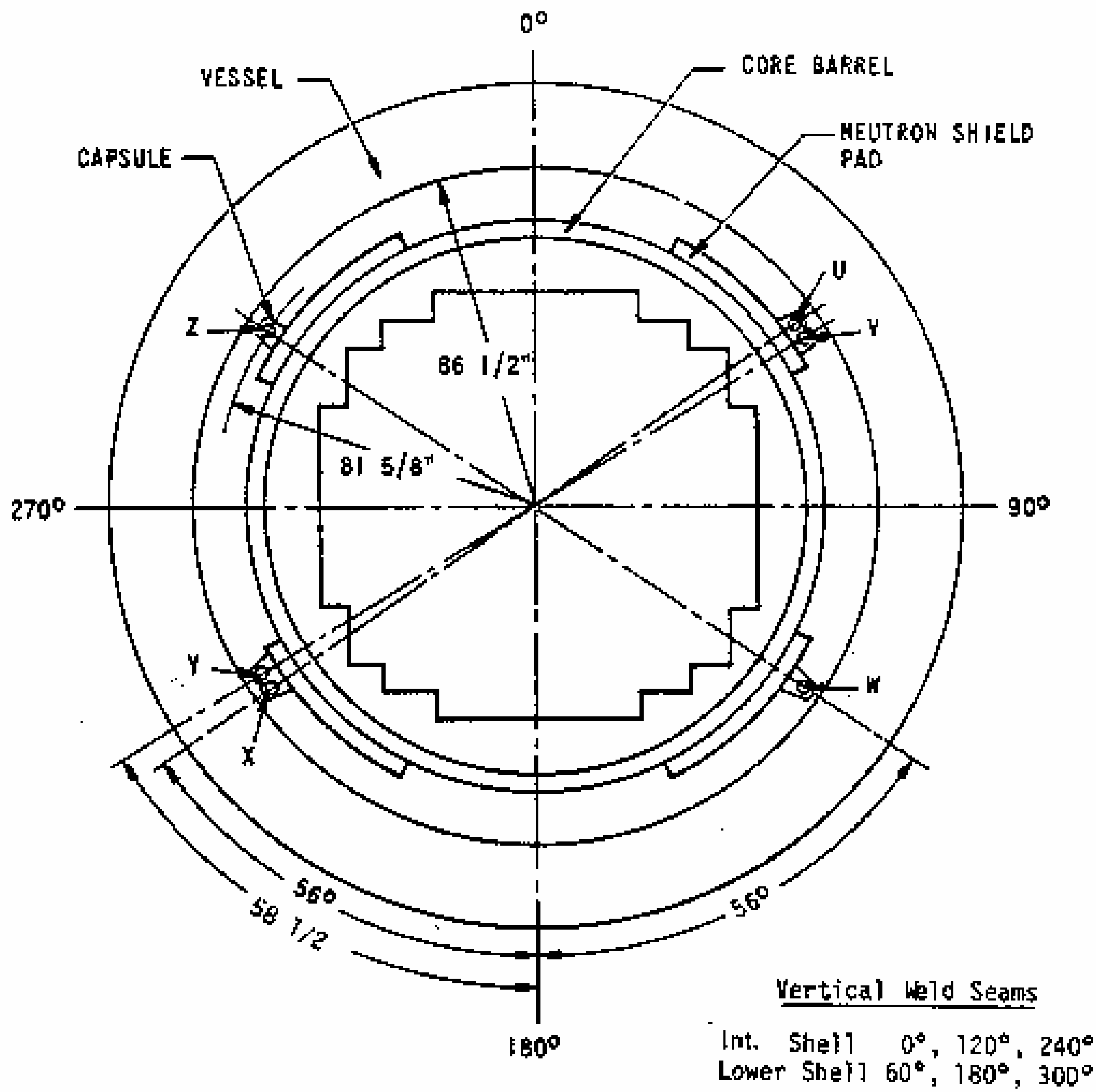
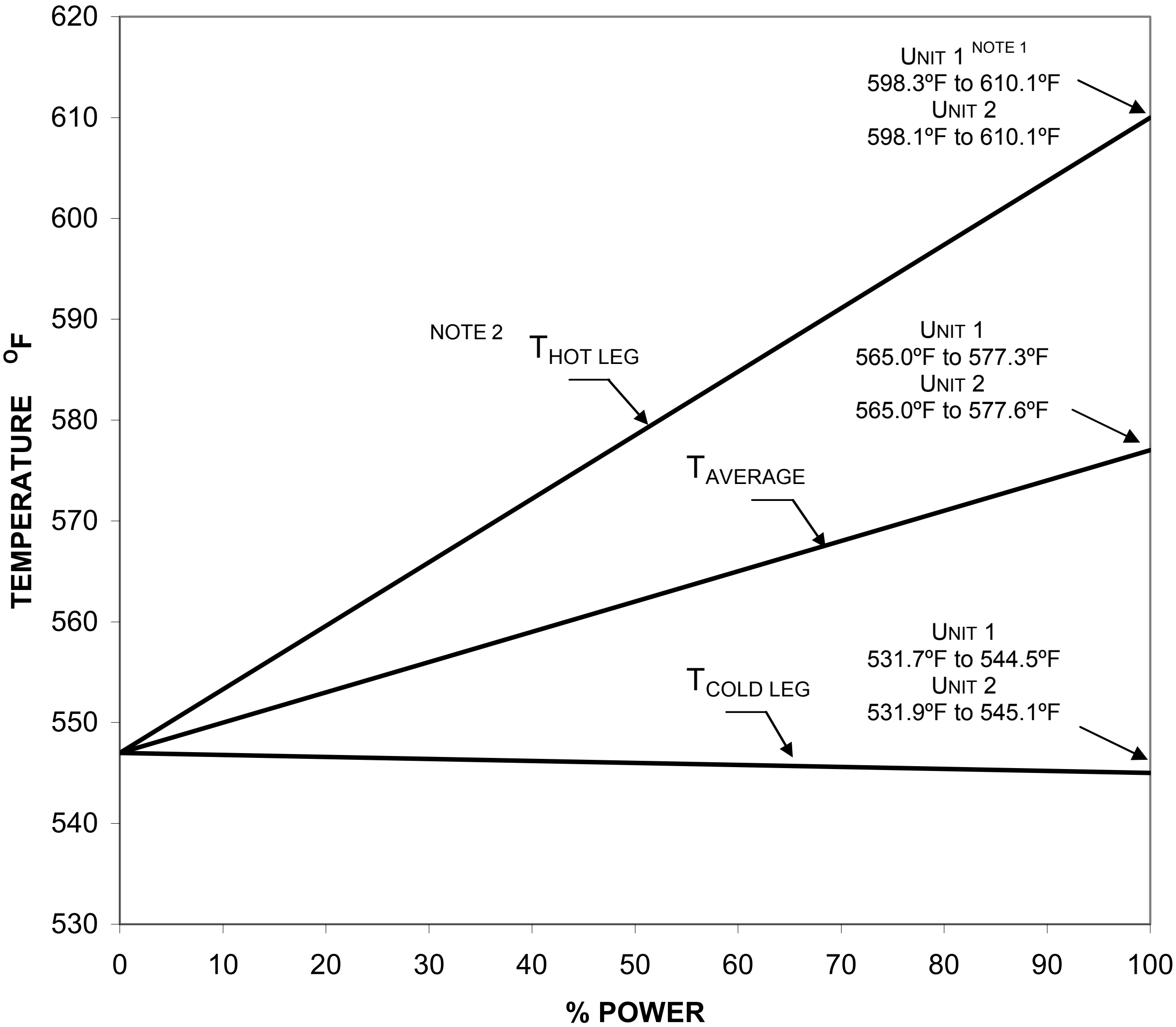
UNIT 2
DIABLO CANYON SITE

FIGURE 5.2-18

SURVEILLANCE CAPSULE ELEVATION VIEW



FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 5.2-19 SURVEILLANCE CAPSULE PLAN VIEW



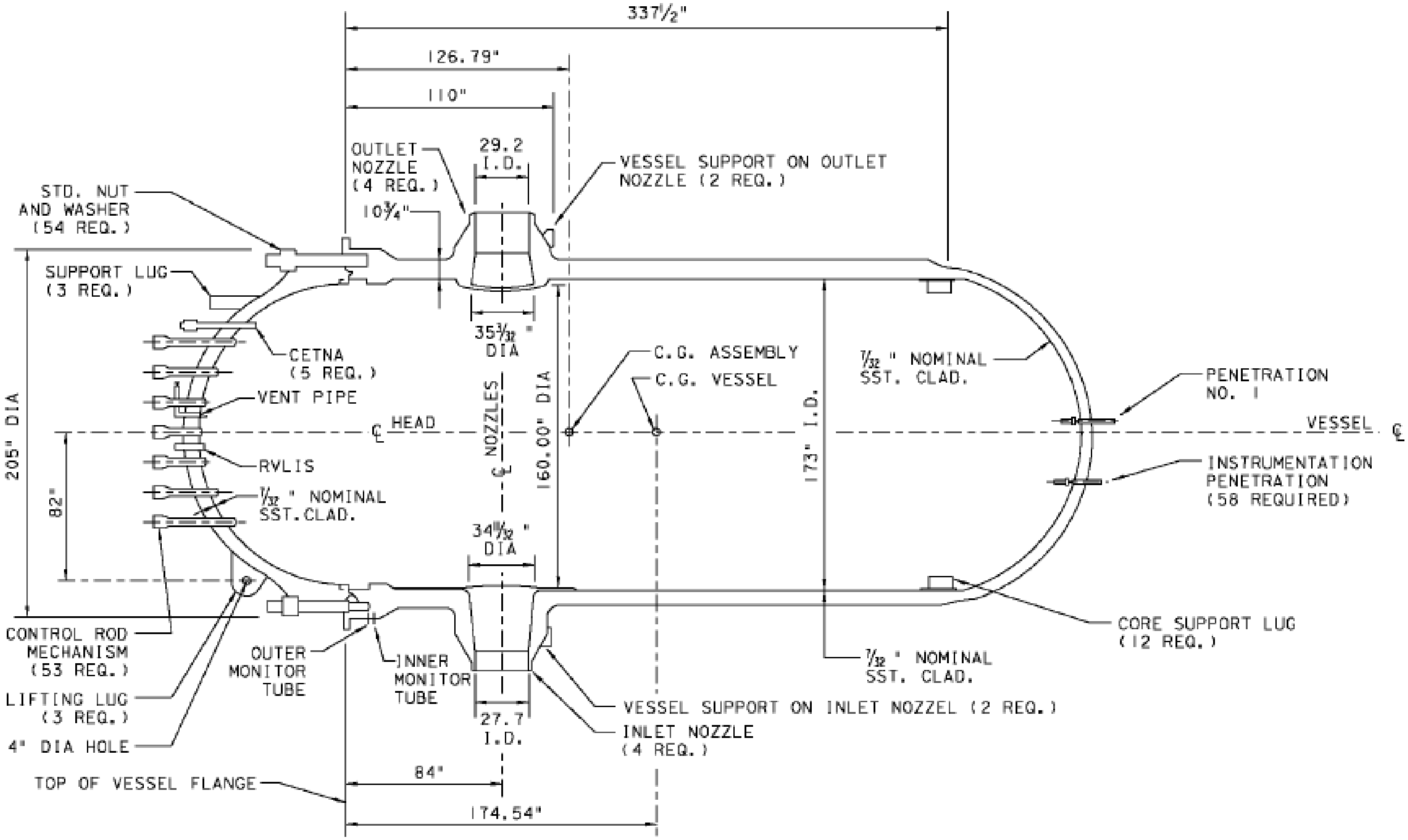
NOTE 1: UNIT 1 AND UNIT 2 DESIGN VALUE RANGES FOR FULL POWER.

NOTE 2: THE PLOTS SHOWN ARE FOR THE MAXIMUM $T_{HOT\ LEG}$, $T_{AVERAGE}$, AND $T_{COLD\ LEG}$ TEMPERATURES AT FULL POWER.

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 5.3-1
HOT LEG, COLD LEG, AND AVERAGE REACTOR COOLANT LOOP TEMPERATURE AS A FUNCTION OF PERCENT FULL POWER



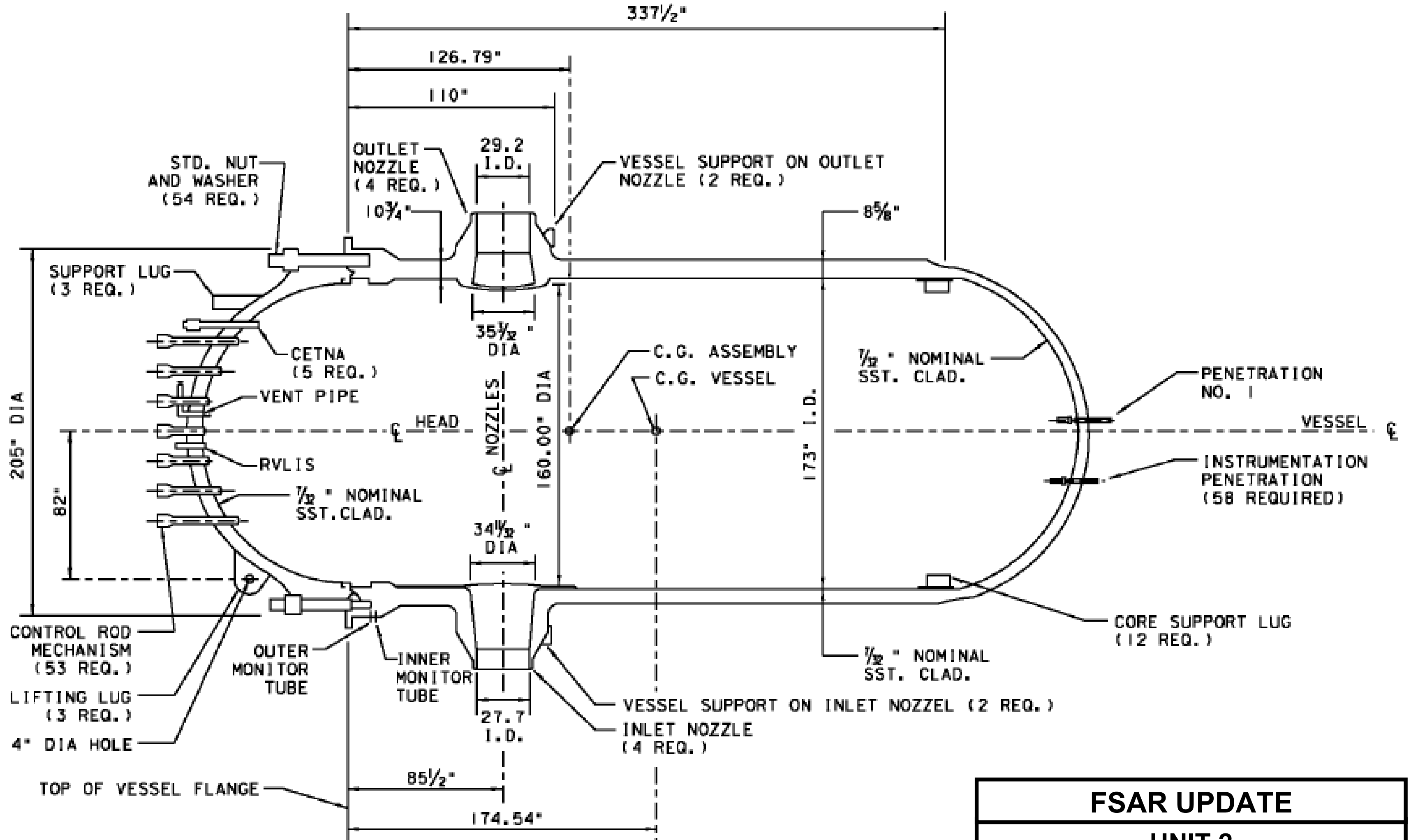
SECTIONAL ELEVATION

FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

FIGURE 5.4-1
REACTOR VESSEL

Revision 20 November 2011



SECTIONAL ELEVATION

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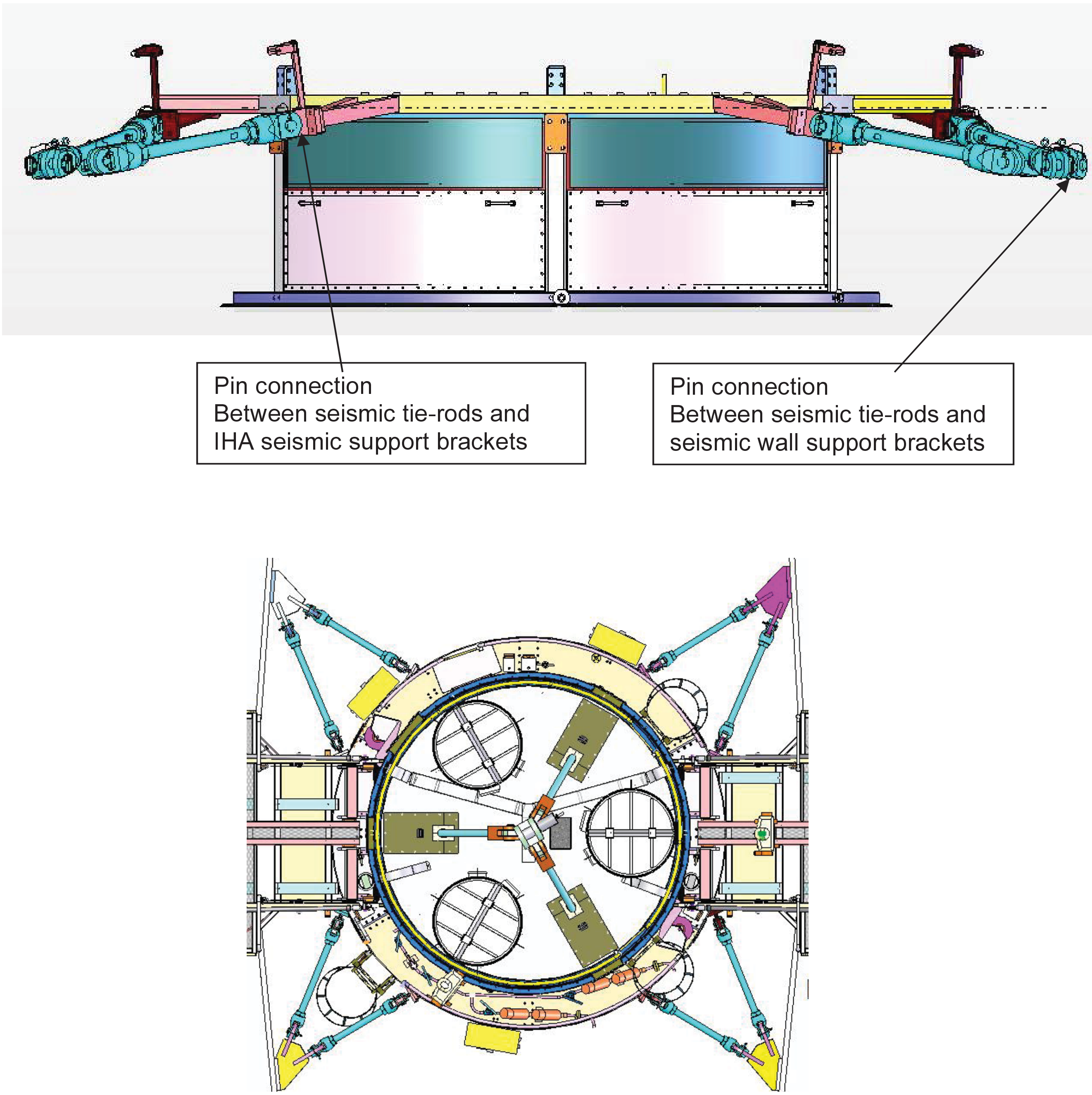
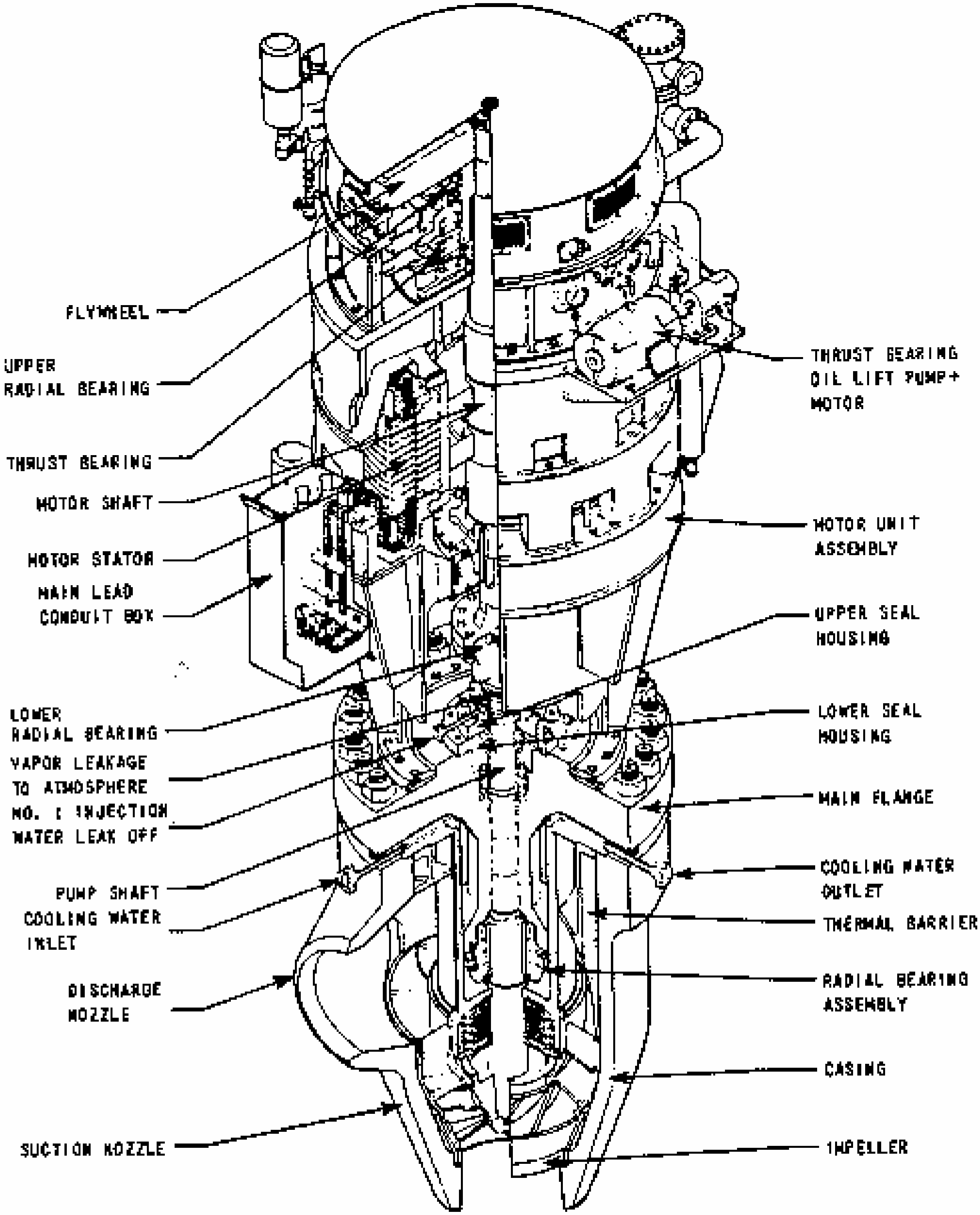
UNIT 2
DIABLO CANYON SITE

FIGURE 5.4-2
REACTOR VESSEL

Revision 20 November 2011



FSAR UPDATE
UNITS 1 AND 2
DIABLO CANYON SITE
FIGURE 5.4-3
INTEGRATED HEAD ASSEMBLY SEISMIC
SUPPORT STRUCTURE ASSEMBLY



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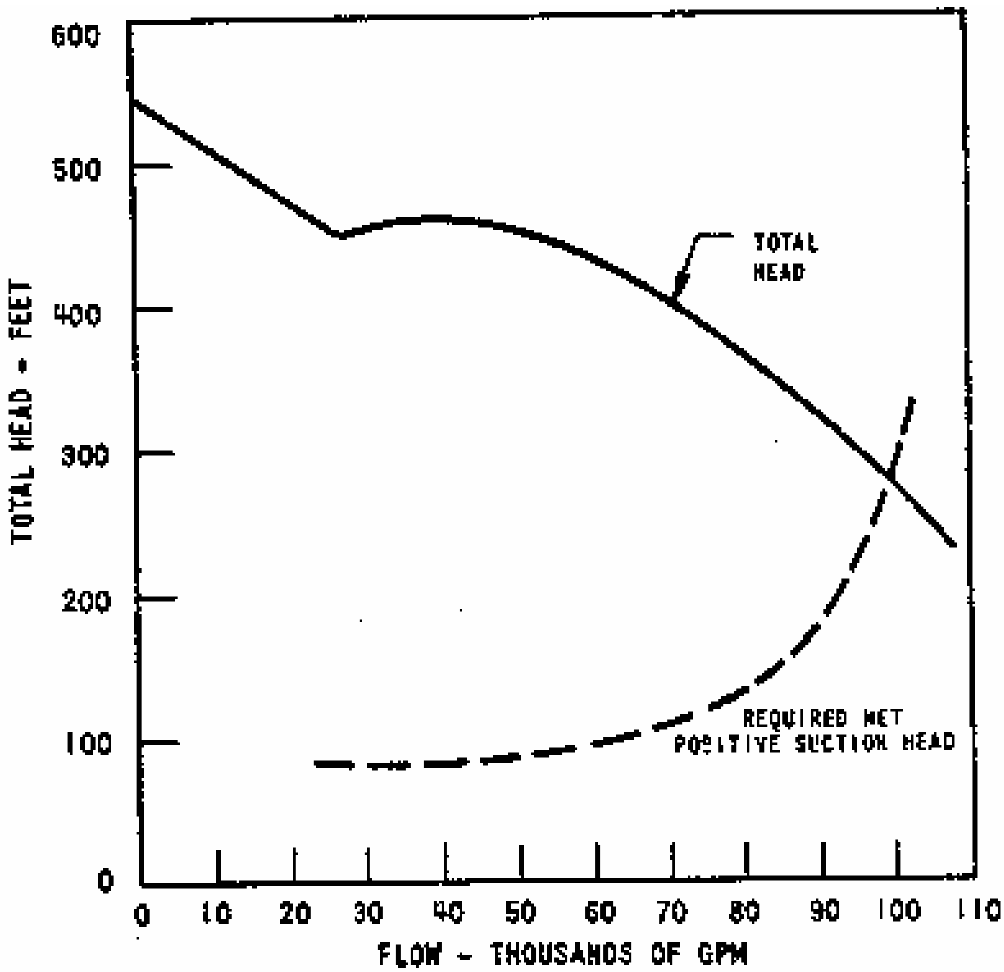
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 5.5-1
REACTOR COOLANT CONTROLLED LEAKAGE PUMP



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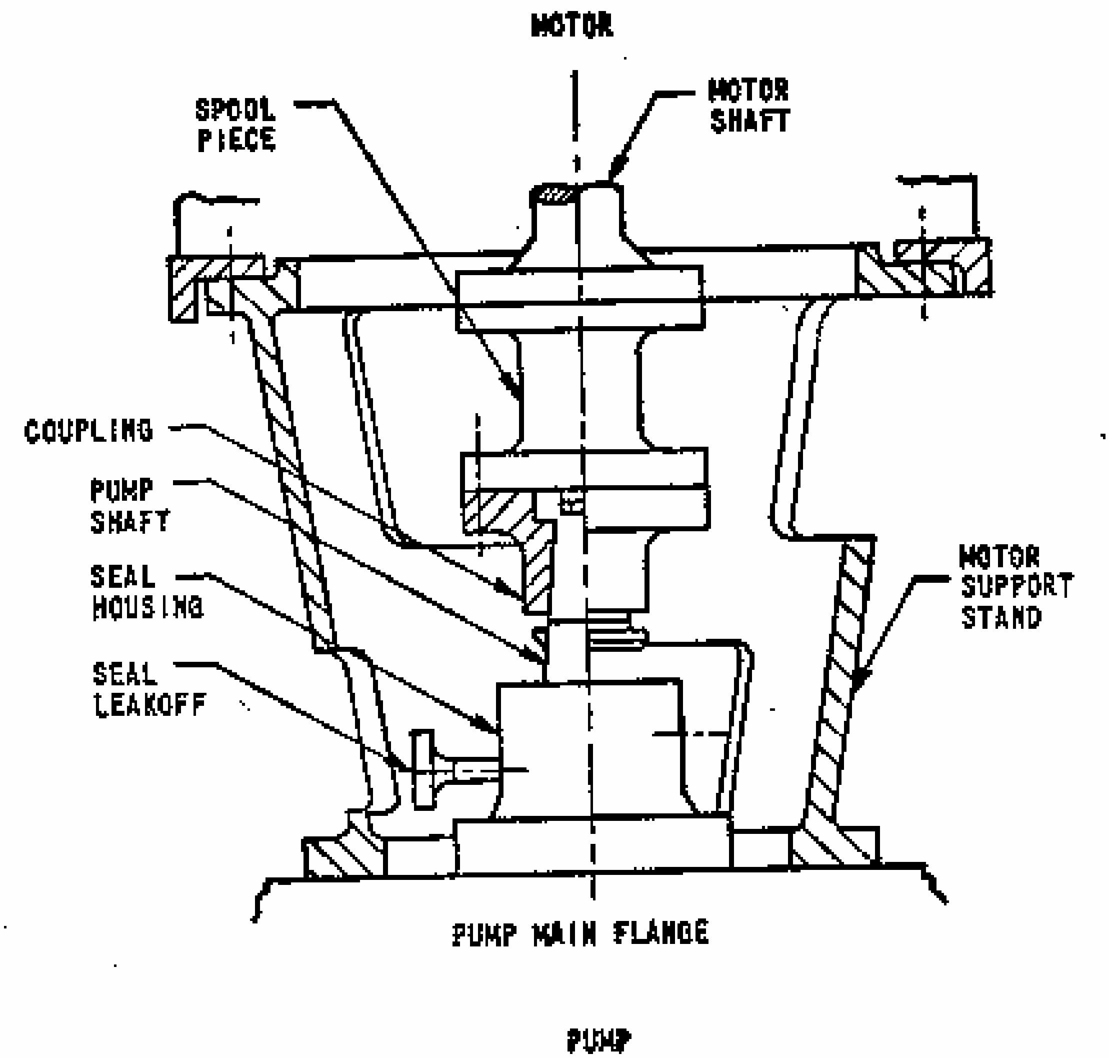
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 5.5-2 REACTOR COOLANT PUMP ESTIMATED PERFORMANCE CHARACTERISTICS

Revision 11 November 1996



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UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 5.5-3 REACTOR COOLANT PUMP SPOOL PIECE AND MOTOR SUPPORT STAND

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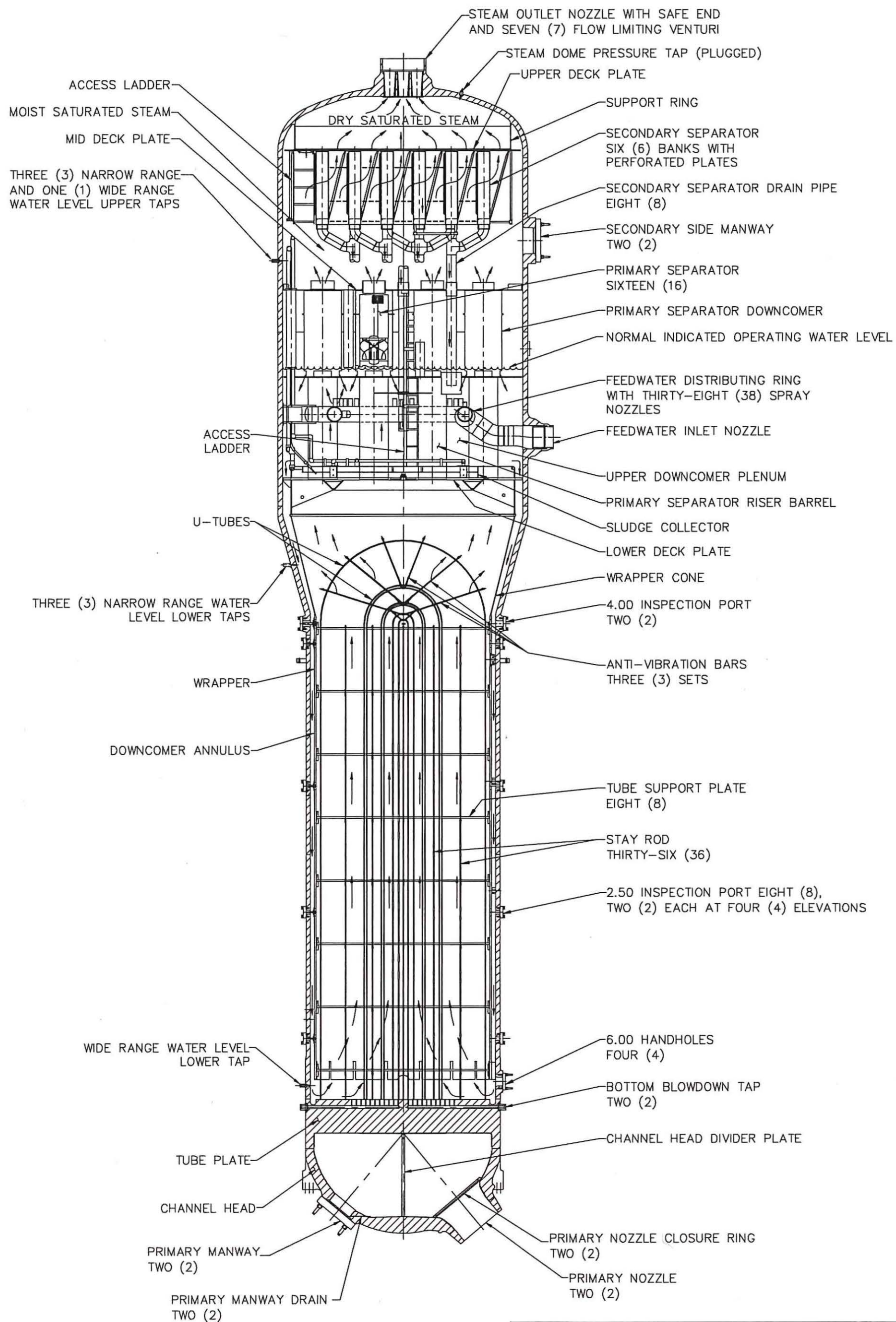

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FIGURE 5.5-4
WESTINGHOUSE DELTA 54
STEAM GENERATOR

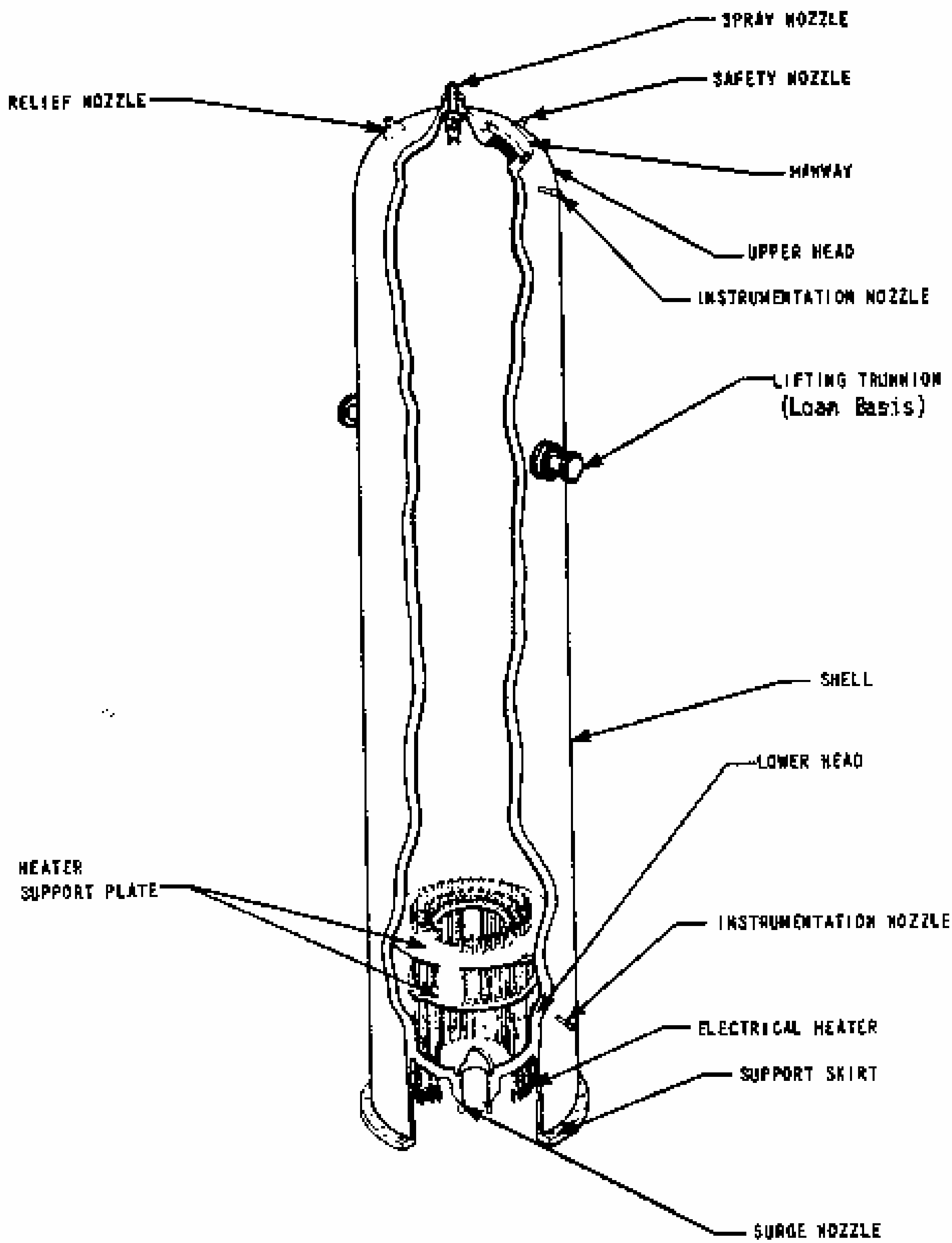

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FIGURE 5.5-8 PRESSURIZER

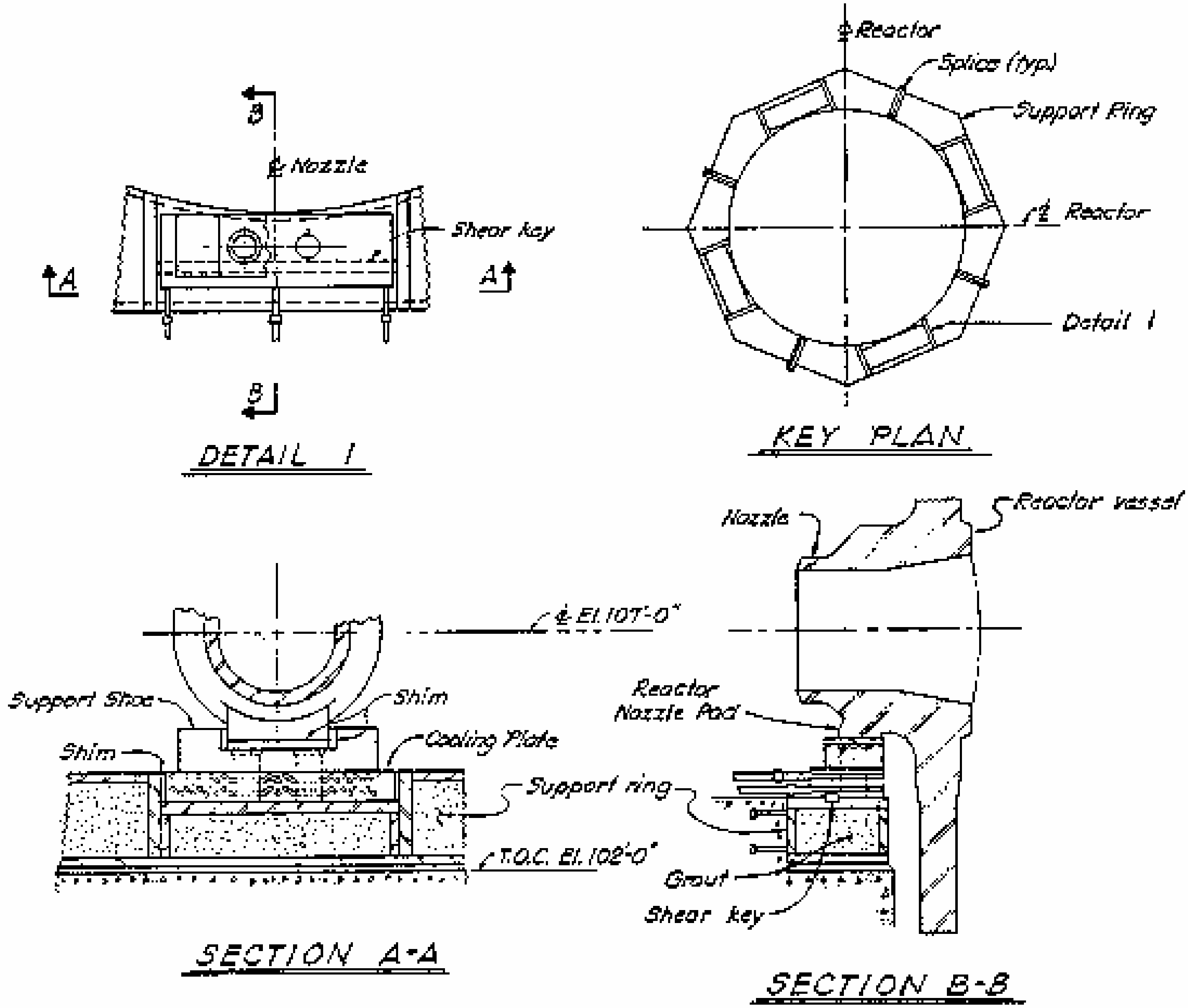

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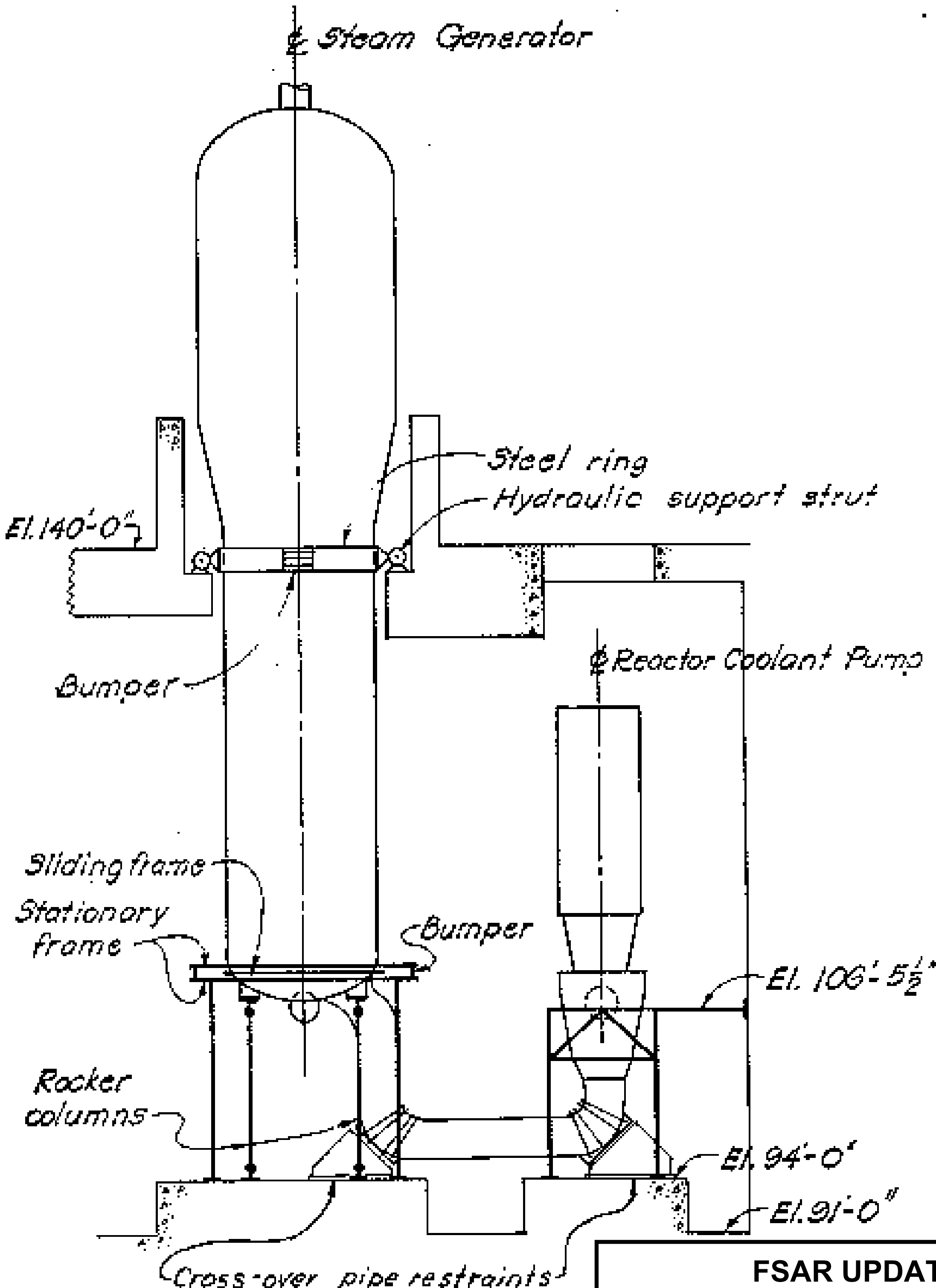
FIGURE 5.5-9 REACTOR SUPPORT



* Crossover pipe restraints Inactive.

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FIGURE 5.5-10

STEAM GENERATOR AND REACTOR COOLANT PUMP SUPPORTS

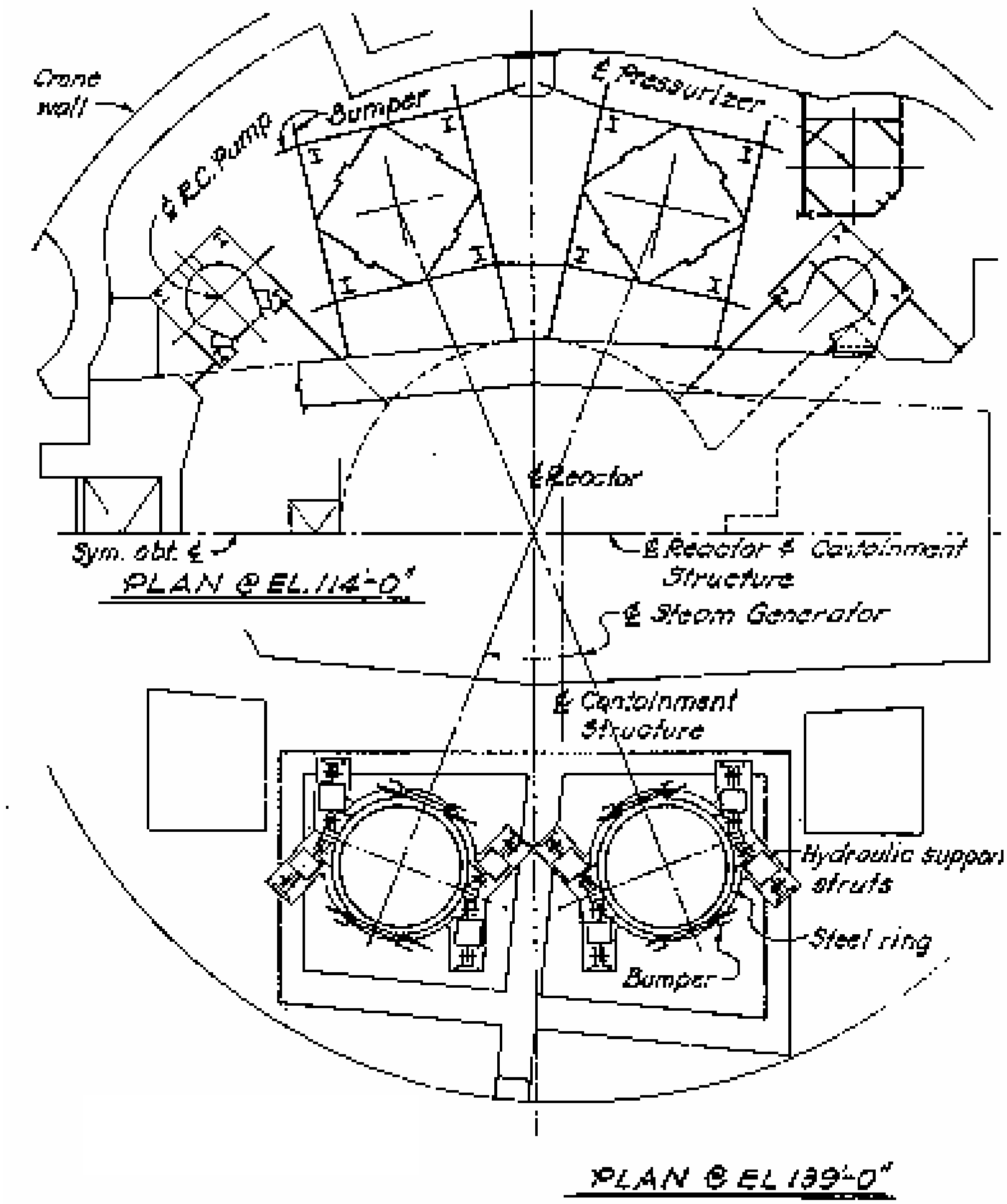

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FIGURE 5.5-11 COMPONENT SUPPORTS

Revision 18 October 2008

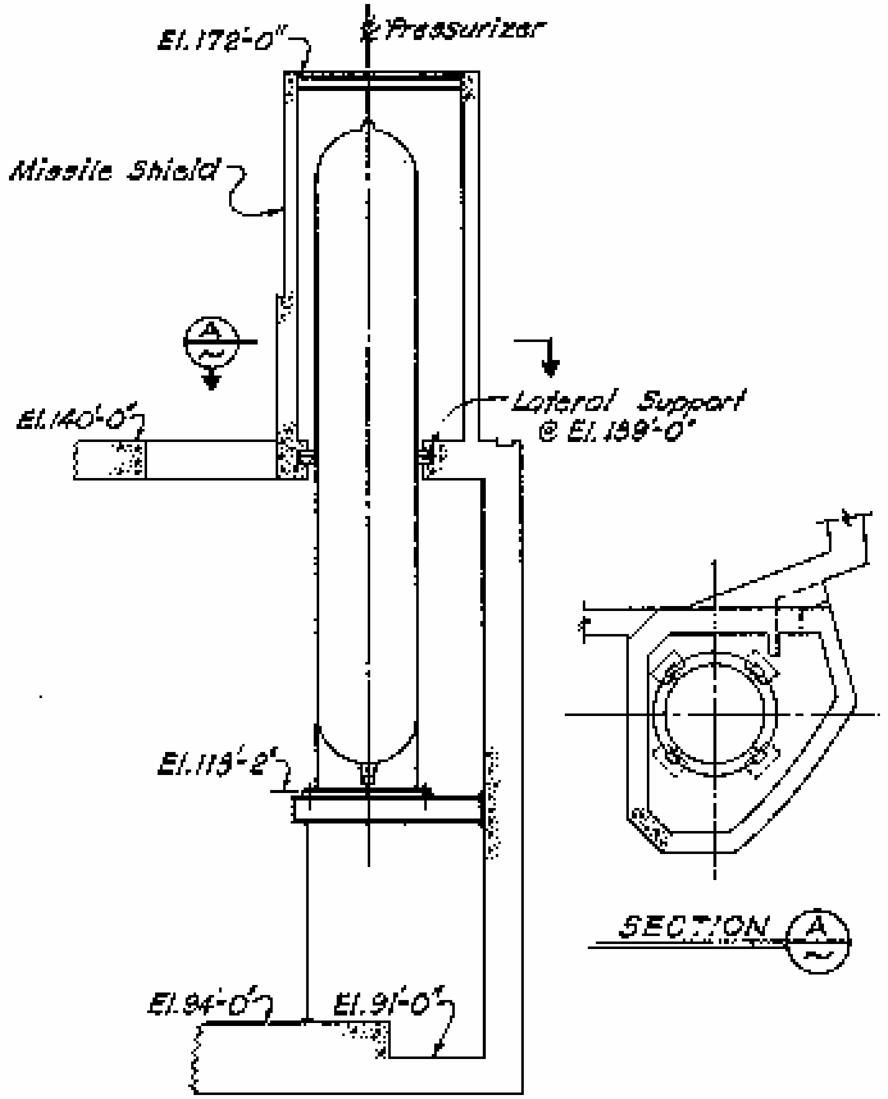

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FIGURE 5.5-12
PRESSURIZER SUPPORT

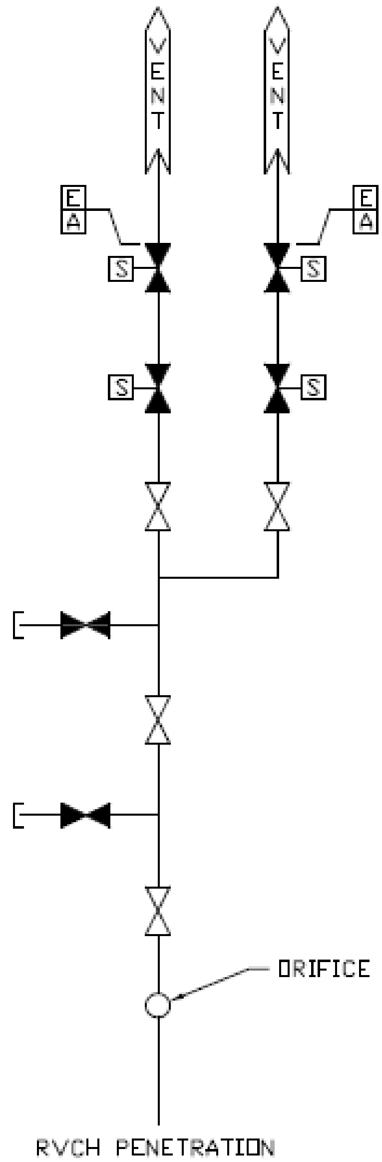

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FIGURE 5.5-14

SCHEMATIC FLOW DIAGRAM OF THE REACTOR VESSEL HEAD VENT SYSTEM

Revision 20 November 2011

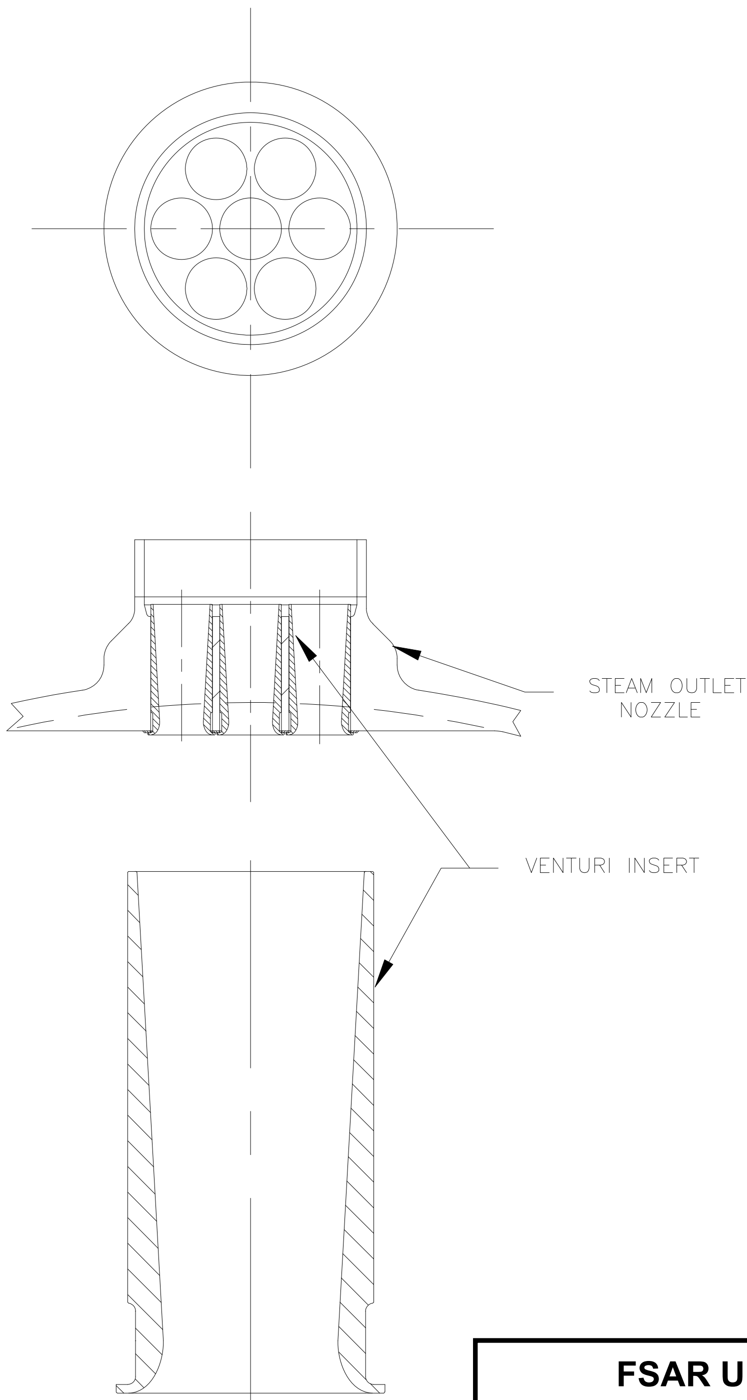

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FIGURE 5.5-18
SEVEN NOZZLE RSG OUTLET
FLOW RESTRICTOR

APPENDIX 5.5A

CAPABILITY OF MAIN STEAM ISOLATION AND CHECK VALVES TO WITHSTAND CLOSURE LOADS FOLLOWING A POSTULATED MAIN STEAM LINE BREAK

Prepared by
Westinghouse Electric Corporation

Appendix 5.5A

CAPABILITY OF MAIN STEAM ISOLATION AND CHECK VALVES TO WITHSTAND CLOSURE LOADS FOLLOWING A POSTULATED MAIN STEAM LINE BREAK

5.5A.1 SUMMARY

During the postulated event of a pipe rupture in the main steam system, the check and isolation valves close under loading conditions that are much more severe than those encountered during normal plant operation. The analyses presented here demonstrate that both the main steam line check and isolation valves are capable of successfully performing their functions during this event.

5.5A.2 RESULTS

Impact energy levels for the most severe pipe rupture conditions are given in Table 5.5A-1. The highest level is 0.888×10^6 in-lb for the isolation valve disc. The disc is capable of absorbing energy levels exceeding twice this predicted value without developing excessive deflections. The check valve disc, which has the same capability, is subjected to lower energy levels.

The bearing stress at the valve seat is determined to be 62.2 ksi resulting from the disc-to-seat reaction. A typical allowable stress for this type of application ranges from 150 to 250 ksi.

For the most part, the tail link is not stressed beyond the elastic limit; where the elastic limit is exceeded, the incursion into the plastic range is slight. The maximum tail link deflection is determined to be 0.0425 in. This deflection will not prevent proper valve closure.

The maximum shearing stress developed in the rockshaft is 21.5 ksi, well within the elastic range of the material. The deflection in the rockshaft will be insignificant.

5.5A.3 BASIC CRITERIA AND ASSUMPTIONS

The following criteria and assumptions were used in the analysis:

(1) The initial angle of the isolation and check valve discs are 80 and 70° from the closed position, respectively.

(2) The postulated break locations that were selected will result in the most severe disc impact energy for each valve. Postulated break locations are established and defined in Reference 1, page 3.6A-41.

(3) The postulated break type that will result in the most severe disc impact energy is used. Types of breaks considered include circumferential, longitudinal, and crack as defined in Reference 2. The circumferential break is used in this analysis.

(4) The ruptured pipe is assumed to separate to full flow area instantaneously. A discharge coefficient of 1 is conservatively assumed for flow through the break area.

(5) It is conservatively assumed that there is no obstruction to discharging flow from the break that would prevent maximum blowdown flow from being developed.

(6) Isolation valve trip is conservatively assumed to occur 0.5 seconds (minimum) after a pipe rupture. Evaluation of larger time delays between pipe rupture and disc release shows that the shorter time is a more severe condition on the valve; and therefore, the shortest possible release time is used in the analysis.

(7) It is assumed that there is no frictional resistance to the valve rockshaft rotation; and that the pneumatic actuators offer no resistance to closure after a trip signal.

(8) Initial steam conditions used in the analysis are as follows:

Hot Standby:	Line pressure	=	1020 psia
	Line flow	=	0 lb/sec
Full Load:	Line pressure	=	800 psia
	Line flow	=	1010 lb/sec

Under a postulated pipe rupture, the maximum flow through the isolation valve occurs under a plant hot standby condition. This results in a maximum acceleration of the valve disc. For the check valve, the plant operating condition that will result in the maximum disc impact energy is full load.

5.5A.4 ANALYSIS

5.5A.4.1 Maximum Disc Impact Energy

The check valve computer program used to solve the equations of motion for the valve disc to determine angular velocity and energy at impact is a modification of RELAP 3[(3)], the AEC's presently accepted loss-of-coolant accident (LOCA) analysis program. The modification consists of incorporating the equations of motion for the valve disc.

The equations incorporated into the program to mathematically describe the valve disc motion include the equations of motion, valve pressure drop as a function of flow rate,

actuator return spring forces, and valve flow area as a function of disc position. Because of the similarity in construction, these equations are the same (except for spring forces) for both the isolation and check valves. The isolation valve calculations are initiated following a trip signal. For the check valve, initiation is when the flow reverses in the pipe creating forces to close the disc.

The disc angular acceleration and velocity and the maximum disc impact energy are calculated as a function of the torque acting on the disc. This torque is comprised of gravitational, fluid flow, actuator, frictional, and viscous components. In this analysis, the frictional and viscous torque components act to delay the closure and thus are conservatively neglected. The gravity torque is a function of disc position and the actuator torque is a function of spring displacement. The fluid flow torque is caused by pressure differential across the disc. The pressure differential across the disc, in the non-choking flow region, is the frictional pressure drop across the disc calculated from the valve loss coefficients established by the valve manufacturer (Schutte and Koerting Company). To determine the pressure drop across the disc in the choking flow region, a static pressure difference in volumes upstream and downstream of the disc is used.

5.5A.5 COMPONENT ANALYSIS

5.5A.5.1 Load Generation

The loads acting on the valve components are generated by the disc angular velocity, disc angular acceleration, and the kinetic energy developed in the disc at instant of impact. These quantities are given in Table 5.5A-1. The maximum of these values for the isolation of check valves were used in the analysis.

5.5A.5.2 Disc Analysis

Analysis of disc closure is accomplished by an equivalent static method whereby the disc is loaded with a pseudoloading which approximates the inertia forces acting on the disc. The magnitude of this loading is varied and a relationship between the strain energy developed in the disc and the pseudoloading is established. The maximum displacements experienced by the disc are taken to correspond to the point at which the strain energy developed under the pseudoloading equals the kinetic energy at instant of impact.

5.5A.5.3 Valve Body Seat Area Analysis

The valve body seat area is analyzed by determining the reaction of the valve seat due to the impact of the disc. This reaction is found from the load-energy relationship derived in the analysis for the valve disc as described above. The load corresponding

to the initial kinetic energy in the disc is determined from this load-energy relationship. The reaction at the valve disc is determined by dividing this load by the circumferential area of the valve seat.

5.5A.5.4 Tail Link Analysis

The critical loading conditions on the tail link occur during travel when the tail link is acted upon by centrifugal forces. In this mode the tail link structure may be considered statically determinate with the centrifugal force resultant applied at the rock shaft and reacted at the disc connection. The maximum loads in the travel mode occur just prior to disc impact, and since the tail link structure is taken as statically determinate, the moment and force resultants throughout for this condition are determined from equilibrium considerations. With the axial and moment resultants known throughout the tail link, deflections are determined by dividing the structure into an appropriate number of sections, then determining and summing the deflections of these individual sections.

5.5A.5.5 Rockshaft Analysis

The design loading condition occurs just prior to valve closure when the rockshaft sees the peak centrifugal forces developed in the tail link. These centrifugal forces are applied as shearing forces to the rockshaft. No coupling between this loading condition and the torque carried by the rockshaft in the open position is considered, since this torque diminishes as the valves close and is zero at instant of valve closure.

5.5A.6 REFERENCES

1. Nuclear Services Corporation, Evaluation for Effects of Postulated Pipe Break Outside Containment for Diablo Canyon Unit 1, Revision 2, June 26, 1974.

2. Letter (Docket Nos. 50-275 and 50-323) from A. Giambusso of the U.S. Atomic Energy Commission to F.T. Searls of the Pacific Gas and Electric Company, dated December 18, 1972, including the attachment "General Information Required for Consideration of the Effects of Piping System Break Outside Containment."

3. W.H. Rettig, et al, "RELAP 3 - A Computer Program for Reactor Blowdown Analysis," IN-1321, June 1970. Also Supplement of June 1971.

TABLE 5.5A-1

SUMMARY OF RESULTS UNDER PIPE RUPTURE CONDITIONS

	Check Valve	Isolation Valve
Velocity at disk impact, rad/sec	74.7	77.6
Acceleration at disk impact, rad/sec^2	6373	5474
Energy at disk impact, 10^6 in-lb	0.817	0.888
Maximum flowrate through valve, lb/sec	2767	3220

Chapter 6

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Chapter 6

TABLES

TABLES (Continued)

TABLES (Continued)

TABLES (Continued)

TABLES (Continued)

Chapter 6

FIGURES

FIGURES (Continued)

FIGURES (Continued)

FIGURES (Continued)

NOTE:

[a] This figure corresponds to a controlled engineering drawing that is incorporated by reference into the FSAR Update. See Table 1.6-1 for the correlation between the FSAR Update figure number and the corresponding controlled engineering drawing number.

Chapter 6

APPENDICES

Chapter 6

ENGINEERED SAFETY FEATURES

6.1 GENERAL

6.1.1 INTRODUCTION

Engineered safety features (ESF) systems are provided to reduce the safety and radiological consequences of possible Diablo Canyon Power Plant (DCPP) accidents. These systems cool the reactor core during a loss-of-coolant accident (LOCA) or main steam line break (MSLB), absorb energy released during accidents, contain solids, liquids, or gases released during accidents, and/or absorb radioactive materials that could otherwise be released from the plant buildings. These systems are standby systems, in that they are called upon to perform their ESF functions only in the event of unexpected severe plant accidents. They provide protection beyond the systems and plant design features that are primarily intended for the prevention of accidents.

The principles and guidelines used in the design, construction, and operation of the ESF systems described in Chapter 6 are specified in the individual sections of Chapter 6 and Table 6.1-1. Refer to Section 3.2 and Table 3.2-4 for a comparison of the PG&E Quality/Code classes to the recommendations of ANSI Standard N18.2, August 1970 Draft.

The methods used to evaluate ESF performance are primarily contained in this chapter and Chapter 15.

The DCPP Technical Specifications (Reference 1) establish limiting conditions for maintenance of ESF components. Maintenance of a particular component is permitted if the remaining components meet the minimum requirements for operation and the following conditions are also met:

(1) The remaining equipment has been demonstrated to be in operable condition.

(2) A suitable limit is placed on the total time required to complete maintenance to return the component to an operable condition.

ESF systems meet redundancy requirements, thus maintenance of active components is possible during operation without impairment of the safety function. Routine servicing and maintenance of equipment of this type that is not required more frequently than on an outage basis would generally be scheduled for periods of refueling and maintenance outages. Any continued reactor operation during outages of individual ESF components will conform to reasonable, experienced judgment and industry practices, thus ensuring safe operation.

This chapter provides detailed descriptions of the DCPP ESFs and evaluates their performance under postulated accident conditions. Specifically, information is provided which shows that:

(1) The concept upon which the operation of each system is predicted has been proven sufficiently by experience, and/or by tests under simulated accident conditions, and/or by conservative extrapolations from present knowledge.

(2) The system will function during the period required and will accomplish its intended purpose.

(3) The system has been designed with adequate consideration of component and system reliability, component and system redundancy, and separation of components and portions of systems.

(4) Provisions have been made for periodic tests, inspections, and surveillance to ensure that the systems will be dependable and effective when called upon to function.

6.1.2 SUMMARY DESCRIPTION

The ESFs provided at DCPP are the following:

(1) *Containment Systems*

The steel-lined, reinforced concrete containment structure, including the concrete cylindrical wall, base, and dome, is designed to prevent significant release to the environs of radioactive materials that could be released into the containment as a result of accidents inside the containment (refer to Sections 6.2.1 and 6.2.4).

(2) *The Emergency Core Cooling System (ECCS)*

The ECCS provides water to cool the core in the event of an accidental loss of primary reactor coolant water. The ECCS also supplies dissolved boron into the cooling water to provide shutdown margin (refer to Section 6.3).

(3) *The Containment Spray System (CSS)*

The primary function of the CSS is to help limit the peak temperature and pressure in the containment in the event of a LOCA or MSLB (refer to Section 6.2.2). The CSS, in conjunction with the spray additive system (SAS), also helps to limit the offsite radiation levels following the

postulated LOCA by removing airborne iodine from the containment atmosphere during the injection phase.

(4) *The Containment Fan Cooler System (CFCS)*

The CFCS functions in conjunction with the CSS to limit the temperature and pressure in the containment structure in the event of a LOCA or MSLB (refer to Section 6.2.2). The CFCS also provides mixing of the sprayed and unsprayed regions of the containment atmosphere to improve airborne fission product removal (refer to Section 6.2.3). The CFCS function of mixing the containment atmosphere for hydrogen control is discussed below.

(5) *The Spray Additive System*

The SAS functions by adding sodium hydroxide, an effective iodine scrubbing solution, to the CSS water to reduce the content of iodine and other fission products in the containment atmosphere and prevent the re-evolution of the iodine in the recirculated core cooling solution following a LOCA (refer to Section 6.2.3).

(6) *Containment Combustible Gas Control*

The long-term buildup of gaseous hydrogen in the containment following a LOCA is primarily controlled by ensuring a mixed containment atmosphere and providing equipment for monitoring hydrogen concentrations. The CFCS is the primary means credited for containment atmosphere mixing (refer to Section 6.2.5).

(7) *The Fuel Handling Building Ventilation System (FHBVS)*

The FHBVS provides a significant reduction in the amounts of volatile radioactive materials that could be released to the atmosphere in the event of a major fuel handling accident (refer to Section 9.4.4).

(8) *The Auxiliary Building Ventilation System(ABVS)*

The ABVS provides the capability for significant reductions in the amounts of volatile radioactive materials that could be released to the atmosphere in the event of leakage from the residual heat removal (RHR) system recirculation loop following a LOCA (refer to Section 9.4.2).

(9) *The Control Room Ventilation System(CRVS)*

The CRVS permits continuous occupancy of the control room and technical support center (TSC) under design basis accidents by providing

the capability to control infiltration of volatile radioactive material (refer to Sections 9.4.1 and 6.4.1).

(10) *The Auxiliary Feedwater (AFW) System*

The AFW system supplies water to the secondary side of the steam generators for reactor decay heat removal, when the main feedwater system is unavailable (refer to Section 6.5).

Instrument air is used in most of the ESF systems. In some cases nitrogen is used. Bottled air or nitrogen is provided, as required, via the backup air/nitrogen supply system. ESF devices are designed to maintain a safe position or move to a safe position on loss of air or nitrogen pressure. Thus, the air and nitrogen systems are not needed to ensure device initial positioning or safe operation and are PG&E Design Class II. Detailed analyses of the compressed air and backup air/nitrogen supply systems, and their relation to PG&E Design Class I devices, are found in Section 9.3.1 (refer to Tables 3.9-9 and 6.2-39 for a listing of such devices).

All ESF remotely operated valves have position indication on the control board in two places. Red and green indicator lights are located next to the manual control station, showing open and closed valve positions. The ESF positions of these valves are displayed on the monitor light panels (four panels), which consist of an array of white lights.

Three of the light panels are de-energized during normal operation; applicable portions of these are energized concurrent with a Phase A containment isolation, a Phase B containment isolation, a safety injection signal, a containment ventilation isolation, a steam generator high-high level, a main steam isolation, or a feedwater isolation. The remaining panel is always energized. The design of these arrays is such that the white lights will be dark when the valves are in their normal or required positions for power operation, or their correct position after automatic actuation. These light panels can be tested during normal operation with switches on the control panel. These monitor lights thus enable the operator to quickly assess the status of the ESF systems. These indications are derived from contacts integral to the valve operators. In the case of the accumulator isolation valves, redundancy of position indication is provided by valve stem-mounted limit switches (the stem-mounted switches are independent of the limit switches in the motor operators), which actuate an annunciator on the control board when the valves are not correctly positioned. Refer to Section 7.6 for additional information.

Pump motor power feed breakers indicate that they have closed by energizing indicating lights on the control board in order to enable additional monitoring of in-containment conditions in the post-LOCA recovery period.

6.1.3 REFERENCES

1. Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.

6.2 CONTAINMENT SYSTEMS

Containment systems enclose the reactor and most plant systems and equipment that operate at high temperatures and pressures and may contain radioactive materials. This section describes and evaluates the design of the containment systems and confirms their capability to fulfill their intended objectives.

6.2.1 CONTAINMENT FUNCTIONAL DESIGN

The containment structure and subcompartments are designed to sustain the resulting pressures and temperatures from gross failure up to and including a loss-of-coolant accident (LOCA). Long-term mass and energy releases and containment integrity from a LOCA or main steam line break (MSLB) are analyzed in Appendix 6.2D for the evaluation of the resulting peak containment pressure. Short-term mass and energy releases and subcompartment integrity analyses are addressed in the following sections.

6.2.1.1 Design Bases

6.2.1.1.1 General Design Criterion 4, 1987 – Environmental and Dynamic Effects Design Bases

The containment is designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including LOCAs. The dynamic effects associated with postulated reactor coolant system (RCS) primary loop pipe ruptures are excluded from the Diablo Canyon Power Plant (DCPP) design basis for subcompartment analysis.

6.2.1.1.2 General Design Criterion 10, 1967 – Containment

The containment is designed to sustain the initial effects of gross equipment failures, such as a LOCA, without loss of required integrity and, together with other engineered safety features (ESFs), to retain the functional capability of the containment to protect the public.

6.2.1.1.3 General Design Criterion 49, 1967 – Containment Design Basis

The containment is designed to accommodate the pressures and temperatures resulting from the largest credible energy release following a LOCA without exceeding the design leakage rate.

6.2.1.1.4 General Design Criterion 54, 1967 – Containment Leakage Rate Testing

The containment is designed with the capability for integrated leakage rate testing to be conducted at design pressure after installation of all penetrations to verify its conformance with required performance.

6.2.1.1.5 General Design Criterion 55, 1967 – Containment Periodic Leakage Rate Testing

The containment is designed so that integrated leakage rate testing can be done at the design pressure periodically during the plant's lifetime.

6.2.1.1.6 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The containment is designed as a barrier to maintain control over plant radioactive effluents, whether gaseous, liquid, or solid meeting the radiological limits of 10 CFR Part 100. Appropriate holdup capacity is provided for retention of gaseous effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment.

6.2.1.1.7 10 CFR Part 50, Appendix J, Option B – Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors

The containment is designed to allow for conductance of a performance-based containment leakage rate testing program for Type A containment integrated leak rate tests (ILRT) and Type B testing for the air lock door seals.

6.2.1.1.8 10 CFR Part 50, Appendix K, Part I.A – ECCS Evaluation Models, Sources of Heat during the LOCA

The containment is designed to accommodate the largest credible energy release following a postulated pipe break taking into account the heat sources listed in Paragraph I.A of 10 CFR Part 50, Appendix K.

6.2.1.1.9 Regulatory Guide 1.163, September 1995 – Performance-Based Containment Leak-Test Program

The containment is designed to allow the use of a performance-based leak-test program, including the leakage-rate test methods, procedures, and analyses as required by Regulatory Guide 1.163, September 1995.

6.2.1.2 Description of Short-Term Mass and Energy Releases and Containment Subcompartment Analysis

6.2.1.2.1 Short-Term Mass and Energy Release Analysis

The short-term LOCA-related mass and energy releases are used as input to the subcompartment analyses. These analyses are performed to ensure that the walls of a subcompartment can maintain their structural integrity during the short pressure pulse (generally less than 3 seconds) accompanying a high-energy line pipe rupture within

that subcompartment. The subcompartments that are evaluated include the loop compartment, reactor coolant pipe annulus, reactor vessel annulus, lower reactor cavity, and pressurizer enclosure. DCPP Unit 1 and Unit 2 are approved for the application of the leak-before-break (LBB) exemption (refer to Section 3.6.2.1.1.1). Changes in RCS operating conditions are typically offset by the LBB benefit of using smaller RCS nozzle breaks. This demonstrates that the subcompartment analyses based on the primary loop pipe breaks would remain bounding. The critical mass flux correlation utilized in the SATAN-V computer program (Reference 59) was used to conservatively estimate the impact of the changes in RCS temperatures on the short-term releases. The evaluation showed that the design basis releases would remain bounding due to LBB.

The short-term releases are linked directly to the critical mass flux (G_{crit}), which increases with decreasing temperatures. The increase in mass flux is created by an increase in the differential pressure between the reservoir pressure and the saturation pressure at the RCS operating conditions. The G_{crit} is the maximum break flow per cross-sectional flow area based on a reservoir pressure and saturation temperature. The short-term LOCA releases would be expected to increase due to any reductions in RCS coolant temperature conditions.

Short-term releases are controlled by density effects, so the lower temperatures from DCPP Unit 1 are more limiting. These analyses conservatively use the cold leg operating conditions at the full power coastdown average temperature (T_{avg}). The comparison of the lower cold leg temperature and the design basis cold leg temperature is shown in Table 6.2-56.

6.2.1.2.2 Containment Subcompartment Analyses

6.2.1.2.2.1 Containment Pressure Differential

The containment subcompartment dynamic pressure differential analysis is performed to determine the ability of the containment subcompartment structural elements to accommodate the resulting differential pressures. The elements, flowpaths, and mass and energy releases for each subcompartment analysis are listed in Tables 6.2-14 through 6.2-23. The resulting pressure differentials are discussed in Table 6.2-24 and asymmetric pressurization across the steam generator in Table 6.2-55. Figures 6.2-33 through 6.2-52 pictorially depict the elements of the model and the results of the analyses. However, as discussed in Section 3.6.2.1.1.1, due to the acceptance of the DCPP LBB evaluation by the Nuclear Regulatory Commission (NRC), the effects of dynamic subcompartment pressurization due to breaks in the primary reactor coolant loop piping no longer have to be considered in the design basis analyses; only the effects resulting from RCS branch line breaks have to be considered. Hence, the pressurizer enclosure analysis is presented below since it results from a branch line break. The analyses for the other compartments are conservative since the breaks postulated in those analyses are more severe than the breaks now required to be considered.

During the early stages of a LOCA, pressure differentials may be briefly established in the containment. While the geometry of the containment, except for the net free volume, has no direct effect upon the containment peak pressure, indirect considerations such as the design of structural supports of ESF equipment and the prevention of missile generation make it desirable to calculate the differential pressure transients caused by different breaks.

Four cases are of interest: (a) a rupture of an RCS hot leg at the biological shield (reactor shield wall) that results in the maximum differential pressure across the loop compartment walls, (b) a rupture of an RCS cold leg at the reactor vessel nozzle weld that results in the maximum reactor cavity differential pressure, (c) a pressurizer spray line rupture that results in the maximum pressurizer enclosure differential pressure, and (d) a hot leg break in one of the steam generator loop compartments that yields the maximum pressure differential across the steam generator.

These four cases were analyzed using the TMD (Reference 45 for case (a) and Reference 60 for cases (b), (c), and (d)) computer code with an unaugmented homogeneous critical mass flowrate correlation. As a result of comparisons at low pressures between measured critical mass flowrates and predictions using the homogeneous critical flow model, an equation has been developed that conservatively bounds experimental critical mass flowrates by applying an augmentation factor of (1.2-0.2X) to the homogeneous model flowrates, where X is steam quality in the upstream compartment. Since critical mass flowrates obtained using the augmentation factor are conservative with respect to experimental data (calculated flowrates are lower than observed), peak compartment pressures calculated using the augmentation factor would be expected to be conservative (higher than expected values). The use of the unaugmented homogeneous critical mass flowrate calculation introduces additional conservatism in the analysis.

The TMD mathematical model used to calculate the flows and pressures throughout the containment is based upon time-dependent equations of conservation of mass, conservation of energy, conservation of momentum, and state. Flow inertia effects between the volumes are also calculated. The model calculates critical flow conditions for application under high-pressure differentials. A 100 percent entrainment of the water emerging from the break is assumed. Subcompartment vent discharge flows are considered as unrecoverable pressure losses and, consequently, vent discharge coefficients are not used. A break flow discharge coefficient of unity is assumed.

Calculated values of peak differential pressure and peak absolute pressure at the time of peak differential pressure are tabulated in Table 6.2-24 for compartments within the containment. Table 6.2-24 also shows design differential pressure for these compartments. In general, considerations other than peak differential pressure determined the design of structural elements within the containment. Consequently, these structural elements can accommodate differential pressures that are significantly higher than the design values shown in Table 6.2-24. The design has been reviewed to determine the as-built capability of these structural elements to accommodate

differential pressure. This review shows that differential pressures that are significantly higher than the design values can be accommodated with resulting stress levels within the applicable acceptance criteria as described in Section 3.8.1. The capability of those structural elements affected by differential pressure between the reactor vessel annulus and surrounding containment spaces was specially investigated, since the calculated peak differential pressure exceeds the design value for those elements of the calculational model that are in the vicinity of the postulated break. The results of this investigation, which considered both overall loading and the possibility of local failure in the vicinity of the postulated break, show that no failure would occur and that resisting structural members are not stressed beyond 73 percent of yield capacity.

6.2.1.2.2.2 Loop Compartment Analysis

If a LOCA is postulated to occur in a loop compartment region, the steam mass that enters this space must be vented to the rest of the containment. The flowpaths potentially available for such venting are through the operating deck and through the crane wall as well as to the adjacent loop compartments. The first of these routes permits steam, air, and water to enter the dome and the second grants access to the annular spaces between the crane wall and the containment shell.

The analysis assumed a double-ended rupture of an RCS hot leg at the biological shield, since this would result in the maximum differential pressure across the loop compartment walls. Compartments in the containment were represented by an 18-element model and pressures in each element were updated at one millisecond intervals until the rapidly changing portion of the blowdown was completed. The description and volume of each of the compartments represented by an element in the model are given in Table 6.2-14. Table 6.2-15 gives the minimum area of the flowpaths connecting these elements. The elements in the model and the flowpaths connecting them are shown diagrammatically in Figure 6.2-33. The mass and energy release rates used in the analysis are given, as a function of time after the postulated break, in Table 6.2-16.

Figures 6.2-34 and 6.2-35 show the transient differential and absolute pressures in the two loop compartments for elements of the model with the highest calculated differential pressure. As shown, the highest differential pressures occur during the first fraction of a second following the postulated break. As shown in Table 6.2-24, the peak differential pressure calculated for a loop compartment is less than the design value.

The containment loop compartments were reanalyzed for assumed double-ended RCS cold and hot leg pipe breaks within the loop compartments. For this analysis, the TMD code (Reference 60) was used, with the compressibility factor and with the non-augmented critical flow correlation, to determine the subcompartments' response. The model used was also reviewed by the NRC. They found that the subcompartment nodalization and input parameters are conservative and, therefore, acceptable for the purpose of evaluating the adequacy of the steam generator supports for postulated

RCS pipe ruptures within the loop compartment. For a discussion of asymmetric pressurization of the steam generators refer to Section 6.2.1.2.2.5.

6.2.1.2.2.3 Reactor Cavity Analysis

The reactor cavity analysis assumes a double-ended rupture of an RCS pipe at the reactor vessel nozzle weld, since this would result in the maximum reactor cavity differential pressure. The analyses using the TMD code (Reference 60), with the compressibility factor and non-augmented critical flow correlation, were performed to determine the response of the reactor cavity to postulated ruptures of the RCS hot and cold leg pipes. The annulus between the reactor vessel and the reactor shield wall is divided into axial and circumferential nodes. The nodalization sensitivity study indicates that the model selected is adequate to determine the asymmetrical pressurization forces that may act upon the vessel. The NRC evaluated the TMD code (Reference 60) and found the methods acceptable provided that non-augmented critical flow relationships are used rather than augmented. The maximum credible break size and locations were identified to be a 115-square inch cold leg break and a 76-square inch hot leg break at the pipe-to-reactor vessel inlet and outlet nozzle welds, respectively. Pipe displacement restraints have been provided to limit the break sizes to those values as shown in Figure 6.2-40 and Figure 6.2-41. Because of the larger break size, the cold leg rupture results in the maximum reactor cavity differential pressure and the analysis described here assumes only a cold leg break.

The volumes of elements of the model are given in Table 6.2-18, and data for flowpaths connecting the elements are given in Table 6.2-19. Figure 6.2-37 shows a diagram of the elements of the model and the flowpaths between them. Figures 6.2-38 and 6.2-39 illustrate the location of some of the elements in the model. The mass and energy release used in the analysis are given, as a function of time after the postulated break, in Table 6.2-20.

<u>Reactor Vessel Annulus</u>

Figure 6.2-42 shows the transient pressure calculated for that element of the model with the highest peak calculated pressure (element 19). This element represents a portion of the reactor vessel annulus in the immediate vicinity of the postulated break. Figure 6.2-43 shows the transient pressure calculated for element 21 of the model, which represents the loop compartment adjacent to the portion of the reactor vessel annulus represented by element 19. By comparing Figures 6.2-42 and 6.2-43, the peak differential pressure between the reactor vessel annulus and the adjacent loop compartment is approximately 182.2 psi. This peak value occurs at the time when element 19 reaches peak pressure, approximately 0.126 second after the postulated break. Table 6.2-24 shows this peak differential pressure for the reactor vessel annulus. From Table 6.2-21, it can be seen that peak pressures calculated for those elements of the model that represent the portion of the reactor vessel annulus in the vicinity of the postulated break are significantly higher than for the remainder of the reactor vessel annulus. Although peak differential pressures for some elements of the

model exceed the design differential pressure for the reactor vessel annulus, structural elements have sufficient margin to accommodate these peak differential pressures without failure.

Lower Reactor Cavity

Table 6.2-21 shows the transient peak pressure calculated for element 2 (refer to Figure 6.2-44), which represents the lower reactor cavity, and for element 32, which represents the upper portion of the containment. The transient pressures calculated for these elements do not reach a peak value during the time period covered by the reactor cavity analysis since this pressure response is a longer term phenomenon. However, the differential pressure between the lower reactor cavity and the upper containment does reach a peak value of approximately 4.6 psi for the break postulated for the reactor cavity analysis. Since the peak pressure calculated for the upper containment by the long-term mass and energy release model is 41.4 psig (refer to Appendix 6.2D) and no other compartments surround the lower reactor cavity, a conservative estimate of the peak differential pressure across the walls of the lower reactor cavity is obtained from the sum of these two pressures. This value (rounded off to 46 psi) is shown in Table 6.2-24, which also shows that the peak calculated differential pressure for the lower reactor cavity is less than the design value.

Reactor Coolant Pipe Annulus

Figure 6.2-46 shows the transient pressure calculated for the reactor coolant system cold leg pipe annulus (element 60). The calculated peak pressure in psig is conservatively assumed to equal the peak differential pressure. For the reactor cavity analysis described here the peak differential pressure calculated is 180.1 psi. As shown in Table 6.2-24, the calculated peak differential pressure for the pipe annulus is significantly lower than the design differential pressure. In addition, structural elements can accommodate pressure within a pipe annulus that are much greater than the design value. A geometrically simplified model of the containment used the elements with the volumes and vent areas shown in Table 6.2-22. The pressure in the pipe annulus was established through a steady state analysis of the peak mass and energy release in the region. Table 6.2-20 lists the mass and energy release rates used in this analysis.

6.2.1.2.2.4 Pressurizer Enclosure Analysis

The analysis assumed a double-ended rupture of the pressurizer spray line, since this would result in the maximum differential pressure across the pressurizer enclosure walls. In the event of such a rupture, fluid from the break would be vented to both the containment dome and the loop compartments. Table 6.2-14 gives a description and the volumes of elements of the model while Table 6.2-15 shows the minimum area of the flowpaths connecting the elements. The mass and energy release rates used in the analysis are given, as a function of time after the postulated break, in Table 6.2-17. Figure 6.2-36 shows the transient differential and absolute pressures in the pressurizer enclosure for that element of the model with the highest calculated differential pressure.

Short-term blowdown transients are characterized by a peak mass and energy release rate that occurs during a subcooled condition, thus the Zaloudek correlation (Reference 59), which models this condition, is currently used in the short term LOCA mass and energy release analyses with the SATAN-V computer program. This correlation appears in the critical flow routine of SATAN-V (Reference 59) and it can be used to conservatively evaluate the impact of the changes in RCS temperature conditions . This is accomplished by maximizing the reservoir pressure and minimizing the RCS inlet and outlet temperatures (which maximizes G_{crit}). Using a lower temperature results in a lower P_{sat} and a higher G_{crit}. Since this maximizes the change in short-term LOCA mass and energy releases, data representative of the lowest inlet temperature with uncertainty subtracted is used for the evaluation for the spray line break.

The result of the comparison of G_{crit} shows that the short-term spray line mass releases for DCPP Unit 1 would result in an overall increase of 1.8 percent when a temperature coastdown is considered. Table 6.2-24 shows that the pressurizer enclosure walls have a design differential pressure of 4.0 psid and a total peak differential pressure of 2.6 psid which remains less than the design differential pressure.

To address the effects of asymmetric pressurization, it was conservatively assumed that the maximum calculated pressure within the enclosure acts uniformly across the projected area of the pressurizer vessel including insulation, which results in a 140,000 pound side load. This load was used in evaluating the adequacy of the pressurizer supports. This pressure load conservatively bounds the maximum differential loads that would result from the asymmetric pressurization.

6.2.1.2.2.5 Steam Generator Analysis

The containment structure immediately surrounding the DCPP steam generators is open and therefore not conducive to the development of asymmetric pressurization loads on the steam generator from a steam line or primary piping rupture. The steam line exits the steam generator area at an elevation above the steam generator, goes behind the crane wall, and does not pass along the side of an enclosed steam generator. Consequently, a rupture in the vertical run parallel to the steam generator would be on the opposite side of the crane wall and would cause no steam generator asymmetric pressurization. A rupture in the steam line at the steam nozzle on the steam generator would cause steam to flow into the upper containment. Because this containment volume is large, the rupture would not necessarily cause any asymmetric pressures on the steam generator. However, the loads calculated for the D.C. Cook Unit 2 steam generator enclosure response analysis for two postulated steam line ruptures were used to evaluate the adequacy of the DCPP steam generator supports, which bound the DCPP loads.

A TMD code (Reference 60) analysis of asymmetric pressurization resulting from double-ended breaks in the primary loops, similar to that for the other subcompartments was performed to evaluate the pressure differentials across the steam generator for an

RCS loop break. The effect of compressibility was evaluated and found to be insignificant (less than 1 percent effect). Calculations for several DEHL and DECL breaks were performed, with the maximum differential pressure of 6.04 psi occurring for a DEHL break. The mass and energy release rates used for the DEHL are shown in Table 6.2-16. Table 6.2-55 shows the maximum calculated pressure differential across the steam generator for the nine cases analyzed. The compartment locations are illustrated in Figure 6.2-51. The pressure history for the worst case DEHL break is shown in Figure 6.2-52. The maximum calculated differential pressure of 6.04 psi, when combined with other postulated loads, is within the design capability of the upper and lower steam generator supports (refer to Section 5.5.13). An assumed differential pressure of 20 psid across the portion of the steam generators within the loop compartment was used in evaluating the steam generator supports.

6.2.1.3 Safety Evaluation

6.2.1.3.1 General Design Criterion 4, 1987 – Environmental and Dynamic Effects Design Bases

The application of LBB is not applicable to the long-term mass and energy release containment integrity analysis in Appendix 6.2D.

LBB is approved as a part of the DCPP license basis for the RCS primary loop piping (refer to Section 3.6.2.1.1.1). Consequently, the RCS primary loop ruptures remain bounding for the effects of short-term mass and energy releases and subcompartment pressurizations with the exception of the pressurizer spray line in the pressurizer enclosure which has been evaluated. The containment subcompartments are designed to sustain the short-term effects of postulated pipe failures as demonstrated in Section 6.2.1.2.2 and Table 6.2-24.

6.2.1.3.2 General Design Criterion 10, 1967 – Containment

The containment is designed to sustain the effects of LOCA and MSLB events as demonstrated by the containment integrity analysis in Appendix 6.2D. This demonstrates that the containment, supported by the containment heat removal system (CHRS), will retain its functional capability. Refer to Section 6.2.2 for the discussion of the CHRS.

6.2.1.3.3 General Design Criterion 49, 1967 – Containment Design Basis

The results of the containment integrity analysis demonstrate that the containment pressure and temperature are maintained below the design conditions following limiting LOCA events (refer to Appendix 6.2D). This demonstrates that the containment, supported by the containment heat removal system (CHRS), will retain its functional capability to not exceed the design leakage rate in order to protect the public. Refer to Section 6.2.2 for a discussion of the CHRS.

6.2.1.3.4 General Design Criterion 54, 1967 – Containment Leakage Rate Testing

Containment leakage rate testing was conducted after completion of construction and installation of all penetrations to verify its conformance with required performance (refer to Section 6.2.1.4.1).

6.2.1.3.5 General Design Criterion 55, 1967 – Containment Periodic Leakage Rate Testing

Periodic ILRT of the containment is performed as part of the DCPP Containment Periodic Leakage Rate Testing Program (refer to Sections 6.2.1.3.7 and 6.2.1.3.9).

6.2.1.3.6 General Design Criterion, 70, 1967 – Control of Releases of Radioactivity to the Environment

The containment, in conjunction with the containment isolation system (CIS) (refer to Section 6.2.4.4.12), is designed to be a barrier to maintain control over plant radioactive effluents, whether gaseous, liquid, or solid. The containment is designed to withstand the effects of a LOCA (refer to Section 6.2.1.3.3), ensuring that the offsite radiological exposures resulting from a LOCA are within the limits of 10 CFR Part 100 (refer to Section 15.5).

6.2.1.3.7 10 CFR Part 50, Appendix J, Option B – Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors

10 CFR Part 50, Appendix J, Option B, Type A and B testing, as modified by approved exemptions, are performed in accordance with Technical Specification 5.5.16, Containment Leakage Rate Testing Program. The ILRT is performed at a P_a, calculated peak containment internal pressure, of 43.5 psig. The maximum allowable leakage rate is not greater than 0.10% of the containment air weight per day. For the discussion of Type C testing (testing of containment penetrations) refer to Section 6.2.4.4.12.

6.2.1.3.8 10 CFR Part 50, Appendix K, Part I.A – ECCS Evaluation Models, Sources of Heat during the LOCA

The initial conditions for the LOCA and MSLB events of the containment integrity analyses are established at the maximum calculated power for the reactor with additional margins for instrument error for the sources of heat listed in accordance with 10 CFR Part 50, Appendix K, Part I.A (refer to Section 6.2D.3.1.4).

6.2.1.3.9 Regulatory Guide 1.163, September 1995 – Performance-Based Containment Leak-Test Program

The DCPP Containment Leakage Rate Testing Program utilizes a performance-based approach, consistent with Regulatory Guide 1.163, September 1995, to comply with the requirements of 10 CFR Part 50, Appendix J, Option B (refer to Section 6.2.1.3.7).

6.2.1.4 Tests and Inspections

6.2.1.4.1 Preoperational Testing

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Following completion of each containment structure, a structural integrity test was performed by pressurizing the containment with air to 115 percent of design pressure, or 54 psig. These tests were performed as described in Section 3.8.1.7.

During the depressurization phase of the structural integrity tests, overall integrated leakage rate tests were performed in accordance with the requirements of Appendix J to 10 CFR Part 50 (refer to Section 3.8.1.7).

6.2.1.4.2 Inservice Surveillance

Periodic leakage rate testing will be performed over the life of the units in accordance with the requirements of Appendix J to 10 CFR Part 50, Option B, as modified by approved exemptions (refer to Section 6.2.1.3.7). Applicable surveillance requirements for such testing are included in the Technical Specifications. A leakage detection system has been installed to measure leakrate for the personnel air lock door seals to ensure compliance with the Technical Specifications (Reference 46). Periodic testing of the containment isolation valves is discussed in Sections 6.2.4.4.12 and 6.2.4.5.

6.2.1.5 Instrumentation Applications

Pressure inside the containment is continuously monitored by independent pressure transmitters located at widely separated points outside the containment. Instruments with range of -5 to 55 psig and 0 to 200 psig are available. Section 7.3.2 describes containment pressure as an input to the ESFs actuation system and Section 7.5.2 describes containment pressure display instrumentation.

Other instrumentation available for monitoring conditions within the containment include:

(1) Containment water level monitors (described in Sections 6.3.3.4.4 and 7.5.2.1.3)

(2) Containment hydrogen monitors (described in Section 6.2.5.5)

(3) Temperature detectors positioned at various locations within the containment air volume (described in Section 9.4.5.3.3)

(4) Containment radiation and plant vent monitors (described in Sections 9.4.2 and 11.4.2)

6.2.1.6 Materials

Containment structural heat sink materials used for containment integrity analyses following a LOCA or main steam line break are listed in Table 6.2D-19; corresponding material properties are listed in Table 6.2D-20 (refer to Section 6.2D.3.2.4). A current record of paint used on containment heat sink structures and equipment is maintained in engineering files.

6.2.2 CONTAINMENT HEAT REMOVAL SYSTEMS

The containment heat removal systems (CHRS) are the containment fan cooler system (CFCS) and the containment spray system (CSS). The functional performance objectives of the CHRS are:

(1) The CFCS limits the containment ambient temperature during normal plant operating conditions (refer to Section 9.4.5);

(2) The CFCS and CSS reduce the containment ambient temperature and pressure following a loss-of-coolant accident (LOCA) or main steam line break (MSLB) inside containment. While performing this cooling function, the CHRS also helps limit offsite radiation levels by reducing the pressure differential between containment and outside atmosphere, thus reducing the driving force for leakage of fission products from the containment atmosphere;

(3) The CFCS provides mixing of the sprayed and unsprayed regions of the containment to improve airborne fission product removal (refer to Section 6.2.3);

(4) The CSS removes airborne fission products from the containment atmosphere following a LOCA (refer to Section 6.2.3);

(5) The CSS, in conjunction with the spray additive system (SAS), prevents the re-evolution of the iodine in the recirculated core cooling solution (i.e. sump water) following a LOCA (refer to Section 6.2.3);

(6) The CFCS provides a mixed atmosphere for hydrogen control (refer to Section 6.2.5).

Used in conjunction with one another during the injection phase, one containment spray pump and two containment fan cooler units (CFCUs) will provide the heat removal capability to maintain the post-accident containment atmospheric pressure and temperature below the design values of 47 psig and 271°F, respectively. The CFCS is credited for long-term containment pressure and temperature control throughout the injection and recirculation phases following a LOCA or MSLB. The CSS is credited only for operation during the spray injection phase following a LOCA or MSLB; it is not

required for operation during the recirculation phase for mitigating the effects of a LOCA. The physical SSC design bases, testing, and inspection requirements of the CFCS and CSS are discussed in this section.

6.2.2.1 Design Bases

6.2.2.1.1 General Design Criterion 2, 1967 - Performance Standards

The CFCS and CSS are designed to withstand the effects of, or are protected against, natural phenomena, such as earthquakes, flooding, tornadoes, winds, and other local site effects.

6.2.2.1.2 General Design Criterion 10, 1967 - Containment

The CFCS and CSS are designed to aid other ESFs in retaining the functional capability of the containment to protect the public in the event of gross equipment failures, such as a large coolant boundary break.

6.2.2.1.3 General Design Criterion 11, 1967 - Control Room

The CFCS and CSS are designed to support actions to maintain and control the safe operational status of the plant from the control room.

6.2.2.1.4 General Design Criterion 12, 1967 - Instrumentation and Control Systems

The CFCS and CSS are provided with instrumentation and controls as required to monitor and maintain the CHRS variables within prescribed operating ranges.

6.2.2.1.5 General Design Criterion 15, 1967 - Engineered Safety Features Protection Systems

The CFCS and CSS are provided with instrumentation for sensing accident conditions.

6.2.2.1.6 General Design Criterion 19, 1971 - Control Room

The CFCS and CSS, in conjunction with the SAS, are designed to limit radiation exposure to personnel to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident.

6.2.2.1.7 General Design Criterion 21, 1967 - Single Failure Definition

The CFCS and CSS are designed to tolerate a single failure during the period of recovery following an accident without loss of their protective functions, including multiple failures resulting from a single event, which is treated as a single failure.

6.2.2.1.8 General Design Criterion 37, 1967 - Engineered Safety Features Basis for Design

The CFCS and CSS are designed to provide back-up to the safety functions provided by the core design, the reactor coolant pressure boundary, and their protection systems.

6.2.2.1.9 General Design Criterion 38, 1967 - Reliability and Testability of Engineered Safety Features

The CFCS and CSS are designed to provide high functional reliability and ready testability.

6.2.2.1.10 General Design Criterion 40, 1967 - Missile Protection

The CFCS and CSS are designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

6.2.2.1.11 General Design Criterion 41, 1967 - Engineered Safety Features Performance Capability

The CFCS and CSS are designed to provide sufficient performance capabilities to accommodate a partial loss of installed capacity, including a single failure of an active component, and still perform their required safety functions.

6.2.2.1.12 General Design Criterion 42, 1967 - Engineered Safety Features Components Capability

The CFCS and CSS are designed so that the capability of each component and system to perform its required function is not impaired by the effects of a LOCA.

6.2.2.1.13 General Design Criterion 49, 1967 - Containment Design Basis

The CFCS and CSS are designed so that the containment structure can accommodate, without exceeding the design leakage rate, the pressures and temperatures resulting from the largest credible mass and energy releases following a LOCA, including a considerable margin for effects from metal-water or other chemical reactions that could occur as a consequence of failure of emergency core cooling systems.

6.2.2.1.14 General Design Criterion 52, 1967 - Containment Heat Removal Systems

The CFCS and CSS are designed as two systems of different principles, each with full capacity, for active heat removal from the containment under accident conditions.

6.2.2.1.15 General Design Criterion 54, 1971 - Piping Systems Penetrating Containment

The CSS piping that penetrates containment is provided with leak detection, isolation, redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating this system. The piping is designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

6.2.2.1.16 General Design Criterion 56, 1971 - Primary Containment Isolation

The CSS contains valving in piping that penetrates containment and that is connected directly to the containment atmosphere. Remote manual isolation valves are provided outside containment and automatic (check) valves are provided inside containment to ensure containment integrity is maintained.

6.2.2.1.17 General Design Criterion 58, 1967 - Inspection of Containment Pressure-Reducing Systems

The CFCS and CSS are designed to facilitate the periodic physical inspection of all important components, such as fans, pumps, valves, dampers, and spray nozzles.

6.2.2.1.18 General Design Criterion 59, 1967 - Testing of Containment Pressure-Reducing Systems

The CFCS and CSS are designed so that active components, such as fans, pumps, valves, and dampers can be tested periodically for operability and required functional performance.

6.2.2.1.19 General Design Criterion 60, 1967 - Testing of Containment Spray Systems

The CSS is designed to allow periodic testing of the delivery capability of the system at a position as close to the spray nozzles as is practical.

6.2.2.1.20 General Design Criterion 61, 1967 - Testing of Operational Sequence of Containment Pressure-Reducing Systems Components

The CFCS and CSS are designed to provide the capabilities to test under certain conditions as close to the design as practical, the full operational sequence that would bring the CHRS into action, including the transfer to alternate power sources.

6.2.2.1.21 General Design Criterion 62, 1967 - Inspection of Air Cleanup Systems

The CFCS and CSS are designed to facilitate physical inspection of all critical parts, such as ducts, fans, pumps, valves, dampers, and spray nozzles.

6.2.2.1.22 General Design Criterion 63, 1967 - Testing of Air Cleanup Systems Components

The CFCS and CSS are designed so that active components, such as fans, pump, valves, and dampers, can be tested periodically for operability and required functional performance.

6.2.2.1.23 General Design Criterion 64, 1967 - Testing of Air Cleanup Systems

The CFCS is designed to provide for in situ periodic testing and surveillance to ensure trapping materials have not deteriorated beyond acceptable limits.

6.2.2.1.24 General Design Criterion 65, 1967 - Testing of Operational Sequence of Air Cleanup Systems

The CFCS and CSS are designed with the capability to test, under conditions as close to design as practical, the full operational sequence that would bring the CHRS into action, including the transfer to alternate power sources and design air flow delivery capability.

6.2.2.1.25 General Design Criterion 70, 1967 - Control of Releases of Radioactivity to the Environment

The CFCS and CSS, in conjunction with the SAS, are designed with provisions for maintaining control of the plant's radioactive gaseous effluents to meet the radiological limits of 10 CFR Part 100.

6.2.2.1.26 10 CFR 50.49 - Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants

CFCS and CSS components that require environmental qualification (EQ) are qualified to the requirements of 10 CFR 50.49.

6.2.2.1.27 10 CFR 50.55a(f) - Inservice Testing Requirements

CFCS and CSS ASME code components are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

6.2.2.1.28 10 CFR 50.55a(g) - Inservice Inspection Requirements

CFCS and CSS ASME code components are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

6.2.2.1.29 Regulatory Guide 1.97, Revision 3, May 1983 - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The CFCS and CSS provide instrumentation to monitor containment isolation valve position, containment spray flow, containment pressure, containment temperature during and following an accident, and a two-step process for monitoring heat removal by the CFCS.

6.2.2.1.30 NUREG-0737 (Item III.D.1.1), November 1980 - Clarification of TMI Action Plan Requirements

Item III.D.1.1 - Integrity of Systems Outside Containment Likely to Contain Radioactive Material for Pressurized-Water Reactors and Boiling-Water Reactors:

The CSS is designed to allow for the performance of leak rate tests as part of the containment isolation valve surveillance test program.

6.2.2.1.31 Generic Letter 89-10, June 1989 - Safety-Related Motor-Operated Valve Testing and Surveillance

The CSS PG&E Design Class I and position changeable motor-operated valves (MOVs) meet the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996.

6.2.2.1.32 Generic Letter 97-04, October 1997 – Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps

The CSS is evaluated to assure adequate NPSH is available to the containment spray pumps under all design basis accident (DBA) scenarios.

6.2.2.2 System Description

The CHRS is designed to provide sufficient heat removal capability to maintain the post-accident containment atmospheric pressure and temperature below the design values of 47 psig and 271°F, respectively (refer to Section 3.8.1.1). The containment atmospheric temperature after a MSLB does briefly increase greater than the containment design temperature, but, as discussed in Section 6.2D.4.2.4, there is no explicit design temperature limit for a MSLB. Heat energy sources considered are described in Section 6.2D.2.1.12.

The CFCS also functions during normal operating conditions to limit the containment ambient temperature to 120°F and is described in Section 9.4.5.

The CFCS, shown schematically in Figure 9.4-4, consists of five identical fan coolers, each including cooling coils, fan and drive motor, locked-open air flow dampers and pressure relief dampers, duct distribution system, instrumentation, and control. During operation of the units, air is drawn into the cooling coils, cooled, and discharged back through the ductwork to the containment atmosphere.

The design parameters for the CHRS components and materials are listed in Table 6.2-26. Codes and standards used as a basis for the design of the components are given in Table 6.2-25.

Ductwork distributes the cooled air to the various containment compartments and areas. During normal and post-accident operations, the flow sequence through each air fan cooler is as follows: locked-open normal and accident air flow dampers, cooling coils, fan, and distribution ductwork.

Airflow through the exhaust ducting, towards the fan, can occur when the fan is idle. Incorporated into the fan/motor coupling is an anti-reverse rotation device (AARD) that precludes the fan motor from rotating backwards. This device replaces backdraft dampers previously installed in the fan discharge duct.

The CSS, shown schematically in Figure 3.2-12, consists of two pumps, spray ring headers and nozzles, valves, and connecting piping. Following a LOCA, water from the refueling water storage tank (RWST) is initially used for containment spray. Later, water recirculated from the containment sump can be supplied by the residual heat removal (RHR) pumps for recirculation spray. If no component failures affect the RHR train capability, the emergency procedures direct the initiation of recirculation sprays. However, single failures that result in the loss of one RHR train cause the decision of how to divide the recirculation flow between spray and core injection to be made by the technical support center in charge of accident mitigation.

6.2.2.2.1 Component Descriptions

6.2.2.2.1.1 Containment Spray System

6.2.2.2.1.1.1 Refueling Water Storage Tank

The RWST serves as a source of emergency borated cooling water for the injection phase. The RWST will normally be aligned to the suction of the emergency core cooling pumps and the containment spray pumps. During a MSLB inside containment or LOCA the containment spray pumps will continue to take suction from the RWST until the RWST low-low level signal is provided. Refer to Section 6.3 for additional details on the RWST.

6.2.2.2.1.1.2 Containment Spray Pumps

The containment spray pumps are of the horizontal centrifugal type and are driven by electric motors. The motors are powered from separate Class 1E, 4.16-kV buses.

6.2.2.2.1.1.3 Spray Nozzles

The spray nozzles are of the hollow cone design having an open throat and 3/8 inch spray orifice and are not subject to clogging by particles less than 1/4 inch in size. Refer to discussion in Section 6.2.2.3.8.1.2.

6.2.2.2.1.1.4 Containment Spray System Piping and Valves

The piping and valves for the CSS have design pressures and temperatures of 240 psig and 200°F, respectively.

6.2.2.2.1.2 Containment Fan Cooler System

The design data of the CFCS are presented in Table 6.2-26. During normal operation, the number of units running will depend on the amount of cooling required in the containment. The operator uses the containment temperature and pressure readings to determine how many fan cooler units should be operating. At full power operation, four or fewer units are usually required, while at cold shutdown only one unit may be needed (refer to Section 9.4.5). Limiting conditions for operation are included in the Technical Specifications.

6.2.2.2.1.2.1 Cooling Coils

The coils are fabricated with copper plate fins on copper tubes. Each fan cooler consists of 12 individual coils mounted in two banks, 6 coils high. These banks are located one behind the other for horizontal series air flow, and the tubes of the coil are horizontal with vertical fins.

The cooling coil assembly consists of one bank of WC-36114-4H (1/2 water velocity circuiting) coils four rows deep and one bank of WC-36114-6T (1/3 water velocity circuiting) coils six rows deep. Each coil is provided with a drain pan and drain piping to prevent flooding of the coil face area during accident conditions. This condensate is drained to the containment sump. The monitoring of this condensate for the leakage detection system of the RCS pressure boundary is discussed in Section 5.2.7.1.2.

The component cooling water system (CCW) supplies cooling water to the containment fan coolers and is discussed in Section 9.2.2.

6.2.2.2.1.2.2 Fans

The five containment cooling fans are of the centrifugal, nonoverloading direct-drive type. The fan bearings have a specially designed seal, are heavy duty, and are selected for the proper thrust and axial loads. Special lubricant is used to ensure protection during accident operation (refer to Section 6.2.2.3.26).

6.2.2.2.1.2.3 Enclosure

Each of the five fan cooler enclosure assemblies consists of four prefabricated modular units. Modules 1, 2, and 3 are located on the inlet side of the cooling coils. Module 4 is located on the outlet side of the cooling coils and serves as a plenum for the fan inlet.

The CFCS was modified to remove the moisture separators and HEPA filters.

6.2.2.2.1.2.4 Anti-Reverse Rotation Device

An AARD is incorporated into the fan/motor coupling that prevents the fan motor from rotating backwards. This device protects the fan motor from airflow that could cause an over-current trip condition when the idle fan starts.

6.2.2.2.1.2.5 Pressure Relief Damper

Each fan cooler unit is equipped with a pressure relief damper. These dampers are normally closed counterweighted devices that open progressively as the pressure differential across them exceeds 0.25 psi.

6.2.2.2.1.2.6 Ductwork

Vacuum relief dampers and pressure relief dampers are provided along the ductwork to limit the differential pressure acting on the duct to 0.2 psi during accident conditions. The debris screen, flexible connection, duct branch, and vacuum relief dampers are required to function from the beginning of an accident to full closure of the containment purge isolation valves (assuming the valve is open for containment purge when the accident occurs). This is to ensure that debris generated during an accident will not lodge in the seat of the containment isolation valve to prevent its full closure.

Ducts are constructed of galvanized sheet steel. Bolted flanges are provided with gaskets suitable for 300°F service. All longitudinal seams are tack welded or riveted and sealed.

6.2.2.2.1.2.7 Air Flow Dampers

Dampers are locked in their normal operating position. The air flow dampers are an integral part of the fan coolers. Each damper is constructed of steel painted with corrosion-inhibiting paint, with multiple blades and edge seals to minimize leakage.

6.2.2.2.1.2.8 Motors for Fan Coolers

A two-speed, single-winding motor is used to drive each fan cooler. The motor operates at the high speed during normal operation and at the low speed during post-accident operation.

The motor unit is provided with an integral air-to-water heat exchanger.

The motor heat exchanger consists of the cooling coil, the housing, and two pressure equalization dampers (relief valves to vent containment pressure into the heat exchanger).

The motor heat exchanger circulates component cooling water. The joints of the motor heat exchanger cooling coil are brazed with a high-temperature alloy.

The motor heat exchanger cooling coil is mounted within the motor heat exchanger housing and is generally of the same type construction as the main coils. The plenum after the coil has a condensate drain connection.

The fan cooler motor heat exchanger housing is equipped with two pressure equalization dampers to relieve pressure differentials resulting from a post-accident pressure transient. The valves begin to open at 5 inches water gauge. The valves are designed for a maximum pressure differential of 30 inches of water. Each valve has a maximum flow area of 7.07 square inches. The valves and body flapper plates are electrolytically nickel-coated carbon steel. The valve brackets, links, shafts, springs, and fasteners are Type 316 stainless steel. The seat seals are a silicone rubber O-ring. Each valve is subjected to a certification test before shipment to ensure proper opening pressure and leaktightness.

The motor, motor heat exchanger, and fan are mounted on a common base for extra rigidity.

6.2.2.2.1.3 Electrical Supply

The CFCS fan motors and CSS valves are powered from separate Class 1E 480-V buses and the containment spray pumps are powered from separate Class 1E 4.16-kV buses (refer to Section 8.3.1.1.3).

6.2.2.3 Safety Evaluation

6.2.2.3.1 General Design Criterion 2, 1967 - Performance Standards

With the exception of the RWST and connected piping, the CFCS and CSS components are located within the PG&E Design Class I auxiliary and containment buildings. The applicable portions of these buildings are designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), and earthquakes (refer to Section 3.7). The design of the auxiliary and containment buildings will protect the CFCS and CSS components against natural phenomena and local site effects, ensuring their design functions will be performed.

The evaluation of the performance standards for the RWST is provided in Section 6.3.2.2.2.

The CFCS fan coolers are designed to PG&E Design Class I criteria.

The fan cooler discharge ductwork and supports, up to and including the backdraft dampers' frame, are PG&E Design Class I to maintain the integrity and the design heat removal capability of the operating fan coolers. Except for the short section of branch duct between the containment purge exhaust isolation valve and its debris screen, the ducting is PG&E Design Class II and is seismically designed. This duct section must maintain its integrity during an accident up to the time full closure of the containment purge isolation valve has been attained to ensure that debris generated during an accident will not lodge in the seat of the containment isolation valve to prevent its full closure. The duct branch bounded by the containment purge isolation valve and its debris screen, including the flexible connection, is classified as PG&E Design Class I. The vacuum relief dampers are classified as PG&E Design Class I and the pressure relief dampers are classified as PG&E Design Class II. This greatly minimizes the collapsing/damage to the distribution ductwork from pressure transients during an accident condition.

The HE and DDE piping analyses for the piping located inside containment downstream of sealed-open isolation valves 9006 A and B take credit for the empty piping configuration that exists during normal plant operation.

6.2.2.3.2 General Design Criterion 10, 1967 – Containment

The CFCS and CSS are designed to support containment integrity to sustain the effects of a LOCA or MSLB. The CHRS maintains the containment within its maximum design conditions therefore retaining its functional capability. The containment atmospheric temperature after a MSLB does briefly increase greater than the containment design temperature, but, as discussed in Section 6.2D.4.2.4, there is no explicit design temperature limit for a MSLB. The containment integrity analyses are demonstrated in Appendix 6.2D.

6.2.2.3.3 General Design Criterion 11, 1967 - Control Room

The CFCS and CSS are designed with remote-manual operation for each train of CSS and CFCUs in the control room.

The CFCS and CSS are designed with control room indication including containment pressure, containment isolation valve position, containment spray pump discharge flow, heat removal by containment fan heat removal system through: CFCU motor speed indication, CCW flow indication, containment pressure indication, and containment atmosphere temperature indication (refer to Section 7.5.2).

Therefore, indication and controls are provided in the main control room to maintain safe operational status of the CFCS and CSS.

6.2.2.3.4 General Design Criterion 12, 1967 - Instrumentation and Control Systems

The CFCS and CSS are provided with instrumentation and controls to monitor and maintain CHRS variables within prescribed operating ranges. In addition to actuating based on signals generated by the engineered safety features actuation system (ESFAS), which receives input from containment pressure-related instrumentation (refer to Section 7.3.2), CHRS instrumentation requirements include the capabilities for measurement and local indication of suction pressure which can be used to evaluate NPSH and discharge pressure in the containment spray pumps and containment spray pump flow to containment. To ensure that water flows to the safety injection system (SIS) after a LOCA and determine when to shift from the injection to the recirculation mode, RWST level indication and alarm are provided. High-high containment pressure (“P” signal) coincident with a safety injection signal (“S” signal) will automatically initiate the CSS as discussed in Section 6.2.2.3.5.

The containment fan cooler bearings are monitored for vibration. Similarly, the containment fan cooler motor assembly bearings and windings are monitored to ensure that vibration and temperature limits are not exceeded.

The following instrumentation associated with the containment fan coolers enables additional monitoring of in-containment conditions in the post-LOCA recovery period:

(1) The CCW discharge flow for the containment fan coolers is indicated in the control room and alarmed if the flow is low.

(2) The CCW exit temperatures are indicated locally outside the containment building.

(3) Bearing temperatures are indicated and alarmed on the plant process computer.

6.2.2.3.5 General Design Criterion 15, 1967 - Engineered Safety Features Protection Systems

The CHRS is designed with instrumentation that measures containment pressure. The CSS will be actuated through ESFAS by a "P" signal (high-high containment pressure actuation setpoint) on coincidence of two-out-of-four high-high containment pressure signals. Coincidence of "S" (safety injection) and "P" signals starts the containment spray pumps and opens the discharge valves to the spray headers. Refer to Section 7.3 for a description of the ESFAS.

6.2.2.3.6 General Design Criterion 19, 1971 - Control Room

The CSS is designed to deliver borated water from the RWST to the containment atmosphere during the injection phase following a LOCA. The CSS, in conjunction with the CFCS, reduces the containment ambient temperature and pressure following a LOCA or MSLB, thus reducing the driving force for leakage of fission products from the containment atmosphere. The CFCS provides mixing of the sprayed and unsprayed regions of the containment to improve airborne fission product removal. The SAS, as discussed in Section 6.2.3, injects sodium hydroxide to the suction of the CSS for delivery to the containment atmosphere to prevent the re-evolution of the iodine in the recirculated core cooling solution. The CSS removes iodine from the containment atmosphere to ensure that radiological exposures for control room personnel are within 5 rem whole body. Refer to Section 15.5 for radiological consequences of plant accidents. Therefore, the CSS, in conjunction with the CFCS and SAS, limits the control room doses to 5 rem whole body.

6.2.2.3.7 General Design Criterion 21, 1967 - Single Failure Definition

The CFCS and CSS are designed such that no single failure in either train will prevent the CHRS from performing its design function. The CSS is comprised of two completely independent trains of containment spray. Each CSS train of pumps and valves are powered by separate Class 1E 4.16-kV and 480-V power supplies, respectively. The CFCS is comprised of five independent fan coolers; two are powered from Class 1E 480-V Bus F, two are powered from Class 1E 480-V Bus G, and one is powered from Class 1E 480-V Bus H.

Any single failure will still leave sufficient CSS and CFCS capability to together mitigate DBAs. Used in conjunction with one another during the injection phase, one containment spray pump and two containment fan cooler units will provide the heat removal capability to maintain the post-accident containment pressure below the design value of 47 psig. CHRS design parameters are listed in Table 6.2-26.

A single failure analysis on all active components of the CHRS was performed to show that the failure of any single component will not prevent performance of the design function. This analysis is summarized in Table 6.2-27.

6.2.2.3.8 General Design Criterion 37, 1967 - Engineered Safety Features Basis for Design

The CSS is credited only for operation during the injection phase following a LOCA and MSLB. The CFCS is credited for containment pressure and temperature control throughout the injection and recirculation phases following a LOCA or MSLB.

The CSS and CFCS limit the effects of post blowdown energy additions to the containment during the injection phase following a LOCA. For a detailed description of the analytical methods and models used to assess the performance capability of the CHRS, refer to the containment integrity analysis presented in Appendix 6.2D.

The CHRS provides a backup to the safety provided by the core design, the reactor coolant pressure boundary, and their protection systems. As discussed in this section, the CHRS is designed to withstand any size reactor or secondary coolant pressure boundary break, including a LOCA or MSLB.

6.2.2.3.8.1 Containment Spray System

The CSS, in conjunction with the CFCS, reduces the containment ambient temperature and pressure following a LOCA or MSLB, thus reducing the driving force for leakage of fission products from the containment atmosphere. The CSS removes airborne iodine from the containment atmosphere following a LOCA (refer to Section 6.2.3). The CSS, in conjunction with the spray additive system (SAS), prevents the re-evolution of the iodine in the recirculated core cooling solution (also known as sump water) following a LOCA (refer to Section 6.2.3).

6.2.2.3.8.1.1 Containment Spray Pumps

The containment spray pumps are designed to perform at rated capacity against a total head composed of containment design pressure, nozzle elevation head, and the line and nozzle pressure losses. Adequate NPSH is available for operation of the containment spray pumps throughout the entire spray injection phase considering the low-low level in the RWST. A performance curve for the containment spray pumps is shown in Figure 6.2-10.

During the spray injection phase, a single containment spray pump delivers approximately 2466 gpm to the spray header, at containment design pressure (47 psig). If both of the two spray pumps are available in this phase, approximately 4932 gpm is delivered to the containment spray headers from the RWST. This flowrate is not ECCS dependent.

6.2.2.3.8.1.2 Containment Spray Nozzles

The CSS nozzles produce a mean drop diameter of 700 microns at rated system conditions (40 psi Δp and 15.2 gpm per nozzle). The minimum fall path for CSS water droplets is conservatively assumed to be the distance from the lowest spray ring to the operating deck. The heat transfer calculations presented in Section 6.2.1 and Appendix 6.2D show that essentially all spray droplets reach thermal equilibrium at containment design temperature and pressure in a distance considerably less than the minimum fall path. The spray solution is stable and soluble at all temperatures of interest in the containment and will not precipitate or otherwise interfere with nozzle performance. If containment spray is used in the recirculation phase, the containment recirculation sump screens (refer to Figures 6.3-6 and 6.3-7) limit particle size to preclude the possibility of clogging (refer to Section 6.3). Nozzle design and performance characteristics are listed in Table 6.2-26 and in Figure 6.2-12. A plan view of the containment spray headers showing the location of the spray nozzles is given in Figure 6.2-13. An evaluation of the containment spray pattern, including droplet size and distribution, is discussed in Section 6.2.3.

6.2.2.3.8.1.3 Containment Spray System Phases of Operation

The CSS may operate over an extended period and under the environmental conditions existing following a LOCA or an MSLB. The system operation can be divided into the following two distinct phases.

6.2.2.3.8.1.3.1 Injection Phase

The CSS will be actuated by a "P" signal, either manually from the control room, or on coincidence of two-out-of-four high-high containment pressure signals. Coincidence of "S" and "P" signals starts the containment spray pumps and opens the discharge valves to the spray headers. The "P" signal alone will open the valves associated with the spray additive tank. During the spray injection phase, the pumps are drawing borated water from the RWST and mixing it with NaOH solution from the spray additive tank (refer to Section 6.2.3). Spray injection will continue until the RWST low-low level is reached, at which time the containment spray pumps are manually tripped and isolated.

6.2.2.3.8.1.3.2 Recirculation Phase

If the CSS is used in the spray recirculation phase, recirculation spray is provided by the RHR pumps, which draw suction from the containment sump. Spray recirculation phase operation of the RHR pumps is discussed in Section 6.3.2.4.3.1 and Section 5.5.6.

6.2.2.3.8.2 Containment Fan Cooler System

6.2.2.3.8.2.1 Containment Fan Coolers

In addition to limiting maximum containment pressure and temperature, the containment fan coolers provide mixing of the containment atmosphere for iodine removal and control of hydrogen buildup as discussed in Sections 6.2.3 and 6.2.5, respectively.

The heat removal capability of the containment fan cooler cooling coils is 81 x 10^6 Btu/hr per fan cooler unit at saturation conditions (271°F, 47 psig), with 2000 gpm cooling water supply at 125°F (refer to Table 6.2-26).

The design internal pressure of each coil is 200 psig and the coils can withstand an external pressure of 47 psig at a temperature of 271°F without damage.

Each cooling coil assembly has a top and bottom horizontal coil casing made of galvanized steel. The safety function of the cooling coil casings is to fill the air gap between each stacked cooling coil assembly and direct airflow through the cooling fins to ensure that adequate heat transfer occurs within the containment fan cooler units.

Each fan can provide a minimum flowrate of 47,000 cfm (in low speed) when operating against the system resistance of approximately 3-3/4 inches of water existing during the accident condition.

As discussed in Section 6.2.2.2.1.2.3, each CFCS unit is comprised of four, pre-fabricated modular units. As a result of the modifications made to the fan cooler enclosure assemblies, only Module 3 serves to direct the airflow into the coils for normal and post-LOCA operations. Modules 1 and 2 are no longer required for service.

Module 1 contains the locked-open accident flow inlet dampers. Locking the accident inlet damper open prevents module overpressurization during a LOCA. Module 2 contains the locked-closed accident flow outlet dampers. Modules 1 and 2 are open to one another (i.e., Module 1 and Module 2 do not have a division or dampers separating the two). Module 3 contains the locked-open normal flow inlet dampers and the pressure-relief damper.

The AARD is designed to withstand the dynamic loads associated with *a* 7 psi pressure differential.

The pressure relief dampers limit the pressure differential across the fan cooler enclosure walls in the event of a LOCA or MSLB, and thus maintain the structural integrity of the fan cooler units during the pressure transient.

The fan cooler motor heat exchanger has sufficient capacity to remove all motor assembly heat losses and external heat loads under all operating conditions, while limiting the maximum thermal environment consistent with motor design.

In the event of a LOCA or MSLB, two of the five fan coolers are required to operate. The units are placed in post-accident mode of operation either by a safety injection signal or manually from the control room.

As shown in Table 6.2-26, during a LOCA or MSLB, each fan cooler motor will automatically trip. The motors will then restart at low speed (600 rpm) and provide a heat removal capacity of 81 x 10^6 Btu/hr at containment design conditions. The cooler heat removal capacity is based on 125°F cooling water and other parameters as specified in Table 6.2-26.

A high degree of mechanical reliability is incorporated in the containment ventilation system. The fan cooler system regularly demonstrates its availability because it is used during normal plant operation to control temperature inside the containment (refer to Section 9.4.5). In the event of a failure of offsite electric power concurrent with a LOCA or MSLB, the fan cooler units and the CCW pumps supplying cooling water to these coolers are started automatically and supplied with power from the standby power source.

Immediately following a LOCA, the peak steam-air mixture entering the cooling coils is at approximately 271°F with a density of 0.175 pounds per cubic foot. Part of the water vapor condenses on the cooling coils. The air-side pressure drop is not appreciably affected by the condensate on the cooling coils. The air leaving the coils is saturated at a temperature somewhat below 271°F.

The steam-air mixture remains in this condition as it flows into the fan. At this point it picks up some sensible heat from the fan and fan motor before entering the distribution header and the dry-bulb temperature rises slightly above 271°F and the relative humidity drops to slightly below 100 percent.

6.2.2.3.8.2.2 Flow Distribution and Flow Characteristics

The location of the distribution ductwork outlets, together with the location of the fan cooler unit inlets, ensures that the air will be directed to all areas requiring ventilation before returning to the units.

In addition to ventilating areas inside the periphery of the polar crane wall, the distribution system also includes branch ducts for ventilating the upper portion of the containment. These ducts extend upward along the containment wall to the dome area, although the volume control dampers have been closed and no longer supply air flow. Refer to Section 6.2.2.3.1 for a discussion on the PG&E design classification of the ductwork.

The air discharged inside the periphery of the polar crane wall will circulate and rise above the operating floor though openings around the steam generators where it will mix with air displaced from the dome area. This mixture will return to the fan cooler inlets located on the operating floor. The temperature of this air will essentially be the design ambient for the containment (refer to Section 9.4.5).

In the accident mode of operation, the recirculation rate with five coolers operating is approximately 5.4 containment volumes per hour.

6.2.2.3.8.2.3 Cooling Water for the Fan Cooler Units

The cooling water requirements for the fan cooler units during a LOCA or MSLB and the recovery are supplied by the CCW system, which is described in Section 9.2.2 and in Table 6.2-26.

The CFCS removes sufficient heat from the containment, following the initial LOCA or MLSB containment pressure transients, to keep the containment pressure from exceeding the design pressure. The fans and cooling coils continue to remove heat after the LOCA or MSLB and reduce the containment pressure close to atmospheric within the first 24 hours.

In addition, the following objectives are met to provide the ESF functions:

(1) Each of the five fan cooler units is capable of transferring heat from the containment atmosphere, at the design basis rate for post-accident design conditions (refer to Table 6.2-26).

(2) In removing heat at the design basis rate, the coils are capable of discharging the resulting condensate without impairing their flow capacities and without raising the cooling water exit temperature to the boiling point. Since condensation of water from the air-steam mixture is the principal mechanism for removal of heat from the post-accident containment atmosphere by the cooling coils, the coil fins will operate as wetted surfaces under these conditions. Entrained water droplets added to the air-steam mixture will therefore have essentially no effect on the heat removal capability of the coils.

The post-accident heat removal capability of the fan coolers is demonstrated by the Westinghouse computer program HECO (Reference 36).

6.2.2.3.9 General Design Criterion 38, 1967 - Reliability and Testability of Engineered Safety Features

The CFCS and CSS are designed with high reliability and testability. This is demonstrated through testing included in the surveillance test procedures for the plant delineated in the Technical Specifications as discussed in Sections 6.2.2.3.8.2, 6.2.2.3.15, 6.2.2.3.17 through 6.2.2.3.23, 6.2.2.3.26, 6.2.2.3.27, and 6.2.2.3.28.

6.2.2.3.10 General Design Criterion 40, 1967 - Missile Protection

All of the fan coolers, the distribution ductwork to the annulus ring (inclusive), and cooling water piping are located outside the missile shield wall. This arrangement provides protection from missiles for all system components.Portions of the branch ductwork from the annulus penetrate and extend past the missile shield wall. However, as described in Section 6.2.2.3.12, they are not required for accident mitigation.

The CSS is protected from missiles, pipe whip, or jet impingement from the rupture of any nearby high-energy lines (refer to Sections 3.5 and 3.6). A vulnerability of the system to this is with the portion of the CSS piping located outside of containment in the containment penetration area (GE/GW area) which could potentially result in missiles as a result of a MSLB; however, a MSLB outside of containment does not require operation of the CSS.

6.2.2.3.11 General Design Criterion 41, 1967 - Engineered Safety Features Performance Capability

The CFCS and CSS, including required auxiliary systems, are both designed to tolerate a single active failure during the spray injection phase following a LOCA or MSLB without loss of protective function. Therefore, the CFCS and CSS provide sufficient performance capability to accommodate partial loss of installed capacity and still fulfill the required functions for containment heat removal, airborne fission product removal, and CFCS mixing for hydrogen control.

6.2.2.3.12 General Design Criterion 42, 1967 - Engineered Safety Features Components Capability

The CFCS and CSS component design pressure and temperature conditions in Table 6.2-26 are specified as the most severe conditions to which each component is exposed during either normal or post-LOCA operation.

During a LOCA, the primary objective of the CFCS is heat removal for containment pressure reduction. The exact distribution of the recirculation flow through the ductwork is not critical. In the event of breakage/damage to PG&E Design Class II ductwork branches, no significant reduction in CFCS performance is anticipated because ductwork damage will not reduce the total heat removal capability of the operating fan coolers.

Therefore, the CFCS and CSS are designed so that the capabilities to perform the required functions are not impaired by the effects of a LOCA.

6.2.2.3.13 General Design Criterion 49, 1967 - Containment Design Basis

The CFCS and CSS ensure that the containment design pressure and temperature are maintained below the design conditions following limiting LOCA events. Refer to Appendix 6.2D for the containment integrity analysis.

The CSS penetrations are designed to withstand the pressures and temperatures that could result from a LOCA without exceeding the design leakage rates. Refer to Section 3.8.1.1.3 for additional details.

6.2.2.3.14 General Design Criterion 52, 1967 - Containment Heat Removal Systems

Adequate heat removal capability for the containment atmosphere is provided by two diverse and separate ESFs, the CSS and the CFCS, capable of maintaining the containment below the maximum design pressure and temperature following a LOCA or MSLB. During the recirculation phase, the CFCS alone is capable of maintaining the containment below its maximum design pressure and temperature. These two systems are designed to work in conjunction with one another to meet the single failure criteria as discussed in Section 6.2.2.3.7.

6.2.2.3.15 General Design Criterion 54, 1971 - Piping Systems Penetrating Containment

The CSS containment isolation valves are periodically tested for operability and leakage. Testing of the components required for the containment isolation system (CIS) is discussed in Section 6.2.4. Test connections are provided in the penetration and in the piping to verify valve leakage and penetration leakage are within prescribed limits.

6.2.2.3.16 General Design Criterion 56, 1971 - Primary Containment Isolation Valves

The CSS containment penetrations that are part of the CIS include the containment spray pump discharge lines which comply with the requirements of GDC 56, 1971, as described in Section 6.2.4 and Table 6.2-39.

6.2.2.3.17 General Design Criterion 58, 1967 - Inspection of Containment Pressure-Reducing Systems

Access is available for visual inspection of the fan cooler components, including fans, cooling coils, enclosure dampers, and ductwork. Since these units are in use during power operation, continuous checks of their status are available.

The containment fan cooler cooling coils are designed to be easily removed for inspection and maintenance.

Refer to Section 6.2.2.3.19 and 6.2.2.3.27 for a discussion on testing and inspection of the CSS.

Therefore, provisions are available to facilitate periodic inspection of all important components of the CFCS and CSS.

6.2.2.3.18 General Design Criterion 59, 1967 - Testing of Containment Pressure-Reducing Systems

Provisions are available for periodic testing of active CSS components to ensure operability and required functional performance is maintained (refer to Section 6.2.2.3.19).

The fan cooling units are used during normal operation (refer to Section 9.4.5). The fans not in use can be started from the control room to verify readiness. A test signal is used to demonstrate proper fan starting.

6.2.2.3.18.1 Anti-Reverse Rotation Device Tests

The air is discharged through the ducting to the annular ring where the air is distributed to various compartments and areas. The return air to the fan coolers is taken at elevation 140 feet where the containment fan coolers are located. After a LOCA, the pressure rise at the upper elevation is relatively slow and, as a result, the pressure difference that is expected between the inlet and outlet of the containment fan cooler unit is extremely small. A value of 7 psi pressure difference was chosen as a conservative design limit.

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To demonstrate the adequacy of the ARRD design, dynamic tests were performed to demonstrate that the device will withstand the dynamic loads associated with a 7 psi pressure differential. Static tests were performed to show that the subsequent transient differential pressure can react on the ARRD without failure. The results of these tests and subsequent stress analyses are summarized below:

(1) The ARRD was statically loaded to 3828 ft-Ib driven torque and 2400 ft-Ib reverse rotation torque with no failure. Spin testing was performed to validate retraction of the pawls. The ARRD showed no permanent deformation.

(2) The ARRD was tested to validate its ability to react to reverse rotation of the fan shaft under dynamic loading conditions. The dynamic load test

conditions include the following: 317 ft-lb of torque, 3 degrees total rotation, 0.391 radians/second angular velocity at end of rotation.

From these results, it was concluded that the ARRD will withstand the load imposed by a 7 psi pressure differential and the design of the ARRD is adequate for the intended use.

6.2.2.3.18.2 Containment Fan Cooler Cooling Coil Test Summary

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Plate-finned cooling coils are an integral part of the CFCS. These heat exchangers remove sensible heat during normal operation, but become condensers in the post-accident environment. Because of limited experimental information concerning the performance of plate-finned cooling coils operating in a condensing environment in the presence of a noncondensible (air), a demonstration test was undertaken.

The test method was to subject a scaled coil to a parametric test. These parameters were (a) containment pressure (with corresponding steam density and temperature), (b) air flowrate, (c) cooling water flowrate, (d) cooling water temperature, and (e) entrained water content. Each parametric test condition was then used as input to the HECO computer program used in coil selections. The results of the test and the computer program predictions were compared.

In all cases, the measured heat transfer rate was greater than that predicted by the HECO code. The range of parameter variations was selected to be consistent with the design points of the containment fan cooling coils contained in actual plants. It is apparent that for this specific type of heat exchanger, functioning in the range of environments tested, no moisture separator is needed to protect the coils from excessive waterlogging due to entrained spray droplets.

The extension of the test to full-size units is merely an increase in component size and total flow quantities, but not a change in controlling parameters. It is concluded that the test demonstrates that the computer code used to select cooling coil design is valid in defining the heat removal rates of plate-finned tube cooling coil assemblies of the CFCS. Therefore, these tests demonstrate that fan cooler designs, which are selected by this computer program, will perform as required in the post-accident containment environment.

6.2.2.3.19 General Design Criterion 60, 1967 - Testing of Containment Spray Systems

The CSS is designed so that component surveillance can be performed periodically to demonstrate system readiness. Containment spray valve alignment is periodically verified.

The containment spray pumps are tested individually by manually shutting the spray header isolation valves, manually opening the RWST test return line isolation valves, and manually starting the pumps. Pump differential pressure can be used to verify pump performance.

Periodic testing of the containment spray nozzles, as required by Technical Specifications, will ensure that nozzles are unobstructed. Each containment spray header can be tested individually by connecting an air source to the normally capped flange connection on the spray pump discharge header, shutting the manual spray header isolation valve, and opening the air test line isolation valve and the motor-operated spray header isolation valve. Individual nozzles can then be checked for proper performance by streamers, which indicate unobstructed air flow.

6.2.2.3.20 General Design Criterion 61, 1967 - Testing of Operation Sequence of Containment Pressure Reducing Systems

The CFCS is periodically tested to verify the CFCUs actuate properly upon receipt of an actual or simulated actuation signal and transfer to the standby power supply in the required timeframe.

The aim of the periodic CSS testing is to:

(1) Verify the proper sequencing of valves and pumps on initiation of the containment spray signal and demonstrate the proper operation of remotely operated valves. A spray test interlock prevents accidental actuation of containment spray during testing.

(2) Verify the operation of the spray pumps; each pump will be run at minimum flow and the flow directed through the normal path back to the RWST.

Testing of the “S” and “P” actuation signals is addressed in Section 7.3.4.1.5.2. Component actuation logic, transfer to the standby power supply, and component capability are governed and tested in accordance with the Technical Specifications.

6.2.2.3.21 General Design Criterion 62, 1967 - Inspection of Air Cleanup Systems

During periodic tests, the CFCS and CSS equipment are inspected visually. Leaking seals, packing, or flanges are corrected to eliminate the leak. Valves and pumps are operated and inspected after every maintenance activity to ensure proper operation. Visual inspection of major components of the CFCS is regularly performed. The major components inspected include access doors to the fan cooler units, the fan cooler housings, the CFCS duct work, cooling coils, and dampers. Therefore, the CFCS and CSS are designed with provisions to allow for physical inspection of all critical components.

6.2.2.3.22 General Design Criterion 63, 1967 - Testing of Air Cleanup Systems Components

Periodic testing of the CFCS is performed in accordance with the Technical Specifications. The testing performed on the CFCS includes operation of the fans and ensuring that equipment in the CFCS actuates upon receipt of actual or simulated actuation signals.

Provisions are available for periodic testing of active CSS components to ensure operability and required functional performance is maintained (refer to Section 6.2.2.3.19).

Therefore, provisions are provided for testing of the active components of the CFCS and CSS.

6.2.2.3.23 General Design Criterion 64, 1967 - Testing of Air Cleanup Systems

The CSS, in conjunction with the SAS, serves as the air cleanup system. System water flow can be tested through the test lines permitting the test of the system up to the containment isolation valves. Periodically, a sample of the sodium hydroxide solution is tested to assure proper concentration. Testing of the sodium hydroxide additive solution is discussed in Section 6.2.3.3.14. The fan coolers are normally in use and, therefore, the readiness of the system is verified.

6.2.2.3.24 General Design Criterion 65, 1967 - Testing of Operational Sequence of Air Cleanup Systems

The testing of the operational sequences of the CFCS and CSS are performed in accordance with the Technical Specifications. The surveillance tests include verifying that the containment spray pumps, automatic valves, and fan cooler units actuate properly upon receipt of an actual or simulated actuation signal and transfer to the standby power supply in the required timeframe; therefore, provisions for testing of the operational sequence of the CFCS and CSS is provided.

6.2.2.3.25 General Design Criterion 70, 1967 - Control of Releases of Radioactivity to the Environment

As discussed in Section 6.2.3, the functional performance requirements of the CFCS and CSS, in conjunction with the SAS, are to ensure that the offsite radiological exposures resulting from a LOCA are within the limits of 10 CFR Part 100. Refer to Section 15.5 for a discussion of offsite radiological exposures resulting from a LOCA.

6.2.2.3.26 10 CFR 50.49 - Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants

The CFCS and CSS meet the requirements of 10 CFR 50.49 as described in the DCPP EQ Program. CFCS and CSS SSCs required to function in harsh environments under accident conditions are qualified to the applicable environmental conditions to ensure that they will continue to perform their safety functions. Section 3.11 describes the DCPP EQ Program and the requirements for the environmental design of electrical and related mechanical equipment. The affected equipment includes CFCU motors, valves, pressure sensors, and flow transmitters and are listed on the EQ Master List. The containment spray pump motors are not located within a harsh environment area and are therefore not environmentally qualified.

6.2.2.3.26.1 Containment Fan Cooler System

The containment fan cooler motor insulation is Class F (National Electrical Manufacturers Association rated hot spot temperature of 155°C). At incident ambient and load conditions, the motor insulation hot spot temperature is not expected to exceed 118°C. The motors have 2300-V insulation for 460-V service that provides additional insulation margin. The motor ball bearings are lubricated with high-temperature grease.

The motor heat exchanger housings enclose the major functional element of the motor and limit exposure to the environment that would exist in the containment under post-accident conditions.

The containment fan cooler motor heat exchanger is designed to maintain the environment of the fan cooler motor within an acceptable range during normal and post-accident operation.

The design of the motor and heat exchanger housing seals out the post-accident environment to minimize the amount of moisture entering the motor windings. In addition, any moisture entering the motor housing will condense on the motor heat exchanger. The chief attribute of this design approach is that it ensures that the internal motor parts are maintained in a "usual service condition" despite the hostile environment outside the motor.

The motors are designed for Class F temperature in normal operation, which is consistent with the 40-year plant life requirement. During post-accident operation, the motor heat exchanger keeps winding temperatures below the 155°C insulation hot spot temperature rating.

Qualification of the fan cooler motors is described in PG&E EQ File IH-05 (Reference 39). Since issuance of this report, a revised heat transfer analysis has been performed by Westinghouse to verify the performance of the motor heat exchanger. The bases for motor temperature rise calculations are complete engineering tests of typical motors,

which provide winding temperatures rises and heat losses. These data are used to validate equations that predict temperature rises and heat losses for various design parameters and service conditions. A number of machines are tested to permit computer interpolation of each loss curve. Revised analysis results for prediction of motor winding hot spot temperatures are as follows:

	Ambient Air at Motor Inlet	Previously Reported (WCAP-7829) Rise	Previously Reported (WCAP-7829) Total	Revised Analysis Rise	Revised Analysis Total
Normal	57°C Max	48°C	105°C	45°C	102°C
DBA	75°C Max	47°C	122°C	36°C	111°C
Post-DBA	58°C Avg	34°C	92°C	34°C	92°C

These results confirm the ability of the motor heat exchanger to maintain winding hot-spot temperatures below the qualification level temperatures established in WCAP-7829 (Reference 4 of EQ File IH-05).

The motor insulation system is Class F (National Electrical Manufacturers Association rated hot-spot temperature at 155°C) thermalastic epoxy. The basic mica structure has high-voltage (2300-V) insulation impregnated and coated to give a homogeneous insulation system that is highly moisture resistant. Internal leads and terminal box-motor interconnections are given special design consideration to ensure that the level of insulation exceeds that of the service voltage for the motor.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

Tests indicate that the insulation system will survive direct exposure to the postulated post-accident environment. Hence, the heat exchanger system used to cool the windings provides an additional margin of safety. In addition, it should be noted that at the time of the postulated incident, the fan motor would be started if not already running, and its internal temperature, being higher than the ambient, would tend to drive any moisture present out of the windings.

The heat exchanger was designed using a very conservative fouling factor. However, if surface fouling reduces the capability of the heat exchanger by one-half, the motor would still have a normal life expectancy, even under postulated accident conditions.

To prove the effectiveness of the heat exchanger in inhibiting large quantities of the steam-air mixture from impinging on the winding and bearings, several full-scale motor tests were performed at representative accident conditions. The tests exposed the motors to a steam-air mixture as well as boric acid and alkaline spray at 80 psig and saturated temperature conditions. Insulation resistance, winding and bearing temperatures, relative humidity, voltage and current, as well as heat exchanger water temperature and flow, were recorded periodically during the test. Following the test, the

motors were disassembled and inspected and tested to further ensure that the units had performed as designed. In all tests, the motor unit performed satisfactorily.

The bearings are designed to perform in the ambient temperature conditions resulting from the postulated incident. It should be noted, however, that the interior bearing housing details are cooled by the heat exchanger, thus providing an extra margin of assurance. In addition, separate tests were performed on bearings mounted within a test rig. These bearings were directly exposed to the immediate accident environment including temperature, pressure, steam-air mixture, and chemical sprays. The bearing ran continuously for 22 months without failure. In all tests, bearings were lubricated with fully irradiated grease prior to testing.

To further ensure motor insulation effectiveness (thermalastic epoxy), a separate motor test was conducted by Westinghouse in accordance with IEEE-334-1971 (Reference 47) without the heat exchanger attached to the motor. The test was completed satisfactorily.

6.2.2.3.26.2 Motor Unit Testing

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

Tests were conducted (Reference 39) to demonstrate the effectiveness of a heat exchanger assembly in isolating motor windings from the steam and chemistry of the post-LOCA environment. Additional tests were conducted in 1971 to comply with provisions of IEEE 334-1971. These tests also qualified design features not included in the original motor. Steam exposure tests per IEEE 334-1971 were performed on the same motor with and without the heat exchanger to qualify it for both types of application.

Objectives given particular attention in the current tests to meet proposals of IEEE 334-1971 included:

(1) Aging of all samples to full service life prior to exposure to simulated DBA conditions

(2) Vibration of thermally aged models prior to steam exposure

(3) Change of facilities to provide fast pressure transients to simulate accident conditions during the initial transient

(4) Performance of five pressure transients and exposure to a saturated steam environment for 7 days on the prototype in accordance with the DBA simulation model

(5) Comparisons between insulation samples subjected to combined environment and irradiation and those exposed sequentially to thermal aging, irradiation, moisture, and voltage

(6) Irradiation of all lubricants to 2 x 10^8 rads before use

(7) Destructive tests of statistically selected insulation samples to measure degradation caused by environments including irradiation, with various combinations and durations

The tests in this series qualified all motor materials and design features for the conditions and duration of the test.

6.2.2.3.26.3 Containment Fan Cooler Motor Insulation Irradiation Testing

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

The testing program on the effects of radiation on the WF-SAC "Thermalastic" Epoxy insulation system used in the fan cooler motors has been completed. In these tests, irradiation of form-wound motor coil sections was accomplished up to exposure levels exceeding that calculated for the design basis LOCA. Three coil samples received the following treatment sequence: irradiation, vibration test, high-potential test, and vibration test. Six of the nine coil samples received high-potential and breakdown voltage tests. All coil samples passed the high-potential tests. The breakdown voltage levels of all coils were well in excess of those required by the design and clearly indicate that the fan cooler motor insulation system will perform satisfactorily following exposure to the radiation levels calculated for the DBA.

6.2.2.3.26.4 Containment Fan Cooler Motor Lubricant Irradiation Testing

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

This section summarizes the results of tests performed on samples of unirradiated and irradiated Westinghouse Style No. 773A773G05 (Chevron SRI) lubricant, which is used in the fan cooler fan bearing as well as in the motor bearing. The results of these tests indicate that the shear stability or consistency of the grease is increased by irradiation levels anticipated in the containment following a DBA. The consistency of the grease following irradiation remained within the most commonly recommended consistency for ball bearing application (NLGI No. 2).

The purpose of this test program was to establish the effect of irradiation on the bearing lubrication used on both the fan cooler motor and fan bearings. The maximum calculated 1-year integrated dose for the bearing lubricant, using the DBA with no credit for fission product removal from the containment atmosphere other than by natural decay, is 1.5 x 10^8 rads. The fan and motor bearings would receive a lesser exposure due to self-shielding effects of the motor housing bearing seals and bearing pillow blocks.

Samples of the lubricant were placed in a vented 1.5- x 12 inch aluminum tube. The tube was then placed adjacent to a 34 kilo-curie Cobalt 60 source and irradiated for 79 hours. Dosimetry measurements were made at various locations in the tube using Dupont light blue calibration paper 300 MS-C, No. CB-91639.

Following exposures to average levels of 1.2 x 10^8, 1.5 x 10^8, and 1.8 x 10^8 rads, the irradiated grease along with unirradiated grease taken from the same supply were subjected to the Micro-Cone Penetration Test using standard apparatus conforming to ASTM D1403-56T.

The results of the penetration test indicate that as exposure increased, the grease underwent a change in thickness function to the point that, at 1.8 x 10^8 rads, sufficient change had taken place to cause the grease to increase in consistency to an NLGI No. 2 rating, as the grease was "worked" or sheared rather than decreased as in the unirradiated grease. The most commonly used greases, for ball bearing applications such as those in the fan cooler, have consistencies ranging between NLGI No. 1 and No. 3.

Based on the tests results from irradiation and ASTM Micro-Cone penetration measurements, the containment fan cooler bearing lubricant, Westinghouse Style No. 773A773G05 (Chevron SRI) undergoes no significant change in properties, as measured in terms of consistency.

6.2.2.3.27 10 CFR 50.55a(f) - Inservice Testing

The CFCS and CSS meet the inservice testing requirements as described in the DCPP IST Program Plan.

6.2.2.3.28 10 CFR 50.55a(g) - Inservice Inspection

Design provisions have been made, to the extent practicable, to facilitate access for periodic visual inspection of all important components of the CFCS. Testing of any components, after maintenance or as a part of a periodic inspection program, may be performed at any time, since the CFCS units are in operation on an essentially continuous schedule during normal plant operation. The inservice inspection requirements for the CFCS and CSS are contained in the DCPP ISI Program Plan.

6.2.2.3.29 Regulatory Guide 1.97, Revision 3, May 1983 - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

CFCS and CSS post-accident instrumentation for meeting Regulatory Guide 1.97, Revision 3, requirements consist of containment isolation valve position indication, containment spray flow indication, containment pressure indication, heat removal by containment fan heat removal system through: CFCU motor speed indication, CCW flow indication, containment pressure indication, and containment atmosphere temperature indication (refer to Table 7.5-6). The instrumentation described above is directly monitored in the control room.

Based on the above discussion, the CFCS and CSS instrumentation satisfy the requirements of Regulatory Guide 1.97, Revision 3, as described in Table 7.5-6.

6.2.2.3.30 NUREG-0737 (Item III.D.1.1), November 1980 - Clarification of TMI Action Plan Requirements

Item III.D.1.1 - Integrity of Systems Outside Containment Likely to Contain Radioactive Material for Pressurized-Water Reactors and Boiling-Water Reactors:

The pressure-containing portions of the CSS are tested periodically to check for leakage. This testing includes the portions of the system that would circulate radioactive water from the containment sump, if recirculation spray is required.

6.2.2.3.31 Generic Letter 89-10, June 1989 - Safety-Related Motor-Operated Valve Testing and Surveillance

The CSS PG&E Design Class I MOVs are subject to the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996, and meet the requirements of the DCPP MOV Program Plan.

6.2.2.3.32 Generic Letter 97-04, October 1997 – Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps

The containment spray pumps have been evaluated in accordance with Generic Letter 97-04, October 1997 and adequate NPSH is shown to be available. Refer to Section 6.3 for the evaluation of the ECCS pumps.

6.2.2.4 Tests and Inspections

Refer to Sections 6.2.2.3.15, 6.2.2.3.17 through 6.2.2.3.23, 6.2.2.3.26, 6.2.2.3.27, and 6.2.2.3.28 for details regarding tests and inspections of the CHRS.

6.2.2.4.1 Preoperational Testing

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

The aim of preoperational CSS testing was to:

(1) Demonstrate that the system is adequate to meet the design pressure conditions. Outside containment piping welds were subjected to radiographic inspection and/or partial hydrotesting; inside the containment the spray header welds were subjected to 100 percent radiographic inspection.

(2) Demonstrate that the spray nozzles in the containment spray header are clear of obstructions by passing air through the test connections.

(3) Verify that the proper sequencing of valves and pumps occurs on initiation of the containment spray signal and demonstrate the proper operation of remotely operated valves.

(4) Verify the operation of the spray pumps; each pump is run at minimum flow and the flow directed through the normal path back to the RWST. During this time, the minimum flow is adjusted to that required for routine testing.

Each fan cooler unit was tested after installation for proper flow and distribution through the duct distribution system.

6.2.2.4.2 Periodic Testing

Periodic testing of the CHRS is discussed in Sections 6.2.2.3.15, 6.2.2.3.18 through 6.2.2.3.20, 6.2.2.3.22, 6.2.2.3.23, and 6.2.2.3.26.

6.2.2.5 Instrumentation Applications

Refer to Section 6.2.2.3.4 for the instrumentation requirements related to the CHRS.

6.2.2.6 Materials

Design parameters and materials used in the construction of CHRS components are listed in Table 6.2-26. Those parts of the system that may come in contact with borated water or sodium hydroxide solution are made of stainless steel or a similarly corrosion-resistant material.

6.2.3 CONTAINMENT AIR PURIFICATION AND CLEANUP SYSTEMS

The containment air purification and cleanup systems are made up of the spray additive system (SAS), the containment spray system (CSS), and the containment fan cooler system (CFCS). The functional performance objectives of the containment air purification and cleanup systems are:

(1) The SAS provides a chemical additive to the CSS to prevent the re-evolution of the iodine in the recirculated core cooling solution (also known as sump water) following a loss-of-coolant-accident (LOCA);

(2) The CSS removes airborne iodine from the containment atmosphere following a LOCA;

(3) The CFCS provides mixing of the sprayed and unsprayed regions of the containment to improve airborne iodine removal. Mixing the containment atmosphere maximizes the gas volume treated by the containment spray;

(4) The CFCS and CSS reduce the containment ambient temperature and pressure following a LOCA or a main steam line break (MSLB). While performing this cooling function, the containment heat removal system (CHRS) also helps limit offsite radiation levels by reducing the pressure differential between containment and outside atmospheres, thus reducing the driving force for leakage of fission products from the containment atmosphere (refer to Section 6.2.2);

(5) The CFCS provides a mixed containment atmosphere for hydrogen control (refer to Section 6.2.5);

(6) The CFCS limits the containment ambient temperature during normal plant operating conditions (refer to Section 9.4.5).

The SAS boundary consists of all piping and valves between, and including, the isolation valve from the refueling water storage tank (RWST), the spray additive tank and the spray eductors. The safety function of iodine removal occurs during operation of the containment spray system and while core coolant is retained in the containment sump. The physical SSC design bases, testing and inspection requirements of the CSS and CFCS are discussed in Section 6.2.2, therefore the following section addresses the SAS SSCs only.

The two small charcoal filter units in the containment air purification system are not classified as ESFs and are described in Section 9.4.5. These units are not necessary for cleanup during accident conditions.

6.2.3.1 Design Bases

6.2.3.1.1 General Design Criterion 2, 1967 – Performance Standards

The SAS is designed to withstand the effects of, or is protected against, natural phenomena, such as earthquakes, winds and tornadoes, floods and tsunamis, and other local site effects.

6.2.3.1.2 General Design Criterion 3, 1971 – Fire Protection

The SAS is designed and located to minimize, consistent with other safety requirements, the probability and effects of fires and explosions.

6.2.3.1.3 General Design Criterion 11, 1967 – Control Room

The SAS is designed to support actions to maintain and control the safe operational status of the plant from the control room.

6.2.3.1.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain SAS variables within prescribed operating ranges.

6.2.3.1.5 General Design Criterion 19, 1971 – Control Room

The SAS, in conjunction with the iodine removal function of the CSS and CFCS, is designed to support radiation protection to permit access and occupancy of the control room under accident conditions without personnel receiving radiation in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident.

6.2.3.1.6 General Design Criterion 21, 1967 – Single Failure Definition

The SAS is designed to tolerate a single failure during the period of recovery following an accident without loss of its protective function, including multiple failures resulting from a single event, which is treated as a single failure.

6.2.3.1.7 General Design Criterion 37, 1967 – Engineered Safety Features Basis for Design

The SAS, in conjunction with the iodine removal function of the CSS, is designed to prevent the re-evolution of iodine in the core cooling solution and provide back-up to the safety function provided by the core design, the reactor coolant pressure boundary, and their protection systems.

The CFCS is designed to ensure mixing of the sprayed and unsprayed regions of the containment atmosphere, to improve airborne fission product removal following any size reactor coolant pressure boundary break.

6.2.3.1.8 General Design Criterion 38, 1967 – Reliability and Testability of Engineered Safety Features

The SAS is designed to provide high functional reliability and ready testability.

6.2.3.1.9 General Design Criterion 40, 1967 – Missile Protection

The SAS is designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

6.2.3.1.10 General Design Criterion 41, 1967 – Engineered Safety Features Performance Capability

The SAS is designed to provide sufficient performance capability to accommodate a partial loss of installed capacity, such as a single failure of an active component, and still perform its required safety function.

6.2.3.1.11 General Design Criterion 42, 1967 – Engineered Safety Features Components Capability

In support of the iodine removal function, the CSS and CFCS are designed so that the capability of each component and system to perform its required function is not impaired by the effects of a LOCA.

6.2.3.1.12 General Design Criterion 62, 1967 – Inspection of Air Cleanup Systems

The SAS is designed to facilitate physical inspection of critical parts required for operation.

6.2.3.1.13 General Design Criterion 63, 1967 – Testing of Air Cleanup Systems Components

The SAS is designed so that active components can be tested periodically for operability and required functional performance.

6.2.3.1.14 General Design Criterion 64, 1967 – Testing of Air Cleanup Systems

The SAS is designed for in-situ periodic testing and surveillance.

6.2.3.1.15 General Design Criterion 65, 1967 – Testing of Operational Sequence of Air Cleanup Systems

The SAS is designed with the capability to test, under conditions as close to design as practical, the full operational sequence that would bring the SAS into action.

6.2.3.1.16 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The SAS, in conjunction with the iodine removal function of the CSS and CFCS, is designed with provisions for maintaining control over the plant's radioactive gaseous effluents.

6.2.3.1.17 10 CFR 50.55a(f) – Inservice Testing Requirements

American Society of Mechanical Engineers (ASME) code components within the SAS are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

6.2.3.1.18 10 CFR 50.55a(g) – Inservice Inspection Requirements

ASME code components within the SAS are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

6.2.3.1.19 Generic Letter 89-10, June 1989 – Safety-Related Motor-Operated Valve Testing and Surveillance

The SAS PG&E Design Class I motor-operated valves (MOVs) meet the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996.

6.2.3.2 System Description

6.2.3.2.1 General Description

The SAS is designed to add sodium hydroxide to the containment spray water to enhance the absorption of elemental iodine from the containment atmosphere and to retain the iodine in the containment sump water in nonvolatile forms.

According to the known behavior of elemental iodine in highly dilute solutions, the hydrolysis reaction, described by the relationships:

$$I_2 + OH^- \rightleftarrows HIO + I^- \qquad (6.2\text{-}8)$$

proceeds nearly to completion (Reference 4) at pH values between 8 and 9.5. The iodine form is highly soluble, and HIO readily undergoes additional reactions to form iodate.

The overall iodate reaction is:

$$3I_2 + 3H_2O \rightleftarrows 5HI + HIO_3 \tag{6.2-9}$$

Values of the spray removal half-life of the molecular iodine in a typical containment are on the order of minutes, or less. This makes the spray system a very efficient fission product removal system in comparison to such alternatives as charcoal filtration systems.

The SAS, as shown schematically in Figure 3.2-12, consists of the spray additive tank, eductors, valves, and connecting piping. The design parameters are presented in Table 6.2-29. Applicable codes and standard are given in Table 6.2-30.

The CFCS ensures appropriate mixing of the containment atmosphere following a design basis accident to maximize the containment gas volume treated by the containment spray.

On actuation, approximately 4 percent of each spray pump discharge flow will be diverted through each spray additive eductor to draw sodium hydroxide from the tank. This sodium hydroxide solution will then mix with the liquid entering the suction line of the pumps to give a solution suitable for removal of iodine from the containment atmosphere.

During the injection phase, the emergency core cooling pumps will inject borated water drawn from the RWST into the reactor and containment. Since these flowpaths will not inject sodium hydroxide, the ratio of the total volume injected by all pumps to the volume injected by the spray pumps will determine the change in sodium hydroxide concentration during the injection phase. The total volume of water in the sump includes the total amount contained in the primary coolant and accumulators that could be released to the containment recirculation sump at the start of the LOCA.

6.2.3.2.2 Component Descriptions

6.2.3.2.2.1 Spray Additive Tank

The stainless steel tank will contain sufficient 30 to 32 weight percent sodium hydroxide solution to bring the containment sump fluid to a minimum pH of 8.0 on mixing with the borated water from the RWST, the accumulators, and reactor coolant following a large break LOCA. This will ensure continued iodine removal and retention effectiveness of the containment sump water during the recirculation phase.

6.2.3.2.2.2 Spray Additive Eductors

Sodium hydroxide will be added to the spray liquid by a liquid jet eductor, a device which uses kinetic energy of a pressurized liquid to entrain another liquid. The pressurized liquid in this case is the spray pump discharge used to entrain the sodium hydroxide solution, which is then discharged back into the suction of the spray pumps. On actuation, approximately 4 percent of each spray pump discharge flow is diverted through each spray additive eductor to draw sodium hydroxide solution from the spray additive tank. An eductor motive flowrate of 104 gpm and an eductor suction flowrate of 35 gpm results in a spray solution pH of greater than or equal to 9.5 (refer to design case in Table 6.2-36).

6.2.3.2.2.3 Spray Nozzles

A description of the containment spray nozzles is provided in Section 6.2.2.

6.2.3.2.2.4 Piping and Valves

The piping and valves for the SAS are designed for 240 psig at 200 degrees F.

6.2.3.2.2.5 Electrical Supply

Details of the Class 1E power sources are discussed in Chapter 8.

6.2.3.3 Safety Evaluation

6.2.3.3.1 General Design Criterion 2, 1967 – Performance Standards

The SAS is located within the auxiliary building, which is a PG&E Design Class I structure (refer to Section 3.8). The auxiliary building is designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), and earthquakes (refer to Section 3.7) therefore protecting the SAS, ensuring its design functions will be performed.

The SAS is designed to accommodate the DE within applicable code stress limits and to withstand the DDE or HE without rupture or loss of function.

6.2.3.3.2 General Design Criterion 3, 1971 – Fire Protection

The SAS is designed to the fire protection guidelines of Branch Technical Position APCSB 9.5-1 (refer to Appendix 9.5B Table B-1).

6.2.3.3.3 General Design Criterion 11, 1967 – Control Room

Each of the system's MOVs can be operated individually by switches in the control room. Valve position indication on the same control room panel is used to verify valve operability.

The spray additive tank level instruments provide two alarms to announce when the solution in the tank has dropped below a level approaching the Technical Specification minimum requirements.

6.2.3.3.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Analog and logic channels employed for initiation of SAS operation are discussed in Section 7.3. All alarms will be annunciated in the control room.

The SAS will be actuated by a "P" signal initiated either manually from the control room or on coincidence of two sets of two-out-of-four high-high containment pressure signals. Coincidence of "S" and "P" signals will start the containment spray pumps and open the discharge valves to the spray headers. The "P" signal alone will open the valves associated with the spray additive tank.

A locally mounted indicator on the nitrogen line monitors the spray additive tank pressure while adding nitrogen and during periodic inspections.

A flow element is located in the discharge line from the spray additive tank. Flow indication is provided in the control room.

For the spray additive tank, two separate instruments are provided: one to supply readout in the control room and the other to provide local indication.

6.2.3.3.5 General Design Criterion 19, 1971 – Control Room

The CSS provides iodine removal from the containment atmosphere. The CFCS provides mixing of the containment atmosphere to maximize iodine removal. The SAS increases pH in the containment recirculation sump water. The SAS, CSS and CFCS work in conjunction to ensure that radiological exposures for control room personnel are within 5 rem whole body, refer to Section 15.5 for radiological consequences of plant accidents.

6.2.3.3.6 General Design Criterion 21, 1967 – Single Failure Definition

A failure analysis was conducted on the active components, MOVs 8994A/B, of the SAS to show that failure of any single active component will not prevent the design function from being fulfilled. This analysis is summarized in Table 6.2-38.

MOV 8992 in the spray additive line, which is required only in the short term, is not included in the single failure analysis of Table 6.2-38 because it is not an active component. It performs no active function, is normally open, receives a "P" signal to ensure positive opening, and is designed to fail as is, i.e., in the open position.

In addition, during power operation, power is removed from the single inline SAS outlet MOV 8992 at the circuit breaker at the motor control center with the valve in the open position to prevent a single active failure.

The single failure analysis for the CSS is given in Section 6.2.2.

6.2.3.3.7 General Design Criterion 37, 1967 – Engineered Safety Features Basis for Design

The design basis of the system is two-fold:

(1) Sufficient sodium hydroxide must be added to the containment spray water to ensure rapid absorption by the spray of elemental iodine present in the containment atmosphere following a LOCA.

(2) During the injection phase operation of the spray pumps, a sufficient amount of sodium hydroxide must be carried to the containment sump water via the containment spray to ensure retention of the iodine in the sump solution.

Performance of the CSS as an iodine removal mechanism is conservatively evaluated at the containment design temperature and pressure. Since this peak pressure condition is expected to exist for a few minutes at most, and mass transfer parameters and spray flowrate improve with decreasing pressure, an appreciable margin is added to the evaluation. The design case removal constant for the CSS (λ_s) provided in Table 6.2-36 was calculated by applying the model derived in Section 6.2.3.3.7.3 at this back pressure condition to the sprayed portion of the containment volume.

The CSS, by virtue of the large contact surface area provided between the droplets and the containment atmosphere, affords an excellent means of absorbing radioactive iodine released as a consequence of a LOCA. Sodium hydroxide is added to the spray fluid to increase the absorption of iodine in the spray to the point where the rate of absorption is largely limited by the transfer rate through the gas film surrounding the drops. Reference 5 describes in detail the analytical and experimental basis for the above containment atmosphere iodine removal mechanism. The approach used is summarized below.

The SAS is dependent upon the CSS for operation. The CSS can function with one spray train operating (abnormal operating mode) or with both spray trains operating (normal operating mode). In addition, the operation of one or both ECCS trains affects

the rate of withdrawal of water from the RWST, the duration of the spray injection phase, and thus the amount of sodium hydroxide added to the containment.

Spray iodine removal performance has been evaluated for the design case, a double-ended LOCA, assuming that:

(1) Only one-out-of-two spray pumps operate (one spray train operating)

(2) The ECCS operates at its maximum capacity (two ECCS trains operating)

(3) Borated water is retained in the RWST for the exclusive use of the spray during the first part of the ECCS recirculation phase

The second assumption maximizes ECCS flow from the RWST. Overall, the first two assumptions give the most conservative prediction of sodium hydroxide introduction into the containment (minimum containment recirculation sump pH). The third assumption ensures that sufficient sodium hydroxide solution is added to provide for a sump pH of 8.0 or greater when spray injection terminates. Figure 6.2-15 presents various resulting sump pH versus time curves.

The variation of sump pH with time after the accident is shown for various cases in Figure 6.2-15 (Reference 51). At the time spray injection terminates, the sump water has reached an equilibrium pH of at least 8.0. The sump pH will remain at the same pH after the spray injection phase because no additional water is added to the sump.

Any reevolution of dissolved iodine from the sump to the containment atmosphere depends upon the concentration gradient between the liquid and vapor phases. The equilibrium between these iodine concentrations is given by the partition coefficient, H, and is a function of concentration, pH, and temperature. The partition coefficient at pH 8.0 exceeds the value of approximately 4×10^3 required to maintain a decontamination factor of 100 in the containment atmosphere for sump temperature above 120° F, and thus a containment atmosphere decontamination factor of 100 or greater can be expected. Figure 6.2-16 presents equilibrium elemental iodine partition coefficients in the containment at various temperatures for the minimum sump pH case. The equations given by Eggleton (Reference 8) were used to determine the partition coefficients. Although the iodate reaction is expected to contribute significantly to the iodine partition at high sump pH values, it has been neglected in these calculations in the interest of conservatism.

Approximately 17 percent of the containment free air volume is not reached by the spray. The values listed below were used to estimate the total unsprayed volume in the containment.

(1)	Containment radius	70 ft
	Height between operating deck and spring line	91 ft
	Approximate deck area covered only by grating	2,990 ft^2

Height between elevation 91 feet and deck	49 ft
Average fall height below deck through grating	12 ft

(2) These data result in the following volumes:

Volume in dome	717,000 ft^3
Volume in cylinder above deck	1,400,000 ft^3
Occupied volume above deck	-95,000 ft^3
Sprayed volume below deck	36,000 ft^3
Sprayed refueling cavity volume	45,000 ft^3
Total sprayed volume	2,103,000 ft^3
Total free volume	2,550,000 ft^3
Total unsprayed volume	447,000 ft^3
Percent unsprayed volume	~17 %

The calculations of thyroid exposures in Section 15.5.17.2.4 were based on the assumption of uniform mixing in the full free volume of the containment. As a result of the circulation of air from the unsprayed portions of the containment free volume to the sprayed areas by the CFCS, good mixing is provided. As shown in Table 6.2-26, the fan cooler unit capacity is 47,000 cfm. If a simplified two-volume model were used, in combination with assumptions that some iodine was available for leakage from the lower containment section (unsprayed), some reduction in the effective calculated spray removal coefficient would result.

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In order to evaluate these and other possible combinations of degraded performance of the spray system, a sensitivity study was performed to determine the effect of a reduced removal coefficient on thyroid exposures. The results of this study are presented in Figures 15.5-6, 15.5-7, and 15.5-8. As shown in these figures, both the short-term and the long-term thyroid exposures are very insensitive to reduced spray removal coefficient down to values as low as 10 hr^{-1}.

6.2.3.3.7.1 Drop Size Distribution

The drop size distribution used in the analytical model is based on data obtained from measurements of the actual size distribution from the Spraco 1713A nozzle for the range of pressure drops encountered during operation of the spray system. A complete analysis of the expected drop size distributions, including a statistical analysis is contained in References 5, 6, and 33. The parameters used in applying these distributions to the calculation of the iodine removal coefficient for the DCPP units are given in Tables 6.2-29, 6.2-36, and 6.2-37.

6.2.3.3.7.2 Condensation

As the spray solution enters the high-temperature containment atmosphere, steam will condense on the spray drops. The amount of condensation is calculated by an enthalpy balance on the drop:

$$mh + m_c h_g = m'h_f \tag{6.2-10}$$

where:

m and m' = mass of the drop before and after condensation
m_c = mass of condensate, lb
h = initial enthalpy of the drop, Btu/lb
h_g and h_f = saturation enthalpy of water vapor and liquid, respectively, Btu/lb

The increase in each drop diameter in the distribution is, therefore, given by:

$$\left(\frac{d'}{d}\right)^3 = \left(\frac{v}{v_f}\right)\left(\frac{h_g - h}{h_{fg}}\right) \tag{6.2-11}$$

where:

v_f = specific volume of liquid at saturation, ft^3/lb
v = specific volume of the drop before condensation, ft^3/lb
h_{fg} = latent heat of evaporation, Btu/lb
h_g = enthalpy of steam at saturation, Btu/lb
d = drop diameter before condensation, cm
d' = drop diameter after condensation, cm

The increase in drop size due to condensation is expected to be complete in a few feet of fall for the majority of drop sizes in the distribution. More detailed calculations by Parsly show that even for the largest drops in the distribution, thermal equilibrium is reached in less than half the available drop fall height.

6.2.3.3.7.3 Mass Transfer Model

The basic equation for the iodine concentration in the containment atmosphere is derived from a material balance of the elemental iodine in the containment. The iodine removal by the spray system may be expressed by:

$$V_c \frac{dC_g}{dt} = -EF(HC_g - C_{L1}) \tag{6.2-12}$$

where:

V_c = containment free volume, cc
C_g = iodine concentration in the containment atmosphere, gm/cc
H = iodine partition coefficient, (gm/liter of liquid)/(gm/liter of gas)
F = spray flowrate, cc/sec

The resulting change in the drop size distribution is taken into consideration in the mass transfer calculations described below.

The variable E is the absorption efficiency, which may also be described as the fractional approach to saturation:

$$E = \frac{C_{L2} - C_{L1}}{C_{L^*} - C_{L1}} \qquad (6.2\text{-}13)$$

where:

C_{L1} = iodine concentration in the liquid entering the dispersed phase, gm/cc
C_{L2} = iodine concentration in the liquid leaving the dispersed phase, gm/cc
C_{L^*}= equilibrium iodine concentration in the liquid, gm/cc

This absorption efficiency is calculated from the time-dependent mass transfer model suggested by L. F. Parsly (Reference 7).

The absorption efficiency calculated is a function of drop size, and the removal constant λ_s, in reciprocal hours, for the entire spray is, therefore, obtained by an appropriate summation over all drop size groups:

$$\lambda_s = \sum_{i=1}^{n} \frac{E_i F_i H}{V_c} \qquad (6.2\text{-}14)$$

A further discussion of drop size distribution, drop trajectories, drop coalescence and mass transfer modeling is presented in References 5, 6, and 33.

6.2.3.3.7.4 Experimental Verification of Models

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The ability of the model described to give conservative estimates of actual spray performance was demonstrated in test runs made at Oak Ridge National Laboratory (ORNL) and Battelle Pacific Northwest Laboratory. The results of these tests (Reference 5), shown in Figure 6.2-14 for Run A6, verified that the spray removal model used is conservative in all cases.

6.2.3.3.8 General Design Criterion 38, 1967 – Reliability and Testability of Engineered Safety Features

The SAS testing and inspections are enveloped by the inservice inspection (ISI) and inservice testing (IST) programs. Pressure containing portions of the CSS and SAS are inspected in accordance with ASME BPVC, Section XI, as required by the Technical Specifications and the Inservice Inspection Program Plan (Reference 38) (refer to Section 6.2.3.3.17 for inservice testing and Section 6.2.3.3.18 for inservice inspection).

6.2.3.3.9 General Design Criterion 40, 1967 – Missile Protection

The SAS is protected from internal missiles, pipe whip, and jet impingement from the rupture of any nearby high-energy line (refer to Sections 3.5.1.2 and 3.6.1.2).

6.2.3.3.10 General Design Criterion 41, 1967 – Engineered Safety Features Performance Capability

The SAS is designed to tolerate a single active failure without loss of protective function and as such is designed with the redundancy to accommodate a partial loss of installed capacity. The SAS is in use only during the injection period following a LOCA (refer to Section 6.2.3.3.6).

6.2.3.3.11 General Design Criterion 42, 1967 – Engineered Safety Features Components Capability

The CSS and CFCS component design pressure and temperature conditions in Table 6.2-26 are specified as the most severe conditions to which each component is exposed during either normal or post-LOCA operation while maintaining the capability of the system to provide its required design function in post-LOCA conditions (refer to Section 6.2.2).

6.2.3.3.12 General Design Criterion 62, 1967 – Inspection of Air Cleanup Systems

During periodic tests, the equipment is inspected visually for leaks. Leaking seals, packing, or flanges are corrected to eliminate the leak. Valves and pumps are operated and inspected after every maintenance to ensure proper operation.

All critical parts of the SAS are inspected in accordance with the plant ISI Program and in compliance with 10 CFR 50.55a(g). Refer to Section 6.2.3.3.18 for further discussion.

6.2.3.3.13 General Design Criterion 63, 1967 – Testing of Air Cleanup Systems Components

Routine periodic testing of the SAS components and all necessary support systems at power, under the conditions defined in the Technical Specifications, is performed.

Each of the SAS MOVs are tested while the pumps are shut down. During eductor suction valve operation, the normally open spray additive tank valve is closed. Relief valves and vacuum breakers on the sodium hydroxide tank are set and tested prior to installation and periodically thereafter.

The purpose of the motor-operated double-disk gate valve in the spray additive line, shown in Figure 3.2-12 , is to permit periodic testing of the two parallel MOVs downstream from that valve.

6.2.3.3.14 General Design Criterion 64, 1967 – Testing of Air Cleanup Systems

The concentration of the sodium hydroxide additive solution is established at the time of initial tank fill, and then periodically checked by titration of tank samples taken from the local sample connection.

The testing of the CSS and CFCS is discussed in Section 6.2.2.

6.2.3.3.15 General Design Criterion 65, 1967 – Testing of Operational Sequence of Air Cleanup Systems

Provisions are made in the circuitry of the various system alarms to test the proper operations of the alarm circuitry with a test signal input. These circuits include the sodium hydroxide tank low-level alarms, the RWST low-level alarms, and the containment high-pressure alarms.

The SAS is tested to verify operational sequence under conditions as close to design as practical. For testing of the operational sequence required to actuate the SAS, refer to Section 7.3.4.1.5.2.

6.2.3.3.16 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The functional performance requirement for the SAS, in conjunction with the iodine removal functions of the CSS and CFCS, is to ensure that offsite radiological exposures resulting from a LOCA are within the limits of 10 CFR Part 100, refer to Section 15.5.

The use of the spray removal constant in the radiological release calculations for the LOCA is described in Section 15.5.17.2.4.

6.2.3.3.17 10 CFR 50.55a(f) – Inservice Testing Requirements

The IST requirements for SAS ASME code class valves are contained within the IST Program Plan.

6.2.3.3.18 10 CFR 50.55a(g) – Inservice Inspection Requirements

Pressure containing portions of the CSS and SAS are inspected in accordance with ASME BPVC, Section XI, as required by the Technical Specifications and the Inservice Inspection Program Plan (Reference 38).

6.2.3.3.19 Generic Letter 89-10, June 1989 – Safety-Related Motor-Operated Valve Testing and Surveillance

The SAS MOVs are subject to the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996, and meet the requirements of the DCPP MOV Program Plan.

6.2.3.4 Tests and Inspections

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The CSS was tested functionally in accordance with written procedures, as outlined in Chapter 14.

Spray pump delivered flow and head data were recorded to verify that the containment spray pumps meet design criteria.

Spray additive eductor performance data were provided by the manufacturer based on actual tests of a similar eductor. These tests were conducted using a 1.3 specific gravity solution to verify eductor design performance. Additional manufacturer's tests were run using water so that comparative performance data were available for the two different additive solutions at eductor design conditions. Eductor performance was checked subsequent to installation into the system. Spray additive flowrates were measured, with resulting rates in the range 31.5 to 38.5 gpm (35 gpm ± 10 percent) considered acceptable.

Each containment spray header was tested individually by connecting a source of air to the normally capped flange connection on the spray pump discharge header, shutting the manual spray header isolation valve and opening the air test line isolation valve and the motor-operated spray header isolation valve. Individual nozzles were checked for proper performance by streamers, which indicated unobstructed air flow.

The containment sump recirculation mode was tested initially as part of a preoperational flow test under ambient conditions of the safety injection system (SIS). The purpose of

the test was to demonstrate the capability of appropriate subsystems to deliver fluid from the containment sump into the reactor coolant system (RCS) in the required time.

6.2.3.5 Instrumentation Applications

Refer to Section 6.2.3.3.4 for instrumentation important to the operation of the SAS.

6.2.3.6 Materials

The SAS design parameters and materials of construction are listed in Table 6.2-29. Code compliance is shown in Table 6.2-30.

Parts of the system in contact with borated water, the sodium hydroxide spray additive, or mixture of the two are stainless steel or an equivalent corrosion-resistant material.

6.2.4 CONTAINMENT ISOLATION SYSTEM

The containment isolation system (CIS) prevents excessive radioactivity from passing through the containment to the atmosphere in the event of a LOCA. This is accomplished by automatically sealing the various lines through the containment walls.

6.2.4.1 Design Bases

The CIS is designed to meet the containment isolation requirements of the 1971 General Design Criteria (GDC) except where specifically indicated. When deviations are noted, these cases do not meet the 1971 GDC because of commitment to design and construction prior to issuance of these criteria. Such cases do comply with the 1967 GDC, however.

6.2.4.1.1 General Design Criterion 2, 1967 – Performance Standards

The components that make up the CIS are designed to withstand the effects of, or are protected against, natural phenomena, such as earthquakes, flooding, tornados, winds, and other local site effects.

6.2.4.1.2 General Design Criterion 10, 1967 – Containment

The CIS is designed, together with other engineered safety features as may be necessary, to retain the functional capability of the containment to protect the public.

6.2.4.1.3 General Design Criterion 11, 1967 – Control Room

The CIS is designed with indication and controls located in the control room as necessary to shut down and maintain safe control of the facility.

6.2.4.1.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

The CIS is designed with instrumentation and controls as required to monitor and maintain variables within prescribed operating ranges.

6.2.4.1.5 General Design Criterion 21, 1967 - Single Failure Criterion

The CIS is designed to tolerate a single failure during the period of recovery following an accident without loss of its protective function, including multiple failures resulting from a single event, which is treated as a single failure.

6.2.4.1.6 General Design Criterion 40, 1967 – Missile Protection

The CIS is designed with protection against dynamic effects and missiles that might result from plant equipment failures.

6.2.4.1.7 General Design Criterion 53, 1967 – Containment Isolation Valves

The CIS is designed such that the component cooling water (CCW) penetration to the excess letdown heat exchanger is provided with redundant valving and associated apparatus. The CCW penetration to the excess letdown heat exchanger does not meet GDC 57, 1971 because of commitments to design and construction made prior to the issuance of the 1971 GDC. This penetration does comply with GDC 53, 1967.

6.2.4.1.8 General Design Criterion 54, 1971 - Piping Systems Penetrating Containment

The CIS is designed such that the piping systems that penetrate containment are provided with leak detection, isolation, and containment capabilities having redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating these piping systems. These piping systems are designed with a capability to test periodically that operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

6.2.4.1.9 General Design Criterion 55, 1971 - Reactor Coolant Pressure Boundary Penetrating Containment

The CIS is designed such that each line that is part of the reactor coolant pressure boundary that penetrates containment is provided with containment isolation valves as follows, unless otherwise demonstrated that the containment isolation provisions for a specific class of lines are acceptable on another defined basis:

(1) One locked closed isolation valve inside and one locked closed isolation valve outside containment; or

(2) One automatic isolation valve inside and one locked closed isolation valve outside containment; or

(3) One locked closed isolation valve inside and one automatic isolation valve outside containment. A simple check valve is not used as the automatic isolation valve outside containment; or

(4) One automatic isolation valve inside and one automatic isolation valve outside containment. A simple check valve is not used as the automatic isolation valve outside containment.

Isolation valves outside containment are located as close to the containment as practical and upon loss of actuating power, automatic isolation valves are designed to take the position that provides greater safety.

6.2.4.1.10 General Design Criterion 56, 1971 - Primary Containment Isolation

The CIS is designed such that each line that connects directly to the containment atmosphere and penetrates containment is provided with containment isolation valves as follows, unless it is demonstrated that the containment isolation provisions for a specific class of lines are acceptable on another defined basis:

(1) One locked closed isolation valve inside and one locked closed isolation valve outside containment; or

(2) One automatic isolation valve inside and one locked closed isolation valve outside containment; or

(3) One locked closed isolation valve inside and one automatic isolation valve outside containment. A simple check valve is not used as the automatic isolation valve outside containment; or

(4) One automatic isolation valve inside and one automatic isolation valve outside containment. A simple check valve is not used as the automatic isolation valve outside containment.

Isolation valves outside containment are located as close to the containment as practical and upon loss of actuating power, automatic isolation valves are designed to take the position that provides greater safety.

6.2.4.1.11 General Design Criterion 57, 1971 - Closed System Isolation Valves

The CIS is designed such that each line that penetrates containment and is neither part of the reactor coolant pressure boundary nor connected directly to the containment atmosphere has at least one containment isolation valve which is either automatic or locked closed or capable of remote-manual operation. This valve is outside

containment and located as close to the containment as practical. A simple check valve is not used as the automatic isolation valve.

Refer to Table 6.2-39 for exceptions to GDC 57, 1971.

6.2.4.1.12 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The containment is designed as a barrier to maintain control over plant radioactive effluents, whether gaseous, liquid, or solid to meeting the radiological limits of 10 CFR Part 100. Appropriate holdup capacity is provided for retention of gaseous effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment.

6.2.4.1.13 10 CFR Part 50, Appendix J, Option B - Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors

The CIS is designed to enable implementation of a performance-based containment leakage rate testing program for Type C local leak rate tests with approved exemptions.

6.2.4.1.14 Regulatory Guide 1.163, September 1995 - Performance-Based Containment Leak-Test Program

The CIS is designed to allow the use of a performance-based leak-test program, including the leakage-rate test methods, procedures, and analyses as required by Regulatory Guide 1.163, September 1995.

6.2.4.1.15 NUREG-0737 (Item II.E.4.2), November 1980 - Clarification of TMI Action Plan Requirements

Item II.E.4.2 - Dependability of Containment Isolation:

Position (1) - The CIS is designed with diverse parameters sensed for the initiation of containment isolation.

Position (2) - The CIS process penetrations are classified as nonessential, essential, and safety system process lines for the determination of those penetrations isolated by a containment isolation signal.

Position (3) - The CIS nonessential systems use either manually sealed closed valves or are automatically isolated on a Phase A containment isolation signal. Additionally, essential systems are automatically isolated on a Phase B isolation signal.

Position (4) - The CIS is designed so that re-setting of a containment isolation signal will not result in the automatic re-opening of any containment isolation valves. Ganged re-

opening cannot result from a single operator action after the containment isolation signal has been reset.

Position (5) - The CIS is designed so that the containment setpoint pressure that initiates containment isolation for nonessential penetrations is set to the minimum compatible with normal operating conditions with additional margin to allow for a small pressure transient.

Position (6) - The DCPP purge system valves satisfy Branch Technical Position CSB 6-4, September 1975.

Position (7) - The containment vent and purge isolation valves close on a high radiation signal.

6.2.4.1.16 Generic Letter 89-10, June 1989 - Safety-Related Motor-Operated Valve Testing and Surveillance

In the CIS, PG&E Design Class I position-changeable motor-operated valves (MOVs) meet the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996.

6.2.4.1.17 Generic Letter 96-06, September 1996 - Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions

The CIS is designed to prevent thermally induced overpressurization of isolated water-filled piping sections in containment during design-basis accidents.

6.2.4.2 System Description

The CIS includes the mechanical and instrumentation fluid penetrations and associated valves and isolation devices. These penetrations are identified in Figure 6.2-19 and Table 6.2-39. The CIS design uses the following premises:

(1) An automatic containment isolation barrier is provided by a closed system, a trip valve, or a check valve.

(2) A closed system meets the following requirements:

a) Inside the containment:

1. No mass transfer with either the RCS or the reactor containment interior

2. Has the same safety classification as ESFs (PG&E Design Class I, Quality/Code Class II)

3. Must withstand an external pressure and temperature that is greater than containment design pressure and temperature

4. Must withstand accident transient and environmental parameters

5. Must be protected against missiles and high-energy jets

b) Outside the containment:

1. Does not communicate with the atmosphere outside the containment

2. Has the same safety classification as ESFs (PG&E Design Class I, Quality/Code Class II)

3. Internal design pressure and temperature must be greater than containment design pressure and temperature

4. Must be protected against missiles and high-energy jets

(3) A trip valve is a motor-, air-operated, or solenoid valve that moves to a preferred position upon a containment isolation signal. It can additionally be opened or closed manually from a remote location.

(4) Lines that must remain in service subsequent to certain accidents have, as a minimum, one manual isolation valve.

(5) Lines 1 inch nominal pipe size and larger that penetrate the containment and are connected to the RCS have at least two valves inside the containment. The valves are normally closed or have automatic closure. For incoming lines, check valves are permitted and are considered as an automatic barrier inside containment.

(6) All isolation valves (automatic and manual) and associated equipment are PG&E Design Class I. The isolation section piping is PG&E Design Class I, Quality/Code Class II.

6.2.4.2.1 Containment Penetration Piping Isolation Grouping

The definitions used in the design bases and the physical configuration of various systems that penetrate the containment divide themselves naturally into five groups. These groups were used to determine the necessary valves on lines penetrating the containment. The lines and valves are shown graphically in Figure 6.2-17. PG&E has named and defined each group as shown below. The groupings, A through E, do not correspond to the piping code classes described in Section 3.2.2.3.

6.2.4.2.1.1 Group A Piping

Group A piping complies with the requirements of either GDC 55, 1971 or GDC 56, 1971. Outside the containment this piping either connects directly to the atmosphere or is considered open, even though it may be physically closed. Inside the containment, it is either part of the reactor coolant pressure boundary (RCPB), opens directly to the containment atmosphere, or is considered open, even though it may be physically closed. In this group, the following minimum requirements apply:

(1) Incoming Lines: One trip valve inside the containment and one trip valve outside the containment, or one check valve inside the containment and one trip valve outside the containment

(2) Outgoing Lines: One trip valve inside the containment and one trip valve outside the containment

6.2.4.2.1.2 Group B Piping

Group B piping complies with the requirements of either GDC 55, 1971 or GDC 56, 1971. Outside the containment, this piping operates in a closed system (physically closed and PG&E Design Class I), and inside the containment it is either part of the RCPB or connects directly to the containment atmosphere. For this group the following minimum requirements apply:

(1) Incoming Lines: One check valve inside the containment and a closed system outside the containment

(2) Outgoing Lines: One trip valve inside the containment and a closed system outside the containment

6.2.4.2.1.3 Group C Piping

Group C piping complies with the requirements of GDC 57, 1971 which states that isolation valves in closed systems must be outside the containment and no simple check valve may be used. Outside the containment, this piping connects with systems that are either opened or closed. Inside the containment, both types of systems are separated from the RCPB and from the containment atmosphere by a membrane barrier. For this group, the following minimum requirements apply:

(1) Incoming Lines: One trip valve outside containment

(2) Outgoing Lines: One trip valve outside containment

6.2.4.2.1.4 Group D Piping

Group D piping complies with the requirements of the applicable GDC 55, 1971; GDC 56, 1971; or GDC 57, 1971 to the extent that valves are provided in the proper locations. These lines must, however, remain in service following an accident and, therefore, the valves do not isolate automatically, but trip to the required position. Piping for the ESFs and supporting systems are included in this class. For this group, the following minimum requirements apply:

(1) Incoming Lines: One local or remote-manual valve outside the containment

(2) Outgoing Lines: One local or remote-manual valve outside the containment

6.2.4.2.1.5 Group E Piping

Group E piping complies with the requirements of either GDC 55, 1971; GDC 56, 1971; or GDC 57, 1971. This piping is characterized by sealed closed valves and is used for intermittent service not related to system functions. For this group, the following minimum requirements apply:

(1) Incoming Lines: Sealed closed manual valve outside the containment and a sealed closed manual valve or a check valve inside the containment

(2) Outgoing Lines: Sealed closed manual valve outside the containment and a sealed closed manual valve inside the containment

(3) No-flow Lines: Diaphragm or sealed closed valve outside containment and diaphragm inside containment

6.2.4.2.2 Piping Systems

With some exceptions, such as those noted in Table 6.2-39, piping systems penetrating the containment conform to GDC 54, 1971; GDC 55, 1971; GDC 56, 1971; and GDC 57, 1971. The number and location of isolation valves are shown graphically in Figure 6.2-19; the legend for the diagrams is given in Figure 6.2-18. The criteria to which each penetration complies and a description of the isolation valves are given in Table 6.2-39. To the extent indicated in Table 6.2-39 and Figure 6.2-19, piping penetrations are designed with the capability of leak detection and periodic testing of the isolation valve operability.

6.2.4.3 System Design

All piping, valves, and connected equipment necessary to maintain the containment isolation boundary are designed to withstand post-accident conditions with respect to pressure, temperature, and atmospheric conditions at which they are required to maintain that boundary.

Analyses were made to ensure the integrity of the isolation valve system and connecting lines due to the forces resulting from inadvertent closure of isolation valves under operating conditions. Potential maximum forces and moments have been calculated, and valves, piping systems, and piping configurations have been designed to withstand these forces. Flued heads have also been designed to withstand these forces. Where required, snubbers and pipe restraints have been installed to absorb forces and prevent pipe ruptures caused by the inadvertent closure of an isolation valve.

6.2.4.3.1 Valve Positioning

Valves that operate as part of the SIS are designated by the letter "S" in the penetration diagrams in Figure 6.2-19.

Specific administrative procedures govern the positioning of all of the containment isolation valves (except check valves) during normal operation, shutdown, and accident conditions. The positioning of all of the valves required to maintain the penetration pressure boundary and containment integrity, as well as any flanged closures, is governed by the administrative procedures.

The main steam lines each have a check valve in series with the isolation valve to prevent reverse flow of steam in the event of the rupture of a steam line inside the containment. Instrumentation and logic circuits are provided to detect a ruptured steam line and to close the automatic trip isolation valves on the steam lines.

6.2.4.3.2 Systems Data

Table 6.2-39 lists the CIS penetrations and the valves and closed systems employed for containment isolation. This table lists the number and types of isolation valves, valve positions during normal operation, shutdown, accident conditions, and primary and secondary modes of actuation, as well as their functional classification in accordance with the definitions in Section 6.2.4.2.1 above. The containment isolation valves that are normally closed to maintain the containment isolation and do not perform an active function following an accident are administratively sealed closed. Associated isolation devices required to maintain containment leakage integrity of penetrations and closed systems such as vent, drain, test, instrumentation and branch line valves, blind flanges, caps or other passive devices are not shown on Table 6.2-39, but are administratively controlled to be in their proper isolation configuration by plant procedures.

Supplementary information regarding the listing in the table is discussed in the following paragraphs:

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

(1) *Leakage Characteristics at Accident Pressures*

All valves for containment isolation were specified, constructed, and tested to the maximum allowable leakage rates as shown in the following (Type C leakage limits are administratively assigned in the Containment Leakage Rate Testing Program):

Valve Type	*Seat Leakage*[(a)]
Ball	*<0.3*
Globe and gate	*3*
Check[(b)]	*3*
Diaphragm (Saunders Patent)	*Negligible*
Butterfly (rubber-seated)	*Negligible*

Notes:

(a) Leakage is expressed in units of cubic centimeters of water per hour per inch of nominal pipe size at valve design conditions

(b) The main steam isolation valve is a Schutte-Koerting reverse check which does not meet this seat leakage criterion.

Maximum allowable stem leakage for open backseated valves was specified as one cubic centimeter of water per hour per inch of stem diameter at design conditions.

(2) *Control System Type*

Containment isolation valves are provided with actuation and control features appropriate to the valve type. For example, air-operated globe and diaphragm valves are generally equipped with air diaphragm operators, spring loaded to fail-closed on loss of air or electrical signal. Motor-operated gate valves can be supplied from Class 1E Standby Power Supply as well as their normal power source. Manual and check valves do not require actuation or control systems. Valve and operator types are listed in Table 6.2-39.

(3) *Signal to Operate the Valve*

All remote-manual containment isolation valves are opened and closed normally from the control room or from local control panels (e.g., sampling system valves are operated from a panel in the post-accident sample room).

(4) *Power Source Required to Actuate or Operate the Valve*

Remote-manual containment isolation valves are actuated by compressed gas or electrical power (refer to Table 6.2-39).

(5) *Time Necessary to Close the Valve*

Standard closing times normally available are adequate for the sizes of containment isolation valves used. Valves equipped with air diaphragm operators generally close in approximately 2 seconds; 10 seconds is typical of the closing time available in large motor-operated gate valves.

(6) *Normal and Failed Positions of the Valves*

Normal and failed positions of the valves are indicated in Table 6.2-39. Diagrams for each penetration, showing all valves, barriers, missile shielding, and leakage test connections are shown in Figure 6.2-19. The parts of the piping systems that are PG&E Design Class I are also indicated in this figure. The conditions requiring containment isolation are listed in Table 6.2-40.

6.2.4.4 Safety Evaluation

6.2.4.4.1 General Design Criterion 2, 1967 – Performance Standards

The CIS is designed such that many of the CIS components are contained in the auxiliary building and containment structure. These structures are PG&E Design Class I (refer to Section 3.8). These buildings or applicable portions thereof are designed to withstand the effects of winds and tornados (refer to Section 3.3) , floods and tsunamis (refer to Section 3.4) , external missiles (refer to Section 3.5) , earthquakes (refer to Section 3.7), and other natural phenomena, and to protect CIS components, ensuring their design function will be performed.

Portions of the containment isolation system are not contained within a building and are exposed directly to potential wind and tornado loads and have been evaluated. Loss or failure of this equipment does not compromise the capability of maintaining containment integrity (refer to Section 3.3.2).

All valves, piping, and equipment that are considered to be isolation barriers are designed to PG&E Design Class I requirements and are protected against potential missiles and water jets.

6.2.4.4.2 General Design Criterion 10, 1967 – Containment

6.2.4.4.2.1 Piping Penetrations

The CIS limits radioactivity passing from the containment to the atmosphere in the event of a design basis accident. This is accomplished as described in Section 6.2.4.2 and Table 6.2-39.

The CIS provides a minimum of two barriers to prevent leakage of radioactivity to the outside environment. Either barrier is sufficient to keep leakage within the allowable limits.

6.2.4.4.2.2 Instrument Lines

Instrument lines penetrating containment meet the intent of Safety Guide 11, March 1971 (Reference 48), by providing a double barrier (one inside and one outside) between containment and the outside atmosphere. It provides double barrier isolation without operator action and without sacrificing any reliability with regard to its engineered safety functions (refer to Figure 6.2-19 and Table 6.2-39 for the penetration configurations).

The containment pressure instrumentation penetration lines (refer to Sheet 15 of Figure 6.2-19 and Table 6.2-39) consist of a sealed, fluid-filled system with a sealed bellows sensor connected to the diaphragm of the pressure transmitter by a sealed fluid-filled tube. The bellows and tubing inside containment and transmitter diaphragm and tubing outside containment are protected from postulated missile and HELB pipe whip/jet impingement effects by their location, which provides separation and shielding from these hazards. Isolation valving is not essential to meet the intent of Safety Guide 11, March 1971.

The abandoned-in-place deadweight pressure calibrator penetration line (refer to Sheet 22 of Figure 6.2-19 and Table 6.2-39) meets the intent of Safety Guide 11, March 1971, by the use of a diaphragm on both Units plus one sealed-closed valve on Unit 1 and an instrument cap on Unit 2. 1-PT-458A and 2-PT-458A have been abandoned-in-place, resulting in the isolation valves being closed. Therefore, the inboard barrier is a closed valve with the PT-458A diaphragm as a back-up. The calibrator and tube are filled with distilled water that is separated from the reactor coolant by the diaphragm in the pressure sensor. This diaphragm is designed to withstand full RCS pressure from either side.

The spare instrument test line penetrations used to measure containment pressure during the integrated leakrate test meet the intent of Safety Guide 11, March 1971 by

providing a double barrier, one inside and one outside containment (refer to Sheet 11 of Figure 6.2-19 and Table 6.2-39).

Reactor vessel level instrumentation penetration lines (refer to Sheet 25 of Figure 6.2-19 and Table 6.2-39) consist of a sealed fluid-filled system, with a sealed bellows sensor inside containment connected to one side of a differential pressure unit (DPU) outside of containment by a sealed fluid-filled system. The sensor and the DPU are capable of withstanding full RCS pressure. Isolation valving is not essential to meet the intent of Safety Guide 11, March 1971.

6.2.4.4.3 General Design Criterion 11, 1967 – Control Room

The CIS is designed with indication and controls located in the control room as necessary to shut down and maintain safe control of the facility.

Each automatic isolation valve is provided with a manual switch for operation. The position of each automatic isolation valve and remote-manual valve is displayed in the control room. All automatic isolation valves are operable from the control room. All remote-manual containment isolation valves are opened and closed normally from the control room or from local control panels (e.g., sampling system valves are operated from a panel in the sampling room). Position indicators are provided for each valve near its manual control switch. Control room indication, valve actuators, trip signals, and valve positions are listed in Table 6.2-39.

6.2.4.4.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

The CIS is designed with automatic and remote-manual containment isolation valves that are provided with instrumentation and controls as required to monitor and maintain variables within prescribed operating ranges. Governing conditions regarding closure of isolation valves and the instrumentation and controls for the system are described in Sections 6.2.4.4.3 and in 7.3.2.4.3, and in Table 6.2-39.

6.2.4.4.5 General Design Criterion 21, 1967 – Single Failure Criterion

The CIS is designed with penetration configurations to ensure that a single failure will not prevent the CIS from performing its design function. Refer to Section 6.2.4.2.1 for a description of the PG&E containment penetration piping isolation grouping.

No manual operation is required for Phase A and Phase B containment isolation although isolation can be accomplished manually. Each remote-manual and automatic isolation valve is designed to close or go to a preferred position on a loss of power or air or nitrogen supply, except for motor-operated valves, which fail as-is.

Also, a single failure in the instrumentation and control circuits will not prevent isolation. The instrumentation and control circuits are redundant in the sense that a single failure cannot prevent containment isolation.

Control circuits are designed to close the air and solenoid operated isolation valves on a de-energized state. No power is therefore required to isolate the containment. The exception to this is steam line isolation, which requires the energization of one of two mutually redundant circuits.

6.2.4.4.6 General Design Criterion 40, 1967 – Missile Protection

The CIS is designed with adequate protection for containment isolation, including piping, valves, and vessels, against dynamic effects and missiles that might result from plant equipment failures, including a LOCA.

No valve is considered to be an isolation valve if it is not missile-protected. Isolation valves, actuators, and control devices required inside the containment are located between the crane wall or some other missile shield and the outside containment wall. Isolation valves, actuators, and control devices outside the containment are located outside the path of potential missiles or are provided with missile protection. Piping or vessels that provide one of the isolation barriers outside the containment are similarly protected. The missile barrier for each isolation valve is shown schematically on the penetration diagrams (Figure 6.2-19). Refer to Section 3.5 for additional information on missile protection. Refer to the individual system sections for a discussion regarding missile protection.

6.2.4.4.7 General Design Criterion 53, 1967 – Containment Isolation Valves

The CIS is designed such that penetrations that require closure for containment function are provided with at least two barriers. The CIS is designed to meet either GDC 55, 1971; GDC 56, 1971; or GDC 57, 1971 requirements with exceptions. The CCW penetration to the excess letdown heat exchanger is an exception that does not meet the 1971 GDC because of commitments to design and construction made prior to the issuance of the 1971 GDC. The CCW penetration to the excess letdown heat exchanger does comply with GDC 53, 1967. Refer to Table 6.2-39 for penetration and configuration details with regards to GDC 53, 1967.

6.2.4.4.8 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The CIS design provides for a double barrier at the containment penetration in those fluid systems that are not required to function following a design basis event. The capability for periodic leakage testing is discussed in Section 6.2.4.4.13. Those automatic isolation valves that do not restrict normal plant operation are periodically tested to ensure operability. Refer to Section 6.2.4.2.1 and Table 6.2-39 for penetration and configuration details with regards to GDC 54, 1971.

Automatic Phase A and Phase B valves and sealed closed containment isolation valves are periodically tested for leak-tightness as described in Table 6.2-39.

6.2.4.4.9 General Design Criterion 55, 1971 – Reactor Coolant Pressure Boundary Penetrating Containment

The CIS is designed such that for each line that is part of the reactor coolant pressure boundary that penetrates containment is provided with containment isolation valves in compliance with GDC 55, 1971. Refer to Section 6.2.4.2.1 and Table 6.2-39 for penetration and configuration details with regards to GDC 55, 1971.

6.2.4.4.10 General Design Criterion 56, 1971 – Primary Containment Isolation

The CIS is designed such that each line that connects directly to the containment atmosphere and penetrates containment is provided with containment isolation valves in compliance with GDC 56, 1971. Refer to Section 6.2.4.2.1 and Table 6.2-39 for penetration and configuration details with regards to GDC 56, 1971.

6.2.4.4.11 General Design Criterion 57, 1971 – Closed System Isolation Valves

The CIS is designed such that each line that penetrates containment and is neither part of the reactor coolant pressure boundary nor connected directly to the containment atmosphere is provided with at least one containment isolation valve in compliance with GDC 57, 1971. Refer to section 6.2.4.2.1 and Table 6.2-39 for penetration and configuration details with regards to GDC 57, 1971.

6.2.4.4.12 General Design Criterion, 70, 1967 – Control of Releases of Radioactivity to the Environment

The CIS, in conjunction with the containment (refer to Section 6.2.1.3.6), is designed to be a barrier to maintain control over plant radioactive effluents, whether gaseous, liquid, or solid. The CIS is designed to withstand the effects of a LOCA (refer to Section 6.2.4.4.2), ensuring that the offsite radiological exposures resulting from a LOCA are within the limits of 10 CFR Part 100 (refer to Section 15.5).

6.2.4.4.13 10 CFR Part 50, Appendix J, Option B – Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors

Testing of containment penetrations (Type C testing) is performed in accordance with the Technical Specifications 5.5.16, Containment Leakage Rate Testing Program, as required by 10 CFR 50.54(o), and 10 CFR Part 50, Appendix J, Option B, as modified by approved exemptions. As a general requirement, all containment isolation valves will be tested periodically with a gas to determine leaktightness. Refer to Section 6.2.1 for information regarding Type A (ILRT) and Type B (air locks, electrical penetrations, hatches, etc.) testing.

Exceptions to this requirement are those valves not required to be testable by Appendix J to 10 CFR Part 50, and certain valves that cannot be isolated for air testing. These include the first of double check valves to the RCS and valves for which such testing would require draining significant portions of the RHR system or the SIS. Even if these systems were drained, the presence of other valves associated with the systems would make it impractical to determine the source of any measured leakage. Where a quantitative leakage test is necessary, provisions are made for each valve to measure the inflow of the pressurizing medium, collect and measure leakage, or calculate the leakage from the rate of pressure drop. The test pressure on the valve will be at a differential pressure of not less than the peak calculated containment internal pressure related to the design basis LOCA (P_a). The P_a value specified in Technical Specification 5.5.16 bounds the calculated LOCA containment integrity results in Section 6.2D.3.2.6.

Check valves and single-disk gate valves will have the test pressure applied to the inboard side of the valve. Exceptions are the three RHR injection lines. The valves in these lines will be tested from the outboard side, as there is no practical method to test from the inboard side. Diaphragm valves may be tested on either side since their leakage characteristics are the same in either direction. Double-disk gate valves may be tested by applying the test pressure between the disks. Globe valves may be tested by pressurizing either the inboard side or under the seat.

Piping systems are provided with test vents (TV) and test connections (TC) or have other provisions to allow periodic leakage testing of the containment isolation valves, as required. Locations of TC and TV are shown on the penetration diagram (refer to Figure 6.2-19). In most cases, equipment vents or drains can be used as TC or TV.

6.2.4.4.14 Regulatory Guide 1.163, September 1995 – Performance-Based Containment Leak-Test Program

The DCPP Containment Leakage Rate Testing Program is performed in accordance with the Technical Specifications. The DCPP Containment Leakage Rate Testing Program utilizes a performance-based approach, consistent with Regulatory Guide 1.163, September 1995, to comply with the requirements of 10 CFR Part 50, Appendix J, Option B (refer to Section 6.2.4.4.13).

6.2.4.4.15 NUREG-0737 (Item II.E.4.2), November 1980 – Clarification of TMI Action Plan Requirements

Item II.E.4.2 - Containment Isolation Dependability:

Position (1) – The automatically tripped isolation valves are actuated to the closed position by one of two separate containment isolation signals.

Immediate isolation of the containment is accomplished automatically. There are two automatic phases of containment isolation at DCPP. 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. Valves which close automatically upon receipt of a Phase A isolation signal are designated by the letter "T" in the penetration diagrams (Figure 6.2-19). The letter "P" is used to designate those valves that close automatically upon receipt of a Phase B isolation signal.

Phase A isolation is initiated by high containment pressure, low pressurizer pressure, low steamline pressure, or manual initiation. Phase B isolation is initiated by high-high containment pressure or manual initiation.

Section II.6 of SRP 6.2.4 establishes the DCPP licensing basis, but the design basis preceded the issuance of NUREG-0578, July 1979, and subsequently NUREG-0737, May 1980. The DCPP Phase A and Phase B containment isolation signals comply with Section II.6 of Standard Review Plan (SRP) 6.2.4, 1975, for diversity of parameters that initiate containment isolation. Section II.6 of SRP 6.2.4 does not constitute the DCPP design basis because the definitions of “essential,” “nonessential,” and “safety system process lines,” as well as those parameters that initiate a Phase A or Phase B containment isolation signal, were established prior to the issuance of NUREG-0578, July 1979, and subsequently NUREG-0737, May 1980.

Position (2) – Three levels of containment process penetrations have been defined for the DCPP:

(1) "Nonessential" process lines are defined as those that 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 ESF system.

Table 6.2-39 identifies nonessential, essential, and safety systems penetrating containment.

Position (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 Position (2) above) are automatically isolated on a Phase B containment isolation signal.

Position (4) – Resetting the isolation signals will not result in the automatic reopening of containment isolation valves. Reopening of containment isolation valves requires deliberate action and ganged reopening will not result from a single operator action after the signal has been reset.

Position (5) – Table 6.2-40 shows operating conditions that make containment isolation mandatory. Setpoints are specified in the Technical Specifications.

Position (6) – The DCPP containment purge system valves and vacuum/overpressure relief valves satisfy the operability criteria set forth in BTP CSB 6-4, 1975. The opening of the 12 inch vacuum/overpressure relief valves is restricted to no more than 50 degrees.

Position (7) - The containment purge and vent isolation valves are closed automatically by any one of the following:

(1) Phase A containment isolation signal

(2) High gaseous or air particulate radioactivity in containment

(3) High radiation at the plant vent

6.2.4.4.16 Generic Letter 89-10, June 1989 – Safety-Related Motor-Operated Valve Testing and Surveillance

The CIS MOVs are subject to the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996, and meet the requirements of the DCPP MOV program.

6.2.4.4.17 Generic Letter 96-06, September 1996 – Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions

Containment isolation valves LWS-FCV-253 and LWS-FCV-500 (Penetrations 49 and 50, respectively) have both been modified through the addition of a pressure relief hole to prevent overpressurization of the associated isolated section of piping during design-basis accidents to ensure containment integrity is maintained. All other piping penetrations that are susceptible to overpressurization either have valves whose design prevents overpressurization (air-operated diaphragm valves, solenoid valves, or air-operated globe valves) or have been drained to prevent overpressurization and thereafter maintained drained as appropriate.

6.2.4.5 Tests and Inspections

The CIS design provides such functional reliability and ready testing facilities as are necessary to avoid undue risk to the health and safety of the public. CIS periodic tests and inspections are provided to ensure a continuous state of readiness to perform its safety function.

Containment isolation signal actuation channels are designed with sufficient redundancy to provide the capability for channel testing and calibration during power operation without tripping the system (refer to Section 7.3.3.4 for more details).

The pneumatic-operated isolation valves close on loss of control power or compressed gas. Isolation valves will be periodically tested for operability.

For additional details regarding periodic testing and inspection of valves, refer to the Technical Specifications.

6.2.4.6 Materials

Materials selection for the penetration lines and isolation valves of the CIS depends on the particular application and function of the systems involved. Further information is provided in the sections describing the individual systems of interest, and in Section 3.8 where details of penetration designs are presented.

6.2.5 COMBUSTIBLE GAS CONTROL IN CONTAINMENT

Following a loss-of-coolant accident (LOCA), hydrogen may be produced inside the reactor containment by radiolysis of the core and sump solutions, by corrosion of aluminum and zinc, by reaction of the zirconium in fuel cladding with water, and by release of the hydrogen contained in the reactor coolant system.

The original design of the containment structure utilized the containment hydrogen purge system (CHPS) which includes dedicated containment penetrations for the purposes of purging hydrogen.

Following the TMI-2 incident and issuance of NUREG-0737, November, 1980, PG&E committed to provide an electrical hydrogen recombiner system (EHRS) inside the containment structure as the primary means of hydrogen buildup mitigation. In addition, PG&E committed to providing the installed capability to connect external hydrogen recombiners outside the containment structure, cross tying the CHPS supply and exhaust piping into a closed loop.

In 2003, revisions to 10 CFR 50.44 removed the definition of a design basis LOCA hydrogen release, and eliminated the requirements for hydrogen control systems to mitigate such a release. The requirements remaining include the need to maintain a mixed atmosphere to prevent coalescence of high concentration local hydrogen collections that may provide a flammability risk and the need to provide equipment for monitoring hydrogen concentrations in the containment atmosphere.

To fulfill the requirements of 10 CFR 50.44, PG&E credits the use of the containment fan cooler system (CFCS) as the means of containment atmosphere mixing. Refer to Section 6.2.2 for discussion of other CFCS design bases.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

The research and development work discussed in more detail in Section 6.2.5.3 substantially reduced the uncertainties in both the expected rates of hydrogen accumulation and the potential exposures that would result from hydrogen control by venting as follows:

(1) Research on the corrosion of aluminum and associated hydrogen production rates by Westinghouse (References 12 - 15 and 42) has reduced uncertainties on corrosion rates in the expected post-accident environment and allowed a reduction in the expected corrosion rate from the 42 mg/dm^2/hr used in the Unit 2 PSAR to the value shown in Figure 6.2-24.

(2) The amounts of aluminum used in the as-built plant have been minimized through materials design specifications. Zinc is another significant contributor. The uncertainties in the amounts of hydrogen produced from both have been reduced by itemized accounting (refer to Table 6.2-42).

(3) The amounts of hydrogen expected to be produced by the zirconium-water reaction have been reduced by the more stringent limits established on ECCS performance.

(4) Research by the Atomic Energy Commission (AEC) and its contractors (a partial compilation is included in Reference 16) in the context of emergency core cooling system (ECCS) studies has substantially reduced uncertainties in the extent of zirconium-water reactions following a LOCA.

(5) Reevaluation of energy generation rates has allowed reduction of hydrogen generation rate from sump radiolysis.

(6) Research on hydrogen yield in the core and sumps by Westinghouse (References 13-15) has reduced uncertainties in these constants.

(7) *Refined analysis of the distribution of fission product decay energy (Reference 17) has resulted in more precise values for the fractions of beta and gamma energies absorbed by water.*

(8) *Additional meteorological data and analysis (References 18-20) conducted by PG&E as a part of the 2-year site program has established high probabilities of conditions favorable for controlled venting.*

(9) *Development of the general purpose EMERALD (Reference 21) computer program for the calculation of doses following accidents has resulted in more accurate estimates of potential exposures, and permitted additional sensitivity studies of the influence of various parameters on potential exposures.*

6.2.5.1 Design Bases

6.2.5.1.1 General Design Criterion 2, 1967 – Performance Standards

The CHPS, the EHRS and the hydrogen monitoring system (containment penetrations and containment isolation valves only) are designed to withstand the effects of, or are protected against, natural phenomena such as earthquakes, winds and tornadoes, floods and tsunamis, and other local site effects.

6.2.5.1.2 General Design Criterion 3, 1971 – Fire Protection

The CHPS, the EHRS and the hydrogen monitoring system SSCs are designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

6.2.5.1.3 General Design Criterion 11, 1967 – Control Room

The CHPS and hydrogen monitoring system are designed to support actions to maintain and control the safe operational status of the plant from the control room.

6.2.5.1.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain hydrogen concentrations within prescribed operating ranges.

6.2.5.1.5 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

Means are provided for monitoring the effluent discharge path of the CHPS for radioactivity that could be released.

6.2.5.1.6 General Design Criterion 37, 1967 – Engineered Safety Features Basis for Design

Means are provided in the containment to back up the safety function provided by the core design, the reactor coolant pressure boundary, and their protection systems. The CFCS is designed to ensure containment atmosphere mixing as a result of any size reactor coolant pressure boundary break to prevent the coalescence of local hydrogen concentrations within containment.

6.2.5.1.7 General Design Criterion 41, 1967 – Engineered Safety Features Performance Capability

The CFCS is designed to provide sufficient performance capability to accommodate partial loss of installed capacity and still fulfill containment atmosphere mixing.

6.2.5.1.8 General Design Criterion 42, 1967 – Engineered Safety Features Components Capability

The CFCS is designed so that the capability of each component and system to perform its required function is not impaired by the effects of a LOCA.

6.2.5.1.9 General Design Criterion 49, 1967 – Containment Design Basis

The containment combustible gas control systems are designed so that the containment structure can accommodate, without exceeding the design leakage rate, the pressures and temperatures resulting from the largest credible energy release following a LOCA, including a considerable margin for effects from metal-water or other chemical reactions that could occur as a consequence of failure of emergency core cooling systems.

6.2.5.1.10 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The piping that is part of the CHPS and hydrogen monitoring system that penetrate containment is provided with leak detection, isolation, redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating this system. The piping is designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

6.2.5.1.11 General Design Criterion 56, 1971 – Primary Containment Isolation Valves

The CHPS and hydrogen monitoring system contain valves in piping that penetrate containment and connect directly to the containment atmosphere. Remote manual isolation valves are provided outside containment and automatic (check) valves are provided inside containment to ensure containment integrity is maintained.

6.2.5.1.12 10 CFR 50.44 – Combustible Gas Control for Nuclear Power Reactors

The CFCS ensures a mixed atmosphere is maintained within containment to prevent high localized concentrations of hydrogen gas accumulation.

The hydrogen monitoring system is designed to be functional, reliable, and capable of continuously measuring the concentration of hydrogen in the containment atmosphere.

6.2.5.1.13 10 CFR 50.49 – Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

CHPS, EHRS and the hydrogen monitoring system components that require environmental qualification (EQ) are qualified to the requirements of 10 CFR 50.49.

6.2.5.1.14 10 CFR 50.55a(f) – Inservice Testing Requirements

American Society of Mechanical Engineers (ASME) code components of the CHPS and hydrogen monitoring system are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

6.2.5.1.15 10 CFR 50.55a(g) – Inservice Inspection Requirements

ASME code components of the CHPS and hydrogen monitoring system are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

6.2.5.1.16 Regulatory Guide 1.7, Revision 2, November 1978 – Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident

The CFCS is designed to provide a mixed atmosphere in containment and thus control combustible gas concentrations without relying on purging of the containment atmosphere following a LOCA. The CFCS meets the design, quality assurance, redundancy, energy source, and instrumentation requirements for an engineered safety feature. The hydrogen monitoring system provides a means to measure the hydrogen concentration in the containment.

6.2.5.1.17 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The hydrogen monitoring system is designed to provide continuous indication in the control room of hydrogen concentration in the containment atmosphere following a beyond design basis accident and meets the design provisions of Regulatory Guide 1.97, Revision 3, May 1983 including qualification, redundancy and testability.

6.2.5.1.18 NUREG-0737 (Items II.E.4.1, II.F.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.E.4.1 – Dedicated Hydrogen Penetrations:

The CHPS for post-accident combustible gas control of the containment atmosphere is provided with dedicated containment penetrations separate from other containment venting systems.

Item II.F.1 – Additional Accident Monitoring Instrumentation:

Position (6) - The display instrumentation is designed to include the containment hydrogen monitors. Indication of hydrogen concentration in the containment atmosphere is provided in the control room.

6.2.5.1.19 Generic Letter 89-10, June 1989 – Safety-Related Motor-Operated Valve Testing and Surveillance

The CHPS motor-operated valves (MOVs) meet the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996.

6.2.5.2 System Description

6.2.5.2.1 Containment Fan Cooler System

The CFCS provides mixing of the containment atmosphere following a design basis accident to ensure that hydrogen concentrations are within prescribed limits. Refer to Sections 6.2.2 and 9.4.5 for further details on the CFCS.

6.2.5.2.2 Electric Hydrogen Recombiner System

Internal EHRSs are installed in both units of the DCPP as a means of controlling containment atmosphere hydrogen concentration following a LOCA.

The EHRSs are natural convection, flameless, thermal reactor-type hydrogen-oxygen recombiners. In their basic operation, they heat a continuous stream of air-hydrogen mixture to a temperature sufficient for spontaneous recombination of the hydrogen with the oxygen in the air to form water vapor.

The system for each unit consists of two independent recombiners, each of which contains the electric heater banks, a power supply panel that contains the equipment for powering the heaters, and a power control panel to the heaters. The recombiners are located inside the containment building; the power supply and control panels are located outside this building. The EHRS units are completely enclosed and the internals are protected against impingement from containment spray.

Each recombiner consists of an inlet preheater section, a heater-recombination section, and a mixing chamber (refer to Figure 6.2-23). Air and the hydrogen are drawn into the unit by natural convection via the inlet louvers and pass through the preheater section, which consists of a shroud placed around the central heaters to take advantage of heat conduction through the walls. In this area, the temperature of the inlet air is raised. This rise in temperature accomplishes the dual function of increasing system efficiency and evaporating any moisture droplets that may be entrained in the air. The warmed air then passes through the flow orifice that has been specifically sized to regulate air flow through the unit. After passing through the orifice plate, the air flows vertically upward through the heater section, where its temperature is raised to the range of 1150°F to 1400°F, causing the recombination of H_2 and O_2 to occur. The recombination temperature is approximately 1135°F.

Next, the air rises from the top of the heater section and flows into the mixing chamber, which is at the top of the unit. Here, the hot air is mixed with the cooler containment air and then discharged back into the containment at a lower temperature. The cooler containment air enters the mixing chamber through the lower part of the upper louvers located on three sides of the unit.

The major structural components are manufactured from stainless steel and Incoloy-800. The heater sheathing is also Incoloy-800. Each bank is constructed of Incoloy-800 sheathed tubular elements mounted in a heavy-gauge steel flange with holes for mounting into the recombiner heater frame.

There are four banks of heaters in each recombiner. Each bank contains 60 individual, U-type heating elements connected in series-parallel arrangements as required to obtain the power rating for each bank. The internal connections are wired to special terminal blocks located outside the heater flange. Each bank is sized for a specific power rating.

The power supply panel contains all the necessary electrical equipment to provide the power required by the heaters in the recombiner.

The panel consists of an isolation transformer, silicon-controlled rectifier module, an auxiliary control power transformer, and a main line contactor. The control panel contains all the control and monitoring equipment required for operating the recombiner and is easily accessible to the plant operators.

Thermocouples are provided for convenience in testing and periodic checkout; they are not considered necessary, however, to ensure proper operation of the recombiner.

The EHRS design characteristics conservatively bound the design conditions following a LOCA and are as follows:

	Normal Operating Conditions	Post-LOCA Operating Conditions
Temperature, °F	120	288 (max)
Pressure, psia	15	77 (max)
Pressure transient, psia	N/A	77 (max in 10 sec)
Relative humidity, %	0-100	100
Radiation, rads/hr	5	3.3×10^5
Radiation-total dose, rads	NA	2×10^8 (max)
Spray solution, ppm B/pH	NA/NA	2550/9-10.5
Design life, yr	40	NA
Recombiner capacity, scfm of containment gas at 1 atm	NA	100 (min)

From the results shown in Figures 6.2-26 through 6.2-29, a 100 scfm hydrogen recombiner, started when the bulk containment hydrogen concentration reaches 3.5 percent by volume (after 3 days), or earlier, will ensure that the bulk containment hydrogen concentration will not reach the lower flammability limit of 4 percent by volume. The licensing limit of 4.0 percent by volume is assured by operating procedures that direct operators to initiate recombiner operation at hydrogen concentrations as low as 0.5 percent by volume. Thus, neither hydrogen burning nor detonation will occur.

6.2.5.2.3 Containment Hydrogen Purge System

The CHPS is designed for either intermittent or continuous flow operation. While the hydrogen recombiner system is the primary system for post-LOCA containment hydrogen control, in the event that hydrogen concentration were to reach the control limit of 3.5 percent, the hydrogen purge system may be placed into operation under strict administrative controls.

The CHPS is a PG&E Design Class I system consisting of two diverse purge routes and two redundant supply routes. The system is available for control of hydrogen and includes provisions for post-accident installation of portable recombiners. The basic features of the CHPS are shown in Figures 6.2-20, 6.2-21, and 6.2-22.

Each purge stream leaves the containment through a motor-operated isolation valve, which opens remotely during venting. One purge stream is routed through a manual valve, roughing filter, HEPA filter, charcoal, HEPA after-filter, a blower, a hand control valve, a flow measuring device, plant vent radiation monitor, and the associated plant vent radiation monitoring systems. The second purge stream is routed through a flow measuring device, a hand-controlled valve, and the containment excess pressure relief line to the auxiliary building ventilation system carbon filter plenum. This purge stream

then follows the auxiliary building ventilation exhaust flowpath through the roughing filter, HEPA filter, carbon adsorber, exhaust fan, plant vent and the associated plant vent radiation monitoring system. The purge stream can be operated independently of the supply stream.

The supply stream is drawn through a roughing filter and a blower and routed through a hand control valve, a flow measuring device, a gate valve, and isolation check valves. The supply stream can be operated independently of the purge stream.

The supply stream entrance and the purge stream exit are widely separated to prevent short circuiting. The containment fan cooler units ensure complete mixing of the post-accident containment atmosphere.

All CHPS motor-operated valves inside containment are supplied with Class 1E power.

Prior to initiation of hydrogen purge, the containment radiation monitoring system is used to monitor, either continuously or intermittently, the radioactivity in containment. The plant vent radiation monitors measure the radioactivity in the purge stream. Refer to Section 9.4.2 for information on the plant vent.

The supply stream isolation valves and blower are operated manually.

The supply stream provides for immediate dilution, and the hydrogen concentration decreases. The purge stream is initiated after the supply stream begins diluting hydrogen.

The containment hydrogen purge system is provided with charcoal filters to minimize the release of radioactive iodine. The filters are sized in accordance with activity loading specifications associated with ESFs.

The analysis of potential radiation exposures that could result from venting for hydrogen control is contained in the LOCA analysis in Section 15.5.17.2.9. The estimated incremental exposures resulting from containment venting are a negligible addition to those estimated for containment leakage.

The operators are provided with current data on containment hydrogen concentration, containment activity levels, wind direction, and wind speed to determine optimum purge schedules.

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In the Preliminary Safety Analysis Report (PSAR) (Reference 9) for DCPP Unit 2, an analysis of the expected hydrogen production concluded that any hydrogen accumulation could be controlled by containment venting, with radiological exposures below the annual limits specified in 10 CFR Part 20. Using more conservative parameters, the AEC regulatory staff calculated that the lower flammability limit would

be attained in less than 40 days (Reference 10). The staff concluded that the purging operation could result in offsite activity concentration levels that exceed 10 CFR Part 20 limits. Additional capability for filtering of containment effluent, including charcoal beds, would, however, reduce the I-131 concentration level. Assuming 90 percent filter efficiency for iodine removal, the staff estimated (Reference 11) that doses at the site boundary would be about 0.8 rem whole body and about 8.5 rem to the thyroid if the entire contents of the containment were vented over a 30-day period. Estimated exposures were, therefore, less than 10 percent of the guideline levels established in 10 CFR Part 100.

6.2.5.2.4 Hydrogen Monitoring System

The hydrogen monitors are located outside containment in the containment hydrogen monitor panels. The sample flows pass from the containment through inner and outer solenoid containment isolation valves to the monitors. The sample flows return to the containment through outer solenoid containment isolation valves and inner containment isolation check valves. Refer to Figure 6.2-22 for schematic configuration of the system.

Refer to Section 6.2.5.5.1 for additional information on the hydrogen monitors.

6.2.5.3 Safety Evaluation

6.2.5.3.1 General Design Criterion 2, 1967 – Performance Standards

The auxiliary building and containment structure, which contain the EHRS, CHPS and hydrogen monitoring system SSCs are PG&E Design Class I (refer to Section 3.8). These buildings or applicable portions thereof are designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), earthquakes (refer to Section 3.7), and other natural phenomena, and to protect EHRS, CHPS and hydrogen monitoring system SSCs ensuring their design functions will be performed.

The EHRS and CHPS are PG&E Design Class I and are maintained as such to withstand additional forces that might be imposed by natural phenomena such as winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5) and earthquakes (refer to Section 3.7).

6.2.5.3.2 General Design Criterion 3, 1971 – Fire Protection

The CHPS, EHRS and hydrogen monitoring system are designed to the fire protection guidelines of Branch Technical Position APCSB 9.5.1 (refer to Appendix 9.5B Table B-1).

6.2.5.3.3 General Design Criterion 11, 1967 – Control Room

Two redundant hydrogen monitors are installed in each unit to provide continuous indication and recording in the control room of containment hydrogen concentration.

Containment isolation valve status is shown on the main control board as indicated in Table 6.2-39. For the CHPS, annunciation is provided to alarm on high radioactivity, high flowrate, and fan failure.

Refer to Section 6.2.5.5 for additional discussion of instrumentation and controls.

6.2.5.3.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

The EHRS does not require any instrumentation inside the containment for proper operation after a LOCA. Proper recombiner operation after an accident is ensured by measuring the amount of electric power to the recombiner from the control panel located outside containment accessible to operators following an accident. The temperature readout device is a monitoring unit, not a control unit. For additional information refer to Section 6.2.5.2.2.

For the CHPS, the supply and the purge streams may be adjusted to regulate the flowrates to values required to maintain hydrogen level in the containment at or below the 4.0 percent limit. Instrumentation is provided to monitor flowrate and hydrogen concentration. The containment radiation monitoring system and the plant vent radiation monitors are used to monitor the radioactivity in containment and the hydrogen purge line.

Refer to Section 6.2.5.5 for additional discussion of instrumentation and controls.

6.2.5.3.5 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

The CHPS is vented through the plant vent which is equipped with a radiation monitoring system. Refer to Sections 9.4.5.3.5 and 11.4 for further details on the plant vent and radiation monitoring system.

6.2.5.3.6 General Design Criterion 37, 1967 – Engineered Safety Features Basis for Design

The basis for design is centralized upon the requirements set forth in 10 CFR 50.44 in which the containment structure must have the capability for ensuring a mixed atmosphere. A mixed atmosphere is obtained through use of the CFCS in which post-accident hydrogen produced is circulated throughout the containment structure in conjunction with other gases to prevent local hydrogen concentrations from reaching a lower flammability limit of 4 percent hydrogen by volume. The method of analysis used

to determine the post-accident production rate of hydrogen used in the basis of the system design is given below.

6.2.5.3.6.1 Analysis of Hydrogen Generation and Accumulation

The quantity of zirconium, which reacts with the core cooling solution, depends on the performance of the ECCS.

The criteria for ECCS evaluation (10 CFR 50.46) requires that the zirconium-water reaction be limited to 1 percent by weight of the total quantity of zirconium in the core. ECCS calculations have shown the zirconium-water reaction to be less than 1 percent.

Aluminum inside the containment is not used in safety-related components that are in contact with the recirculating core cooling fluid. It is more reactive with the containment spray alkaline borate solution than other plant materials such as galvanized steel, copper, and copper nickel alloys.

The zirconium-water reaction and aluminum and zinc corrosion with containment spray are chemical reactions, which are essentially independent of the radiation field inside the containment following a LOCA. Radiolytic decomposition of water is dependent on the radiation field intensity. The radiation field inside the containment is calculated for the maximum credible accident for which the fission product activities are given in TID-14844 (Reference 24).

The hydrogen generation is calculated using the NRC model discussed in Regulatory Guide 1.7, Revision 2, November 1978 (Reference 22), Standard Review Plan 6.2.5 (Reference 40) and Branch Technical Position CSB 6-2 (Reference 41).

6.2.5.3.6.1.1 Hydrogen Generation from the Zirconium-Water Reaction

The zirconium-water reaction is described by the chemical equation:

$$Zr + 2H_2O \rightarrow Zr\ O_2 + 2H_2 + \text{Heat}$$

Hydrogen generation due to this reaction will be completed during the first day following the LOCA. The NRC model assumes a 5 percent (5 times the maximum allowable value defined by 10 CFR Part 50, Appendix K (ECCS)) zirconium-water reaction. The hydrogen generated is assumed to be released immediately to the containment atmosphere.

6.2.5.3.6.1.2 Hydrogen Available from the Reactor Coolant System

The quantity of hydrogen in the RCS during normal operation includes hydrogen from the pressurizer gas space and hydrogen dissolved in the reactor coolant. The pressurizer gas space hydrogen is based on:

(1) A maximum allowable coolant hydrogen concentration of 60 cc(stp)/kg of coolant (stp denotes standard temperature and pressure)

(2) Control banks of pressurizer heaters will modulate to control pressurizer heat losses to maintain constant pressurizer temperature and pressure

(3) Minimum bypass spray rate of 2.0 gpm

(4) Normal liquid level of the pressurizer (60 percent)

(5) Pressurizer power-operated relief valves closed

The hydrogen from the reactor coolant and the pressurizer vapor space is available for release to the containment immediately following a LOCA.

6.2.5.3.6.1.3 Hydrogen Generation from the Corrosion of Plant Materials

Oxidation of metals in aqueous solution generates hydrogen gas as one of the corrosion products. Extensive corrosion testing has been conducted to determine the behavior of the various metals used within the containment. Metals tested include zirconium alloys, Inconel, aluminum alloys, cupronickel alloys, carbon steel, galvanized carbon steel, and copper.

Tests conducted at Oak Ridge National Laboratory (ORNL) (References 25 and 26) and Westinghouse (Reference 42) have verified the compatibility of the various materials with alkaline borate solution and have shown that aluminum and zinc will corrode at a rate that will significantly add to the hydrogen accumulation in the containment atmosphere.

The corrosion of aluminum may be described by the overall reaction:

$$2\ Al + 3\ H_2O \rightarrow Al_2O_3 + 3\ H_2$$

Three moles of hydrogen are produced for every two moles of aluminum oxidized.

The corrosion of zinc may be described in the overall reaction:

$$Zn + 2H_2O \rightarrow Zn(OH)_2 + H_2$$

One mole of hydrogen is produced for each mole of zinc oxidized.

The time-temperature cycle (refer to Table 6.2-41) considered in the calculation of aluminum and zinc corrosion is a step-wise representation of the postulated post-accident containment temperature transient. The corrosion rates at the various steps were determined from the aluminum and zinc corrosion rate design curves (References 42 and 55) shown in Figure 6.2-24, which include the effects of temperature and spray

solution conditions. For conservative estimation, no credit was taken for protective shielding effects of insulation or enclosures from the spray, and complete and continuous immersion was assumed.

The calculations were performed by Westinghouse using the methodology of Regulatory Guide 1.7, Revision 2, November 1978, but using the corrosion rates given in Figure 6.2-24 and the containment time-temperature values given in Table 6.2-41.

For this hydrogen generation reanalysis the aluminum and zinc inventories inside containment are as shown in Table 6.2-42.

6.2.5.3.6.1.4 Hydrogen Generation from the Radiolysis of Core and Sump Water

Water radiolysis is a complex process involving reactions of numerous intermediates. However, the overall radiolytic process may be described by the reaction:

$$H_2O \rightleftarrows H_2 + 1/2\ O_2$$

Table 6.2-43 presents the total decay energy ($\beta + \gamma$) of a reactor core. It assumes full power operation with extended fuel cycles prior to the accident. For the maximum credible accident case, the contained decay energy in the core accounts for the assumed TID-14844 release of 50 percent halogens and 1 percent other fission products. In the TID-14844 model, the noble gases are assumed to escape to the containment vapor space.

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The yield of hydrogen from radiolytically decomposed solution has been studied extensively by Westinghouse and ORNL. The results of static capsule tests conducted by Westinghouse indicate hydrogen yields much lower than 0.44 molecules per 100 eV for core radiolysis.

There are, however, differences between the static capsule tests and the dynamic condition in core, where the cooling fluid is continuously flowing. The flow is assumed to disturb the steady state conditions that are observed in static capsule tests, and while the occurrence of back reactions is still significant, the overall net yield of hydrogen is somewhat higher in the flowing system.

Westinghouse studies of radiolysis in dynamic systems (Reference 15) show 0.44 molecules per 100 eV to be a maximum yield for high solution flowrates through a gamma radiation field. Work by ORNL (References 25 and 26), Zittel (Reference 28), and Allen (Reference 29) confirm this value.

Analysis, based on Regulatory Guide 1.7, Revision 2, November 1978, is conservative because it assumes a hydrogen yield value of 0.5 molecules per 100 eV. It also

assumes that 10 percent of the gamma energy, produced from fission products in the fuel rods, is absorbed by the solution in the region of the core, and the noble gases escape to the containment vapor space.

Another potential source of hydrogen assumed for the post-accident period arises from water in the reactor containment sump being subjected to radiolytic decomposition by fission products. An assessment must therefore be made of the decay energy deposited in the solution and the radiolytic hydrogen yield, much in the same manner as for core radiolysis.

The energy deposited in solution is computed using the following basis:

(1) For the maximum credible accident, a TID-14844 release model (Reference 24) is assumed where 50 percent of the total core halogens and 1 percent of all other fission products, excluding noble gases, are released from the core to the sump solution.

(2) The quantity of fission product release considers a reactor operating with extended fuel cycles prior to the accident.

(3) The total decay energy from the released fission products, both beta and gamma, is assumed to be fully absorbed in the solution.

The calculation of the fission product decay energy deposited in the sump solution considers the decay of halogens and the decay of the remaining 1 percent of fission products. The energy release rates and integrated energy release for various times after a LOCA are listed in Table 6.2-44.

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The yield of hydrogen from sump solution radiolysis is most nearly represented by the static capsule tests performed by Westinghouse and ORNL with an alkaline sodium borate solution. The differences between these tests and the actual conditions for the sump solution, however, are important and render the capsule tests conservative in their predictions of radiolytic hydrogen yields.

In this assessment, the sump solution will have considerable depth, which inhibits the ready diffusion of hydrogen from solution, as compared to the case with shallow-depth capsule tests. This retention of hydrogen in solution will have a significant effect in reducing the hydrogen yields to the containment atmosphere. The buildup of hydrogen in solution will enhance the back reaction to form water and lower the net hydrogen yields, in the same manner as a reduction in the gas to liquid volume ratio will reduce the yield. This is illustrated by the data presented in Figure 6.2-25 for capsule tests with various gas to liquid volume ratios. The data show a significant reduction in the net hydrogen yield from the primary maximum yield of 0.44 molecules per 100 eV. Even at

the very highest ratios, where capsule solution depths are very low, the yield is less than 0.30, with the highest scatter data point at 0.39 molecules per 100 eV.

Taking these data into account, a reduced hydrogen yield is a reasonable assumption for the case of sump radiolysis. The expected yield is on the order of 0.1 molecules per 100 eV or less. Regulatory Guide 1.7, Revision 2, November, 1978 does not, however, allow credit for the reduced hydrogen yields and a yield value of 0.5 molecules per 100 eV is used in the analyses.

All containment volumes are connected by large vent areas to promote good air circulation. Hydrogen will diffuse very rapidly giving an even distribution under the conditions existing in the containment structure. In addition, thermal mixing effects, heating of air above the hot sump water, and possible steam released from the RCS will move the hydrogen-laden air from the points of generation toward the cool external walls. Although hydrogen is lighter than air, it will not concentrate significantly in high areas because of the high diffusion rate, the open design of the containment, and the fan cooler air mixing.

The ability of hydrogen to diffuse rapidly into all volumes is inferred from a CSE experiment (Reference 23). These tests showed very good mixing in the main chamber and a rapid interchange by diffusion and mixing with the atmosphere of other chambers that had limited communication. The diffusivity of hydrogen is approximately 10 times that of iodine, so a more uniform mixture is expected for hydrogen. Also, higher concentration provides greater concentration gradients for better diffusion than indicated by the CSE tests.

Table 6.2-45 summarizes the calculated hydrogen production and accumulation data.

6.2.5.3.6.1.5 Results of the Hydrogen Generation and Accumulation Analyses

The results of the hydrogen generation and accumulation analyses are presented in Figures 6.2-26 through 6.2-29.

6.2.5.3.7 General Design Criterion 41, 1967 – Engineered Safety Features Performance Capability

The CFCS, including required auxiliary systems, is designed to tolerate a single active failure following a LOCA without loss of protective function. Refer to Section 6.2.2.3.2 for further discussion.

6.2.5.3.8 General Design Criterion 42, 1967 – Engineered Safety Features Components Capability

The component design pressure and temperature conditions in Table 6.2-26 are specified as the most severe conditions to which each CFCS component is exposed during either normal or post-LOCA operation allowing the system to provide a mixed atmosphere in post-LOCA conditions. Refer to Section 6.2.2.3.1 for further discussion.

6.2.5.3.9 General Design Criterion 49, 1967 – Containment Design Basis

The CFCS ensures a mixed atmosphere within the containment structure to prevent the ignition of high concentration hydrogen collections that may produce quick and large pressure and temperature rises.

The containment penetrations, including the CHPS and hydrogen monitoring system piping and valves required for containment isolation, are designed and analyzed to withstand the pressures and temperatures that could result from a LOCA without exceeding design leakage rates. Refer to Section 3.8.1.1.3 for additional details.

6.2.5.3.10 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The CHPS and hydrogen monitoring system valves required for containment isolation are periodically tested. Testing of the components required for the containment isolation system (CIS) is discussed in Section 6.2.4.

6.2.5.3.11 General Design Criterion 56, 1971 – Primary Containment Isolation Valves

The CHPS and containment hydrogen monitoring system containment penetrations comply with the requirements of GDC 56, 1971, as described in Section 6.2.4 and Table 6.2-39.

6.2.5.3.12 10 CFR 50.44 – Combustible Gas Control for Nuclear Power Reactors

The CFCS is credited as the means for providing a mixed atmosphere in the containment structure in accordance with 10 CFR 50.44. Refer to Section 6.2.2.2 for discussion of the CFCS.

The hydrogen monitoring system is provided to continuously measure hydrogen concentrations in the containment structure following a significant beyond design basis accident for accident management, including emergency planning. Refer to Section 6.2.5.5 for further details on the hydrogen monitoring instrumentation.

6.2.5.3.13 10 CFR 50.49 – Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

CHPS, EHRS and hydrogen monitoring system components required to function in harsh environments under accident conditions are qualified to the applicable environmental conditions to ensure that they will continue to perform their safety functions. Section 3.11 describes the DCPP EQ Program and the requirements for the environmental design of electrical and related mechanical equipment. The affected equipment, including the CFCS motors, containment isolation solenoid valves, containment isolation valve motor actuators, and the recombiners, are listed on the EQ master equipment list.

6.2.5.3.14 10 CFR 50.55a(f) – Inservice Testing Requirements

Periodic inservice testing (IST) of all containment isolation valves, in the system is performed. The IST requirements are contained within the IST Program Plan and comply with the ASME code for Operation and Maintenance of Nuclear Power Plants. Refer to Section 6.2.2.4 for a discussion of testing of the CFCS.

6.2.5.3.15 10 CFR 50.55a(g) – Inservice Inspection Requirements

The inservice inspection (ISI) requirements for the CHPS and containment hydrogen monitoring penetrations are contained within the ISI Program Plan and comply with the ASME BPVC, Section XI. Refer to Section 6.2.2.4 for a discussion of inspection of the CFCS.

6.2.5.3.16 Regulatory Guide 1.7, Revision 2, November 1978 – Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident

The CFCS, serving as the credited means for containment atmosphere mixing in accordance with 10 CFR 50.44, is designed and constructed to PG&E Design Class I standards.

The hydrogen monitoring system includes two hydrogen monitors to measure the hydrogen concentration in the containment.

The hydrogen monitoring system was originally designed and constructed as Category 1, as defined by Regulatory Guide 1.97, Revision 2, December 1980 however has been reclassified as Category 3, as defined by Regulatory Guide 1.97, Revision 3, May 1983 as a result of the rulemaking revision to 10 CFR 50.44 (refer to Section 6.2.5.3.17).

The EHRS is available to control containment hydrogen concentration following a LOCA to at or below 4.0 percent by volume without relying on the CHPS. Each of the two redundant recombiners is capable of providing the required removal capacity. The CHPS is also available.

To ensure that the lower flammability limit (4 percent) will not be exceeded, the internal electric hydrogen recombiners will be started at or below 3.5 percent by volume.

The EHRS and CHPS systems meet PG&E Design Class I design and construction standards.

The EHRS provides 100 percent redundancy since each recombiner and its associated power supply and control panel are capable of providing the required hydrogen removal capacity. The second unit, including its associated power supply and control panels, is normally on standby following a postulated LOCA.

The CHPS is provided as a means to carry out controlled purging of the containment atmosphere. While it is intended to serve only as an additional option for containment hydrogen control, and may not be acceptable for operation following a LOCA, the CHPS otherwise satisfies the design requirements for an ESF system. Two redundant systems complete with separate lines, blowers, and filters have been provided. These lines, valves, instrumentation, and blowers are PG&E Design Class I. Each blower and its associated controls are powered by independent electrical power supplies.

The basic data and analytical models and assumptions used for determining hydrogen production and accumulation shall be based on Regulatory Guide 1.7, Revision 2, November 1978 (Reference 22). The parameter values listed in Table 1 of Regulatory Guide 1.7, Revision 2, November 1978 were used in calculating the hydrogen gas concentration in containment. Refer to Section 6.2.5.3.6 for further discussion of the analysis. In addition, refer to Section 15.5.17.2.9 for analysis of potential radiation exposures that could result from venting hydrogen.

The use of corrodible materials that yield hydrogen due to corrosion from the emergency cooling or containment spray solutions has been controlled in the containment to minimize hydrogen production.

6.2.5.3.17 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Two Category 3 hydrogen monitors per unit monitor post-accident hydrogen concentration (refer to Figure 6.2-22) and indication is provided in the control room for Regulatory Guide 1.97, Revision 3, May 1983 monitoring. Although designed to Category 1, the monitors have been reclassified to meet the requirements of Category 3 as described in Section 6.2.5.3.16. Their characteristics are described in Section 6.2.5.5 and Table 7.5-6.

6.2.5.3.18 NUREG-0737 (Items II.E.4.1, II.F.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.E.4.1 – Dedicated Hydrogen Penetrations:

Dedicated penetrations are used for the purge system. Refer to Section 6.2.5.2.2 for a description of the CHPS and Sections 6.2.5.3.10 and 6.2.5.3.11 for discussions of GDC 54, 1971 and GDC 56, 1971, respectively.
Item II.F.1 – Additional Accident Monitoring Instrumentation:

Position (6) - The display instrumentation for containment hydrogen monitoring is described in Section 6.2.5.5.1.

6.2.5.3.19 Generic Letter 89-10, June 1989 – Safety-Related Motor-Operated Valve Testing and Surveillance

The CHPS MOVs are subject to the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996, and meet the requirements of the DCPP MOV Program Plan.

6.2.5.4 Tests and Inspections

Tests and inspections for the containment hydrogen control equipment are discussed in Sections 6.2.2, 6.2.5.3.14, and 6.2.5.3.15. The valves associated with containment isolation will be tested as described in Sections 6.2.4.4.13 and 6.2.4.5. Tests and inspections of filters and fans are described in Section 9.4.

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All PG&E Design Class I components of the combustible gas control systems were designed, fabricated, installed, and tested under quality assurance requirements in accordance with 10 CFR Part 50, Appendix B, as described in Chapter 17.

Nondestructive examination has been performed on the components of the systems in accordance with the requirements of the applicable codes as described in Section 3.2. The systems have been tested in accordance with the procedures outlined in Chapter 14.

During preoperational startup testing of the plant, a functional test using predetermined sample hydrogen gas mixtures was performed to verify hydrogen analyzer operation.

6.2.5.5 Instrumentation Applications

Because of the possibility of hydrogen release to the containment atmosphere following a LOCA, means to monitor and control the post-accident concentration of hydrogen in the containment are necessary.

6.2.5.5.1 Hydrogen Monitoring System

Two redundant hydrogen monitors are installed in each unit to provide continuous indication and recording in the control room of containment hydrogen concentration. The monitors are Instrument Class II, Type C, Regulatory Guide 1.97 Category 3 and each has its own dedicated containment penetration and isolation valves to meet single failure criteria (refer to Figure 6.2-22 for system layout). The monitoring system is capable of sampling and measuring the hydrogen concentration inside the containment to diagnose the course of beyond-design-basis accidents. The system has a range of 0-10 percent by volume. The normal system configuration is with the hydrogen monitors off-line and their respective containment isolation valves closed.

Refer to Sections 6.2.5.3.3, 6.2.5.3.16, and 6.2.5.3.17 for additional discussion on the hydrogen monitors.

6.2.5.5.2 Containment Hydrogen Purge System

Instrumentation is provided to monitor the flowrate and the amount of radioactivity released by the purging operation.

The containment radiation monitoring system and the plant vent radiation monitors are used to monitor the radioactivity in containment and the hydrogen purge line. Refer to Sections 9.4.2 and 11.4 for information regarding the plant vent.

A manual sample point is provided on each exhaust line to obtain a grab sample for laboratory analysis.

Flow indicators are provided for each CHPS exhaust line. The indicators are PG&E Design Class I. The range is 500 to 4000 feet per minute (corresponding to flowrates of approximately 45 to 350 cfm).

Containment isolation valves status is shown on the main control board as indicated in Table 6.2-39. Annunciation is provided to alarm on high radioactivity, high flowrate, and fan failure.

Refer to Sections 6.2.5.3.3 and 6.2.5.3.4 for additional discussion on the CHPS instrumentation.

6.2.5.6 Materials

Materials of construction of components are indicated in Section 6.2.5.2.

6.2.6 REFERENCES

1. Deleted in Revision 18.

2. Deleted in Revision 18.

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6.2.7 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

6.3 EMERGENCY CORE COOLING SYSTEM

The emergency core cooling system (ECCS) is comprised of the refueling water storage tank (RWST) and piping and components of the residual heat removal (RHR) system, safety injection (SI) system, and chemical and volume control system (CVCS).

The primary function of the ECCS is to deliver borated cooling water to the reactor core in the event of a loss-of-coolant accident (LOCA). This limits the fuel cladding temperature and thereby ensures that the core will remain intact and in place, with its essential heat transfer geometry preserved. This protection is afforded for:

- All pipe break sizes up to and including the hypothetical circumferential rupture of a reactor coolant loop

- A loss of coolant associated with a rod ejection accident

The following normal operation functions are not covered in this section:

- The RHR system pumps, heat exchangers, valves, and associated piping are normally used during the latter stages of normal reactor cooldown and during refueling operations (refer to Section 5.5.6).

- The centrifugal charging pumps (CCPs) are normally aligned for charging and letdown service; along with providing seal water to the reactor coolant pumps (refer to Section 9.3.4).

- The RWST is used to fill the refueling canal for refueling operations (refer to Section 9.1.4).

The CCPs, SI pumps, and RHR pumps are commonly referred to as "high-head pumps," “intermediate-head pumps,” and "low-head pumps,” respectively. The term "high-head injection" is used to denote CCP and SI pump injection; while the term "low-head injection" refers to RHR pump injection.

6.3.1 Design Bases

6.3.1.1 General Design Criterion 2, 1967 – Performance Standards

The ECCS is designed to withstand the effects of, or be protected against, natural phenomena, such as earthquakes, flooding, tornadoes, winds, and other local site effects.

6.3.1.2 General Design Criterion 3, 1971 – Fire Protection

The ECCS is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

6.3.1.3 General Design Criterion 11, 1967 – Control Room

The ECCS is designed to support actions to maintain and control the safe operational status of the plant from the control room.

6.3.1.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided, as required, to monitor and maintain ECCS variables within prescribed operating ranges.

6.3.1.5 General Design Criterion 21, 1967 – Single Failure Definition

The ECCS is designed to tolerate a single failure during the period of recovery following an accident without loss of its protective function, including multiple failures resulting from a single event, which is treated as a single failure.

6.3.1.6 General Design Criterion 37, 1967 – Engineered Safety Features Basis for Design

The ECCS is designed to provide back-up to the safety provided by the core design, the reactor coolant pressure boundary (RCPB), and their protection systems. The ECCS is designed to cope with any size RCPB break, up to and including the circumferential rupture of any pipe in that boundary, assuming unobstructed discharge from both ends.

6.3.1.7 General Design Criterion 38, 1967 – Reliability and Testability of Engineered Safety Features

The ECCS is designed to provide high functional reliability and ready testability.

6.3.1.8 General Design Criterion 40, 1967 – Missile Protection

The ECCS is designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

6.3.1.9 General Design Criterion 41, 1967 – Engineered Safety Features Performance Capability

The ECCS is designed to provide sufficient performance capability to accommodate a partial loss of installed capacity, such as a single failure of an active component, and still perform its required safety function.

6.3.1.10 General Design Criterion 42, 1967 – Engineered Safety Features Components Capability

The ECCS is designed so that the capability of each component and system to perform its required function is not impaired by the effects of a LOCA.

6.3.1.11 General Design Criterion 43, 1967 – Accident Aggravation Prevention

The ECCS is designed so that any action of the engineered safety features (ESF) which might accentuate the adverse after effects of the loss of normal cooling is avoided.

6.3.1.12 General Design Criterion 44, 1967 – Emergency Core Cooling Systems Capability

The ECCS is designed to provide the capability of accomplishing abundant emergency core cooling with two systems of different design principles. Each ECCS and the core are designed to prevent fuel and clad damage that would interfere with the emergency core cooling function and to limit the clad metal-water reaction to negligible amounts for all sizes of breaks in the RCPB, including the double-ended rupture of the largest pipe. The performance of each ECCS is evaluated conservatively in each area of uncertainty. The systems do not share active components and do not share other features or components unless it is demonstrated that (a) the capability of the shared feature or component to perform its required function is readily ascertained during reactor operation, (b) failure of the shared feature or component does not initiate a LOCA, and (c) capability of the shared feature or component to perform its required function is not impaired by the effects of a LOCA and is not lost during the entire period this function is required following the accident.

6.3.1.13 General Design Criterion 45, 1967 – Inspection of Emergency Core Cooling Systems

The ECCS is designed to facilitate physical inspection of all critical parts, including reactor vessel internals and water injection nozzles.

6.3.1.14 General Design Criterion 46, 1967 – Testing of Emergency Core Cooling Systems Components

The ECCS is designed so that active components, such as pumps and valves, can be tested periodically for operability and required functional performance.

6.3.1.15 General Design Criterion 47, 1967 – Testing of Emergency Core Cooling Systems

The ECCS is designed to provide the capability to periodically test the delivery capability at a location as close to the core as is practical.

6.3.1.16 General Design Criterion 48, 1967 – Testing of Operational Sequence of Emergency Core Cooling Systems

The ECCS is designed to provide the capability to test, under conditions as close to design as practical, the full operational sequence that would bring the ECCS into action, including the transfer to alternate power sources.

6.3.1.17 General Design Criterion 49, 1967 – Containment Design Basis

The emergency core cooling systems is designed so that the containment structure can accommodate, without exceeding the design leakage rate, the pressures and temperatures resulting from the largest credible energy release following a LOCA, including a considerable margin for effects from metal-water or other chemical reactions that could occur as a consequence of failure of emergency core cooling systems.

6.3.1.18 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The piping that is part of the ECCS that penetrates containment is provided with leak detection, isolation, redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating this system. The piping is designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

6.3.1.19 General Design Criterion 55, 1971 – Reactor Coolant Pressure Boundary Penetrating Containment

Each ECCS line that penetrates the containment is provided with containment isolation valves.

6.3.1.20 General Design Criterion 56, 1971 – Primary Containment Isolation

The ECSS contains valving in piping that penetrates containment and that is connected directly to the containment atmosphere. Remote manual isolation valves are provided outside containment and either automatic (check) valves are provided inside containment, or the system outside containment is considered a closed system, to ensure containment integrity is maintained.

6.3.1.21 10 CFR 50.46 – Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Plants

The ECCS is designed so that its calculated cooling performance following postulated LOCAs conforms to the criteria set forth in 10 CFR 50.46. ECCS cooling performance is calculated in accordance with an acceptable evaluation model for a number of postulated LOCAs of different sizes, locations, and other properties sufficient to provide assurance that the most severe postulated LOCAs are calculated.

6.3.1.22 10 CFR 50.49 – Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

ECCS components that require environmental qualification (EQ) are qualified to the requirements of 10 CFR 50.49.

6.3.1.23 10 CFR 50.55a(f) – Inservice Testing Requirements

ECCS ASME Code components are tested to the requirements of 10 CFR 50.55a(f)(4) and a(f)(5) to the extent practical.

6.3.1.24 10 CFR 50.55a(g) – Inservice Inspection Requirements

ECCS ASME Code components are inspected to the requirements of 10 CFR 50.55a(g)(4) and a(g)(5) to the extent practical.

6.3.1.25 Safety Guide 1, November 1970 – Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps

The ECCS is designed such that adequate net positive suction head (NPSH) is provided to system pumps assuming maximum expected temperatures of pumped fluids and no increase in containment pressure from that present prior to postulated LOCAs.

6.3.1.26 Regulatory Guide 1.79, June 1974 – Preoperational Testing of Emergency Core Cooling Systems for Pressurized Water Reactors

A series of comprehensive preoperational tests were performed on the ECCS in accordance with Regulatory Guide 1.79, June 1974, with noted exceptions, to assure the ECCS will accomplish its intended function when required.

6.3.1.27 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The ECCS provides instrumentation to monitor RHR system flow, SI pump discharge flow, CCP 1 and 2 injection header flow, RHR heat exchanger outlet temperature, containment recirculation sump water level and temperature, accumulator tank level and pressure, accumulator isolation valve position, RWST level, containment isolation valve position, and subcooling margin indication during and following an accident.

6.3.1.28 NUREG-0737 (Items I.C.1, I.D.2, II.B.2, II.F.1, II.F.2, II.K.3.30, II.K.3.31, III.D.1.1), November 1980 – Clarification of TMI Action Plan Requirements

Item I.C.1 – Guidance for the Evaluation and Development of Procedures for Transients and Accidents: NUREG-0737, Supplement 1, January 1983 provides the requirements for I.C.1 as follows:

Section 7.1(b) – Transients and accidents were reanalyzed for the purposes of preparing technical guidelines and upgrading emergency operating procedures.

Item I.D.2 – Plant Safety Parameter Display Console: NUREG-0737, Supplement 1, January 1983 provides the requirements for I.D.2 as follows:

Section 4.1(f)(v), Containment Conditions: The ECCS provides instrumentation for control room personnel to monitor containment recirculation sump water level during and following an accident. Additional monitors are provided in the technical support center (TSC) and emergency operations facility (EOF).

Item II.B.2 – Design Review of Plant Shielding and Environmental Qualification of Equipment for Space/Systems Which May Be Used in Postaccident Operations: Plant shielding provides adequate access to, and occupancy of, the switchgear rooms for the purpose of restoring power to normally de-energized ECCS valves.

Item II.F.1 – Additional Accident Monitoring Instrumentation:

Position (5) – The ECCS provides continuous instrumentation to monitor containment recirculation sump water level in the control room.

Item II.F.2 – Instrumentation for Detection of Inadequate Core Cooling: ECCS instrumentation provides an unambiguous indication of inadequate core cooling by indicating the existence of inadequate core cooling caused by various phenomena and does not erroneously indicate inadequate core cooling due to the presence of an unrelated phenomenon. The instrumentation includes reactor water level indication and provides an advance warning of the approach to inadequate core cooling. The instrumentation covers the full range from normal operation to complete core uncovery.

Item II.K.3.30 – Revised Small-Break Loss-Of-Coolant-Accident Methods to Show Compliance with 10 CFR Part 50, Appendix K: The analysis method for small-break loss-of-coolant accidents (SBLOCAs) was revised for compliance with 10 CFR Part 50, Appendix K. The revision accounts for comparisons with experimental data, including data from the loss of fluid test and semiscale test facilities.

Item II.K.3.31 – Plant-Specific Calculations to Show Compliance with 10 CFR Part 50.46: Plant-specific calculations for SBLOCA, using a Nuclear Regulatory Commission (NRC) approved model, show compliance with 10 CFR 50.46.

Item III.D.1.1 – Integrity of Systems Outside Containment Likely to Contain Radioactive Material for Pressurized-Water Reactors and Boiling-Water Reactors: Appropriate portions of the ECCS are periodically pressure leak tested and visually inspected for leakage into the building environment.

6.3.1.29 Generic Letter 89-10, June 1989 – Safety-Related Motor-Operated Valve Testing and Surveillance

ECCS PG&E Design Class I and position changeable motor-operated valves (MOVs) meet the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996, “Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves.”

6.3.1.30 Generic Letter 95-07, August 1995 – Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves

ECCS PG&E Design Class I, power-operated gate valves meet the requirements of Generic Letter 95-07, August 1995.

6.3.1.31 Generic Letter 96-06, September 1996 – Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions

ECCS piping has been evaluated for the issue of thermal overpressurization of isolated piping sections that could affect containment integrity during accident conditions, as described in Generic Letter 96-06, September 1996.

6.3.1.32 Generic Letter 97-04, October 1997 – Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps

The ECCS has been evaluated to assure adequate NPSH is available to ECCS pumps under all design basis accident scenarios.

6.3.1.33 Generic Letter 98-04, July 1998 – Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment

The ECCS and containment recirculation sump have been evaluated to assure construction and protective coating deficiencies or foreign material in containment will not cause degradation of the ECCS, as required by Generic Letter 98-04, July 1998 and discussed in associated NRC Bulletin 93-02, May 1993, “Debris Plugging of Emergency Core Cooling Suction Strainers.”

6.3.1.34 Generic Letter 2004-02, September 2004 – Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized-Water Reactors

The ECCS and containment recirculation sump have been evaluated to assure that potential debris blockage due to a design basis accident will not impact the ECCS safety-related functions, as required by Generic Letter 2004-02, September 2004.

6.3.1.35 Generic Letter 2008-01, January 2008 – Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems

The ECCS is designed, periodically inspected, and procedurally managed to assure that gas accumulation in ECCS piping will not impact the ECCS safety-related functions, as required by Generic Letter 2008-01, January 2008.

6.3.1.36 IE Bulletin 79-06A (Position 8), April 1979 – Review of Operational Errors and System Misalignments Identified During the Three Mile Island Incident

Position (8) (subsequently NUREG-0737, November 1980, Item II.K.1.5, Safety Related Valve Position):

ECCS PG&E Design Class I valve positions, positioning requirements, and positive controls have been assured such that the valves remain positioned (open or closed) in a manner to ensure the proper operation of the ESF to satisfy Position (8) of IE Bulletin 79-06A, April 1979.

6.3.1.37 IE Bulletin 80-18, July 1980 – Maintenance of Adequate Minimum Flow Thru Centrifugal Charging Pumps Following Secondary Side High Energy Line Rupture

The availability of adequate ECCS CCP minimum flow has been ensured under all conditions in order to protect the pumps during the possible deadheading conditions described in IE Bulletin 80-18, July 1980.

6.3.1.38 NRC Bulletin 88-04, May 1988 – Potential Safety-Related Pump Loss

The ECCS is designed such that PG&E Design Class I pumps that share a common minimum flow recirculation line will not be susceptible to the pump-to-pump interaction described in NRC Bulletin 88-04, May 1988.

6.3.1.39 NRC Bulletin 88-08, June 1988 – Thermal Stresses in Piping Connected to Reactor Coolant Systems

Unisolable ECCS piping sections connected to the RCS, which have the potential to be subjected to unacceptable thermal stresses due to temperature stratifications induced by leaking valves, have been identified. Means have been provided to ensure that the pressure upstream from block valves, which might leak, is monitored and controlled.

6.3.1.40 NRC Bulletin 2003-01, June 2003 – Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized-Water Reactors

Modifications have been implemented to prevent potential blockage of drainage paths to the containment recirculation sump due to post-accident debris.

6.3.1.41 Branch Technical Position EICSB 18, November 1975 – Application of the Single Failure Criterion to Manually-Controlled Electrically-Operated Valves

Certain ECCS manually-controlled, electrically-operated valves have their electric power removed during normal operation to satisfy the single failure criterion, as discussed in Branch Technical Position EICSB 18, November 1975. Continuous, redundant position indication for these valves is provided in the control room.

6.3.2 System Description

The ECCS is designed to cool the reactor core as well as to provide additional shutdown capability following initiation of the following accident conditions:

(1) A pipe break or spurious valve lifting in the reactor coolant system (RCS) that causes a discharge larger than that which can be made up by the normal makeup system, up to and including the circumferential rupture of the largest pipe in the RCS (refer to Sections 15.3.1 and 15.4.1 for a discussion of these accidents.)

(2) Rupture of a control rod drive mechanism (CRDM) causing a rod cluster control assembly (RCCA) ejection accident (refer to Section 15.4.6)

(3) A pipe break or spurious valve lifting in the steam system, up to and including the instantaneous circumferential rupture of the largest pipe in the steam system (refer to Sections 15.2.14, 15.3.2, and 15.4.2)

(4) A steam generator tube rupture (SGTR) (refer to Section 15.4.3)

6.3.2.1 Range of Coolant Ruptures and Leaks

Sections 15.3.1 and 15.4.1 provide discussion on the ranges of coolant ruptures and leaks evaluated for ECCS performance.

6.3.2.2 Fission Product Decay Heat

The primary function of the ECCS following a LOCA is to remove the stored and fission product decay heat from the reactor core to prevent fuel rod damage to the extent that such damage may impair effective core cooling. The acceptance criteria for the accidents, as well as their analyses, are provided in Sections 15.3.1 and 15.4.1.

6.3.2.3 Reactivity Required for Cold Shutdown

The ECCS provides shutdown capability for the accidents listed in Section 6.3.2 by means of shutdown chemical (boron) injection. The most critical accident for shutdown capability is the main steam line break (MSLB) and for this accident the ECCS meets the criteria defined in Sections 15.3.2 and 15.4.2.

6.3.2.4 Equipment and Component Descriptions

The major components of the ECCS are described in the following sections. Pertinent design and operating parameters for ECCS components are given in Table 6.3-1.

6.3.2.4.1 Accumulators

The accumulators are pressure vessels partially filled with borated water and pressurized with nitrogen gas. During normal operation each accumulator is isolated from the RCS by two check valves in series. Should the RCS pressure fall below the accumulator pressure (refer to Table 6.3-1), the check valves open and borated water is forced into the RCS. One accumulator is attached to each of the cold legs of the RCS. Mechanical operation of the swing-disk check valves is the only action required to open the injection path from the accumulators to the core via the cold leg. Sections 6.3.3.4.5.1 and 6.3.3.5.5 describe the accumulator MOVs and their position indicators.

Connections are provided to remotely adjust the level and boron concentration of the borated water in each accumulator during normal plant operation, as required. Accumulator water level may be adjusted either by draining to the reactor coolant drain tank and then to the liquid holdup tank (LHUT), or by pumping borated water from the RWST to the accumulator. Samples of the solution in the accumulators are taken periodically to check boron concentration.

Accumulator pressure is provided by a supply of nitrogen gas and can be adjusted as required during normal plant operation. The accumulators are, however, normally isolated from this nitrogen supply. Gas relief valves on the accumulators protect them from pressures in excess of design pressure.

The accumulators are located within the containment but outside of the secondary shield wall, which protects them from missiles. Since the accumulators are located within the containment, a release of the nitrogen gas from the accumulators would cause an increase in normal containment pressure. Containment pressure increase following release of the gas from all accumulators has been calculated and is well below the containment pressure setpoint for ECCS actuation.

Release of accumulator gas is detected by the accumulator pressure indicators and alarms. Thus, the operator can take action promptly as required to maintain plant operation within the requirements of the Technical Specification (Reference 10) covering accumulator operability.

6.3.2.4.2 Refueling Water Storage Tank

The content of the RWST is normally used to supply borated water to the refueling canal for refueling operations. In addition to its usual service, this tank provides borated water to the ECCS pumps and the containment spray system (CSS) pumps following a LOCA or MSLB. For RWST volume requirements, refer to Section 6.3.2.11 and Table 6.3-1. For ECCS operation requirements following a LOCA or MSLB, refer to Section 6.3.3.6.1.1.

During normal operation, the RWST is aligned to the suction of the SI pumps, RHR pumps, and CSS pumps. The suction of CCP1 and CCP2 is automatically aligned to the tank by the safety injection signal ("S" signal).

The water in this tank is borated to a minimum concentration of 2300 ppm boron that ensures reactor shutdown by at least 5 percent $\Delta k/k$ when all RCCAs are inserted with the most reactive RCCA completely removed from its fuel assembly, and when the reactor is cooled down for refueling.

The RWST is vented directly to the atmosphere.

6.3.2.4.3 Pumps

6.3.2.4.3.1 Residual Heat Removal Pumps

The RHR pumps are provided to deliver water from the RWST to the RCS should the RCS pressure fall below their shutoff head during the injection phase. The pumps are automatically started upon receipt of the "S" signal. Each RHR pump is a single-stage, vertical, centrifugal pump. It has an integral motor-pump shaft, driven by an induction motor, and is powered by the Class 1E 4.16-kV system. The unit has a self-contained mechanical seal, which is cooled by component cooling water (CCW).

During the injection mode of ECCS operation, the RHR pumps draw water from the RWST; during the recirculation mode, they draw water from the containment

recirculation sump. The changeover from the injection mode to recirculation mode (refer to Section 6.3.3.6.1.1.2 and Table 6.3-5) is initiated by low level in the RWST, which results in an automatic trip of the RHR pumps. The operator then manually changes system alignment to the recirculation mode after water is available in the containment recirculation sump and before water is exhausted from the RWST. Adequate NPSH is always available to the RHR pumps in both the injection phase and the recirculation phase. Table 6.3-11 lists available and required NPSH. Phase I of the preoperational system test (refer to Section 6.3.3.26.1.1) verified that the RHR pump performance was satisfactory for all required alignments.

A minimum flow recirculation line is provided for the pumps to recirculate fluid through the RHR heat exchangers and return the cooled fluid to the pump suction should these pumps be started with their normal flowpaths blocked. Once flow to the RCS is established, the recirculation line is automatically closed. This line prevents deadheading the pumps and permits pump testing during normal operation. The RHR pumps are also discussed in Section 5.5.6.

6.3.2.4.3.2 Centrifugal Charging Pumps (CCP1 and CCP2)

When aligned for safety injection operation, CCP1 and CCP2 deliver water from the RWST to the RCS at the prevailing RCS pressure. The pumps are automatically started upon receipt of the "S" signal. CCP1 and CCP2 are multistage, diffuser design, barrel-type casing pumps with vertical suction and discharge nozzles.

The pump is driven by an induction motor, powered by the Class 1E 4.16-kV system. The unit has a self-contained lubrication system cooled by CCW and a mechanical seal system that requires no external cooling.

A minimum flow bypass line is provided on each pump discharge to recirculate flow to the pump suction after cooling in the seal water heat exchanger during normal operation. Valves in minimum flow bypass lines are closed by the operator when the ECCS is transferred to the recirculation mode of operation following a LOCA. During normal plant operation, CCP1 or CCP2 may be in use. CCP1 and CCP2 may be tested during normal operation through the use of the minimum flow bypass line.

6.3.2.4.3.3 Safety Injection Pumps

SI pumps deliver water from the RWST to the RCS after the RCS pressure is reduced below the shutoff head of the pumps. The pumps are automatically started upon receipt of the "S" signal. Each SI pump is a multistage, centrifugal pump. The pump is driven directly by an induction motor, powered by the Class 1E 4.16-kV system. The unit has a self-contained lubrication system and a mechanical seal system that are cooled by CCW.

A minimum flow bypass line is provided on each pump discharge to recirculate flow to the RWST in the event the pumps are started with the normal flowpaths blocked. This

line also permits pump testing during normal operation. Two MOVs in series are provided in this line. These valves are closed by operator action during the switchover to the ECCS recirculation mode.

6.3.2.4.4 Residual Heat Removal Heat Exchangers

The RHR heat exchangers are conventional shell- and U-tube-type units. During normal cooldown of the primary system, reactor coolant flows through the tube side while CCW flows through the shell side. During the emergency core cooling recirculation phase, water, from the containment recirculation sump, flows through the tube side. Further discussion of the RHR heat exchangers is found in Section 5.5.6. Design characteristics are included in Table 5.5-10.

6.3.2.4.5 Valves

Stroke times for MOVs used in the ECCS are given in Table 6.3-1. This table also lists the leakage specification for the various types of valves used in the ECCS. Setpoints and capacities for relief valves are given in Table 6.3-10.

Design features employed to minimize valve leakage include the following:

(1) Globe valves, which during post-accident recirculation are normally closed, are installed with the recirculated fluid pressure under the seat to prevent stem leakage of recirculated (radioactive) water.

(2) Relief valves are enclosed; i.e., they are provided with a closed bonnet and discharge to a closed system.

(3) Control and motor-operated valves (2-1/2 inches and above) in the RHR portion of the ECCS recirculation loop outside containment have double-packed stuffing boxes and stem leakoff connections to the equipment drain system. Valves in the other portions of the ECCS recirculation loop outside containment have their leakoff connections capped.

6.3.2.4.5.1 Motor-Operated Gate Valves

The seating design of all motor-operated gate valves is of either the parallel-disk design or the flexible wedge design. The seating surfaces are hard-faced to prevent galling and reduce wear.

Where a gasket is employed for the body-to-bonnet joint, it is either a fully trapped, controlled compression, spiral-wound gasket with provisions for seal welding, or of the pressure-seal design. The valve stuffing boxes are designed with a lantern ring leakoff connection with a minimum of a full set of packing below the lantern ring and a minimum

of one-half of a set of packing above the lantern ring for valves that have leakoff connections piped to an equipment drain system.

The motor operator incorporates a "hammer blow" feature that allows the motor to attain its full speed prior to being placed under load. MOVs are further discussed in Sections 6.3.3.29 and 6.3.3.30.

6.3.2.4.5.2 Accumulator Check Valves (Swing-Disk)

The accumulator check valves are designed with a low pressure drop configuration with all operating parts contained within the body.

Design considerations and analyses that ensure that leakage across the check valves located in each accumulator injection line will not impair accumulator availability are as follows:

(1) During normal operation the check valves are in the closed position with a nominal differential pressure across the disk of approximately 1650 psi. Since the valves remain in this position except for testing or when called upon to function, and are therefore not subject to abuse of flowing operation or impact loads caused by sudden flow reversal and seating, they do not experience significant wear of the moving parts and are expected to function with minimal leakage.

(2) When the RCS is being pressurized during the normal plant heatup operation, the check valves are tested for leakage as soon as there is a stable differential pressure of about 100 psi or more across the valve. This test confirms the seating of the disk and whether or not there has been an increase in the leakage since the last test. When this test is completed, the discharge line motor-operated isolation valves are opened and the RCS pressure increase is continued. There should be no increase in leakage from this point on since increasing reactor coolant pressure increases the seating force and decreases the probability of leakage.

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(3) The experience derived from the check valves employed in the emergency injection systems indicates that the system is reliable and workable. This is substantiated by the satisfactory experience obtained from operation of the Ginna and subsequent plants where the usage of check valves is identical to this application.

(4) The accumulators can accept some inleakage from the RCS without affecting availability. Inleakage would require, however, that the

accumulator water volume be adjusted in accordance with Technical Specification (Reference 10) requirements.

6.3.2.4.5.3 Relief Valves

Relief valves are installed in various sections of the ECCS to protect the system from overpressure. Valves that normally see liquid service have their stem and spring adjustment assemblies isolated from the system fluid by a bellows seal between the valve disk and spindle. The closed bonnet provides an additional barrier for enclosure of the relief valves. Table 6.3-10 lists the system relief valves with their capacities and setpoints. The accumulator relief valves are sized to pass nitrogen gas at a rate in excess of the accumulator gas fill line delivery rate. The relief valves will also pass water in excess of the maximum water fill rate, but this is not considered important, because the time required to fill the gas space gives the operator ample opportunity to correct the situation.

6.3.2.4.5.4 Ball Valves

Each main RHR line has an air-operated ball valve, which is normally open and is designed to fail in the open position, thus maximizing flow from this system to the RCS during ECCS operation. These ball valves at the discharge of each RHR system heat exchanger along with the ball valve in the RHR system heat exchanger bypass line are adjusted during RHR system operation to meet the design plant cooldown requirements.

6.3.2.4.6 Piping

All piping joints are either welded, flanged, or threaded connections.

Weld connections for pipes sized 2-1/2 inches and larger are butt-welded.
Minimum piping and fitting wall thickness, as determined by ANSI B31.7-1969 with 1970 Addenda Code formula, are increased to account for the material specifications permissible tolerance on the nominal wall and an appropriate allowance for wall thinning on the external radius during any pipe bending operations in the shop fabrication of the subassemblies.

6.3.2.4.7 Heat Tracing

With the lowering of the normal boric acid solution from 12 to 4 percent, for Cycle 5 and later, the heat tracing on piping, valves, flanges, and instrumentation lines carrying boric acid solution were downgraded to PG&E Design Class II. Refer to Section 9.3.4.2.9.30 for further discussion.

6.3.2.4.8 Containment Recirculation Sump and Strainer

The containment recirculation sump and strainer is a large collecting reservoir designed to provide an adequate supply of water with a minimum amount of particulate matter to the SI system, CCP1 and CCP2, the RHR system, and the CSS, if recirculation spray is used, during the recirculation mode of ECCS operation following a postulated LOCA.

The sump is located in the annulus area of the containment between the crane wall and the containment liner at the 91 foot elevation. It is approximately 50 feet from RCS piping and components that could become sources of debris. The two 14-inch suction pipes are located on opposite sides of the sump for ECCS train separation. In the sump, there is a strainer assembly, which includes a trash rack with integral debris curb and two strainers (front and rear). Each strainer is designed with 3/32-inch nominal diameter openings, which are sized for the smallest credible restriction in the ECCS flowpath. Each strainer has a plenum. These plenums come together above the two 14-inch RHR pump suction lines and both plenums feed both RHR lines. The lower or rear plenum assembly is water tight to allow collection of any potential back leakage from the RHR system.

The strainer assemblies are designed to minimize blockage. The design provides enough screen area to ensure, with maximum accident debris loads and RHR flowrates, the RHR system has sufficient NPSH margin. Since both plenums feed both RHR trains, without complete blockage of both strainer assemblies, there is no condition that would cause both RHR trains to fail.

The physical arrangement of the strainer for DCPP Unit 1 is shown in Figure 6.3-6 and the DCPP Unit 2 arrangement is shown in Figure 6.3-7.

Any debris or other matter that passes into the sump through the 3/32-inch maximum hole size allowed for the strainers will pass through the SI system, CCP1 and CCP2, the RHR system, and the CSS, if recirculation spray is used, without restriction and eventually will be pumped back into the containment. This is based on the maximum nominal-sized debris (i.e., the evaluation is based on a 1/8 inch diameter, therefore conservative using a 3/32 inch diameter) that could potentially pass through the sump strainers and pass through the ECCS throttle valves.

<u>Safety Injection System Flow Path</u>

Fluid from the containment recirculation strainer passes into the 14 inch RHR pump suction piping. The flow passes through the RHR pumps and heat exchangers. The flowpath continues from the exit of the RHR heat exchanger to the suction of the SI pumps. The SI pumps discharge to either the cold or hot legs of the RCS loops. The flowpath continues through the RCS cold or hot legs into the core, through the reactor vessel, into the ruptured RCS loop, through the rupture into the containment and, finally, ends in the containment recirculation sump.

Centrifugal Charging Pump System (CCP1 and CCP2) Flow Path

Fluid from the containment recirculation strainer passes into the 14 inch RHR pump suction piping. The flow passes through the RHR pumps and heat exchangers. The flowpath continues from the exit of the RHR heat exchangers to the suction of CCP1 and CCP2. From these CCPs, it goes through the charging injection to the cold legs of the RCS loops. The flowpath continues through the 27-1/2 inch piping of the RCS cold legs, into the core, through the reactor vessel, into the ruptured RCS loop, through the rupture into the containment and, finally, into the containment recirculation sump. CCP3, which replaced the positive displacement pump, is not credited as part of the centrifugal charging pump system (CCP1 and CCP2) described within this section and Chapter 15.

Residual Heat Removal System Flow Path

Fluid from the containment recirculation strainer passes into the 14 inch RHR pump suction piping. The flow passes through the RHR pumps and heat exchangers. The flowpath continues from the exit of the RHR heat exchangers to either the cold or hot legs of the RCS loops. The flowpath continues through the cold legs or hot legs of the RCS loop piping, into the core, through the reactor vessel, into the ruptured RCS loop, through the rupture into the containment and, finally, into the containment recirculation sump. During normal plant operation, when the RCS is hot and pressurized, there is no direct connection between the RWST and the RCS. Also during normal plant shutdown, when the RCS is being cooled down and the RHR system begins to operate, the RHR system is isolated from the RWST by an MOV in addition to a check valve.

Containment Spray System Flow Path

Fluid from the containment recirculation strainer passes into the 14 inch RHR pump suction piping. The flow passes through the RHR pumps and heat exchangers. The flowpath continues from the exit of the RHR heat exchangers to the spray headers and out of the 3/8 inch spray nozzles into the containment. Finally, fluid in the containment drains into the containment recirculation sump. The CSS is discussed in Section 6.2.2.

6.3.2.4.8.1 Sump Strainer Submergence During an SBLOCA

Since SBLOCA scenarios may result in a partially-submerged strainer, a set of flow straighteners were added to the strainer system to reduce the tendency to vortex and to eliminate air entrainment as a concern. The performance of the DCPP strainers at water levels representative of a SBLOCA will not result in conditions which would entrain excessive amounts of air into the suctions of the RHR pumps.

6.3.2.5 Motor-Operated Valves and Controls

Each containment recirculation sump isolation valve is interlocked with its respective pump suction/RWST isolation valve to the RHR system. The interlock is provided with redundant signals from each isolation valve. This interlock prevents opening the sump isolation valve when the RWST isolation valves are open and thus prevents dumping the RWST contents into the containment recirculation sump.

To preclude spurious movement of specific MOVs that could result in a loss of ECCS function, electric power is removed from certain valves during normal operation. These valves are listed in Table 6.3-12 and further discussion is provided in Section 6.3.3.41.

6.3.2.6 Schematic Piping and Instrumentation Diagrams

Piping schematic diagrams of the ECCS are shown in Figures 3.2-8, 3.2-9, and 3.2-10.

6.3.2.7 ECCS Flow Diagrams

Alignment of the major ECCS components during the injection and recirculation phases is shown in Figures 6.3-4 and 6.3-5, respectively. Tables 15.3-2 and 15.3-3 summarize the calculated times at which the major components perform their safety-related functions for various accident conditions (tabulated in Table 15.1-2) that require ECCS operations.

6.3.2.8 Applicable Codes and Classifications

The codes and standards to which the individual ECCS components are designed are listed in Table 6.3-2.

6.3.2.9 Materials

Table 6.3-3 lists the materials used in ECCS components.

6.3.2.9.1 Material Specifications and Compatibility

Materials employed for ECCS components are given in Table 6.3-3. Materials are selected to meet the applicable material code requirements of Table 6.3-2 and the following additional requirements:

(1) All parts of components in contact with borated water are fabricated of or clad with austenitic stainless steel or similar corrosion-resistant material.

(2) All parts of components in contact (internal) with sump solution during recirculation are fabricated of austenitic stainless steel or similar corrosion resistant material.

(3) Valve seating surfaces are hard-faced with Stellite No. 6 or similar to prevent galling and to reduce wear.

(4) Valve stem materials were selected for their corrosion resistance, high tensile properties, and resistance to surface scoring by the packing.

The elevated temperature of the sump solution during recirculation is well within the design temperature of all ECCS components. In addition, consideration has been given to the potential for corrosion of various types of metals exposed to the fluid conditions prevalent immediately after the accident or during long-term recirculation operations.

Environmental testing of ECCS equipment inside the containment, which is required to operate following a LOCA, is discussed in Section 3.11. The results of the test program indicate that the equipment will operate satisfactorily during and following exposure to the combined containment post-accident environmental temperature, pressure, chemistry, and radiation.

6.3.2.10 Design Pressures and Temperatures

The component design pressure and temperature conditions as given in Table 6.3-1 are specified as the most severe conditions to which each component is exposed to during either normal plant operation or during ECCS operation.

6.3.2.11 Coolant Quantity

The quantities and minimum boron concentration of coolant available to the ECCS are summarized in Table 6.3-1.

The minimum volume that will be maintained in the RWST is 455,300 gallons (this includes the usable and unusable volume). In the event of a LOCA, this volume also provides a sufficient amount of borated water to meet the following requirements:

(1) Provide adequate coolant during the injection phase to meet ECCS design objectives (refer to Sections 15.3 and 15.4).

(2) Increase the boron concentration of reactor coolant and recirculation water to a point that ensures no return to criticality with the reactor at cold shutdown and all control rods, except the most reactive RCCA, inserted into the core (refer to Sections 15.3.1 and 15.4.1).

(3) Fill the containment recirculation sump to support continued operation of the ECCS pumps at the time of transfer from the injection mode to the recirculation mode of cooling. The sump strainer assemblies are required to be fully submerged to prevent vortexing and air ingestion, during changeover from the injection mode to the recirculation mode, for a large-break loss-of-coolant accident (LBLOCA) (Reference 16). Refer to

Section 6.3.2.4.8.1 for discussion on partial submergence of the strainer assemblies during an SBLOCA.

(4) Fulfill spray requirements (refer to Section 6.2.2).

6.3.2.12 Accumulator Availability

Accumulator availability requirements during power operation, hot standby, and startup conditions are detailed in the Technical Specifications (Reference 10).

6.3.2.13 Dependence on Other Systems

Other systems that operate in conjunction with the ECCS are as follows:

(1) The CCW system (refer to Section 9.2.2) cools the RHR heat exchangers during the recirculation mode of operation. It also supplies cooling water to CCP1 and CCP2, the SI pumps, and the RHR pumps during the injection and recirculation modes of operation.

(2) The auxiliary salt water (ASW) system (refer to Section 9.2.1) provides cooling water to the CCW heat exchangers.

(3) The Preferred Power Supply (230-kV and 500-kV), Onsite Distribution System (120-Vac, 480-V, and 4.16-kV), and Standby Power Supply provide normal and emergency power sources for the ECCS (refer to Sections 8.2, and 8.3.1.1.3 through 8.3.1.1.6).

(4) The engineered safety features actuation system (ESFAS) (refer to Section 7.3) generates the initiation signal for emergency core cooling.

(5) The auxiliary feedwater (AFW) system (refer to Section 6.5) supplies feedwater to the steam generators.

(6) The auxiliary building ventilation system (ABVS) (refer to Section 9.4.2) removes heat from the pump compartments and provides for radioactivity contamination control should some leakage occur in a compartment.

6.3.2.14 Lag Times

The sequence and time-delays for actuation of ECCS components for the injection and recirculation phases of emergency core cooling are given in Table 6.3-7. Alignment of the major ECCS components during the injection and recirculation phases is shown in Figures 6.3-4 and 6.3-5, respectively. Tables 15.3-2 and 15.3-3 summarize the calculated times at which the major components perform the safety-related functions for those various accident conditions (tabulated in Table 15.1-2) that require the ECCS.

The minimum active components will be capable of delivering full rated flow within a specified time interval after process parameters reach the setpoints for the "S" signal. Response of the system is automatic with appropriate allowances for delays in actuation of circuitry and active components. The active portions of the system are actuated by the "S" signal. In analyses of system performance, delays in reaching the programmed trip points and in actuation of components are established on the basis that only Standby Power Supply is available. The starting sequence following a loss of offsite power is discussed in detail in Chapter 8.

The ECCS is operational after an elapsed time not greater than 25 seconds, including the time to bring the RHR pumps up to full speed.

The starting times for components of the ECCS are consistent with the delay times used in the LOCA analyses for large and small breaks.

In the LOCA analysis presented in Sections 15.3 and 15.4, no credit is assumed for partial flow prior to the establishment of full flow and no credit is assumed for the availability of the Preferred Power Supply.

For smaller LOCAs, there is some additional delay before the process variables reach their respective programmed trip setpoints since this is a function of the severity of the transient imposed by the accident. This is allowed for in the analyses of the range of LOCAs (refer to Tables 15.3-1, 15.4.1-1A, and 15.4.1-1B).

Accumulator injection occurs immediately when RCS pressure has decreased below the operating pressure of the accumulator.

6.3.3 Safety Evaluation

6.3.3.1 General Design Criterion 2, 1967 – Performance Standards

With the exception of the RWST, all ECCS components are housed within the PG&E Design Class I auxiliary and containment buildings. These buildings, or applicable portions thereof, are designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), earthquakes (refer to Section 3.7), and other natural phenomena, to protect ECCS SSCs, ensuring their safety-related design functions will be performed.

The RWST, as discussed in Section 3.8, is a PG&E Design Class I outdoor water storage tank which is designed to withstand the effects of floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), earthquakes (refer to Section 3.7), and other natural phenomena. The ability of the RWST to withstand the effects of winds and tornadoes is addressed in Section 3.3. The loss of the RWST, which is not contained within a building and is exposed directly to potential wind and tornado loads, has been evaluated. Loss of this equipment does not compromise the capability of shutting down the plant safely (refer to Section 3.3.2.3). Leakage from the refueling water storage tanks due to tornado or missile-induced damage will not result in the

flooding of PG&E Design Class I equipment in the auxiliary building since essentially watertight cover plates are installed over the pipe entranceway from each tank into the auxiliary building. The water will drain away from the building via the plant yard drainage system.

The ECCS is designed to perform its function of ensuring core cooling and providing shutdown capability following an accident under simultaneous DDE or HE loading. The seismic requirements are defined in Sections 3.7 and 3.10, and the provisions to protect the system from seismic damage are discussed in Sections 3.7, 3.9, and 3.10. ECCS components are designed to withstand the appropriate seismic loadings in accordance with PG&E Design Class I criteria.

6.3.3.2 General Design Criterion 3, 1971 – Fire Protection

The ECCS is designed to the fire protection guidelines of Branch Technical Position APCSB 9.5.1 (refer to Appendix 9.5B, Table B-1).

As described in Appendix 9.5B, Table B-1, no fire hazards exist that could adversely affect the availability of the RWST. No combustible materials are stored in proximity to the RWST, and hose stations and fire hydrants from the yard main provide fire suppression capability, if required.

6.3.3.3 General Design Criterion 11, 1967 – Control Room

No manual actions are required from the operator during the injection phase of ECCS operation. Those manual actions from the control room required for changeover from the injection phase to the recirculation phase are described in Section 6.3.3.6.1.1.2 and in Table 6.3-5.

Instrumentation, alarms, and controls are provided in the control room for operators to monitor and maintain ECCS parameters. Instrumentation and alarms for the ECCS is further discussed in Section 6.3.3.4.

6.3.3.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Varied instrumentation is available to assist the operator in assessing post-accident conditions. This instrumentation is listed below.

Instrumentation and associated analog and logic channels used to initiate ECCS operation are discussed in Section 7.3. This section describes the instrumentation employed to monitor ECCS components during normal plant operation and ECCS post-accident operation. All alarms are annunciated in the control room.

6.3.3.4.1 Temperature Indication

6.3.3.4.1.1 Residual Heat Exchanger Outlet Temperature

The fluid temperature at the outlet of each RHR heat exchanger is recorded in the control room.

6.3.3.4.1.2 ECCS Pump-motor Temperatures

Temperature indicators are provided to monitor RHR pump, CCP1 and CCP2, and SI pump motor/motor bearing temperatures. High temperatures activate alarms in the control room.

6.3.3.4.1.3 Containment Recirculation Sump Water Temperature

The fluid temperature of the containment recirculation sump water is provided on the post-accident monitoring panel, PAM1.

6.3.3.4.2 Pressure Indication

6.3.3.4.2.1 Charging Injection Line Pressure

The charging injection line pressure (PT-947 between valves 8801A & 8801B and 8803A & 8803B) shows that the CCPs are operating. The transmitters are outside the containment, with indicators on the control board.

6.3.3.4.2.2 Safety Injection Header Pressure

SI pump discharge pressure for each pump shows that the SI pumps are operating. The transmitters are outside the containment, with indicators on the control board.

6.3.3.4.2.3 Accumulator Pressure

Duplicate pressure channels are installed on each accumulator. Pressure indication in the control room and high- and low-pressure alarms are provided by each channel.

6.3.3.4.2.4 Residual Heat Removal Pump Discharge Pressure

RHR pump discharge pressure for each pump is indicated in the control room. A high-pressure alarm is actuated by each channel.

6.3.3.4.3 Flow Indication

6.3.3.4.3.1 CCP1 and CCP2 Injection Flow

Injection flow through the common header to the reactor cold legs is indicated in the control room.

6.3.3.4.3.2 Safety Injection Pump Header Flow

Flow through the SI pump headers is indicated in the control room.

6.3.3.4.3.3 Residual Heat Removal Pump Injection Flow

Flow through each RHR injection and recirculation header leading to the reactor cold or hot legs is indicated in the control room.

6.3.3.4.3.4 Test Line Flow

Local indication of the leakage test line flow is provided to check for proper seating of the accumulator check valves between the injection lines and the RCS.

6.3.3.4.3.5 Safety Injection Pump Minimum Flow

A local flow indicator is installed in the SI pump minimum flow line.

6.3.3.4.3.6 Residual Heat Removal Pump Minimum Flow

A flowmeter installed in each RHR pump discharge header provides control for the valve located in the pump minimum flow line.

6.3.3.4.4 Level Indication

6.3.3.4.4.1 Refueling Water Storage Tank Level

Three water level instrumentation channels are provided for the RWST. Each channel provides independent indication on the main control board, thus satisfying the requirements of paragraph 4.20 of IEEE 279-1971 (Reference 12). Two-out-of-three logic is provided for RHR pump trip and low-level alarm initiation. One channel provides low-low water level alarm initiation. One channel also provides a high water level alarm.

6.3.3.4.4.2 Accumulator Water Level

Duplicate water level channels are provided for each accumulator. Both channels provide indication in the control room and actuate high- and low-water level alarms.

6.3.3.4.4.3 Containment Recirculation Sump Water Level

Two redundant containment wide-range water level channels are provided to measure level from the bottom of the reactor cavity. Wide-range recorders are located on the post-accident monitoring panel.

Two redundant narrow-range instruments measure level from the bottom of the containment recirculation sump. The containment recirculation sump level instrumentation consists of two level sensor elements, junction boxes, and connection sleeves designed to operate in a post-accident environment inside containment. The junction boxes and connection sleeves are located above any possible flooding level. Level transmitters are located outside of containment and are not required to be environmentally qualified as they are not required for a postulated line break outside of containment. Narrow-range indicators are located on the main control board. The containment recirculation sump level instrumentation is described in more detail in Section 7.5.

6.3.3.4.5 Valve Position Indication

Valve positions that are indicated on the control board are done so by a "normal off" system; i.e., should the valve not be in its proper position, a bright white light will give a highly visible indication to the operator. This indication is only active upon receipt of an "S" signal for those ECCS-related valves that are required to automatically change position to align CCP1 and CCP2 for injection, as described in Section 6.3.3.6.1.1.1.

6.3.3.4.5.1 Accumulator Isolation Valve Position Indication

The accumulator MOVs are provided with red (open) and green (closed) position indicating lights located at the control switch for each valve. These lights are energized from the Class 1E 120-Vac Instrument Power Supply System and actuated by the associated valve motor operator limit switches.

A monitor light that is on when the valve is not fully open is provided in an array of monitor lights that are all off when their respective valves are in proper position enabling safety features operation. This light is energized from a separate Class 1E 120-Vac circuit and actuated by a valve motor-operated limit switch.

An alarm annunciator point is activated by a valve motor operator limit switch or a stem travel limit switch whenever an accumulator valve is not fully open with the system at pressure (the pressure at which the safety injection block is unblocked). The alarm is reinstated once an hour. A separate annunciator point is used for each accumulator valve.

6.3.3.4.6 Subcooling Meter

Each subcooling meter provides continuous digital-type display of either the temperature or pressure subcooling margin. The displays are a subset of the reactor vessel level instrumentation system (RVLIS) and are located on PAM panels, PAM3 and PAM4, with low and low-low alarms being provided. A digital display of the temperature margin is fed from train B and is available on the main control board. A recorder fed from train A is located on PAM1. The subcooling meter displays, calculators, and inputs are described in Sections 5.6 and 7.5.

6.3.3.5 General Design Criterion 21, 1967 – Single Failure Definition

To ensure that the ECCS will perform its intended function if any of the accidents listed in Section 6.3.2 occurs, it is designed to tolerate a single active failure during the short-term immediately following an accident, or to tolerate a single active or passive failure during the long-term following an accident. This subject is detailed in Section 3.1 and the following subsections.

6.3.3.5.1 Definition of Terms

Definitions of terms used in this section are located in Section 3.1.1.1.

6.3.3.5.2 Active Failure Criteria

The ECCS is designed to accept a single failure following the incident without loss of its protective function. The system design will tolerate the failure of any single active component in the ECCS itself or in the necessary associated service systems at any time during the period of required system operations following the incident.

A single active failure analysis is presented in Table 6.3-13, and demonstrates that the ECCS can sustain the failure of any single active component in either the short- or long-term and still meet the level of performance for core cooling.

Since the operation of the active components of the ECCS following an MSLB is identical to that following a LOCA, the same analysis is applicable and the ECCS can sustain the failure of any single active component and still meet the level of performance for the addition of shutdown reactivity.

6.3.3.5.3 Passive Failure Criteria

The following philosophy provides for necessary redundancy in component and system arrangement to meet the single failure criterion, as it specifically applies to failure of passive components in the ECCS. Thus, for the long-term, the system design is based on accepting either a passive or an active failure.

6.3.3.5.3.1 Redundancy of Flow Paths and Components for Long-Term Emergency Core Cooling

In the design of the ECCS, Westinghouse utilizes the following criteria:

(1) During the long-term cooling period following a loss of coolant, the emergency core cooling flow paths are separable into two subsystems, either of which can provide minimum core cooling functions and return spilled water from the floor of the containment back to the RCS.

(2) Either of the two subsystems can be isolated and removed for service in the event of a leak outside the containment.

(3) Adequate redundancy of check valves is provided to tolerate failure of a check valve during the long-term as a passive component.

(4) Should one of these two subsystems be isolated in this long-term period, the other subsystem remains operable.

(5) Provisions are also made in the design to detect leakage from components outside the containment and collect this leakage.

Thus, for the long-term emergency core cooling function, adequate core cooling capacity exists with one flow path removed from service whether isolated due to a leak, because of blocking of one flow path, or because failure in the containment results in a spill of the delivery of one subsystem.

6.3.3.5.3.2 Subsequent Leakage from Components in Engineered Safety Systems

With respect to piping and mechanical equipment outside the containment, considering the provisions for visual inspection and leak detection, leaks will be detected before they propagate to major proportions. A review of the equipment in the system indicates that the largest sudden leak potential would be the sudden failure of a pump shaft seal. Evaluation of leak rate assuming only the presence of a seal retention ring around the pump shaft showed flows less than 50 gpm would result. Piping leaks, valve packing leaks, or flange gasket leaks have been of a nature to build up slowly with time and are considered less severe than the pump seal failure.

Larger leaks in the ECCS are prevented by the following:

(1) The system piping is located within a controlled area on the plant site.

(2) The piping system receives periodic pressure tests and is accessible for periodic visual inspection (refer to Sections 6.3.3.23 and 6.3.3.24).

(3) The piping is austenitic stainless steel that, due to its ductility, can withstand severe distortion without failure.

Based on this review, the design of the auxiliary building and related equipment is based on handling of leaks up to a maximum of 50 gpm. Means are also provided to detect and isolate such leaks in the emergency core cooling flow path within 30 minutes.

With these design ground rules, continued function of the ECCS will meet minimum core cooling requirements, and offsite doses resulting from the leak will be within 10 CFR 100.11 limits. Refer to Section 15.5 for discussion of radiological consequences of plant accidents.

A single passive failure analysis is presented in Table 6.3-14. It demonstrates that the ECCS can sustain a single passive failure during the long-term phase and still retain an intact flow path to the core to supply sufficient flow to maintain the core covered and effect the removal of decay heat. The procedure followed to establish the alternate flow path also isolates the component that failed.

6.3.3.5.4 Single Failures in Electrical and Control Circuitry

ESF systems, including the ECCS, are designed to tolerate single failures in the electrical and control circuitry as defined below. Each ECCS train is supplied from separate Class 1E power sources. In addition, provisions are made in construction, layout, and installation that minimize the occurrence of electrical faults.

Single failures of switching components that are considered in the design include (a) a single instance of contact failure, (b) a loss of control power, or (c) mechanical failure resulting in the sticking of a component in any position. Faults that require a particular time sequence of abnormal connections or that involve selective combinations of multiple contact closures are considered to involve more than one failure, and hence to be incredible. Examples of a single wiring failure considered in design include the single short and open circuit faults. Single short circuits considered are (a) a single conductor shorted to ground or to a structure such as a cable tray, or (b) two conductors in the same cable shorted together. Faults that require several particular wires to be connected, or which require sustained application of power through a short circuit, are not considered to be credible. Open circuit faults considered include (a) a single conductor breaking, (b) a single connector being disconnected, or (c) a single field-run cable severed.

The random shorting to the manual closing switch contacts or a hot short in the cable run to the closing coil have been identified as control system failure modes that could lead to spurious movement of a passive MOV.

During the safety review of the operating license application for the DCPP, the Atomic Energy Commission (AEC, now NRC) regulatory staff adopted the position that failures

of the type discussed above that could lead to spurious movement of passive MOVs must be considered in relation to satisfying the single failure criterion. The regulatory staff's position, as stated in Branch Technical Position EICSB 18, November 1975, considers removal of electric power an acceptable means, under certain conditions, of satisfying the single failure criterion. Refer to Section 6.3.3.41 for further discussion.

6.3.3.5.5 Control of Accumulator Motor-Operated Isolation Valves

During power operation, electrical power is removed from the valves by opening the 480-V breaker, thereby preventing inadvertent closure due to an electrical short. As the valve is provided with an automatic opening signal whenever RCS pressure exceeds the unblocking pressure, P11, a manual override permits closing of the valves at pressures exceeding P11 (refer to Figure 7.3-33 for controls). Additionally, it will open automatically upon receipt of the "S" signal should the valve be closed and the breaker is racked in. This "S" signal overrides any bypass feature. Position indicators for these valves are discussed in Section 6.3.3.4.5.1.

The accumulator MOVs are considered to be “operating bypasses” in the context of IEEE 279-1971 (Reference 12), which requires that bypasses of a protective function be removed automatically whenever permissive conditions are not met. In addition, as these accumulator isolation valves fail to meet single failure criteria, removal of power to the valves is required.

6.3.3.6 General Design Criterion 37, 1967 – Engineered Safety Features Basis for Design

6.3.3.6.1 Systems Operation

The operation of the ECCS following a LOCA or MSLB is discussed below.

6.3.3.6.1.1 Operation After Loss of Primary Coolant

The operation of the ECCS following a LOCA can be divided into two distinct modes:

(1) The injection mode in which any reactivity increase following the postulated accident is terminated, initial cooling of the core is accomplished, and coolant lost from the primary system is replenished

(2) The recirculation mode in which long-term core cooling is provided during the accident recovery period

A discussion of these modes follows:

6.3.3.6.1.1.1 Injection Mode After Loss of Primary Coolant

As shown in Figure 6.3-4, the principal mechanical components of the ECCS that provide core cooling immediately following a LOCA are the accumulators (one for each loop), the SI pumps, the CCPs (CCP1 and CCP2), the RHR pumps, and the associated valves, tanks, and piping.

For large pipe ruptures, (0.5 square feet equivalent and larger), the RCS would be depressurized and voided of coolant rapidly. A high flowrate of emergency coolant is required to quickly cover the exposed fuel rods and limit possible core damage. This high flow is provided by the passive accumulators, followed by CCP1 and CCP2, SI pumps, and the RHR pumps discharging into the cold legs of the RCS.

During the injection mode, the RHR and SI pumps deliver into the accumulator injection lines between the two check valves. CCP1 and CCP2 deliver through the charging injection line directly into the cold legs.

Emergency cooling is provided for small ruptures primarily by high-head injection. Small ruptures are those, with an equivalent diameter of 6 inches or less, that do not immediately depressurize the RCS below the accumulator discharge pressure. CCP1 and CCP2 deliver borated water at the prevailing RCS pressure to the cold legs of the RCS, from the RWST during the injection mode.

The SI pumps also take suction from the RWST and deliver borated water to the cold legs of the RCS. The SI pumps begin to deliver water to the RCS after the pressure has fallen below the pump shutoff head.

The RHR pumps take suction from the RWST and deliver borated water to the RCS. These pumps begin to deliver water to the RCS only after the pressure has fallen below the pump shutoff head.

The injection mode of emergency core cooling is initiated by the "S" signal. This signal is actuated by any of the following:

(1) Pressurizer low pressure

(2) Containment high pressure

(3) Low steamline pressure

(4) Manual actuation

Operation of the ECCS during the injection mode is completely automatic. The "S" signal automatically initiates the following actions:

(1) Starts the diesel generators and, if all other sources of power are lost, aligns them to the Class 1E buses (refer to Section 8.3.1.1.6)

(2) Starts CCP1 and CCP2, the SI pumps, and the RHR pumps

(3) Aligns CCP1 and CCP2 for injection by:

(a) Closing the valves in the charging pump discharge line to the normal charging line

(b) Opening the valves in the charging pumps suction line from the RWST

(c) Closing the valves in the charging pump normal suction line from the volume control tank

(d) Opening the charging injection inlet and outlet line isolation valves

(4) Provides an open signal to the accumulator isolation valves; and if they are energized and closed, they will open (refer to Section 6.3.3.5.5).

The injection mode continues until the low level is reached in the RWST, at which time the RHR pumps are automatically tripped. The operator then manually changes system alignment to the recirculation mode. The remaining water in the RWST provides a reserve to be used by the CSS pumps to ensure that enough sodium hydroxide has been added to the containment, utilizing the spray additive system (SAS), to maintain the pH of the recirculation fluid greater than 8.0. Three channels of RWST instrumentation are used, providing three independent and redundant RWST level indications that are displayed in the control room, to inform the operator of the water level in the tank at all times. Any two of these three channels will actuate the low-level alarm and will automatically trip the RHR pumps on low RWST level. After the changeover begins, the rate of possible demand on the tank is reduced, providing increasing periods of operation for the pumps still drawing water from the tank, and giving further assurance that water will remain in the tank after the completion of the changeover.

6.3.3.6.1.1.2 Changeover from Injection Mode to Recirculation After Loss of Primary Coolant

Water level indication and alarms on the RWST and level indication in the containment recirculation sump provide ample warning to terminate the injection mode while the operating pumps still have adequate NPSH. Since the injection mode of operation following a LOCA is terminated before the RWST is completely emptied, all pipes are kept filled with water before recirculation is initiated. For some SBLOCAs, the RCS pressure may remain above the shut off head of the RHR pumps that would be providing only recirculation flow. For these scenarios, the operators will trip the RHR

pumps or initiate CCW flow to an RHR heat exchanger within 30 minutes. This ensures that pump recirculation does not result in heating and pressurizing the RHR suction piping.

Following receipt of the RWST low-level alarm and automatic tripping of the RHR pumps, the remainder of the changeover sequence from injection mode to recirculation mode is accomplished manually by the operator from the control room (except for restoring power to the RWST supply valves to the RHR and the SI pumps). The same sequence (as delineated in Table 6.3-5) is followed regardless of which power supply is available (Offsite Power System or Standby Power Supply). Controls for ECCS components are grouped together on the main control board. The component position lights verify when the function of a given switch has been completed. The total required switchover time for the changeover from injection to recirculation is approximately 10 minutes, as shown in Table 6.3-5. The postulated single failure during the changeover sequence is the failure of an RHR pump to trip on low RWST level. The operator action requires approximately 5 minutes to locally open the breaker for an RHR pump motor. The operator action is performed concurrently with the changeover sequence and there is no increase in the total time for the changeover. The changeover sequence can be completed, with the single failure, and the remaining useable RWST volume exceeds the licensing basis of 32,500 gallons.

6.3.3.6.1.1.3 Recirculation Mode After Loss of Primary Coolant

After the injection operation, water collected in the containment recirculation sump is cooled and returned to the RCS by the low-head/high-head recirculation flowpath. The RCS can be supplied simultaneously from the RHR pumps and from a portion of the discharge from the RHR heat exchanger that is directed to CCP1 and CCP2 and SI pumps that return the water to the RCS. The latter mode of operation ensures flow in the event of a small rupture where the depressurization proceeds more slowly, so that the RCS pressure is still in excess of the shutoff head of the RHR pumps at the onset of recirculation. Approximately 7.0 hours after LOCA inception, the operators will manually initiate hot leg recirculation and complete the switchover process within 15 minutes. Hot leg recirculation is implemented to ensure termination of boiling and prevent boric acid crystallization. Some cold leg recirculation would be maintained with the CCPs (CCP1 and CCP2) after hot leg recirculation is initiated.

The RWST is protected from back flow of reactor coolant from the RCS. All connections to the RWST except those that are designed to return flow to the RWST are provided with check valves to prevent back flow.

Redundancy in the external recirculation loop is provided by duplicate CCPs (CCP1 and CCP2), SI pumps, and RHR pumps and heat exchangers. Inside the containment, the high-pressure injection system is divided into two separate flow trains. For cold leg recirculation, CCP1 and CCP2 deliver to all four cold legs and the SI and RHR pumps deliver also to all four cold legs by separate flowpaths. For hot leg recirculation, each SI

pump delivers through separate paths to two hot legs, while the RHR pumps deliver to two of the four hot legs.

The sump isolation valves are located in steel-lined pressure-tight compartments. This arrangement contains any leakage from an isolation valve stem or bonnet.

6.3.3.6.1.2 Operation After MSLB

Following an MSLB, the ECCS is automatically actuated to deliver borated water from the RWST to the RCS. The response of the ECCS following an MSLB is identical to its response during the injection mode of operation following a LOCA. The "S" signal initiates identical actions as described for the injection mode of the LOCA, even though not all of these actions are required following an MSLB; e.g., the RHR pumps are not required since the RCS pressure will remain above the pump shutoff head.

The delivery of the concentrated boric acid from the RWST provides negative reactivity to counteract the increase in reactivity caused by the system cooldown. CCP1 and CCP2 continue to deliver borated water from the RWST until enough water has been added to the RCS to make up for the shrinkage due to cooldown. The SI pumps also deliver borated water from the RWST for the interval when the RCS pressure is less than the shutoff head of the SI pumps. After pressurizer water level has been restored, the injection is manually terminated.

The sequence of events following a postulated MSLB is described in Section 15.4.2.

6.3.3.6.2 ECCS Performance

The following events were analyzed to ensure that the limits on core behavior following an RCS pipe rupture are not exceeded when the ECCS operates with minimum design equipment:

(1) Large pipe break analysis

(2) Small line break analysis

(3) ECCS recirculation mode cooling

The adequacy of flow delivered to the RCS by the ECCS with the operation of minimum design equipment is demonstrated in Sections 15.3.1 and 15.4.1.

The design basis performance characteristic is derived from the specified performance characteristic for each pump with a conservative estimate of system piping resistance, based on the final piping layout. The performance characteristic utilized in the accident analyses includes a decrease in the design head for margin. When the initiating incident is assumed to be the severance of an injection line, the injection curve utilized in the analyses accounts for the loss of injection water through the broken line.

6.3.3.6.2.1 Large Pipe Break Analysis

The large pipe break analysis is used to evaluate the initial core thermal transient for a spectrum of pipe ruptures from a break size greater than 1.0 square foot up to the double-ended rupture of the largest pipe in the RCS.

The injection flow from active components is required to control the cladding temperature subsequent to accumulator injection, complete reactor vessel refill, and eventually return the core to a subcooled state. The results indicate that the maximum cladding temperature attained at any point in the core is such that the limits on core behavior as specified in Section 15.4.1 are met.

6.3.3.6.2.2 Small Pipe Break Analysis

The small pipe break analysis is used to evaluate the initial core thermal transient for a spectrum of pipe ruptures, which bounds breaks corresponding to the smallest break size, typically a 3/8 inch diameter opening (0.11 square inch), up to and including a break size of 1.0 square foot. For a break opening 3/8 inch or smaller, the makeup flow rate from either CCP1 or CCP2 is adequate to allow time for an orderly plant shutdown without automatic ECCS actuation.

The results of the small pipe break analysis indicate that the limits on core behavior are adequately met, as shown in Section 15.3.1.

6.3.3.6.2.3 Recirculation Cooling

Core cooling during recirculation can be maintained by the flow from one RHR pump if RCS pressure is low. If RCS pressure remains high, either CCP1 or CCP2 and one SI pump operating in series with one RHR pump provide the added head and flow needed to maintain adequate cooling.

Heat removal from the recirculated sump water is accomplished via operation of one or both of the RHR heat exchangers.

6.3.3.6.2.4 Required Operating Status of ECCS Components

Normal operating status of ECCS components is given in Table 6.3-6.

ECCS components are available whenever the coolant energy is high and the reactor is critical. During low temperature physics tests, there is a negligible amount of stored energy and low decay heat in the coolant; therefore, an accident comparable in severity to accidents occurring at operating conditions is not possible in low temperature physics tests, and ECCS components are not required.

6.3.3.6.2.5 Loss of Offsite Power

The ECCS is designed to meet its minimum required level of functional performance with onsite electrical power system operation (assuming offsite power is not available) or with offsite electrical power system operation for any of the above abnormal occurrences assuming a single failure as discussed in Sections 3.1 and 6.3.3.5.

Diesel generators supply power to ECCS components in the event that all sources of offsite power become unavailable.

The supply of emergency power to the ECCS components is arranged so that, as a minimum, CCP1 or CCP2, one SI pump, and one RHR pump together with the associated valves will automatically receive adequate power in the event that a loss of offsite power occurs simultaneously with any of the design basis accidents described in Section 6.3.2. Adequate power is provided even if the single failure is the failure of an emergency diesel generator to start.

6.3.3.6.2.6 Range of Core Protection

Core protection is afforded with the minimum ESF equipment, defined by consideration of the single failure criteria as discussed in Sections 3.1 and 6.3.3.5. The minimum design case will ensure that the entire break spectrum is accounted for and the core cooling design bases of Section 6.3.2 are met. The analyses for this case are presented in Sections 15.3 and 15.4.

For large RCS ruptures, the accumulators and the active high-head (CCP), intermediate-head (SI), and low-head (RHR) pumping components serve to complete the core refill. One RHR pump is required for long-term recirculation.

If the break is small (1.0 square foot or less), the accumulators, CCP1 or CCP2, and one SI pump ensure adequate cooling during the injection mode. Long-term recirculation requires operation of one RHR pump in conjunction with CCP1 or CCP2 and one SI pump and components of the auxiliary heat removal systems that are required to transfer heat from the ECCS (e.g., CCW system and ASW system). The LOCA analyses, presented in Sections 15.3 and 15.4, indicate that certain modifications (i.e., reduced component availability) to the normal operating status of the ECCS, as given in Table 6.3-6, are permissible without impairing the ability of the ECCS, to provide adequate core cooling capacity.

6.3.3.6.2.7 ECCS Piping Failures

The rupture of the portion of an injection line from the last check valve to the connection of the line to the RCS can cause not only a loss of coolant but impair the injection as well. To reduce the probability of an emergency core cooling line rupture causing a LOCA, the check valves that isolate the ECCS from the RCS are installed adjacent to the reactor coolant piping.

For a small break, the reactor pressure maintains a relatively uniform back pressure in all injection lines so that a significant flow imbalance does not occur. Also, system resistances are balanced by adjustment of throttling valves in the injection lines prior to plant operation. A rupture in an accumulator injection line is accounted for in the analyses by assuming that for cold leg breaks the entire contents of the associated accumulator are discharged through the break.

6.3.3.6.2.8 External Recirculation Loop

Major ECCS components are shielded, as required, from their associated redundant train to facilitate maintenance. During recirculation, following a LOCA, access to these components is not credited.

Pressure relieving devices with setpoints below the shutoff head of the high-head ECCS pumps (CCP1 and CCP2), from portions of the ECCS located outside of containment that might contain radioactivity, discharge to the pressurizer relief tank.

An analysis has been performed to evaluate the radiological effects of recirculation loop leakage (refer to Section 15.5). A loop is assumed to include CCP1 or CCP2, an SI pump, an RHR pump, an RHR heat exchanger, and the associated piping. Thus two loops are provided, each of which is adequate for core cooling. In the analysis, maximum leakage was assumed as discussed in Section 6.3.3.5. Analyses indicate that the offsite dose resulting from such leakage is much less than the requirements of 10 CFR 100.11.

Since redundant flowpaths are provided during recirculation, a leaking component in one of the flowpaths may be isolated. This action curtails any further leakage. Maximum potential leakage from components during normal operation is given in Table 6.3-9.

Each pump compartment and heat exchanger compartment are provided with sufficient drains to the RHR room sump to prevent compartment overflow due to the design leakage rate. Containment isolation valves can be remote manually closed before the pump compartment can overflow.

This layout permits the detection of a leaking recirculation loop component by means of a radiation monitor that samples the air exiting the heat exchanger compartment. Alarms in the control room will alert the operator when the activity exceeds a preset level. Sump level alarms and operation of sump pumps will be indicated in the control room as a backup for detection of water leaks.

Should a tube-to-shell leak develop in a RHR heat exchanger, the operator will be warned by a CCW high radiation alarm. For large leaks, the operator will also be warned by a CCW surge tank high-level alarm. In the event that the leak cannot be

isolated before the CCW surge tank fills, the tank relief valve will lift and direct the excess water to the auxiliary building sump.

6.3.3.6.2.9 Evaluation of Shutdown Reactivity Capability Following an Abnormal Release of Steam from the Main Steam System

Analyses are performed to ensure that the core limitations defined in Sections 15.2, 15.3, and 15.4 are met following a steam line rupture or a single active failure in the main steam system.

6.3.3.6.2.9.1 Main Steam System Single Active Failure

Analyses of reactor behavior following any single active failure in the main steam system that results in an uncontrolled release of steam are included in Section 15.2. The analyses assume that a single valve (largest of the safety, relief, or bypass valves) opens and fails to close, resulting in an uncontrolled cooldown of the RCS.

Results indicate that if the incident is initiated at the hot shutdown condition, which results in the worst reactivity transient, the limiting departure from nucleate boiling ratio (DNBR) values will be met. Thus, the ECCS provides adequate protection for this incident.

6.3.3.6.2.9.2 Main Steam Line Break

This accident is discussed in detail in Section 15.4. The limiting MSLB is a complete line severance.

The results of the analysis indicate that the design basis criteria are met. Thus, the ECCS adequately fulfills its shutdown reactivity addition function.

Following a secondary side high-energy (steam or feedwater) line break, CCW is supplied to the seal-water heat exchanger to provide cooling for CCP1 and CCP2 under miniflow conditions. This action prevents damage to the CCPs before safety injection termination criteria are reached and CCP operation is terminated.

6.3.3.6.2.10 Alternate Analysis Methods

The method of break analysis and the spectrum of breaks analyzed are described in Sections 15.3.1 and 15.4.1.

6.3.3.6.2.11 Fuel Rod Perforations

Results of the small pipe break and large pipe break analyses are presented in Sections 15.3.1 and 15.4.1, respectively.

6.3.3.7 General Design Criterion 38, 1967 – Reliability and Testability of Engineered Safety Features

ECCS reliability was considered in all aspects of system evolution, from initial design to periodic testing of the components during plant operation.

The preoperational testing program ensures that the systems, as designed and constructed, meet functional requirements.

The ECCS is designed with the ability for on-line testing of most components so that availability and operational status can be readily confirmed. The integrity of the ECCS is ensured through examination of critical components during routine inservice inspection.

6.3.3.7.1 Provisions for Performance Testing

Design features have been incorporated to ensure that the following testing can be performed:

(1) Active components may be tested periodically for operability (e.g., pumps on miniflow, certain valves, etc.).

(2) An integrated system actuation test can be performed when the plant is cooled down and the RHR system is in operation. The ECCS will be arranged so that no flow will be introduced into the RCS for this test.

(3) An initial flow test of the full operational sequence can be performed.

Specific design features that ensure this test capability are the following:

(1) Power sources are provided to permit actuation of individual ECCS active components.

(2) The SI pumps can be tested periodically during plant operation using the minimum flow recirculation lines provided.

(3) The RHR pumps are used every time the RHR system is put into operation. They can also be tested periodically when the plant is at power using the miniflow recirculation lines.

(4) CCP1 and CCP2 are either normally in use for charging service or can be tested periodically on miniflow.

(5) Remotely operated valves can be exercised during routine plant maintenance.

(6) For each accumulator tank, level and pressure instrumentation is provided for continuous monitoring during plant operation.

(7) Pressure instrumentation and a flow indicator are provided in the SI pump header and in the RHR pump headers.

(8) An integrated system test can be performed when the plant is cooled down and the RHR system is in operation. This test does not introduce flow into the RCS but does demonstrate the operation of the valves, pump circuit breakers, and automatic circuitry including diesel starting and the automatic loading of ECCS components off the diesels (by simultaneously simulating a loss of offsite power to the Class 1E electrical buses).

6.3.3.8 General Design Criterion 40, 1967 – Missile Protection

The provisions taken to protect the ECCS from damage that might result from dynamic effects associated with a postulated rupture of piping are discussed in Section 3.6. The provisions taken to protect the system from missiles are discussed in Section 3.5. The ECCS design is such that physical protection is adequately provided against physical hazards in areas through which the system is routed.

6.3.3.8.1 Safety Injection System Pump Missile Proneness

The capability of SI pump-motor combination to generate an external missile has been evaluated in Section 3.5. The results of this evaluation showed that neither the SI pump nor the motor are capable of generating external missiles.

However, the flexible coupling between the pump and motor could conceivably become a missile in the unlikely event that it should fail to maintain its mechanical integrity, due to a maximum overspeed condition caused by a large pressure head driving the pump in reverse. Such failure would require the failure of two check valves in the open position in conjunction with a rupture of the pipe on the suction side of the pump.

Despite the low probability of such a combination of failures, a shroud has been installed around the flexible coupling to eliminate all possibility of missiles being generated in the unlikely event of gross coupling failure.

6.3.3.9 General Design Criterion 41, 1967 – Engineered Safety Features Performance Capability

The ECCS is a two-train, fully redundant, standby ESF. The system was designed to withstand any single credible active failure during injection or active or passive failure during recirculation and maintain the performance objectives outlined in Section 6.3.2. Two trains of pumps, heat exchangers, and flowpaths are provided for redundancy; only one train is required to satisfy performance requirements. Initiating signals for the ECCS are derived from independent sources as measured from process (e.g., low

pressurizer pressure) or environmental variables (e.g., containment pressure).

Each train is physically separated and protected so that a single event cannot initiate a common mode failure. Each ECCS train is supplied from separate Class 1E power sources. The Class 1E power sources are discussed in Chapter 8.

6.3.3.9.1 Pump Characteristics

Typical performance curves for RHR pumps, CCP1 and CCP2, and SI pumps are shown in Figures 6.3-1, 6.3-2, and 6.3-3, respectively. The upper curves represent the typical performance characteristics of the pump. The lower curves illustrate that margins for the potential pump degradation have been considered in the analyses described in Chapter 15.

6.3.3.9.2 Limits on System Parameters

The specification of individual parameters as indicated in Table 6.3-1 includes due consideration of allowances for margin over and above the required performance value (e.g., pump flow and NPSH), and the most severe conditions to which the component could be subjected (e.g., pressure, temperature, and flow).

This consideration ensures that the ECCS is capable of meeting its minimum required level of functional performance.

6.3.3.9.2.1 Coolant Storage Reserves

A minimum RWST volume is provided to ensure that, after an RCS break, sufficient water is injected and available within containment to permit recirculation cooling flow to the core, to meet the NPSH requirement of the RHR pumps. This volume is less than that required to fill the refueling canal (to permit normal refueling operation). Thus, adequate emergency coolant storage volume for ECCS operation is provided. For RWST operational volumes, refer to Section 6.3.2.11 and Table 6.3-1.

6.3.3.9.2.2 Limiting Conditions for Maintenance During Operation

Maintenance on an active component will be permitted if the remaining components meet the minimum conditions for operation as well as the following conditions:

(1) The remaining equipment has been verified to be in operable condition, ready to function just before the initiation of the maintenance.

(2) A suitable time limit is placed on the total time span of successful maintenance that returns the components to an operable condition, ready to function.

The design philosophy with respect to active components in the high-head/low-head injection system is to provide backup equipment so that maintenance is possible during operation without impairment of the system safety function (refer to Section 6.3.3.5). Routine servicing and maintenance of equipment of this type that is not required more frequently than on an outage basis would generally be scheduled for periods of refueling and maintenance outages. The Technical Specifications (Reference 10) discuss in detail the applicable limiting conditions for maintenance during operations.

6.3.3.10 General Design Criterion 42, 1967 – Engineered Safety Features Components Capability

Instrumentation, motors, and penetrations located inside the containment are selected to meet the most adverse accident conditions to which they may be subjected. These items are either protected from containment accident conditions or are designed to withstand, without failure, exposure to the worst combination of temperature, pressure, and humidity expected during the required operational period.

The ECCS pipes serving each loop are anchored at the missile barrier (i.e., the crane wall) in each loop area to restrict potential accident damage to the portion of piping beyond this point. The anchorage is designed to withstand, without failure, the thrust force exerted by any branch line severed from the reactor coolant pipe and discharging fluid to the atmosphere, and to withstand a bending moment equivalent to that producing failure of the piping under the action of a free-end discharge to atmosphere or motion of the broken reactor coolant pipe to which the ECCS pipes are connected. This prevents possible failure at any point upstream from the support point including the branch line connection into the piping header.

6.3.3.11 General Design Criterion 43, 1967 – Accident Aggravation Prevention

As discussed in Section 15.4.1.4, the introduction of ECCS supplied borated cooling water into the core does not result in a net positive reactivity addition.

When water in the RWST at its minimum boron concentration is mixed with the contents of the RCS, the resulting boron concentration ensures that the reactor will remain subcritical in the cold condition with all control rods, except the most reactive RCCA, inserted into the core.

The boron concentration of the accumulator and the RWST is below the solubility limit of boric acid at the respective temperatures.

Thermal stresses on the RCS are discussed in Section 5.2.

6.3.3.12 General Design Criterion 44, 1967 – Emergency Core Cooling Systems Capability

By combining the use of passive accumulators with two CCPs (CCP1 and CCP2), two SI pumps, and two RHR pumps, emergency core cooling is provided even if there should be a failure of any single component in any system. The ECCS employs a passive system of accumulators that do not require any external signals or source of power for their operation to cope with the short-term cooling requirements of large reactor coolant pipe breaks. Two independent and redundant high-pressure flow and pumping systems, each capable of the required emergency cooling, are provided for small break protection and to keep the core submerged after the accumulators have discharged following a large break. These systems are arranged so that the single failure of any active component does not interfere with meeting the short-term cooling requirements.

Borated water is injected into the RCS by accumulators, SI pumps, RHR pumps, and CCPs. Pump design includes consideration of fluid temperature and containment pressure in accordance with Safety Guide 1, November 1970 (refer to Section 6.3.3.25). The failure of any single active component or the development of excessive leakage during the long-term cooling period does not interfere with the ability to meet necessary long-term cooling objectives with one of the systems.

The primary function of the ECCS is to deliver borated cooling water to the reactor core in the event of a LOCA. This limits the fuel cladding temperature and thereby ensures that the core will remain intact and in place, with its essential heat transfer geometry preserved. This protection is afforded for:

(1) All pipe break sizes up to and including the hypothetical circumferential rupture of a reactor coolant loop

(2) A loss of coolant associated with a rod ejection accident

The basic criteria for LOCA evaluations are (a) no cladding melting will occur, (b) zirconium-water reactions will be limited to an insignificant amount, and (c) the core geometry will remain essentially in place and intact so that effective cooling of the core will not be impaired. The zirconium-water reactions will be limited to an insignificant amount so that the accident:

(1) Does not interfere with the emergency core cooling function to limit cladding temperatures

(2) Does not produce hydrogen in an amount that, when burned, would cause the containment pressure to exceed the design value

For any rupture of a steam pipe and the associated uncontrolled heat removal from the core, the ECCS adds shutdown reactivity so that with a stuck rod, no offsite power, and minimum ESF, there is no consequential damage to the primary system and the core

remains in place and intact. With no stuck rod, offsite power, and all equipment operating at design capacity, there is insignificant cladding rupture.

6.3.3.12.1 Use of Dual Function Components

The ECCS contains components that have no other operating function as well as components that are shared with other systems. Components in each category are as follows:

(1) Components of the ECCS that perform no other function are:

(a) One accumulator for each reactor coolant loop that discharges borated water into its respective cold leg of the reactor coolant loop piping

(b) Associated piping, valves, and instrumentation

(2) Components of the ECCS that also have a normal operating function are as follows:

(a) The RHR pumps and heat exchangers: These components are normally used during the latter stages of normal reactor cooldown and when the reactor is held at cold shutdown for core decay heat removal. However, during all other plant operating periods, they are aligned to perform the low-head injection function.

(b) Two SI pumps that supply borated water for core cooling to the RCS (Note that the SI pumps are also used for SI accumulator fill and makeup, but this is not a significant function.) During refueling, the pumps may be used for the boration flow path with all reactor head bolts fully detensioned.

(c) CCP1 and CCP2: These pumps are normally aligned for charging service. The normal operation of the pumps as part of the CVCS is discussed in Section 9.3.4.

(d) The RWST: This tank is used to fill the refueling canal for refueling operations (refer to Section 9.1). During all other plant operating periods, it is aligned to the suction of the SI pumps and the RHR pumps. CCP1 and CCP2 are automatically aligned to the suction of the RWST upon receipt of the "S" signal.

An evaluation of all components required for operation of the ECCS demonstrates that either:

(1) The component is not shared with other systems.

(2) If the component is shared with other systems, it is aligned during normal plant operation to perform its accident function, or, if not aligned to its accident function, two valves in parallel are provided to align the system for injection, and two valves in series are provided to isolate portions of the system not utilized for injection. These valves are automatically actuated by the "S" signal.

Table 6.3-8 indicates the alignment of components during normal operation, and the realignment required to perform the accident function.

6.3.3.13 General Design Criterion 45, 1967 – Inspection of Emergency Core Cooling Systems

The components outside containment are accessible for leak tightness inspection during operation of the reactor. Periodic visual inspection of portions of the ECCS for leakage is specified in the Technical Specifications (Reference 10). ECCS systems are inspected in accordance with ASME BPVC Section XI-2001 through 2003 Addenda, as stated in the Diablo Canyon Power Plant (DCPP) Inservice Inspection Program Plan (Reference 9). Details of the inspection program for the reactor vessel internals are included in Section 5.4.

6.3.3.14 General Design Criterion 46, 1967 – Testing of Emergency Core Cooling Systems Components

Routine periodic testing of the ECCS components and all necessary support systems is specified in the Technical Specifications (Reference 10). If such testing indicates a need for corrective maintenance, the redundancy of equipment in these systems permits such maintenance without shutting down or reducing load under the conditions established in the Technical Specifications (Reference 10).

Test connections are provided for periodic checks of the leakage of reactor coolant back through the accumulator discharge line check valves and to ascertain that these valves seat properly whenever the RCS pressure is raised. This test will be performed following valve actuation due to automatic or manual action, or flow through the valve in accordance with Technical Specifications (Reference 10). The SI test lines (and associated RCPB test valves) that are used for ECCS check valve surveillance testing are designed for testing in Modes 4 and 5 only. Per Section 6.3.3.6.2.2, maximum flow rate through each RCPB test valve is limited such that, in the event of a downstream pipe break during testing in Modes 4 or 5, the makeup flow rate from either CCP1 or CCP2 is adequate to allow time for an orderly plant shutdown/cooldown without ECCS actuation.

6.3.3.15 General Design Criterion 47, 1967 – Testing of Emergency Core Cooling Systems

In addition to the Technical Specification (Reference 10) requirements, an ECCS subsystem is demonstrated operable during shutdown, following completion of modifications to the ECCS subsystem that alter the subsystem flow characteristics by performing a flow balance test to verify:

For CCP1 and CCP2, with a single pump running that:

(1) The sum of injection line flow rates, excluding the highest flow rate, is greater than or equal to 299 gpm, and

(2) The total flow rate through all four injection lines is less than or equal to 461 gpm, and

(3) The difference between the maximum and minimum injection line flow rates is less than or equal to 15.5 gpm, and

(4) The total pump flow rate is less than or equal to 560 gpm.

For SI pumps, with a single pump running that:

(1) The sum of injection line flow rates, excluding the highest flow rate, is greater than or equal to 427 gpm, and

(2) The total flow rate through all four injection lines is less than or equal to 650 gpm, and

(3) The difference between the maximum and minimum injection line flow rates is less than or equal to 20.0 gpm, and

(4) The total pump flow rate is less than or equal to 675 gpm.

The RHR subsystem is demonstrated operable during shutdown, following completion of modifications to the RHR subsystem that alter the subsystem flow characteristics, by performing a flow test and verifying a total flow rate greater than or equal to 3976 gpm with a single RHR pump running and delivering flow to all four cold legs.

6.3.3.16 General Design Criterion 48, 1967 – Testing of Operational Sequence of Emergency Core Cooling Systems

As discussed in Section 6.3.3.7, a system actuation test can be performed when the plant is cooled down and the RHR system is in operation. Details of the testing of the sensors and logic circuits associated with the generation of an "S" signal, together with the application of this signal to the operation of each active component, are given in Section 7.3.

6.3.3.17 General Design Criterion 49, 1967 – Containment Design Basis

The ECCS containment penetrations, including the system piping and valves required for containment isolation, are designed and analyzed to withstand the pressures and temperatures that could result from a LOCA without exceeding design leakage rates. Refer to Section 3.8.1.1.3 for additional details.

6.3.3.18 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The ECCS isolation valves required for containment closure are periodically tested as part of the Inservice Testing (IST) Program Plan for operability in accordance with GDC 54, 1971. Refer to Section 6.3.3.14 for additional discussion on periodic testing. Test connections are provided in the piping of applicable penetrations to verify valve leakages are within prescribed limits. Testing of the components required for the containment isolation system (CIS) is discussed in Section 6.2.4.

6.3.3.19 General Design Criterion 55, 1971 – Reactor Coolant Pressure Boundary Penetrating Containment

The ECCS is designed such that for each line that is part of the reactor coolant pressure boundary that penetrates containment is provided with containment isolation valves in compliance with GDC 55, 1971. Refer to Section 6.2.4.2.1 and Table 6.2-39 for penetration and configuration details with regards to GDC 55, 1971.

6.3.3.20 General Design Criterion 56, 1971 – Primary Containment Isolation

The ECCS is designed such that each line that connects directly to the containment atmosphere and penetrates containment is provided with containment isolation valves in compliance with GDC 56, 1971. Refer to Section 6.2.4.2.1 and Table 6.2-39 for penetration and configuration details with regards to GDC 56, 1971.

6.3.3.21 10 CFR 50.46 – Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Plants

The ECCS calculated cooling performance is capable of demonstrating a high level of probability that the limits set forth in 10 CFR 50.46 are met. Sections 15.3.1 and 15.4.1 provide discussion of SBLOCA and LBLOCA analyses, respectively, including the approved evaluation methodologies, range of coolant rupture and leak sizes evaluated, other properties sufficient to provide assurance that the most severe postulated LOCAs are calculated, and demonstration that the limits set forth in 10 CFR 50.46 are met.

6.3.3.22 10 CFR 50.49 – Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

The ECCS SSCs required to function in harsh environments under accident conditions are qualified to the applicable environmental conditions to ensure that they will continue to perform their safety functions. Section 3.11 describes the DCPP EQ Program and the requirements for the environmental design of electrical and related mechanical equipment. The affected equipment includes flow and pressure transmitters, valves, and switches, and are listed on the EQ Master List.

6.3.3.22.1 Evaluation of the Capability to Withstand Post-Accident Environment

A comprehensive testing program was undertaken to demonstrate that ECCS components and associated instrumentation and electrical equipment that are located inside the containment will operate for the required time period, under the combined post-LOCA conditions of temperature, pressure, humidity, radiation, chemistry, and seismic phenomena (Reference 6).

6.3.3.23 10 CFR 50.55a(f) – Inservice Testing Requirements

The IST requirements for the ECCS are contained in the DCPP IST Program Plan.

6.3.3.24 10 CFR 50.55a(g) – Inservice Inspection Requirements

ECCS systems are inspected in accordance with ASME BPVC Section XI-2001 through 2003 Addenda, as stated in the DCPP Inservice Inspection Program Plan (Reference 9).

6.3.3.25 Safety Guide 1, November 1970 – Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps

The ECCS is designed so that adequate NPSH is provided to system pumps. In addition to considering the static head and suction line pressure drop, the calculation of available NPSH in the recirculation mode for the RHR pumps assumes that the vapor pressure of the liquid in the sump equals containment pressure. This assumption ensures that the actual available NPSH is always greater than the calculated NPSH. The calculation of available NPSH during recirculation is as follows:

$$NPSH_{actual} = (h)_{containment\ pressure} - (h)_{water\ vapor,\ partial\ pressure} + (h)_{static\ head} - (h)_{loss}$$

$$NPSH_{calculated} = (h)_{static\ head} - (h)_{loss}$$

NPSH for ECCS pumps is further discussed in Section 6.3.3.32.

6.3.3.26 Regulatory Guide 1.79, June 1974 – Preoperational Testing of Emergency Core Cooling Systems for Pressurized Water Reactors

The integrated system test for the ECCS was formulated using Regulatory Guide 1.79, June 1974 as a basis. The integrated system test was divided into three phases and was performed after the five component tests, discussed in Section 6.3.4.2.1, had been completed.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

6.3.3.26.1 Integrated System Tests

6.3.3.26.1.1 System Test - Phase I

The Phase I test was conducted prior to hot functional tests and involved testing the ECCS at ambient conditions with the reactor vessel open.

A loss of offsite power was simulated prior to test initiation. The emergency diesel generators supplied power to the ESF equipment through Phase I of the test.

The ECCS was tested functionally by manually initiating safety injection and monitoring components for correct system alignment, autostarts, and pump delivery rates. Response time data were obtained for components being tested to demonstrate that they meet or exceed acceptance criteria as established in the test.

At the conclusion of the test, the RHR, SI pump, and CCP1/CCP2 were realigned to the recirculation mode to demonstrate the capability of the RHR pumps to deliver water from the containment recirculation sump to the SI pump and CCP1/CCP2 suctions, and to the CSS headers. The time required for changeover to recirculation was evaluated to demonstrate that it can be completed during the time allowed.

6.3.3.26.1.2 System Test - Phase II

The Phase II test was conducted during hot functional testing with the RCS at hot operating conditions.

High-pressure safety injection (CCP1 and CCP2) was tested by manually initiating safety injection and monitoring components for correct alignment, autostarts of pumps, and delivery of water from the RWST to the reactor vessel through the high-pressure safety injection branch lines.

Response time data were obtained for components being tested to demonstrate that they met or exceeded acceptance criteria.

6.3.3.26.1.3 System Test - Phase III

During Phase III tests, the SI pumps and accumulator check valves were tested. The test was conducted during the cooldown phase of hot functional testing as the required RCS pressures were reached.

SI pumps were tested by manually initiating safety injection with the RCS pressure at a value below the shutoff head of the pumps. SI pump autostart and delivery of water from the RWST to the reactor vessel via SI pump injection flowpaths were checked.

Response time data were obtained for components being tested to demonstrate that they meet or exceed acceptance criteria.

Accumulator check valve operation was verified as RCS pressure decreased to a value below the accumulator pressure setpoint. The accumulator discharge isolation valves were closed as soon as flow through the check valves had been verified to minimize the thermal transient to the RCS.

6.3.3.26.2 Preoperational Testing Conformance with Regulatory Guide 1.79, June 1974

The ECCS tests described above meet the requirements of Regulatory Guide 1.79, June 1974, except in the following instances:

During the hot flow test (Section 6.3.3.26.1.3/Paragraph C.3.a(2) of Regulatory Guide 1.79, June 1974), feedwater flow from the AFW pumps is blocked in order to avoid a temperature and pressure transient from this cause in the RCS. The pumps are started on the "S" signal but will be run on recirculation. Flow from the AFW pumps to the steam generators is verified as part of the feedwater system tests. The quantity of water injected into the RCS by CCP1 and CCP2 during this test is limited by pressurizer water level, rather than limiting the quantity to avoid reducing the number of design stress cycles. Calculations indicate that the injection nozzles are subjected to essentially the full thermal shock by the time any meaningful data can be obtained from this test.

During the recirculation phase of the SI pumps low-pressure test at ambient conditions with the reactor vessel open (Section 6.3.3.26.1.1/Paragraph C.3.b(2) of Regulatory Guide 1.79, June 1974), temporary piping is installed from the refueling canal into the containment recirculation sump. This temporary piping bypasses the coarse but not the fine sump screen. The pressure drop across the coarse and fine screens is less than one thousandth of a foot of water head, which is impractical to measure and which will not compromise the pump NPSH.

During the testing of the accumulators under ambient conditions to verify flowrates (Section 6.3.4.2.1/Paragraph C.3.c(1) of Regulatory Guide 1.79, June 1974), the accumulator discharge is initiated by opening the accumulator isolation valves, not by

rapidly reducing RCS pressure. The discharge flowrate is calculated from the change of accumulator pressure with time, not from the change of accumulator level with time. Accumulator discharge tests are not repeated for normal and emergency power supplies; operation of the accumulator isolation valves with both normal and emergency power supplies is demonstrated as a part of other tests.

6.3.3.27 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

ECCS post-accident instrumentation for meeting Regulatory Guide 1.97, Revision 3, requirements consist of RHR system flow indication, SI pump discharge flow indication, CCP1 and CCP2 injection header flow indication, RHR heat exchanger outlet temperature indication, containment recirculation sump water level and temperature indication, accumulator tank level and pressure indication, accumulator isolation valve position indication, RWST level indication, containment isolation valve position indication, and subcooling margin indication (refer to Table 7.5-6).

DCPP uses the RVLIS processors to calculate RCS subcooling. Refer to Section 7.5.2.2.1 for details of the display, calculator, and inputs.

6.3.3.28 NUREG-0737 (Items I.C.1, I.D.2, II.B.2, II.F.1, II.F.2, II.K.3.30, II.K.3.31, III.D.1.1), November 1980 – Clarification of TMI Action Plan Requirements

Item I.C.1 – Guidance for the Evaluation and Development of Procedures for Transients and Accidents: NUREG-0737, Supplement 1, January 1983 provides the ECCS requirements for I.C.1:

Section 7.1(b) – Upgraded emergency operating procedures have been implemented in accordance with the Westinghouse Owners Group (WOG) developed generic emergency response guidelines. The WOG is now known as the Pressurized Water Reactor Owners' Group (PWROG).

Item I.D.2 – Plant Safety Parameter Display Console: NUREG-0737, Supplement 1, January 1983 provides the ECCS requirements for I.D.2:

Section 4.1(f)(v) – Containment Conditions: Containment recirculation sump water level indication is provided on secondary displays of the safety parameter display system (SPDS). The SPDS displays are available in the control room, TSC, and EOF (refer to Section 7.5.2.10).

Item II.B.2 – Design Review of Plant Shielding and Environmental Qualification of Equipment for Space/Systems Which May Be Used in Postaccident Operations: The switchgear rooms are sufficiently shielded from external sources of radiation such that personnel access and occupancy would not be unduly limited by the radiation

environment caused by a degraded core accident.

Item II.F.1 – Additional Accident Monitoring Instrumentation:

Position (5) – Continuous instrumentation to monitor containment recirculation sump water level is provided in the control room (refer to Sections 6.3.3.4.4.3, and 7.5.2.1.3; Figures 7.5-1, and 7.5-1B). Instrument ranges and accuracies are provided in Tables 7.5-2 and 7.5-4.

Item II.F.2 – Instrumentation for Detection of Inadequate Core Cooling: The instrumentation for detection of inadequate core cooling includes the subcooled margin monitors, core exit thermocouple system, and RVLIS. Refer to Section 7.5.2.2 for further discussion.

Item II.K.3.30 – Revised Small-Break Loss-Of-Coolant-Accident Methods to Show Compliance with 10 CFR Part 50, Appendix K: The methodology for calculating SBLOCAs (i.e., the NOTRUMP model) was submitted generically by the WOG (now PWROG), of which PG&E is a participating member. The NOTRUMP model was approved by the NRC Staff for use on DCPP Unit 1 and Unit 2. Refer to Section 15.3.1 for further discussion.

Item II.K.3.31 – Plant-Specific Calculations to Show Compliance with 10 CFR Part 50.46: Plant specific calculations were performed for DCPP using an NRC approved model (NOTRUMP) for evaluating SBLOCAs. These calculations determined the acceptance criteria of 10 CFR 50.46 are met for DCPP. Refer to Section 15.3.1 for further discussion.

Item III.D.1.1 – Integrity of Systems Outside Containment Likely to Contain Radioactive Material for Pressurized-Water Reactors and Boiling-Water Reactors: Pressure containing portions of the ECCS are tested periodically to check for leakage. This testing includes the portions of the system that would circulate radioactive water from the containment recirculation sump. The requirements for a leakage reduction program from reactor coolant sources outside containment are included in the Technical Specifications (Reference 10). Inservice valve leakage requirements are specified in the IST Program. Refer to Section 6.2.4 for additional information on the CIS and Section 6.3.3.14 for additional discussion on ECCS leakage testing.

6.3.3.29 Generic Letter 89-10, June 1989 – Safety-Related Motor-Operated Valve Testing and Surveillance

PG&E Design Class I MOVs are designed to function with a pressure differential across the valve disk determined in accordance with Generic Letter 89-10, June 1989. ECCS MOVs, except the accumulator isolation valves, are subject to the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996, "Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves," and meet the requirements of the DCPP MOV Program Plan. The

accumulator isolation valves have no active or credited safety function; therefore, they are not included in DCPP's formal MOV Program Plan.

6.3.3.30 Generic Letter 95-07, August 1995 – Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves

PG&E Design Class I power-operated gate valves in the ECCS that were determined to be susceptible to pressure locking were modified by installing bonnet cavity leakoffs with block valves to the high pressure inlet lines to prevent pressure locking. No power-operated gate valves in the ECCS were found susceptible to thermal binding.

6.3.3.31 Generic Letter 96-06, September 1996 – Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions

Generic Letter 96-06, September 1996 identified the potential of thermally induced overpressurization of isolated water-filled piping sections in containment that could jeopardize the ability of accident mitigating systems to perform their safety functions and could also lead to a breach of containment integrity via bypass leakage.

In the evaluation to determine potentially affected piping sections, DCPP identified two ECCS piping sections. The evaluation concluded that no corrective actions were necessary on ECCS piping as one section was deemed to meet ANSI B31.1-1967 allowable pressure values and the other section was deemed to have an isolation valve (air-operated globe valve) whose design prevents overpressurization.

For the section of piping that was deemed to have an isolation valve whose design prevents overpressurization, PG&E performed a bench test on a representative globe valve from their warehouse. The prototype test demonstrated that all 3/8-, 3/4- and 1-inch installed globe valves could be credited to relieve pressure prior to their piping section pressure stresses exceeding ANSI B31.1-1973 Summer Addenda allowable design values and, therefore, this section did not need physical modification.

6.3.3.32 Generic Letter 97-04, October 1997 – Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps

The general methodology for calculating NPSH is discussed in Section 6.3.3.25. Evaluation of head loss associated with the ECCS suction strainers is discussed in Section 6.3.3.34. Adequate NPSH is shown to be available for all ECCS pumps as follows:

(1) RHR Pumps

The NPSH of the RHR pumps was evaluated for normal plant shutdown operation, and for both the injection and recirculation modes of operation

for the design basis accident. Recirculation operation gives the limiting NPSH requirement. The NPSH evaluation was based on all pumps (i.e., both RHR, CCP1 and CCP2, both SI, and both CSS pumps) operating at the maximum design (runout) flowrates. The minimum available and required NPSH values for this pump are given in Table 6.3-11.

(2) Safety Injection and Centrifugal Charging Pumps 1 and 2

The NPSH for the SI pumps and CCP1/CCP2 was evaluated for both the injection and recirculation modes of operation for the design basis accident. The end of the injection mode of operation gives the limiting NPSH available. The limiting NPSH was determined from the elevation head and vapor pressure of the water in the RWST, which is at atmospheric pressure, and the pressure drop in the suction piping from the tank to the pumps. The NPSH evaluation is based on all pumps operating at the maximum design flowrates. Following switchover to the recirculation mode, adequate NPSH is supplied from the containment recirculation sump by the booster action of the RHR pumps. The minimum available and required NPSH for these pumps are given in Table 6.3-11.

6.3.3.33 Generic Letter 98-04, July 1998 – Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment

PG&E has implemented controls for procurement, application, and maintenance of Service Level 1 protective coatings used inside containment. The requirements of 10 CFR Part 50, Appendix B, are implemented through specification of appropriate technical and quality requirements for the Service Level 1 coatings program which includes ongoing maintenance activities.

PG&E has implemented a Coating Quality Monitoring Program that includes a thorough visual inspection of selected portions of the coatings inside the containment. As localized areas of degraded coatings are identified, those areas are evaluated and scheduled for repair or replacement, as necessary. The periodic condition assessments, and the resulting repair/replacement activities, assure that the amount of Service Level 1 coatings which may be susceptible to detachment from the substrate during a LOCA event is minimized. PG&E conducts condition assessments of Service Level 1 coatings inside containment every refueling outage.

DCPP Technical Specifications (Reference 10) require periodic verification by visual inspection that the containment recirculation sump suction inlet trash racks and screens are not restricted by debris and show no evidence of structural distress or abnormal corrosion. DCPP plant procedures require internal inspection of sump plenums and RHR suction piping under specific circumstances. DCPP plant procedures ensure no

loose debris (rags, trash, clothing, insulation, plastics, etc.) exists inside containment that could be transported to the containment recirculation sump in the event of a LOCA.

6.3.3.34 Generic Letter 2004-02, September 2004 – Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized-Water Reactors

The evaluation of insulation and other debris affecting containment recirculation sump availability following a LOCA was completed based on the requirements and guidance of Generic Letter 2004-02, September 2004, which was issued by the NRC to address the potential impact of debris blockage on emergency recirculation during design basis accidents at pressurized water reactors. The evaluation is based on the guidance provided in NEI 04-07, Revision 0, "Pressurized Water Reactor Sump Performance Evaluation Methodology," and the subsequently issued safety evaluation of that guidance by the NRC.

- NEI 04-07, along with the NRC safety evaluation, provides an acceptable methodology to evaluate and resolve the potential impact of debris blockage on the emergency recirculation strainer. This methodology, along with subsequent industry guidance, provides a conservative approach to evaluate the following main topics associated with post-accident strainer performance:

  - Upstream Effects
  - Debris Generation
  - Debris Transport
  - Head Loss
  - Downstream Effects

<u>Upstream Effects</u>

The objective of the upstream effects assessment is to evaluate the flowpaths upstream of the containment strainer for holdup of inventory which could reduce flow to and possibly starve the strainer.

This evaluation was performed in accordance with the recommendations contained within NEI 04-07 to identify those flowpaths that could result in the holdup of water not previously considered. These flowpaths included those areas into which CSS and RCS break flow would enter.

After holdup from the refueling cavity drain, ductwork, the portion of the reactor cavity below the 91 foot elevation, and holdup curbs had been conservatively estimated and

the basis for no other significant sources of liquid holdup had been established, it was determined that all other water return flowpaths have sufficiently large openings to prevent the holdup of significant quantities of water that could challenge the containment minimum water level analysis. Therefore, the remaining water level is still sufficient to provide the containment minimum water level.

The required flowpaths for return of water to the containment recirculation sump pool include the refueling canal drains, the stairwells connecting the various elevations of containment, the reactor coolant drain tank hatch cover, and the openings (doorways) within the crane wall.

The refueling canal is provided with a single 8-inch drain line (refer to Figure 3.2-19 Sheets 1 and 2, grid 37-C) with a sealed open valve (HCV-111) and blind flange that is removed when the refueling canal is not in use. The drain is closed only when the refueling canal is in use. The refueling canal drain for both DCPP Unit 1 and Unit 2 is covered with a recessed deck grating that is flush with the refueling canal floor. The grating is protected by a raised basket with openings which are sufficiently large to prevent any credible debris from blocking this flowpath. Therefore, there is no expected blockage of the refueling canal drain. The upper internals laydown area is within the refueling canal and this area is slightly recessed below the nominal refueling canal floor. This is an area of potential holdup of water and it has been estimated that this area could holdup approximately 244 ft^3. This volume is not credited in the minimum containment water level.

The reactor coolant drain tank hatch cover is designed to provide a flow path for injected ECCS water, and spilled RCS fluid, to the containment recirculation sump from a break inside the biological shield wall. The break will flow through the reactor annulus space, fill the portion of the reactor cavity below the 91 foot elevation, and start to fill the floor at the 91 foot elevation through this hatch cover. The fluid will then flow out of the openings in the crane wall and to the containment recirculation sump. For breaks other than inside the biological shield wall, the reactor coolant drain tank hatch cover is not required to function and is not credited.

As a result of the evaluations performed and physical changes completed it was determined that the upstream effects analysis provides the necessary level of assurance that the required volume of water will be available to the containment recirculation sump for the function to meet the applicable requirements as set forth in NEI 04-07 and Generic Letter 2004-02, September 2004.

Debris Generation

Debris generation analysis has two primary inputs. The plant accident analysis identifies the postulated accidents that require RHR strainer operation by the ECCS in the recirculation mode from the containment recirculation sump. An accurate inventory of debris source materials addressing type, quantity, location, and characteristics of the materials is also required.

The purpose of the debris generation evaluation is to determine which breaks have the potential to challenge the sump operation in a post-accident scenario. Break locations are postulated based upon which location gives both the most fibrous debris (e.g., insulation) and the worst combination of debris with regard to expected debris transport and head loss behavior given the respective zone of influence (ZOI) of the debris. The ZOI represents the zone where a given high-energy line break will generate debris that will be transported to the strainer. The locations will be used to determine total debris generated. The debris generated is then assigned size distributions and defined by material characteristics. The methodology as provided in NEI 04-07 was generally followed along with the recommendations from the safety evaluation as applicable.

For break selection, the only exception taken to NEI 04-07 and the safety evaluation was the use of the criterion specifying "every five feet" as described in the safety evaluation. Due to the volume and configuration of DCPP's containment, the overlapping ZOIs essentially covered the same locations. The approach used was to determine the limiting debris generation locations (based on ZOIs) and then determine the quantity and types of debris within the ZOI. This simplification of the process did not reduce the debris generation potential for the worst case conditions as described in NEI 04-07 and the safety evaluation.

Through a review of the breaks evaluated it was determined that all breaks generate similar quantities of debris from erosion of unjacketed fibrous materials, latent dirt/dust, miscellaneous debris (stickers, tags, labels, tape), coatings in the ZOI (particulate), and unqualified coating chips. Therefore, breaks that present the greatest challenge to post-accident sump performance are breaks that generate limiting amounts of cal-sil and fibrous debris. All areas with a significant potential to generate fibrous debris (Loop 2 crossover leg, pressurizer surge line, and pressurizer loop seal lines) have been analyzed. All areas with a significant potential to generate cal-sil debris (hot-leg, cold-leg, and crossover legs on all four loops) have been analyzed. Debris quantities have been calculated for any location which generates substantial quantities of fibrous insulation or cal-sil insulation.

Debris Transport

The purpose of the debris transport evaluation is to estimate the fraction of debris that would be transported from debris sources within containment to the sump strainers. The methodology used in the transport analysis is based on the NEI 04-07, Volume 1, guidance for refined analyses as modified by the refined methodologies suggested in Appendices III, IV, and VI of NEI 04-07, Volume 2. The specific effect of each of four modes of transport was analyzed for each type of debris generated. These modes of transport are:

- Blowdown transport – the vertical and horizontal transport of debris to all areas of containment by the break jet;

- Washdown transport – the vertical (downward) transport of debris by the CSS and break flows;

- Pool fill-up transport – the transport of debris by break and CSS flows from the RWST to regions that may be active or inactive during recirculation; and

- Recirculation transport – the horizontal transport of debris from the active portions of the recirculation pool to the sump screens by the flow through the ECCS.

The logic tree approach was then applied for each type of debris determined from the debris generation calculation. The logic tree used by DCPP is somewhat different than the baseline logic tree provided in NEI 04-07, Volume 1. This departure was made to account for certain nonconservative assumptions identified in NEI 04-07, Volume 2, including the transport of large pieces, the potential for washdown debris to enter the pool after inactive areas have been filled, and the direct transport of debris to the sump screens during pool fill-up. Also, the generic logic tree was expanded to account for a more refined debris size distribution.

As part of DCPP's debris reduction modifications, debris interceptors were installed in all three crane wall doors. These debris interceptors are vertically mounted perforated stainless steel plates (18-inches tall, 11 gauge, with 1/8-inch diameter holes) with a horizontal lip (10 inches, also perforated stainless steel plate) that projects into the flow.

Prototypical debris interceptors were tested at critical parameters (expected fluid velocity, flood height and turbulent kinetic energy [TKE]) to determine the performance of the debris interceptors. As was shown in testing, debris which transports to the debris interceptor by tumbling along the floor will be stopped by the interceptor. Debris which is suspended near the debris interceptor is assumed to transport over the interceptor, with the exception of paint chips.

This testing replicated an accurate reflective metal insulation (RMI) debris bed in front of the interceptor, and suspended 9-mil unqualified coatings chips and 2-mil high heat aluminum chips (in separate tests) uniformly throughout the flow stream. The test showed that the debris interceptor is effective in capturing a portion of the 9-mil coatings chips and 2-mil coatings chips, even with sufficient TKE to suspend them at the interceptor.

Head Loss

As there are no acceptable analytical methods available for the selection and sizing of a suitable strainer, the resolution of Generic Letter 2004-02, September 2004 for DCPP was an evolution of iterations of head loss testing, fiber bypass testing, and debris mitigation. A base debris loading was obtained from the existing debris within containment. As the replacement screen size was limited due to the space constraints

and fiber bypass limitations, various debris mitigation options were considered. The resulting debris loads were determined and subsequent head loss and bypass tests were performed to verify strainer performance. This iteration process was repeated, as required to obtain successful results. The ultimate resolution was the screen head loss and fuel bottom nozzle head loss testing which confirmed the ability to maintain a coolable core on recirculation with debris-laden fluid.

Sump strainer head losses were determined through a combination of testing and analysis. The testing performed was designed to assure that a conservative design basis head loss would be determined for DCPP. The head losses associated with the portion of the strainers downstream of the perforated plate screens (the strainer plenums and RHR piping entrance) were established using analytical methods.

The testing performed included use of debris loadings representative of the design basis debris loads and included fiber, particulate, coating chips, and chemical precipitate debris. This testing program provides the basis for all strainer head losses and covers both clean-screen and debris-laden conditions.

In addition to strainer head loss testing, DCPP has performed fiber bypass testing to determine the quantity of fibrous debris which could potentially bypass the strainer and be capable of forming a debris bed on the fuel bottom nozzle.

Downstream Effects

The purpose of the downstream effects evaluation is to evaluate the effects of debris carried downstream of the containment recirculation sump strainers on the function of the ECCS and CSS in terms of potential wear of components and blockage of flow streams.

The following specific downstream effects evaluations have been completed:

- Debris ingestion evaluation
- Blockage of equipment in the ECCS/CSS flow paths
- Erosive wear of ECCS/CSS valves
- Wear and abrasion on auxiliary equipment
- Fuel and vessel evaluation

The debris ingestion evaluation determined the quantity and size of debris which may bypass the containment sump strainer assemblies, and the concentration of this debris in the sump pool following a high energy line break. The output of this evaluation is used in the subsequent downstream evaluations.

The blockage evaluation determined that there are no blockage/plugging issues for existing piping, valves, instrumentation lines, orifices, eductors, heat exchanger tubes, and CSS nozzles. As part of the resolution for Generic Letter 2004-02, September 2004, new ECCS screens were installed in DCPP Unit 1 and Unit 2. The new screens were specified to be fabricated from stainless steel plates with holes of 3/32-inch perforations. Although the blockage evaluation was performed on the previous screen configuration with 1/8-inch round openings, the blockage evaluation was reviewed and determined to be conservative for the new replacement screen with nominal 3/32-inch round openings. A post installation inspection was performed on the replacement screens to verify that there were no gaps between the joints of any two adjacent surfaces greater than the nominal hole or gap size. The potential for blockage of the RVLIS is not included in this evaluation. DCPP has a Westinghouse designed RVLIS for which Reference 17 states there is no blockage concern due to the debris ingested through the sump strainer assembly during recirculation.

The erosive wear evaluation determines the downstream effects of sump debris with respect to erosive wear on the valves in the ECCS and CSS at DCPP Unit 1 and Unit 2 using the methodology of Reference 17.

As required by the WCAP methodology, a detailed erosive wear evaluation was required for 12 ECCS throttle valves, Valves 8822A-D, 8904A-D, and 8810A-D. Erosion of valves, calculated as a change in flow area divided by the original flow area (ΔA/A), must remain less than 3 percent ΔA/A. This criterion was established in Reference 17 to prevent erosive wear from significantly impacting the flow rate through the valves. The results of this evaluation show that all valves pass the erosion evaluation using the depleting debris concentration evaluation.

Wear and abrasion of auxiliary equipment evaluation addresses wear and abrasion from debris ingestion on the DCPP auxiliary equipment. This includes the effects of abrasive and erosive wear on applicable pumps, heat exchangers, orifices, and spray nozzles in the ECCS and CSS, following the methodology in Reference 17.

Erosion is defined as the gradual wearing away of material on an object due to particles impinging on the surface of the object. Abrasion is defined as the gradual wearing away of material on an object due to friction of particles rubbing the surface of the object.

For heat exchangers, orifices, and spray nozzles, the two concerns raised by debris ingestion are plugging (previously addressed) and failure due to erosive wear. Failure of the heat exchangers, orifices, and spray nozzles to maintain system performance could occur as a result of loss of wall material caused by erosive wear.

The DCPP heat exchangers, orifices, and spray nozzles were evaluated for the effects of erosive wear for a constant debris concentration as determined in the debris ingestion evaluation. The erosive wear on these components was determined to be insufficient to affect the system performance.

For pumps, the concern raised by debris ingestion through the sump strainer assembly during recirculation is failure due to abrasive and erosive wear. Three aspects of pump operability are potentially affected by debris ingestion including hydraulic performance, mechanical shaft seal assembly performance, and mechanical performance (vibration) of the pump.

For the DCPP ECCS pumps, the effect of debris ingestion through the sump strainer assembly on three aspects of operability, including hydraulic performance, mechanical shaft seal assembly performance, and mechanical performance (vibration) of the pumps, were evaluated. The hydraulic and mechanical performances of the pumps were determined to not be affected by the recirculating sump debris for the 30-day mission time of the pumps.

There has been no demonstration that the ECCS pump primary seals would fail during a postulated LOCA. The 40-hour testing referenced in Section 8.1.3 of Reference 17 showed that the seals did not fail when tested. Mechanical pump seals at DCPP were not considered to fail as a result of the downstream debris after a postulated LOCA. Such seals would still be subject to a postulated single passive failure of the pressure boundary. Section 6.3.3.6.2.8 describes the detection and isolation capabilities to minimize the effects of a post-LOCA recirculation loop leakage.

Fuel and Vessel

The objective of the fuel and vessel downstream evaluation is to determine the effects that debris carried downstream of the containment sump strainer assembly and into the reactor vessel has on core cooling.

The following specific fuel and vessel downstream effects evaluation have been performed:

- Vessel blockage
- Fuel blockage, bottom nozzle tests
- Loss-of-Coolant Deposition Analysis Model (LOCADM) analysis

The vessel blockage evaluation determined the potential for reactor vessel blockage from debris carried downstream of the containment recirculation sump strainer assembly. In addition to locations at the core inlet and exit, other possible locations for blockage within the reactor vessel internals which might affect core cooling were assessed. The smallest clearance in the reactor vessel exclusive of the core was found to be 0.52 inches and 0.46 inches for DCPP Unit 1 and Unit 2, respectively. These dimensions are approximately five times greater than the dimension of the strainer holes in the containment recirculation sump screen.

Therefore, any debris that could make it through the 3/32-inch holes in the strainer would not challenge the limiting (smallest) clearances in the vessel.

DCPP performed fuel bottom nozzle head loss test to determine the effects of debris carried downstream of the containment sump strainer assembly onto the fuel assembly. The test and evaluation is an alternate assessment of fuel blockage performed for DCPP. DCPP is taking exception to the Reference 17 screening evaluation method. A series of fuel assembly bottom nozzle head loss tests were performed.

The test article for the fuel bottom nozzle head loss tests consisted of a simulated core support plate, a bottom nozzle, a P-grid, an intermediate support grid, simulated fuel rods and simulated control rods. Fuel bottom nozzle head loss tests were conducted using the actual fibrous debris which bypassed the test sector during the fiber bypass tests with maximum particulate debris (it was conservatively assumed that 100 percent of the particulate debris which arrives at the strainer also arrives at the fuel bottom nozzle). Unqualified inorganic zinc and unqualified high heat aluminum coatings were conservatively assumed to fail as particulate debris when conducting the fuel bottom nozzle head loss tests, and were conservatively assumed to fail as chips when conducting strainer head loss tests. Fuel bottom nozzle head loss tests conservatively included all chemical precipitate debris.

The fuel bottom nozzle head loss effects were evaluated by Westinghouse through a comparison between the measured head loss of the test data and available driving head for the various DCPP LOCA scenarios.

The Westinghouse comparisons showed that sufficient driving head is available to match the head loss due to debris buildup, therefore, adequate flow will enter the core to match boil-off, and the core will remain covered. Because the core remains covered, Westinghouse concluded that no late heatup occurs, and the maximum local oxidation, the corewide oxidation, and the peak cladding temperature calculations for the traditional LOCA analyses are still considered applicable.

The LOCADM evaluation used the LOCADM code from Reference 18 to predict the growth of fuel cladding deposits and to determine the clad/oxide interface temperature that results from coolant impurities entering the core following a LOCA.

The stated acceptance criterion is that the maximum cladding temperature maintained during periods when the core is covered will not exceed a core average clad temperature of 800°F. This acceptance basis is applied after the initial quench of the core and is consistent with the long-term core cooling requirements stated in 10 CFR 50.46 (b)(4) and 10 CFR 50.46 (b)(5).

An additional acceptance criterion is to demonstrate that the total debris deposition on the fuel rods (oxide plus crud plus precipitate) is less than 50 mils. This is based on the maximum acceptable deposition thickness before bridging of adjacent fuel rods by debris is predicted to occur. Debris accumulation in the fuel was observed at the lower

grid locations during testing. The testing showed that the bridging that occurred at the grids was acceptable, and that flow through the accumulated debris bed was sufficient to ensure cooling of the fuel.

The evaluation was performed with the LOCADM code using DCPP specific data. The results of this evaluation show that the calculated fuel cladding deposits and clad/oxide interface temperature do not challenge the acceptance criteria.

For the minimum sump water volume cases, LOCADM was also run with increased quantities of debris – in accordance with the bump-up factor methodology. The bump-up factor had a negligible effect on both the total thickness and fuel cladding temperature.

The results of these evaluations show that DCPP can maintain adequate long-term core cooling post-LOCA.

6.3.3.35 Generic Letter 2008-01, January 2008 – Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems

Comprehensive piping isometric drawing reviews were performed to evaluate ECCS piping for the potential for gas accumulation and transport to the suction of the ECCS pumps. Plant modifications (e.g., the replacement of air operated valves with manual valves, and the installation of high point vents, void headers, etc.) were implemented to prevent gas intrusion/accumulation in the ECCS.

The DCPP Gas Intrusion Program prevents and manages gas accumulation to within design and licensing requirements. System venting procedures ensure appropriate accumulated gas removal following system breaches and during normal operation. DCPP plant procedures include instructions and controls for performing ultrasonic testing (UT) of ECCS piping to detect gas accumulation. The ECCS is periodically inspected per DCPP Technical Specifications (Reference 10) to verify that ECCS piping is full of water.

Design drawing details support fill and vent activities and periodic venting of gas accumulation during normal plant operations. Drawings and procedures provide guidance for evaluating on-line maintenance including details of flushing capability to preclude gas intrusion into system piping that cannot be vented during refill operations.

6.3.3.36 IE Bulletin 79-06A (Position 8), April 1979 – Review of Operational Errors and System Misalignments Identified During the Three Mile Island Incident

Position (8) (subsequently NUREG-0737, November 1980, Item II.K.1.5, Safety Related Valve Position):

Critical manual valves in the ECCS are sealed in position and a check list is maintained for inspection on a typical audit basis. When the ESF system operates, the misalignment of any remotely-operated critical valve in the ECCS will be shown by a monitor light on the main control board.

All ECCS PG&E Design Class I valves which are operated remotely and whose purpose is to open or close (rather than throttle flow) have position indicating lights on the main control board. Valves with power removed from their motor operators during normal operation have continuously energized position indicating lights on the main control board which are redundant to the monitor lights that indicate misalignment of any remotely-operated critical valve discussed above.

6.3.3.37 IE Bulletin 80-18, July 1980 – Maintenance of Adequate Minimum Flow Thru Centrifugal Charging Pumps Following Secondary Side High Energy Line Rupture

In order to ensure adequate minimum flow is available to the ECCS CCPs, DCPP maintains the CCP recirculation line isolation MOVs in the open position under all pumping conditions, except for post-LOCA recirculation mode when they are closed. The “S” signal no longer provides automatic closure of these valves, as that signal was removed from the valves in response to IE Bulletin 80-18, July, 1980.

6.3.3.38 NRC Bulletin 88-04, May 1988 – Potential Safety-Related Pump Loss

To prevent pump to pump interaction as a result of differences between pump flow characteristics, check valves were installed downstream of the RHR heat exchangers. During minimum flow operation the check valve will prevent the stronger pump from deadheading/reversing flow into the weaker pump, thereby maintaining minimum required recirculation flow.

An evaluation concluded that the existing pump minimum flow rates are adequate for all the pumps evaluated and no changes to hardware or operating procedures would be required, with the exception of the RHR pumps during an inadvertent safety injection. When the RHR pumps are operating in this mode, they could potentially experience unusual wear and aging due to the flow hydraulic effects. This wear and aging is long term in nature and is expected to result in gradual wear to the pumps. Wear and aging of the pumps can be detected through monitoring and trending pump performance parameters, vibration levels, and bearing temperatures. Increased maintenance and part replacement may occur due to the described wear and aging effects.

6.3.3.39 NRC Bulletin 88-08, June 1988 – Thermal Stresses in Piping Connected to Reactor Coolant Systems

The charging injection header, for both DCPP Unit 1 and Unit 2, has been modified to include a recirculation line back to the charging pump suction. This passive recirculation line continuously vents valve seepage and accompanying pressure build-up in the charging injection header during normal operations. During accident conditions, the small size and large resistance of the recirculation line limits the recirculation flow to an acceptable negligible value. The charging injection header is also periodically verified to be less than RCS pressure, and is procedurally directed to be depressurized via venting if RCS pressure is approached. The periodic verification of the charging injection header pressure serves as a redundant means to prevent unacceptable thermal stresses due to temperature stratifications induced by leaking valves in the event of blockage or maintenance to the recirculation line.

In a similar manner, the charging injection bypass line is periodically verified to be less than RCS pressure; thereby eliminating the possibility of undetected leakage from this line. If RCS pressure is approached, the charging injection bypass line is procedurally directed to be vented.

6.3.3.40 NRC Bulletin 2003-01, June 2003 – Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized-Water Reactors

DCPP Unit 1 and Unit 2 had two configurations where the flow paths to the containment recirculation sump were possibly susceptible to the issue of blockage due to the accumulation of debris, as discussed in NRC Bulletin 2003-01, June 2003. These were the refueling cavity drain (at elevation 99 feet 6 inches) and the three doors installed in the crane wall (at elevation 91 feet 0 inches).

To prevent potential blockage due to the accumulation of debris, the refueling cavity drain was modified with a raised drain screen and the three crane wall doors were modified with replacement bars that are less restrictive to flow. This configuration allows the passage of most of the floating debris without causing a blockage of the flow path. The doorframes function as debris curbs.

A licensee controlled program provides administrative control for the crane wall doors to ensure they perform their intended safety function. DCPP plant procedures ensure no loose debris (rags, trash, clothing, insulation, plastics, etc.) exists inside containment and provide instructions to personnel not to use fibrous insulation inside containment as a replacement for reflective metal or calcium silicate insulation without prior authorization.

6.3.3.41 Branch Technical Position EICSB 18, November 1975 – Application of the Single Failure Criterion to Manually-Controlled Electrically-Operated Valves

During the safety review of the operating license application for the DCPP, the AEC (now NRC) regulatory staff adopted the position that failures of the type discussed in Section 6.3.3.5.4, that could lead to spurious movement of passive MOVs, must be considered in relation to satisfying the single failure criterion. The regulatory staff's position, as stated in Branch Technical Position EICSB 18, November 1975, considers removal of electric power an acceptable means, under certain conditions, of satisfying the single failure criterion. As a consequence of the regulatory staff's requirements, electric power will be removed from certain ECCS and RHR valves during normal operation. These valves are listed in Table 6.3-12. When electric power is removed from the valve operators, power is still supplied to position indication circuitry so that there is continuous, redundant position indication on the control board. Redundant position indication is provided by two sets of lights: (a) red and green position lights that indicate open or closed, and (b) white monitor lights that illuminate when the valves are not in their proper locked-out position.

6.3.4 Tests and Inspections

To demonstrate the readiness and operability of the ECCS, all of the components are subjected to periodic tests and inspections. Preoperational performance tests of ECCS components were conducted in the manufacturer's shop. An initial system flow test was performed to demonstrate proper components functioning.

Refer to Sections 6.3.3.7, 6.3.3.13 through 6.3.3.16, 6.3.3.18, 6.3.3.23 and 6.3.3.24 for details regarding tests and inspections of the ECCS.

6.3.4.1 Quality Control

Tests and inspections were carried out during fabrication of each of the ECCS components. These tests were conducted and documented in accordance with the quality assurance program discussed in Chapter 17.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

6.3.4.2 Preoperational System Tests

These tests evaluated the hydraulic and mechanical performance of the passive and active components involved in the injection mode by demonstrating that they have been installed and adjusted so they will operate in accordance with the intent of the design. The tests were divided into two categories: component tests and integrated system test. The components tests were divided into the following five sub-categories: (a) valve and pump actuation, (b) accumulator injection, (c) RHR pump, (d) SI pump,

and (e) CCP1/CCP2 performance tests. The integrated systems tests are described in Section 6.3.3.26.1.

6.3.4.2.1 Component Tests

The actuation tests verified: the operability of all ECCS valves initiated by the "S" signal, the phase A containment isolation signal ("T"), and the Phase B containment isolation signal ("P"), the operability of all safety feature pump circuitry down through the pump breaker control circuits, and the proper operation of all valve interlocks. Sequencing and timing tests were conducted to verify that the ECCS components will be aligned properly to perform their intended functions.

The objective of the accumulator injection test was to verify that the injection lines were free from obstruction and that the accumulator check valves operate correctly. The test objectives were met by a low-pressure blowdown of each accumulator. The test was performed with the reactor head and internals removed. The acceptance criteria for the accumulator blowdown test were based on equaling or exceeding a calculated curve; the curve simulated the system line resistances (L/D). The primary intent of the accumulator blowdown tests was to verify these calculated discharge line resistances.

The purpose of the three pump performances tests (RHR pumps, SI pumps, and CCP1/CCP2) was to evaluate the hydraulic and mechanical performance of the pumps delivering through the flowpath required for emergency core cooling. These tests were divided into two parts: pump operation under miniflow conditions and pump operation at full flow conditions.

The predicted system resistances were verified by measuring the flow in each piping branch, as each pump delivered from the RWST to the open reactor vessel, and adjustments were made where necessary to ensure that flow was distributed properly among branches.

During flow tests, each system was checked to ensure that there is sufficient minimum total line resistance to preclude runout from overloading the motor of any pump. At the completion of the flow tests, the total pump flow and relative flow between the branch lines were compared with the system acceptable flows.

Each system was accepted only after demonstration of proper actuation of all components and after demonstration of flow delivery of all components within design requirements.

6.3.4.3 Containment Recirculation Sump and Screen Inspection

No periodic testing is performed for the containment recirculation sump. However, the sump and screens are inspected during each regularly scheduled refueling outage, and after any maintenance that could result in sufficient debris to block the sump screens. Work area inspections are performed at the conclusion of maintenance activities

anywhere in the containment to ensure that debris that could block the sump screens is removed.

6.3.5 Instrumentation Applications

Refer to Section 6.3.3.4 for the instrument applications related to ECCS.

6.3.6 REFERENCES

1. Deleted in Revision 22.

2. Deleted in Revision 22.

3. Deleted in Revision 22.

4. Deleted in Revision 22.

5. Deleted in Revision 22.

6. Environmental Testing of Engineered Safety Features Related Equipment (NSSS-Standard Scope), WCAP-7744, Volume I, August 1971.

7. Deleted in Revision 22.

8. DELETED

9. Diablo Canyon Power Plant - Inservice Inspection Program Plan - The Third 10 Year Inspection Interval.

10. Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.

11. Deleted in Revision 22.

12. IEEE-Std-279, Criteria for Protection Systems for Nuclear Power Generating Stations, 1971.

13. Deleted in Revision 22.

14. Deleted in Revision 22.

15. Deleted in Revision 22.

16. License Amendment Nos. 199 (DPR-80) and 200 (DPR-82), "Technical Specification 3.5.4, Refueling Water Storage Tank (RWST)," USNRC, March 26, 2008.

17. Rinkacs, W.J., et al., Evaluation of Downstream Sump Debris Effects in Support of GSI-191, WCAP-16406-P, Revision 1 (Proprietary), August 2007.

18. Rinkacs, W.J., et al., Evaluation of Long-Term Cooling Considering Particulate, Fibrous and Chemical Debris in the Recirculating Fluid, WCAP-16793-NP, Revision 0 (Non-Proprietary), May 2007.

6.4 HABITABILITY SYSTEMS

The DCPP habitability systems are associated with the control room and the onsite technical support center (TSC).

Both facilities are designed to be habitable throughout the course of a design basis accident and the resulting radiological conditions, except that the TSC system is manually activated. In addition, the control room is designed to be habitable throughout the course of a hazardous chemical release.

6.4.1 CONTROL ROOM

The DCPP control room, located at elevation 140 feet of the auxiliary building, is common to Unit 1 and Unit 2. The associated habitability systems provide for access and occupancy of the control room during normal operating conditions, radiological emergencies, hazardous chemical emergencies, and fire emergencies. Control room habitability is supported by administrative procedures, shielding, the ventilation and air conditioning system, the fire protection system, kitchen facilities, and sanitary facilities Normal operating and post-accident control room operating, emergency, and administrative procedures are contained in the DCPP Plant Manual. The several volumes of the Plant Manual are listed in Section 13.5.

6.4.1.1 Design Bases

6.4.1.1.1 General Design Criterion 2, 1967 - Performance Standards

The control room habitability systems are designed to withstand the effects of or are protected against natural phenomena, such as earthquakes, flooding, tornados, winds, and other local site effects.

6.4.1.1.2 General Design Criterion 3, 1971 - Fire Protection

The control room habitability systems are designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

6.4.1.1.3 General Design Criterion 4, 1967 - Sharing of Systems

The control room habitability systems and components are not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

6.4.1.1.4 General Design Criterion 11, 1967 - Control Room

A control room is provided from which actions to maintain safe operational status of the plant can be controlled. The control room is designed to support safe shutdown and to maintain safe shutdown from the control room or from an alternate location if control room access is lost due to fire or other causes. The control room provides adequate

radiation protection to permit access without radiation exposures to personnel in excess of 10 CFR Part 20 limits under normal conditions.

6.4.1.1.5 General Design Criterion 12, 1967 - Instrumentation and Control Systems

Instrumentation and controls related to control room habitability are provided to monitor and maintain applicable variables within prescribed operating ranges.

6.4.1.1.6 General Design Criterion 17, 1967 - Monitoring Radioactivity Releases

Radiation monitoring instrumentation is provided to monitor radioactive releases entering each control room normal air intake and pressurization system intake. Area radiation monitoring is provided in the control room.

6.4.1.1.7 General Design Criterion 19, 1971 - Control Room

The control room is designed to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of a design basis accident.

6.4.1.1.8 General Design Criterion 37, 1967 - Engineered Safety Features Basis for Design

The control room habitability systems are designed to provide backup to the safety provided by the core design, the reactor coolant pressure boundary, and their protection systems.

6.4.1.1.9 10 CFR Part 50, Appendix R (Sections III.G, III.J, and III.L) - Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979

Section III.G – Fire Protection of Safe Shutdown Capability: Fire protection of the control room habitability systems is provided by a combination of physical separation, fire-rated barriers, and automatic suppression (except in the control room) and detection.

Section III.J – Emergency Lighting: Emergency lighting or Battery Operated Lights (BOLs) are provided in the control room and associated areas required to safely shut down a unit in the event of a fire.

Section III.L – Alternative and Dedicated Shutdown Capability: Safe shutdown capabilities are provided in the control room and at an alternate location via the hot shutdown panel or locally at the 480-V switchgear, for equipment powered by the 480-V system required for the safe shutdown of the plant, in the event of a fire.

6.4.1.1.10 Regulatory Guide 1.52, Revision 0, June 1973 - Design, Testing, and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants

The control room heating and ventilation system (CRVS) design, testing, and maintenance comply with applicable Regulatory Guide 1.52, June 1973, requirements with exceptions as noted in Table 9.4-2.

6.4.1.1.11 Regulatory Guide 1.97, Revision 3, May 1983 - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Instrumentation is provided to monitor control room emergency ventilation damper position failure on engineered safety features (ESF) actuation.

6.4.1.1.12 Regulatory Guide 1.197, Revision 0, May 2003 - Demonstrating Control Room Envelope Integrity At Nuclear Power Reactors

Control room envelope (CRE) integrity testing is conducted such that:

(1) An integrated in-leakage test (i.e., the American Society for Testing and Materials [ASTM] Standard E741-2000 method) is conducted in concert with the component test.

(2) The results of the two methods correlate; and

(3) The components tested account for no less than 95 percent of the CRE in-leakage as determined by the integrated in-leakage test.

6.4.1.1.13 NUREG-0737 (Items II.B.2 and III.D.3.4), November 1980 - Clarification of TMI Action Plan Requirements

Item II.B.2 – Design Review of Plant Shielding and Environmental Qualification of Equipment for Spaces/Systems Which May Be Used in Postaccident Operations: Adequate access to the control room is provided by design changes, increased permanent or temporary shielding, or post-accident procedural controls.

Item III.D.3.4 – Control-Room Habitability Requirements: The control room is designed to ensure operators are adequately protected against the effects of accidental release of toxic and radioactive gases such that the nuclear power plant can be safely operated or shut down under design basis accident conditions.

6.4.1.1.14 Generic Letter 2003-01, June 2003 - Control Room Habitability

The control room meets the applicable habitability regulatory requirements and the habitability systems are designed, constructed, configured, operated, and maintained in accordance with the facility's design and licensing bases, with emphasis on ensuring:

(1) The most limiting unfiltered in-leakage (and the filtered in-leakage if applicable) into the CRE is no more than the value assumed in the design basis radiological analyses for control room habitability.

(2) The most limiting unfiltered in-leakage into the CRE is incorporated into the hazardous chemical assessments. This in-leakage may differ from the value assumed in the design basis radiological analyses. The reactor control capability is maintained from either the control room or alternate shutdown location in the event of smoke.

(3) Technical specifications verify the integrity of the CRE, and the assumed in-leakage rates of potentially contaminated air.

6.4.1.2 System Description

The design bases for the functional design of control room habitability systems for both normal and emergency radiological hazards were:

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

(1) *10 CFR 20.1 through 20.601, Standards for Protection Against Radiation (pre-1995; compliance with current requirements of Part 20 is addressed in Chapter 12):*

"...no licensee shall possess, use, or transfer licensed material in such a manner as to cause any individual in a restricted area to receive in any period of one calendar quarter from radioactive material and other sources of radiation in the licensee's possession a dose in excess of the standards specified in the following table:

	Rems per calendar quarter
Whole body; head and trunk, active blood-forming organs; lens of eyes, or gonads	*1-1/4*
Hands and forearms; feet and ankles	*18-3/4*
Skin of whole body	*7-1/2"*

(2) GDC 19, 1971 - Refer to Sections 6.4.1.1.7 and 6.4.1.3.7 for discussion

(3) The National Council on Radiation Protection and Measurements (NCRP) Report No. 39 (1971), Basic Radiation Protection Criteria:

"It is compatible with the risk concept to accept exposures leading to doses considerably in excess of those appropriate for lifetime use when recovery from an accident or major operational difficulty is necessary. Saving of life, measures to circumvent substantial exposures to population groups or even preservation of valuable installations may all be sufficient cause for accepting above-normal exposures. Dose limits cannot be specified. They should be commensurate with the significance of the objective, and held to the lowest practicable level that the emergency permits."

As described in Section 12.1.2, control room shielding consists of concrete walls, floor, and roof. Control room shielding design radiation exposure limits are consistent with GDC 19, 1971.

The CRVS is a redundant, PG&E Design Class I system. The PG&E Design Class I systems included in the CRVS are the control room heating, ventilation, and air conditioning (CRHVAC) system and the control room pressurization system (CRPS). The third system included in the CRVS, the plant process computer (PPC) room air conditioning system, is PG&E Design Class II. Sections 9.4 and 12.2 describe the CRVS.

Control room communications are described in Section 9.5.2.

Kitchen and sanitary facilities are shared by Unit 1 and Unit 2 and are designed to support operating personnel during normal operating conditions and for the duration of an accident.

6.4.1.3 Safety Evaluation

6.4.1.3.1 General Design Criterion 2, 1967 - Performance Standards

The structures (auxiliary and turbine buildings) that form the CRE are PG&E Design Class I or QA Class S (refer to Section 3.8). These buildings or applicable portions thereof are designed to withstand the effects of winds and tornados (refer to Section 3.3), floods and tsunami (refer to Section 3.4), external missiles (refer to Section 3.5), earthquakes (refer to Section 3.7), and other applicable natural phenomena, and to protect the CRE and its safety functions from damage due to these events.

Refer to Section 9.4.1 for evaluation of CRVS components.

6.4.1.3.2 General Design Criterion 3, 1971 - Fire Protection

The control room habitability systems are designed to the fire protection guidelines of Branch Technical Position APCSB 9.5-1 (refer to Appendix 9.5B, Table B-1). The adequacy of the control room fire protection system is evaluated in Sections 7.7.1 and 9.5.1.

6.4.1.3.3 General Design Criterion 4, 1967 - Sharing of Systems

The control room is common to DCPP Unit 1 and Unit 2 and therefore requires sharing of SSCs between units. The CRVS is shared between Unit 1 and Unit 2. In addition, CRPS pressurization is shared by the control room and the TSC. The sharing of these systems is addressed in Section 9.4.1.3.3.

6.4.1.3.4 General Design Criterion 11, 1967 - Control Room

Control room habitability is provided by shielding, the CRVS, and the fire protection system. The adequacy of control room shielding is evaluated for normal operating conditions in Chapter 11 and Section 12.1. The adequacy of the CRVS is evaluated for normal operating conditions in Chapter 11 and Sections 9.4.1 and 12.1; for hazardous chemical emergencies in Section 9.4.1; and for fire emergencies in Sections 9.4.1 and 9.5.1.

6.4.1.3.5 General Design Criterion 12, 1967 - Instrumentation and Control Systems

Controls for control room habitability components are provided for system operation. Instrumentation is provided for monitoring habitability system parameters during normal operations and accident conditions (refer to Sections 6.4.1.3.6 and 6.4.1.5).

6.4.1.3.6 General Design Criterion 17, 1967 - Monitoring Radioactivity Releases

Main control room normal air intake radiation monitors and CRPS intake radiation monitors are provided to detect radioactivity in the air flow into the control room ventilation and pressurization systems. A control room area radiation monitor is provided to monitor radiation in the control room environs.

6.4.1.3.7 General Design Criterion 19, 1971 - Control Room

The control room habitability systems permit access and occupancy for operating the plant without personnel receiving radiation exposures in excess of GDC 19, 1971, limits for the duration of a design basis accident. The adequacy of control room shielding is evaluated for post-accident conditions in Section 15.5. The adequacy of the CRVS is evaluated for radiological emergencies in Section 15.5. Note that for the postulated fuel handling accident in the fuel handling building, an alternate source term is assumed per 10 CFR 50.67 (refer to Section 15.5.22).

6.4.1.3.8 General Design Criterion 37, 1967 - Engineered Safety Features Basis for Design

By providing for operator access and occupancy so that the plant can be maintained in a safe condition under accident conditions, the control room habitability system ESF function performed by the CRVS provides the capability to control the airborne radioactive material that could enter the control room atmosphere in the event of a postulated loss-of-coolant accident (LOCA) to acceptable levels (refer to Section 6.1.2).

6.4.1.3.9 10 CFR Part 50, Appendix R (Sections III.G, III.J, and III.L) - Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979

Section III.G - The control room is provided with fire protection features that limit fire damage and support habitability and operator occupancy for safe reactor operation in compliance with 10 CFR Part 50, Appendix R, Section III.G requirements. The control room is constructed of noncombustible, fire-resistant, and fire-retardant materials; and is separated from the rest of the plant by minimum three-hour fire barriers. The existence of doors in the perimeter walls and the absence of an area-wide fixed fire protection system have been evaluated and found acceptable. Extinguishers are located within the control room, and hose stations are located in adjacent rooms. Smoke detectors are provided in control room cabinets and consoles containing redundant safe shutdown cabling. Self-Contained Breathing Apparatus (SCBA) units for operators are readily available in the control room complex. The operator can isolate the control room manually. Also, smoke removal is facilitated by the capability to operate the ventilation system on a once-through basis (refer to Appendix 9.5B, item F.2).

Section III.J - The installed emergency lighting system in the control room provides an acceptable margin of safety equivalent to that provided by 10 CFR Part 50, Appendix R, Section III.J requirements (refer to Appendices 9.5D and 9.5B, item D.5).

Section III.L - Post-fire safe shutdown capability is provided that meets the requirements of 10 CFR Part 50, Appendix R, Section III.L (refer to Appendix 9.5E).

6.4.1.3.10 Regulatory Guide 1.52, Revision 0, June 1973 - Design, Testing, and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants

The CRVS is the ESF system that provides the capability to control the airborne radioactive material that could enter the control room atmosphere during design basis events to acceptable levels. The extent of compliance and noted exceptions to Regulatory Guide 1.52, June 1973, design, testing, and maintenance criteria are discussed in Table 9.4-2. Requirements for the performance of ventilation filter testing are stated in the DCPP Technical Specifications.

6.4.1.3.11 Regulatory Guide 1.97, Revision 3, May 1983 - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Damper failure indication in the control room provides status of the Unit 1 and Unit 2 CRPS fan suction and discharge motorized dampers in response to an ESF actuation (refer to Table 7.5-6, item 63).

6.4.1.3.12 Regulatory Guide 1.197, Revision 0, May 2003 - Demonstrating Control Room Envelope Integrity At Nuclear Power Reactors

Required testing for CRE integrity includes:

(1) An integrated test for total CRE in-leakage per ASTM E741-2000,

(2) The integrated test is conducted in concert with and correlated with component testing, and

(3) The components tested should account for no less than 95 percent of the CRE in-leakage as determined by the integrated in-leakage test.

Testing includes peer reviews to identify in-leakage vulnerabilities, quantitative testing methods, and verification, prior to testing, of the consistency of air sources and ventilation system flow rates with the licensing basis. The requirements for compliance with Regulatory Guide 1.197, May 2003, are described in the DCPP Technical Specifications.

6.4.1.3.13 NUREG-0737 (Items II.B.2 and III.D.3.4), November 1980 - Clarification of TMI Action Plan Requirements

Plant shielding and the CRVS are designed to maintain control room habitability under accident conditions as discussed in the following sections:

Item II.B.2 - Design Review of Plant Shielding and Environmental Qualification of Equipment for Spaces/Systems Which May Be Used in Postaccident Operations: The adequacy of control room shielding is evaluated for post-accident conditions in Section 15.5.

Item III.D.3.4 – Control-Room Habitability Requirements: The adequacy of the CRVS is evaluated for radiological emergencies in Section 15.5, for hazardous chemical emergencies in Section 9.4.1, and for fire emergencies in Sections 9.4.1 and 9.5.1.

A minimum of ten SCBA units (five for each unit) are provided in the control room.

6.4.1.3.14 Generic Letter 2003-01, June 2003 - Control Room Habitability

Testing is performed to demonstrate compliance with guidance provided by Regulatory Guide 1.197, May 2003, using the alignment that would result in the greatest consequence to the control room operator. The purpose of operating the CRVS in mode 4 (the pressurization mode) is to limit radiation exposure to control room personnel in the event of a radiation release. An outside air supply damper and an exhaust damper powered by a common power supply are intentionally failed opened as the single active failure condition for each test configuration. The test alignment involves operating one train in mode 4. The opposite train is placed in mode 3, recirculation, but all fans are shut off.

The DCPP CRE is designed to minimize unfiltered in-leakage. Consistent with Regulatory Guide 1.197, May 2003, Section 1.4, “Test Results and Uncertainty,” the test uncertainty value is not included in results showing in-leakage to be less than 100 standard cubic feet per minute. DCPP Technical Specifications verify the integrity of the CRE with respect to the in-leakage rates of potentially contaminated air assumed in the accident analysis.

There are no offsite or onsite hazardous chemicals that would pose a credible threat to DCPP control room habitability. Therefore, engineered controls for the control room are not required to ensure habitability against a hazardous chemical threat and no amount of assumed unfiltered in-leakage is incorporated into PG&E’s hazardous chemical assessment.

The DCPP assessment of alternate shutdown capability in the event of fire and related smoke effects is discussed in Section 9.5 and associated appendices. SCBA units are provided within the CRE for operator use and portable fans for use with temporary power are appropriately staged to allow operators to provide ventilation in the event that a loss-of-power event has occurred.

6.4.1.4 Tests and Inspections

Testing of the control room habitability systems is discussed in the following sections:

(1)	CRVS	Section 9.4.1
(2)	Fire protection system	Section 9.5.1
(3)	Communication system	Section 9.5.2

Surveillance requirements for inspection and testing of plant equipment are contained in the Technical Specifications (Reference 3) and the Plant Manual. These requirements ensure that performance capability is maintained throughout the lifetime of the plant.

6.4.1.5 Instrumentation Applications

Smoke detector and radiation detector instrumentation employed for monitoring and actuation of the control room habitability systems are discussed in the following sections:

(1)	CRVS	Section 9.4.1
(2)	Fire protection system	Section 9.5.1
(3)	Communication systems	Section 9.5.2

Design details and logic of the instrumentation are discussed in Chapter 7.

6.4.2 TECHNICAL SUPPORT CENTER

The onsite TSC, located on the upper levels of the buttresses on the west side of the Unit 2 turbine building, is common to Unit 1 and Unit 2. The associated habitability systems provide for access and occupancy of the TSC during normal plant operating conditions, fire emergencies, and, with manual activation, throughout the course of a design basis accident. To this end, administrative procedures and shielding, as well as the ventilation and air conditioning, and the fire protection systems, are used.

The TSC is sized to accommodate a minimum of 20 PG&E and 5 Nuclear Regulatory Commission (NRC) personnel as well as necessary data and information displays. It serves as the onsite NRC emergency headquarters. Access to the control room is via the east door of the TSC, across the Unit 2 turbine building at elevation 104 feet, and then to the control room at elevation 140 feet via the elevator or stairway on the east side of the turbine building.

Instrumentation in the TSC is capable of providing displays of vital plant parameters throughout the course of a DBA and personnel have the capability for transmitting technical information between the control room and the TSC by telephone and process computer printout.

6.4.2.1 Design Bases

6.4.2.1.1 General Design Criterion 4, 1967 - Sharing of Systems

The TSC habitability systems are not shared by the DCPP units unless safety is shown not to be impaired by the sharing.

6.4.2.1.2 10 CFR Part 20 - Standards for Protection Against Radiation

TSC personnel are protected from radiation sources such that doses are maintained below limits prescribed in 10 CFR Part 20.

6.4.2.1.3 10 CFR 50.47 - Emergency Plans

Adequate emergency facilities and equipment to support the emergency response are provided and maintained.

6.4.2.1.4 NUREG-0737 (Items II.B.2 and III.A.1.2), November 1980 - Clarification of TMI Action Plan Requirements

Item II.B.2 - Design Review of Plant Shielding and Environmental Qualification of Equipment for Spaces/Systems Which May Be Used in Postaccident Operations: Adequate access to the TSC is provided by increased permanent or temporary shielding.

Item III.A.1.2 - Upgrade Emergency Support Facilities: NUREG-0737, Supplement 1, January 1983 provides the requirements for III.A.1.2 as follows:

Section 8.2.1(e) - The TSC is environmentally controlled to provide room air temperature, humidity, and cleanliness appropriate for personnel and equipment.

Section 8.2.1(f) - The TSC is provided with radiological protection and monitoring equipment necessary to assure that radiation exposure to any person working in the TSC would not exceed 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident.

6.4.2.2 System Description

The TSC is designated to be habitable throughout the course of a design basis accident. The outside walls, with steel bulkhead doors, form an airtight perimeter boundary. The TSC structure is designed to PG&E Design Class III. For seismic qualification, refer to the DCPP Q-List (Reference 8 of Section 3.2).

The TSC has the manual capability to isolate the area from the outside and to recirculate air by the air conditioning system (refer to Section 9.4.11). The hazardous chemical release warning will have to be received from the control room to enable those in the TSC to manually isolate the area from the outside.

The TSC is provided with its own PG&E Design Class II heating, ventilation and air conditioning (HVAC) system. It is not seismically qualified and is fed from a non-Class 1E power source, although the air cleanup portion of the system has the capability to be supplied power from a Class 1E bus. The PG&E Design Class I CRPS system provides a redundant supply of pressurization air to the TSC ventilation system. The CRPS connecting ductwork is designed to PG&E Design Class 1 and the TSC ventilation fans, and filter units are designed to PG&E Design Class II. For seismic qualification, refer to the DCPP Q-List (Reference 8 of Section 3.2). Sections 12.2 and 9.4.11 describe the TSC HVAC system.

TSC fire protection features are designed considering the standards of the National Fire Protection Association, as described in Section 9.5.1. A minimum of ten self-contained breathing apparatuses (five for each unit) are provided in the TSC.
The TSC includes provisions to monitor important plant parameters. The TSC computers provide all necessary plant and health physics data to offsite facilities.

The TSC is tied to the radiological monitoring network such that a laboratory, located adjacent to 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 are unavailable.

Normal operating and post-accident TSC administrative procedures are discussed and evaluated in the DCPP Manual, in Chapters 12 and 13, and in the Emergency Plan.

The TSC communications are described in Section 9.5.2.

6.4.2.3 Safety Evaluation

6.4.2.3.1 General Design Criterion 4, 1967 - Sharing of Systems

The TSC habitability systems are common to Unit 1 and Unit 2 and therefore require sharing of SSCs between units. Because the TSC habitability systems serve no safety functions, sharing between units does not impair safety functions. The CRPS is shared by the control room and the TSC. Sharing of the CRPS by the control room and the TSC is addressed in Section 9.4.1.3.3.

6.4.2.3.2 10 CFR Part 20 - Standards for Protection Against Radiation

TSC personnel are protected from external radiation dose to the extent that doses are maintained within the limits specified in 10 CFR Part 20. Compliance with 10 CFR Part 20 for occupational dose to TSC personnel is discussed in Sections 12.1 (shielding) and 12.2 (ventilation).

6.4.2.3.3 10 CFR 50.47 - Emergency Plans

A TSC that meets applicable requirements is provided and maintained in support of emergency response (refer to Sections 6.4.2, 6.4.2.2 and 6.4.2.3.4). Accessibility to the records of the as-built plant conditions and layout of structures, systems, and components is provided.

6.4.2.3.4 NUREG-0737 (Items II.B.2 and III.A.1.2), November 1980 - Clarification of TMI Action Plan Requirements

Item II.B.2, Design Review Of Plant Shielding And Environmental Qualification Of Equipment For Space/Systems Which May Be Used In Postaccident Operations (originally Recommendation 2.1.6.b of NUREG-0578 [Reference 1]) - The TSC is designed to meet the criteria for shielding provided in NUREG-0737, Item II.B.2. Adequate shielding is provided to permit access to vital areas, including the control room and TSC. Utilizing the guidelines of GDC 19, 1971, and the occupancy factors contained in Standard Review Plan 6.4, the TSC shielding design radiation dose rate limits were established at 10 mrem/hr for direct radiation and 5 mrem/hr for airborne particulate and gaseous releases (internal to TSC). The total dose rate to any individual in the TSC is thus limited to 15 mrem/hr, from a time period beginning 1 hour after start of the design basis accident to 30 days later. The adequacy of shielding for the TSC has been evaluated for normal and post-accident conditions as described in Section 12.1.

Item III.A.1.2, Upgrade Emergency Support Facilities - NUREG-0737, Supplement 1, January 1983 provides the requirements for III.A.1.2.

The TSC is designed to meet the criteria for habitability provided in NUREG-0737, Supplement 1, items 8.2.1(e) and 8.2.1(f) (Reference 4). The guidance of NUREG-0696, 1981 (Reference 2), cited by NUREG-0737, Supplement 1, is followed regarding ventilation, filtration, radiation monitoring, and radiation protection. The TSC HVAC system is designed to PG&E Design Class II (Section 9.4.11.3).

Section 8.2.1(e) - The adequacy of the TSC ventilation system has been evaluated for normal and post-accident operating conditions as described in Sections 9.4.11 and 12.2 and for fire emergencies as described in Sections 9.4.1 and 9.5.1.

The adequacy of TSC fire protection features is evaluated in Section 9.5.1.

Section 8.2.1(f) – TSC shielding and the ventilation system prevent post-accident doses inside the TSC from exceeding 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident.

The TSC is provided the capability for monitoring direct radiation and airborne radioactive contaminants. The monitors will provide warning if the radiation levels in the TSC reach potentially dangerous levels.

6.4.2.4 Tests and Inspections

Preoperational testing of TSC habitability systems is discussed in the following sections:

(1)	Ventilation and air conditioning system	Section 9.4.11
(2)	Fire protection system	Section 9.5.1

(3) Communication systems Section 9.5.2

6.4.2.5 Instrumentation Applications

Instrumentation and habitability support equipment associated with the TSC are addressed in the Emergency Plan.

6.4.3 REFERENCES

1. NUREG-0578, TMI Short-term Lessons Learned Requirements, U. S. Nuclear Regulatory Commission, 1979.

2. NUREG-0696, Functional Criteria for Emergency Response Facilities, U. S. Nuclear Regulatory Commission, 1981.

3. Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.

4. NUREG-0737 Supplement 1, Clarification of TMI Action Plan Requirements - Requirements for Emergency Response Capability, U. S. Nuclear Regulatory Commission, 1983.

6.5 AUXILIARY FEEDWATER SYSTEM

The auxiliary feedwater (AFW) system serves as a backup supply of feedwater to the secondary side of the steam generators when the main feedwater system is not available, thereby maintaining the heat sink capabilities of the steam generators. As an Engineered Safety Features (ESF) system, the AFW system is directly relied upon to prevent core damage and reactor coolant system (RCS) overpressurization in the event of transients such as a loss of normal feedwater or a secondary system pipe rupture, and to provide a means for plant cooldown following any plant transient.

6.5.1 DESIGN BASES

6.5.1.1 General Design Criterion 2, 1967 - Performance Standards

The AFW system is designed to withstand the effects of, or is protected against, natural phenomena, such as earthquakes, flooding, tornados, winds, and other local site effects.

6.5.1.2 General Design Criterion 3, 1971 - Fire Protection

The AFW system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

6.5.1.3 General Design Criterion 4, 1967 - Sharing of Systems

The AFW system and components are not shared by the DCPP Units unless safety is shown to not be impaired by the sharing.

6.5.1.4 General Design Criterion 11, 1967 - Control Room

The AFW system is designed to support actions to maintain and control the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

6.5.1.5 General Design Criterion 12, 1967 - Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain AFW system variables within prescribed operating ranges.

6.5.1.6 General Design Criterion 21, 1967 - Single Failure Definition

The AFW system is designed to tolerate a single failure during the period of recovery following an accident without loss of its protective function, including multiple failures resulting from a single event, which is treated as a single failure.

6.5.1.7 General Design Criterion 37, 1967 - Engineered Safety Features Basis for Design

The AFW system is designed to provide back-up to the safety provided by the core design, the reactor coolant pressure boundary, and their protection systems in the event of a design basis accident.

The AFW system is designed to ensure sufficient supplies of condensate-grade auxiliary feedwater are available to support natural circulation cooldown (Generic Letter 81-21, May 1981).

The AFW system is designed to prevent steam binding of the AFW pumps (Generic Letter 88-03, February 1988).

6.5.1.8 General Design Criterion 38, 1967 - Reliability and Testability of Engineered Safety Features

The AFW system is designed to provide high functional reliability and ready testability.

6.5.1.9 General Design Criterion 40, 1967 - Missile Protection (Dynamic Effects)

The AFW system is designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

6.5.1.10 General Design Criterion 41, 1967 - Engineered Safety Features Performance Capability

The AFW system is designed to provide sufficient performance capability to accommodate a partial loss of installed capacity, such as a failure of a single active component, and still perform its required safety function.

6.5.1.11 General Design Criterion 54, 1971 - Piping Systems Penetrating Containment

The AFW system is provided with leakage detection, isolation, and containment capabilities having redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating this system. The AFW system is provided with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

6.5.1.12 General Design Criterion 57, 1971 - Closed System Isolation Valves

The AFW system contains piping connected to containment penetrations that are neither part of the reactor coolant pressure boundary nor connected directly to the containment atmosphere. These penetrations are Group D containment isolation and are provided with one local or remote-manual valve outside the containment.

6.5.1.13 10 CFR 50.49 - Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants

AFW system components that require EQ are qualified to the requirements of 10 CFR 50.49.

6.5.1.14 10 CFR 50.55a(f) - Inservice Testing Requirements

AFW system ASME Code components are tested to the requirements of 10 CFR 50.55a(f)(4) and 50.55a(f)(5) to the extent practical.

6.5.1.15 10 CFR 50.55a(g) - Inservice Inspection Requirements

AFW system ASME Code components are inspected to the requirements of 10 CFR 50.55a(g)(4) and a(g)(5) to the extent practical.

6.5.1.16 10 CFR 50.62 - Requirements for Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants

The AFW system is designed to initiate upon receipt of a signal from the Anticipated Transient Without Scram (ATWS) Mitigation System Actuation Circuitry (AMSAC).

6.5.1.17 10 CFR 50.63 - Loss of All Alternating Current Power

The AFW system is required to perform its safety function of decay heat removal in the event of a Station Blackout.

6.5.1.18 10 CFR Part 50 Appendix R (Sections III.G, J, and L) - Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979

Section III.G - Fire Protection of Safe Shutdown Capability: The AFW system is designed with fire protection features that are capable of limiting fire damage so that one train of AFW necessary to achieve and maintain hot shutdown conditions from either the control room or hot shutdown panel (HSP) is free of fire damage. Fire protection of the AFW system is provided by a combination of physical separation, fire-rated barriers, and/or automatic suppression and detection.

Section III.J - Emergency Lighting: Emergency lighting or Battery Operated Lights (BOLs) are provided in areas where operation of the AFW system may be required to safety shutdown the Unit following a fire.

Section III.L - Alternative and Dedicated Shutdown Capability: Safe shutdown capabilities are provided in the control room and at an alternate location via the HSP.

6.5.1.19 Regulatory Guide 1.97, Revision 3 - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The AFW system provides instrumentation to monitor AFW flow and Condensate Storage Tank (CST) level indication during and following an accident.

6.5.1.20 NUREG-0737 (Items II.E.1.1 and II.E.1.2), November 1980 - Clarification of TMI Action Plan Requirements

Item II.E.1.1 - Auxiliary Feedwater System Evaluation: The AFW system is designed such that AFW suction flow will not be interrupted by the failure of a common valve. Additionally, the AFW system is designed to provide a train of AFW independent of on-site and off-site ac power and with sufficient redundancy to ensure that only one (1) train of AFW is required to achieve and maintain safe shutdown.

Item II.E.1.2 - Auxiliary Feedwater System Initiation and Flows: The AFW system is designed to automatically initiate and is designed to the requirements of IEEE 279-1971.

6.5.1.21 Generic Letter 89-10, June 1989 - Safety-Related Motor-Operated Valve Testing and Surveillance

The AFW system's PG&E Design Class I and position changeable motor-operated valves (MOVs) meet the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996.

6.5.2 SYSTEM DESCRIPTION

Auxiliary feed pumps are provided and designed to ensure complete reactor decay heat removal under plant transient and accident conditions, including loss of power and loss of the normal heat sink (the condenser circulating water), while maintaining minimum water levels within the steam generator. The AFW system may be used for plant startup and for a controlled shutdown.

Following a reactor trip, decay heat is dissipated by evaporating water in the steam generators and venting the generated steam either to the condensers through the steam dump valves or to the atmosphere through the steam generator safety valves or the power-operated relief valves. Steam generator water inventory must be sufficient to

ensure adequate heat transfer and decay heat removal. The AFW system must be capable of functioning for extended periods, allowing time either to restore main feedwater flow or to proceed with an orderly cooldown of the reactor coolant to 350°F where the RHR system can assume the burden of decay heat removal (refer to Section 5.5.6).

AFW system flow and emergency water supply capacity must be sufficient to remove core decay heat, reactor coolant pump heat, and sensible heat during the plant cooldown. The AFW system can also be used to maintain the steam generator water level above the tubes following a LOCA. The water head in the steam generators prevents leakage of fission products from the RCS into the secondary side once the RCS is depressurized.

The AFW system is comprised of three independent pump trains. Two trains consist of motor-driven AFW pumps backed by Class 1E power supplies, and one train consists of a turbine-driven AFW pump with a Class 1E 125-Vdc steam inlet admission valve.

The motor-driven AFW pumps are each aligned to two steam generators. Flow to the steam generators is modulated by PG&E Design Class I level control valves powered from Class 1E power supplies. These valves also provide for pump runout protection.

The turbine-driven AFW pump is aligned to all four steam generators and contains electro-hydraulic level control valves; however, these valves do not automatically modulate. AFW is provided to the pumps from the PG&E Design Class I CST, which is backed by the PG&E Design Class I fire water storage tank (FWST), and by the PG&E Design Class II raw water storage reservoirs. The branch connection on two main steam lines for the auxiliary feed pump turbine is provided with isolation valves and check valves.

In the unlikely event of a complete loss of the preferred power supply and main generator electrical power to the station, decay heat removal would continue to be ensured by the availability of one turbine-driven, and two motor-driven AFW pumps (powered by the standby power source), and steam discharged to atmosphere through the steam generator power-operated relief valves and/or the spring-loaded safety valves. The system is shown in simplified form in Figure 6.5-1. For the detailed piping schematic, refer to Figure 3.2-3, Sheets 3 and 4.

6.5.2.1 Equipment and Component Descriptions

6.5.2.1.1 Water Sources

The minimum CST volume alone is sufficient to perform the plant cooldown described in Section 6.5.3.7 and to address NRC Generic Letter 81-21, May 1981, postulated worst-case natural circulation cooldown.

In the event the CST becomes exhausted, additional cooling water supplies are available to maintain hot standby conditions or to bring the plant to cold shutdown. These additional long-term cooling water sources use both existing piping systems and pumps, along with temporary portable pump driver units and hoses. Two million gallons of water will be available from the raw water reservoir for both units following exhaustion of preferential water sources (Reference 4). The FWST is the PG&E Design Class I backup water source for AFW. The design basis of the AFW system is to cooldown the RCS utilizing the PG&E Design Class I AFW sources to the point where the RHR system may be relied upon to complete the cooldown of the Unit.

The additional sources, listed in order of preference according to water quality, are as follows:

(1) Unit 1 and 2 CST (supply from un-affected unit if water inventory is not required for that unit)

(2) Main condenser hotwells (using condensate pumps)

(3) Fire water transfer tank

(4) FWST

(5) Main condenser hotwells (using portable fire pumps)

(6) Raw water storage reservoirs (5 million gallons)

(7) Pacific Ocean (via auxiliary saltwater system)

The above order of preference, although desirable relative to control of steam generator secondary side water chemistry, is not necessarily the preferred order in response to a plant transient requiring rapid operator response. The operating procedures identify an order of preference that is based on ensuring rapid alignment of the long-term cooling water supply.

The various long-term cooling water sources and their connections to the AFW system are shown schematically in Figure 6.5-2. Water systems are discussed in Section 9.2.

Connections and valving arrangements are provided to interconnect permanent plant systems by means of special-use hoses as follows:

(1) ASW system at the inlet water box of the CCW heat exchanger to the turbine building fire water system and then into the FWST

(2) Raw water storage reservoir to the plant raw water supply line

(3) Condenser hotwells to the turbine building fire water system and then into the FWST

(4) Fire water system crosstie (through PG&E Design Class I piping) to the AFW system.

The available hoses and portable pumps (not permanently connected to existing systems) are stored in structures that have been verified to survive the postulated Hosgri seismic event.

6.5.2.1.2 Auxiliary Feedwater Pumps and Controls

Each of the two steam supply lines to the turbine-driven AFW pump is provided with a separate, normally open, PG&E Design Class I motor-operated isolation valve with Instrument Class IA control circuitry and a non-return valve. The non-return valves provide protection against potential cross-connection between the steam lines. A normally closed, motor-operated stop valve is located in the steam supply line to the turbine inlet. During normal operation, the steam supply line is pressurized up to this stop valve, with steam available to operate the turbine-driven AFW pump when a control signal is received to open the stop valve. The turbine-driven AFW pump can deliver a net flow of 780 gpm to all four (4) steam generators.

The four motor-driven AFW pumps (two per Unit) are powered from the Class 1E 4.16-kV buses. They are available for standby service when there is insufficient steam to operate the turbine-driven AFW pump, or when the turbine-driven AFW pump is unavailable. Each motor-driven AFW pump can deliver a net flow of 390 gpm to two steam generators. Note that the flow rates of 780 and 390 gpm represent the minimum required flow rates of the turbine- and motor-driven AFW pumps at a steam generator back-pressure corresponding to the lowest steam generator safety valve set pressure, plus 3 percent for setpoint tolerance and 5 psi for accumulation.

Controls for the AFW system are described in Sections 7.1 through 7.7. In addition to the manual actuation of the AFW pumps, the following signals provide for automatic actuation of the motor-driven AFW pumps:

(1) Two-out-of-three low-low level signals in any one steam generator

(2) Trip of both main feedwater pumps

(3) Safety injection signal

(4) Transfer to diesel without safety injection signal

(5) AMSAC

The turbine-driven AFW pump automatic actuation signals are:

(1) Two-out-of-three low-low level signals in any two steam generators

(2) Undervoltage on one-out-of-two relays on both RCP buses (loss of offsite power)

(3) AMSAC

The steam generator blowdown isolation valves and the blowdown sample isolation valves are tripped shut whenever an AFW pump is started automatically.

6.5.2.2 Design Conditions

The reactor plant conditions that impose PG&E Design Class I performance requirements on the AFW system are as follows:

(1) Loss of normal feedwater transient

   (a) Loss of normal feedwater with offsite power available

   (b) Loss of offsite power to the station auxiliaries

(2) Major secondary system pipe ruptures

   (c) Feedline rupture

   (d) Steam line rupture (inside containment)

(3) Loss of all ac power

(4) Small break Loss-of-coolant accident (SBLOCA)

(5) Cooldown

Each of these conditions is discussed in more detail in the following sections.

6.5.2.2.1 Loss of Normal Feedwater Transients

Design basis loss of normal feedwater transients are caused by:

(1) Interruptions of the main feedwater system flow due to a malfunction in the feedwater or condensate system

(2) Loss of offsite power with the consequential shutdown of the system pumps, auxiliaries, and controls

Loss of Normal Feedwater (With Offsite Power Available)

Loss of normal feedwater transients are characterized by a reduction in steam generator water level that results in a reactor trip, a turbine trip, and auxiliary feedwater actuation by the protection system logic. Following reactor trip from a high initial power level, the power quickly falls to decay heat levels. The steam generator water levels continue to decrease, progressively uncovering the steam generator tubes as decay heat is transferred and discharged in the form of steam either through the steam dump valves to the condenser or through the steam generator safety or power-operated relief valves to the atmosphere. The reactor coolant temperature increases since the residual heat exceeds that dissipated through the steam generators. With increased temperature, reactor coolant volume expands and begins to fill the pressurizer. Without the addition of sufficient AFW, further expansion will result in liquid being discharged through the pressurizer safety and/or relief valves.

If the temperature rise and the resulting volumetric expansion of the primary coolant are permitted to continue, then the following may occur: (a) pressurizer safety valve capacities may be exceeded causing overpressurization of the RCS, and/or (b) the continuing loss of fluid from the primary coolant system may result in bulk boiling in the RCS system and eventually in core uncovering, loss of natural circulation, and core damage. If such a situation were to occur, the ECCS would not be effective because the primary coolant system pressure exceeds the shutoff head of the safety injection pumps, the nitrogen overpressure in the accumulator tanks, and the design pressure of the RHR loop.

Loss of Offsite Power to the Station Auxiliaries

The loss of offsite power transient differs from a simple loss of normal feedwater in that emergency power sources must be relied upon to operate vital equipment. The loss of power to the motor-driven circulating water pumps results in a loss of condenser vacuum and, therefore, of use of the condenser dump valves. Hence, steam generated by decay heat is relieved through the steam generator safety valves or the power-operated relief valves. The loss of normal feedwater and loss of offsite power transient analyses are similar with the exception that reactor coolant pump heat input is not a consideration in the loss of offsite power transient following loss of power to the reactor coolant pump bus.

The loss of normal feedwater transient was the original basis for the minimum flow required for the smallest capacity single AFW system pump. Each pump was originally sized so that any single pump will provide sufficient flow against a conservative steam generator safety valve set pressure with 3 percent tolerance and 5 psi accumulation to prevent liquid relief from the pressurizer. The Loss of Normal Feedwater (LONF) analysis requires that at least two motor-driven AFW pumps provide at least 600 gpm of AFW (assuming a single failure of the turbine-driven AFW pump) to four steam

generators to prevent pressurizer overfilling. Refer to Sections 6.5.3.7 and 15.2.8.2 for further discussion on LONF.

6.5.2.2.2 Major Secondary System Pipe Ruptures

Feedwater Line Rupture

A feedwater line rupture results in the loss of feedwater flow to the steam generators and the complete blowdown of one steam generator within a short time if the rupture occurs downstream of the last non-return valve in the main or AFW system piping to an individual steam generator. A feedwater line rupture may also cause spilling of AFW through the break due to the fact that the AFW system branch line may be connected to the main feedwater line in the region of the postulated break. Such situations can result in the injection of a disproportionately large fraction of the total AFW system flow (the system preferentially pumps water to the lowest pressure region) to the faulted loop rather than to the effective steam generators, which are at relatively high pressure. System design provides for terminating, limiting, or minimizing that fraction of AFW flow, which is delivered to a faulted loop or spilled through a break to ensure that sufficient flow is delivered to the remaining effective steam generator(s).

Main Steam Line Rupture Inside Containment

Main steam line rupture accident conditions are characterized initially by a plant cooldown and, for breaks inside containment, by increasing containment pressure and temperature. Auxiliary feedwater is not required during the early phase of the transient. However, modeling AFW flow to the faulted loop contributes to an excessive release of mass and energy to containment, maximizing the peak containment pressure. In this way, these steam line rupture conditions establish the upper limit on AFW flow delivered to a faulted loop and the time required to isolate the faulted steam generator. Eventually, however, the RCS heats up again and AFW flow is required for the non-faulted loops, but at a lower rate than the loss of feedwater transients described previously. Provisions in the design of the AFW system limit, control, or terminate AFW flow to the faulted loop as necessary to prevent containment overpressurization following a steam line break inside containment, or, for steam leads 3 and 4, to maintain the temperature profile in the GE/GW area within analyzed limits, and to ensure minimum flow to the remaining intact loops.

6.5.2.2.3 Loss of All AC Power

The loss of all ac power is postulated as resulting from accident conditions wherein not only onsite and offsite ac power is lost, but also emergency ac power is lost as an assumed common mode failure. Battery power for operation of protection circuits is assumed available. The impact on the AFW system is the necessity for providing both AFW pump power and a control source that are not dependent on ac power (refer to Section 6.5.3.20) and which are capable of maintaining the plant at hot shutdown until

ac power is restored. In the event of a Loss of All AC Power, decay heat removal would continue to be ensured through the availability of one turbine-driven AFW pump.

6.5.2.2.4 Small-Break Loss-of-Coolant Accident

The LOCAs do not impose any flow requirements on the AFW system that are in excess of those required by the other accidents addressed in this section.

Small-Break LOCAs cause relatively slow rates of decrease in RCS pressure and liquid volume. The principal contribution from the AFW system following a small-break LOCA is essentially the same as the system's function during hot shutdown or following a spurious safety injection signal which trips the reactor. Maintaining a water level inventory in the secondary side of the steam generators provides a heat sink for removing decay heat and establishes the capability for providing a buoyancy head for natural circulation. The primary contributor to heat removal during a small-break LOCA, however, is through the break. The AFW system may be used to assist in system cooldown and depressurization following a small-break LOCA while bringing the reactor to a cold shutdown condition.

6.5.2.2.5 Cooldown

The AFW system is required to cool down the RCS from normal zero load temperature to a hot leg temperature of approximately 350°F. This is the maximum temperature recommended for placing the RHR system into service. The RHR system completes the cooldown to cold shutdown conditions. Cooldown may be required following expected transients, following an accident such as a main feedline break, or prior to refueling or plant maintenance. If the reactor trips following extended operation at rated power level, the AFW system delivers sufficient feedwater to remove decay heat and reactor coolant pump heat following reactor trip while maintaining steam generator water level. Following transients or accidents, the recommended cooldown rate is consistent with expected needs and at the same time does not impose additional requirements on the capacities of the AFW pumps, considering a single failure.

6.5.2.3 Applicable Codes and Classifications

All AFW pumps and their appropriate piping and valves are PG&E Design Class I. The AFW system fittings and piping are designed to ANSI Code for Pressure Piping B31.1 and B31.7, as appropriate. The system valves were originally designed to the requirements of the ASME Pump and Valve Code, 1968 Draft. Later additions were designed to ASME B&PV Code, Section III.

6.5.3 SAFETY EVALUATION

6.5.3.1 General Design Criterion 2, 1967 - Performance Standards

The AFW system components are located at the 100 foot elevation of the auxiliary building, a PG&E Design Class I structure (refer to Figure 1.2-6). The auxiliary building is designed to withstand the effects of winds and tornados (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), earthquakes (refer to Section 3.7). This design protects the AFW SSCs, ensuring their design functions will be performed.

Portions of the AFW system are not contained within a building and are exposed directly to potential wind and tornado loads and have been evaluated. Loss of this equipment does not compromise the capability of shutting down the plant safely due to the availability of a train of AFW completely located within qualified structures (refer to Section 3.3.2.3).

The AFW system SSCs are designed to perform their safety functions under the effects of earthquakes. The PG&E Design Class I portion of the AFW system is seismically qualified.

Flooding of PG&E Design Class I equipment due to an AFW line rupture would not occur because of the relatively low flowrates and the location of the system. The consequences of postulated pipe rupture outside the containment, including the postulated rupture of AFW system lines, are discussed in Section 3.6.

6.5.3.2 General Design Criterion 3, 1971 - Fire Protection

The AFW system is designed to the fire protection guidelines of Branch Technical Position 9.5-1 (refer to Appendix 9.5B Table B-1).

6.5.3.3 General Design Criterion 4, 1967 - Sharing of Systems

The Units 1 and 2 CSTs are cross-tied through a 4-inch line. The effective elevation of the nozzles have been raised above the Technical Specification volume requirement for AFW due to the addition of internal plenums, thereby ensuring that failure of the crosstie line cannot reduce the condensate storage capacity below the minimum required volume to ensure steam generator makeup from the AFW pumps. Refer to Section 9.2.6.3 for a discussion on the Condensate Storage Facilities.

There is no direct connection between the raw water supply header in the plant and the CST such that any single failure of a component could cause the loss of both CST inventory and reservoir water. Refer to Section 9.2.3.3 for a discussion on the raw water reservoir. The FWST provides a PG&E Design Class I source of backup water to Units 1 and 2 for the AFW system. This source of water (the FWST) is connected to the common supply header from both the Raw Water Reservoir and the FWST to both

Units' AFW pumps. A normally closed PG&E Design Class I valve separates the PG&E Design Class II Raw Water Reservoir supply and the PG&E Design Class I FWST supply. This ensures that a failure of the PG&E Design Class II Raw Water Reservoir's piping will not result in drain down of the FWST or the prevention of the FWST from supplying backup PG&E Design Class I AFW. The piping from the FWST is provided with isolation valves such that a failure in this line will not prevent sufficient backup supplies of AFW from being provided by other backup AFW sources. As discussed in Section 6.5.3.7, there is a sufficient volume of water available and maintained in the CSTs for the AFW system to perform the worst-case natural circulation cooldown.

The turbine-driven AFW pump leakoffs and bearing cooling water return lines are piped to the PG&E Design Class II common auxiliary steam drain receiver tank. Isolation valves and check valves in these drain lines ensure that a failure of the tank or PG&E Design Class II piping will not impair the operation of either Units' AFW system.

There is no sharing between units that would prevent either Unit 1 or Unit 2 AFW system from performing its design function.

6.5.3.4 General Design Criterion 11, 1967 - Control Room

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.

One PG&E Design Class I AFW flow indicator is provided for each of four steam generators. Indication is provided at the main control board and the HSP (refer to Section 7.5.1.6).

These flow indicators monitor the flow from the turbine-driven AFW pump and the motor-driven AFW pumps.

Additional indication of AFW flow is provided by PG&E Design Class I steam generator wide-range level indication (refer to Section 7.5.2.6). This provides recording on the main control board and indication on the HSP.

The AFW system primary water supply source, the CST, contains redundant, PG&E Design Class I level recording with indication in the main control board (refer to Table 7.5-6). PG&E Design Class II CST level indication is provided at the HSP.

Additional controls for components of the AFW system are available in the control room and at the HSP. Controls for the AFW level control valves, start/stop switches for the motor-driven AFW pump, control of the steam admission valve for the turbine-driven AFW pump, and AFW pump discharge pressure indication are all provided in the control room and at the HSP. In addition to cooling the RCS down to RHR entry conditions (Mode 4), the AFW system allows the plant to remain in hot standby (Mode 3) for an extended period of time if desired by operation and/or required for safe shutdown (refer to Section 7.4.2.1).

Annunciation is provided in the main control room for AFW pump discharge piping temperature to prevent steam binding of the AFW pumps (refer to Section 6.5.3.7).

Controls for the AFW system are provided in the control room such that the AFW system may be operated to perform its design function.

6.5.3.5 General Design Criterion 12, 1967 - Instrumentation and Control Systems

All automatic initiating signals and circuits are installed in accordance with IEEE 279-1971 (Reference 1) and are PG&E Design Class I and redundant (refer to Section 7.3).

As discussed in Section 7.3 and shown in Figures 7.3-8 and 7.3-17 the motor-driven AFW pumps are started by closure of the solid-state protection system (SSPS) output relay and one of the timers. The relay 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 or B. The motor-driven pumps are also automatically started by trip of both main feedwater pumps, or an AMSAC signal.

The turbine-driven AFW system pump is started by opening steam supply valve FCV-95. As shown in Figure 7.3-18, this valve is opened by one of the SSPS output relays. One of these relays starts on loss of offsite power and the other on low-low level in any two steam generators. The turbine-driven pump is also started by an AMSAC signal.

The initiating sensors are powered from separate and redundant nuclear instrumentation and control panels, each of which is supplied by either the Class 1E 120-Vac power supply or Class 1E 125-Vdc batteries. Each of the two redundant SSPS trains is supplied by a separate Class 1E power source.

Instrumentation is provided in the motor-driven AFW pump discharge line to sense low pump discharge pressure indicative of a depressurized steam generator. In a low pump discharge pressure situation, control valves are automatically throttled to prevent pump runout. This automatic action limits flow to any depressurized steam generator.

No such instrumentation is provided for the turbine-driven AFW pump. Manual action by the plant operator is required to terminate flow to a depressurized steam generator.

6.5.3.6 General Design Criterion 21, 1967 - Single Failure Definition

No single failure in the manual initiation portion of the circuit can result in the loss of the AFW system function (refer to Section 7.3.2.1.1 and Figures 7.3-17 and 7.3-18 for the circuitry).

No single failure in the automatic portion of the circuit will result in loss of the capability to manually initiate the AFW system from the control room.

All automatic initiating signals and circuits are installed in accordance with IEEE 279-1971 (Reference 1) and are PG&E Design Class I and redundant (refer to Section 7.3).

A single failure that results in the failure of multiple components, such as the failure of an EDG, will not result in a failure of the AFW system to perform its design function. The AFW system is designed with a train that is completely independent of the preferred power supply or standby power supply (refer to Section 6.5.3.20). Isolation valves are provided in the water supply lines to the AFW pumps such that a single failure of a valve in the suction line of the AFW pumps will not result in the failure of the remaining pumps.

6.5.3.7 General Design Criterion 37, 1967 - Engineered Safety Features Basis for Design

Analyses have been performed for the limiting transients that define the AFW system performance requirements. Specifically, they include:

(1) Loss of normal feedwater

(2) Loss of Offsite Power to the Station Auxiliaries

(3) Rupture of a Main Feedwater Pipe

(4) Rupture of a Main Steam Pipe Inside Containment

(5) Small Break Loss-of-Coolant Accident

In addition, specific calculations for DCPP Units 1 and 2 were performed to determine plant cooldown flow (storage capacity) requirements.

The loss of all ac power was evaluated by comparison with the transient results of a loss of offsite power, assuming an available AFW pump having a diverse (non-ac) power supply. The SBLOCA analysis incorporates system flow requirements defined by other transients and is, therefore, not performed to determine AFW system flow requirements. Each of the above analyses is explained further below.

Loss of Normal Feedwater

A loss of normal feedwater was analyzed in Section 15.2.8 to show that two motor-driven AFW system pumps delivering at least 600 gpm of AFW flow to four steam generators does not result in pressurizer over-filling. Furthermore, the peak RCS pressure remains below the criterion for Condition II transients and no fuel failures occur.

Table 6.5-2 summarizes the assumptions used in the Chapter 15 analysis. All main feedwater flow to the steam generators is terminated at event initiation. Reactor trip is assumed to occur when the water level in any steam generator reaches the low-low level trip setpoint. AFW flow from both motor-driven pumps initiates within 60 seconds after receiving a low-low level signal in any steam generator. The analysis assumes that the plant is initially operating at 102 percent (calorimetric error) of the Nuclear Steam Supply System (NSSS) design rating shown in Table 6.5-2, and includes a conservative assumption in defining decay heat and stored energy in the RCS.

Both the loss of normal feedwater and loss of offsite power analyses demonstrate that there is considerable margin with respect to pressurizer over-filling (refer to Sections 15.2.8 and 15.2.9).

A better-estimate analysis is performed to address the reliability of the AFW system. This analysis is similar to that described above for the Chapter 15 analysis, but assuming that only a single motor-driven AFW system pump supplies a minimum of 390 gpm to two of the four steam generators. The cases considered in this additional analysis assume better-estimate conditions for several key parameters, including initial power level, decay heat, RCS temperature, pressurizer pressure, and the low-low steam generator water level reactor trip setpoint. The results of this better-estimate analysis demonstrate that there is margin to pressurizer over-filling. While this analysis demonstrates that the AFW system remains highly reliable, the DCPP licensing basis requires that at least two AFW pumps delivering at least 600 gpm to four steam generators is required for this event.

Loss of Offsite Power to the Station Auxiliaries

The AFW system is initiated for a loss of offsite power to the station auxiliaries' transient as discussed in Section 15.2.9. The same assumptions discussed above for the loss of normal feedwater transient apply to this analysis, except that power is assumed to be lost to the reactor coolant pumps following reactor trip.

As with all ESF equipment, the ac motor-driven AFW pumps and all valves in the system are automatically and sequentially loaded on the emergency buses on loss of offsite power.

Rupture of Main Feedwater Pipe

The double-ended rupture of a main feedwater pipe downstream of the main feedwater line check valve was analyzed (refer to Section 15.4.2.2). Table 6.5-2 summarizes the assumptions used in this analysis. A reactor trip is assumed to occur when the faulted steam generator reaches the low-low level trip setpoint (adjusted for errors). The initial power rating assumed in the feedline break analysis is 102 percent of the NSSS design rating.

Although the AFW system at DCPP Units 1 and 2 would allow delivery of AFW to two intact loops automatically in 1 minute, no AFW flow is assumed until 10 minutes after the break. At this time it is assumed that the operator has isolated the AFW system from the break and flow from one motor-driven AFW pump of 390 gpm (total) to two steam generators commences. As discussed in Section 15.4.2.2, the analysis assumes a single failure of the most limiting component, the turbine-driven AFW pump, and assumes that all flow from the motor-driven AFW pump aligned to the faulted steam generator is lost through the break. The AFW flow is asymmetrically split between two of the three unaffected steam generators. The analysis demonstrates that the reactor coolant remains subcooled, assuring that the core remains covered with water and no bulk boiling occurs in the hot leg.

Rupture of a Main Steam Pipe Inside Containment

Because the result of the steam line break transient is an initial RCS cooldown, the AFW system does not have a requirement to remove heat in the short term. However, addition of AFW to the faulted steam generator will increase the secondary mass available for release to the containment thus maximizing the peak containment pressure following a steam line break inside containment. This transient is performed at four power levels for several break sizes. AFW is assumed to be initiated at the time the SI setpoint is reached. The AFW flowrate to the faulted SG is maximized based on flow from both motor-driven AFW pumps and the turbine-driven AFW pump where runout protection is not credited. Table 6.5-2 summarizes the assumptions used in this analysis. At 10 minutes after the break, it is assumed that the operator has isolated the AFW system from the faulted steam generator, which subsequently blows down to ambient pressure. This assumption for operator action is also used for temperature profile development for main steam line breaks outside containment. Refer to Section 6.2D.3 for further discussion on a main steam line break inside containment.

Small Break Loss of Coolant Accident

A SBLOCA is described in UFSAR Section 15.3.1. The AFW system plays a minor role in response to an SBLOCA. This is due to the primary means of RCS heat removal occurring through the break. However, once the SG secondary sides' are isolated, the boiling process essentially ceases unless the safety valves are lifting. This means, excluding the safety valves, the only heat removal mechanism through the SGs will be through sensible heat gain of the AFW mass addition. Therefore, the significance of AFW flow with respect to the SBLOCA transient is considered small. For this transient, only 390 gpm of AFW flow is assumed to be provided by one motor-driven AFW pump divided equally to four SGs (97.5 gpm per SG). Normally AFW flow provided by one motor-driven AFW pump would be asymmetrically split between two SGs; however, since the NOTRUMP model used to analyze a SBLOCA event cannot explicitly model this condition, a lumped loop model was used. Refer to Section 15.3.1 for a discussion on the SBLOCA event.

Natural Circulation Cooldown

Maximum and minimum flow requirements from the previously discussed transients meet the flow requirements of plant cooldown. This operation, however, defines the basis for tank size, based on the required cooldown duration, maximum decay heat input, and maximum stored heat in the system. The AFW system partially cools the RCS to the point where the RHR system may complete the cooldown . Table 6.5-2 shows the assumptions used to determine the cooldown heat capacity of the AFW system.

The minimum CST volume alone is sufficient to perform the plant cooldown described in Section 6.5.2.2.5 and to address a NRC Generic Letter 81-21, May 1981, postulated worst-case natural circulation cooldown.

Due to Unit 2 being converted to a T_{cold} reactor vessel head design, the natural circulation cooldown rates, and subsequent water volume requirement, between the two Units is different. With the Unit 2 T_{cold} upper head design, a cooldown rate of up to 50°F per hour can be used. With Unit 1 being a T_{hot} upper head design, a reduced cooldown rate of 25°F per hour is required to maintain sub-cooling in the reactor vessel upper head region. The natural circulation cooldown analysis has shown that with the two reactor vessel head designs, the worst case conditions for each Unit occurred when Unit 2 was held in hot standby for two hours followed by a four hour cooldown at a rate of 50°F per hour. The worst-case natural circulation cooldown for Unit 1 was determined to be when Unit 1 was held in hot standby for one hour followed by an eight hour cooldown at 25 °F per hour.

For a worst-case natural circulation cooldown, 196,881 gallons for Unit 1 and 163,058 gallons for Unit 2 are required to cooldown the RCS to 350°F (Mode 4, RHR entry temperature conditions). An additional volume of 3,119 gallons for Unit 1 and 2,942 gallons for Unit 2 are reserved for allowed leakage through internal plenums at CST connections and for margin. The inventory of the CST at the minimum Technical Specification usable volumes of 200,000 gallons for Unit 1 and 166,000 gallons for Unit 2 envelops this total required amount. The usable reserved inventory in both CSTs was increased from 164,678 gallons to 224,860 gallons (Reference 3). In addition to cooling the RCS down to RHR entry conditions, the AFW system allows the plant to remain in hot standby (Mode 3) for an extended period of time if desired by operation and/or required for safe shutdown. Holding Unit 1 in hot standby for 8 hours requires 140,584 gallons. Holding Unit 2 in hot standby for 8 hours requires 140,703 gallons.

The Technical Specifications do not permit the RCS to be heated above 350°F without at least 200,000 gallons for Unit 1 and 166,000 gallons for Unit 2 of usable water in the CST.

Therefore, the volume of water maintained in the CST, as ensured by the Technical Specifications, is sufficient for all Design Basis Accidents for which the AFW system is required to perform its design function.

In case of an incident, such as a small break in the reactor coolant loop concurrent with a loss of offsite and main generator power, the plant can remain at the hot standby condition for a period of time that depends on the amount of water available in the CST. Cooldown delay guidance is found in the plant operating procedures, which, under certain conditions (e.g., control room inaccessibility), allow a delay in beginning cooldown. Backup sources of AFW are available as described in Section 6.5.2.1.1.

Table 6.5-1 summarizes the criteria used for the AFW system general design bases for various plant conditions.

Steam Binding of the AFW Pumps

In accordance with GL 1988-03, February 1988, the AFW system is equipped with permanently installed temperature sensors on the AFW discharge lines to each steam generator main feedwater line. The temperature sensors detect high temperatures caused by main feedwater system back-leakage through the AFW discharge check valves. This hot water back-leakage could result in steam binding of the AFW pumps. Annunciation is provided in the main control room if the AFW pipe fluid temperatures reach 200 °F. Operations responds to this annunciation by venting the AFW pump casings until the temperatures are reduced. Also, the AFW pumps may be run to feed forward to displace the hot water in the pipes with cold CST water and attempt to reduce check valve leakage by cycling the valve.

6.5.3.8 General Design Criterion 38, 1967 - Reliability and Testability of Engineered Safety Features

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

The AFW system piping also has a periodic inservice inspection (ISI) program in accordance with the ASME B&PV Code, Section XI (refer to Section 5.2.8).

6.5.3.9 General Design Criterion 40, 1967 - Missile Protection (Dynamic Effects)

The AFW system is protected from missiles, pipe whip, or jet impingement from the rupture of any nearby high-energy line (refer to Sections 3.5 and 3.6).

The AFW system is protected by barriers and restraints from the dynamic effects of a ruptured pipe outside the containment.

An analysis, using the methodology presented in Reference 1, shows that cooldown using the AFW system will not be prevented by any postulated auxiliary steam line break within an AFW system compartment.

Rupture of a Steam Supply Line to the Turbine-Driven AFW Pump

The double-ended rupture of a turbine-driven AFW pump steam supply line in the GE/GW area (downstream of the non-return valves associated with steam supply isolation valves, FCV-37/38, and upstream of steam supply stop valve, FCV-95) will not result in loss of all AFW flow.

The postulated break would render the turbine driven AFW pump No. 1 inoperable due to loss of steam supply. FCV-37 and FCV-38 are capable of remote manual closure. FCV-37 is located outside of the GE/GW area and would not be subjected to a harsh environment. FCV-38 is located within the GE/GW area and is qualified for operation in a harsh environment. Therefore, the break can be isolated from the main steamline.

The resulting increased temperature in the GE/GW area would cause the E/H actuated level control valves (LCVs) associated with motor driven AFW pump No. 3 to fail due to a harsh environment. However, due to the small rupture, motor-driven AFW pump No. 3 will not trip due to pump runout and subsequent overcurrent.

The E/H actuated LCVs associated with motor-driven AFW pump No. 2 are located outside of the GE/GW area and would not be subjected to a harsh environment.

If either of the steam supply valves (FCV-37/38) fails to close, isolation of feedwater to the respective SG will effectively isolate the AFW steam supply line break, thus ensuring at least one motor-driven AFW pump is available to provide sufficient AFW flow to two intact loops.

Isolation of the faulted SG within 10 minutes ensures the GE/GW area does not exceed its analyzed temperature profile.

6.5.3.10 General Design Criterion 41, 1967 - Engineered Safety Features Performance Capability

The single failure of any active component in the AFW system will not prevent the system from performing its design function (refer to Sections 6.5.3.6 and 6.5.3.7).

6.5.3.11 General Design Criterion 54, 1971 - Piping Systems Penetrating Containment

The AFW system isolation valves required for containment closure are periodically tested as part of the MOV program for operability in accordance with GDC 54, 1971 (refer to Section 6.5.3.21); however, since the AFW piping must remain in service following an accident, these valves are not tested for leakage (refer to Section 6.2.4 for

leakage testing of the containment isolation system). Leakage detection is provided in the AFW discharge lines that sense back leakage of main feedwater as discussed in Section 6.5.3.4 and 6.5.3.7.

6.5.3.12 General Design Criterion 57, 1971 - Closed System Isolation Valves

The AFW system containment penetrations include the AFW pump discharge lines to the main feedwater lines (Penetrations 1, 2, 3, and 4) and the steam supply lines to the turbine-driven AFW pump (Penetrations 6 and 7).

These penetrations are classified as Group D containment isolation because they are lines that must remain in service following an accident and, therefore, do not isolate automatically.

Refer to Section 6.2.4.1 and Table 6.2-39 for additional information on these penetrations and their containment isolation capabilities.

6.5.3.13 10 CFR 50.49 - Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants

AFW system SSCs required to function in harsh environments under accident conditions are qualified to the applicable environmental conditions to ensure that they will continue to perform their safety functions. Section 3.11 describes the DCPP EQ Program and the requirements for the environmental design of electrical and related mechanical equipment. The affected equipment includes valves, switches, and flow transmitters and are listed on the EQ Master List.

6.5.3.14 10 CFR 50.55a(f) - Inservice Testing Requirements

All AFW pumps and their appropriate piping and valves are PG&E Design Class I (refer to Section 3.2) and PG&E Quality Class II or III. The IST requirements for these components are contained in the IST Program Plan.

6.5.3.15 10 CFR 50.55a(g) - Inservice Inspection Requirements

The AFW system piping also has a periodic inservice inspection (ISI) program in accordance with the ASME B&PV Code, Section XI.

6.5.3.16 10 CFR 50.62 - Requirements for Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants

The AFW system is automatically initiated as part of the ATWS Mitigation System Actuation Circuitry (refer to Section 7.6.2.3).

6.5.3.17 10 CFR 50.63 - Loss of All Alternating Current Power

In the event of a loss of all alternating current power, decay heat is removed from the core by natural circulation of the reactor coolant. This heat is then transferred to the secondary side of the steam generators and discharged to the atmosphere through the 10% atmospheric dump valves.

Makeup feedwater to the steam generators is provided by the motor-driven AFW pump on Bus F (refer to Section 6.5.3.20). If Bus F or Bus H is the bus being used, then, by procedure, the respective motor-driven AFW pump is preferred over the turbine-driven AFW pump.

The AFW system may be used to cool the plant down to hot standby conditions (Mode 3).

6.5.3.18 10 CFR Part 50 Appendix R (Sections III.G, J, and L) - Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979

Section III.G - Fire Protection of Safe Shutdown Capability: A fire protection review of the AFW system electrical cable and control wiring has shown that no single postulated fire can prevent the AFW system from perform its design function to bring the plant to cold shutdown. This is due to physical separation of redundant electrical buses, combined with the ability to control the AFW system from either the main control board, the HSP, 4.16-kV switchgear, or locally at the valves.

Tables 9.5G-1 and 9.5G-2 for DCPP Units 1 and 2, respectively, list the minimum equipment required to bring the plant to a cold shutdown condition as defined by 10 CFR Part 50, Appendix R, Section III.G. Specifically, 1 of 3 AFW pumps, the turbine-driven AFW pump steam isolation valves (when the turbine-driven AFW pump is the one pump relied upon), the steam generator AFW supply level control valves (only the specific valves associated with each pump), and the water supply (CST or raw water storage reservoir) with associated valving are the minimum required equipment to bring the plant to a cold shutdown condition.

Section III.J - Emergency Lighting: Emergency lighting or BOLs are provided in areas where operation of the AFW system may be required to safely shutdown the Unit following a fire as defined by 10 CFR Part 50, Appendix R, Section III.J.

Section III.L - Alternative and Dedicated Shutdown Capability: Safe shutdown capabilities are provided in the control room and at an alternate location via the HSP (refer to Section 7.4) as defined by 10 CFR Part 50, Appendix R, Section III.L. The ability to safely shut down the plant following a fire in any fire area is summarized in Section 4.0 of Appendix 9.5A.

6.5.3.19 Regulatory Guide 1.97, Revision 3 - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

AFW system post-accident instrumentation for meeting Regulatory Guide 1.97, Revision 3, requirements consist of flow indication to all four (4) steam generators and CST level indication.

One AFW flow indicator is provided for each of four steam generators. The indicators are PG&E Design Class I (refer to Section 7.5.2.6 and Table 7.5-6). Indication is provided at the main control board and the HSP.

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 AFW pump is monitored by the same indicators that monitor the motor-driven AFW pump flow.

6.5.3.20 NUREG-0737 (Items II.E.1.1 and II.E.1.2), November 1980 - Clarification of TMI Action Plan Requirements

Item II.E.1.1 - Auxiliary Feedwater System Evaluation: The AFW pumps takes water from the CST, which is the preferred source of AFW. The CST provides redundant level indication and low level alarms in the control room. The purpose of the low-low level alarm is to notify the operator that the AFW supply is running low and must be aligned to an alternate water supply. The alarm provides the operator with at least a 20 minute supply of water for the auxiliary feed pumps at a net flowrate of 880 gpm. The turbine-driven AFW pump has a net flow of 780 gpm available to supply the steam generators. One normally open, manual valve in the common suction piping of the AFW pumps is secured in the open position to prevent interruption of AFW flow. The train of AFW provided by the turbine-driven AFW pump is designed to be completely independent from a standby and preferred ac power source. This train consists of a steam supply stop valve powered from a Class 1E 125-Vdc bus, automatic AFW system actuation instrumentation powered from a vital instrument ac bus (powered by station batteries through an inverter), and steam generator level and AFW flow indication instrumentation powered from station batteries. Driving steam for the turbine-driven AFW pump is taken from two of the four main steam lines upstream of the main steam isolation valves and is exhausted to the atmosphere. Only one steam supply is required for turbine operation. However, steam must always be available from both steam lines during plant operation to preclude a loss of all steam supplies due to any single failure incident. Therefore, in accordance with Item II.E.1.1, the AFW system is designed with one train of AFW that contains a pump power and control source not dependent on ac power and that can provide sufficient AFW flow to the steam generators to bring the plant to hot shutdown conditions.

The motor-driven AFW pumps are powered from the Class 1E buses. They are available for standby service when there is insufficient steam to operate the turbine-driven AFW pump, or when the turbine-driven AFW pump is unavailable (refer to

Section 8.3.1.1.3). Each motor-driven AFW pump can deliver a net flow of 390 gpm to two steam generators.

Note that the flow rates of 780 and 390 gpm represent the minimum required flow rates of the turbine- and motor-driven AFW pumps at a steam generator back-pressure corresponding to the lowest steam generator safety valve set pressure, plus 3 percent for setpoint tolerance and 5 psi for accumulation.

Item II.E.1.2 - Auxiliary Feedwater System Initiation and Flows: The AFW system level control valves are normally open and require no actions for system operation. The AFW initiation circuitry is part of the ESF, and as such, is installed in accordance with IEEE Standard 279-1971 (refer to Section 7.3) and meets the requirements of Item II.E.1.2.

6.5.3.21 Generic Letter 89-10, June 1989 - Safety Related Motor-Operated Valve Testing and Surveillance

The AFW system MOVs are subject to the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996, and meet the requirements of the DCPP MOV Program Plan.

6.5.4 TESTS AND INSPECTIONS

Refer to Sections 6.5.3.8 and 6.5.3.15

6.5.5 INSTRUMENTATION REQUIREMENTS

Refer to Sections 6.5.2.1.2, 6.5.3.4, 6.5.3.5, and 6.5.3.19.

6.5.6 REFERENCES

1. IEEE 279-1971, Criteria for Protection Systems for Nuclear Power Generating Stations.

2. Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.

3. DCPs C-50829 and C-049829, Condensate Storage Tank Modification to Add Plenums

4. PG&E Letter to the NRC, “Review of Systems and Equipment Necessary to Accomplish a Safe Shutdown Following a Major Earthquake,” dated January 26, 1978.

6.5.7 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

TABLE 6.1-1

APPLICABLE DESIGN BASIS CRITERIA

CRITERIA	TITLE	APPLICABILITY								
Engineered Safety Features		Containment Functional Design	Containment Heat Removal Systems	Containment Air Purification and Cleanup Systems	Containment Isolation System	Combustible Gas Control in Containment	Emergency Core Cooling System	Control Room Habitability System	Technical Support Center Habitability System	Auxiliary Feedwater System
Section		6.2.1	6.2.2	6.2.3	6.2.4	6.2.5	6.3	6.4.1	6.4.2	6.5
1. <u>General Design Criteria</u>										
Criterion 2, 1967	Performance Standards		X	X	X	X	X	X		X
Criterion 3, 1971	Fire Protection			X		X	X	X		X
Criterion 4, 1967	Sharing of Systems							X	X	X
Criterion 4, 1987	Environmental and Dynamic Effects Design Bases	X								
Criterion 10, 1967	Containment	X	X		X					
Criterion 11, 1967	Control Room		X	X	X	X	X	X		X
Criterion 12, 1967	Instrumentation and Control System		X	X	X	X	X	X		X
Criterion 15, 1967	Engineered Safety Features Protection Systems		X							
Criterion 17, 1967	Monitoring Radioactivity Releases					X		X		
Criterion 19, 1971	Control Room		X	X				X		
Criterion 21, 1967	Single Failure Definition		X	X	X		X			X
Criterion 37, 1967	Engineered Safety Features Basis for Design		X	X		X	X	X		X
Criterion 38, 1967	Reliability and Testability of Engineered Safety Features		X	X			X			X
Criterion 40, 1967	Missile Protection		X	X	X		X			X

TABLE 6.1-1

CRITERIA	TITLE	APPLICABILITY								
Engineered Safety Features		Containment Functional Design	Containment Heat Removal Systems	Containment Air Purification and Cleanup Systems	Containment Isolation System	Combustible Gas Control in Containment	Emergency Core Cooling System	Control Room Habitability System	Technical Support Center Habitability System	Auxiliary Feedwater System
Section		6.2.1	6.2.2	6.2.3	6.2.4	6.2.5	6.3	6.4.1	6.4.2	6.5
1. General Design Criteria (contd.)										
Criterion 41, 1967	Engineered Safety Features Performance Capability		X	X		X	X			X
Criterion 42, 1967	Engineered Safety Features Components Capability		X	X		X	X			
Criterion 43, 1967	Accident Aggravation Prevention						X			
Criterion 44, 1967	Emergency Core Cooling Systems Capability						X			
Criterion 45,1967	Inspection of Emergency Core Cooling Systems						X			
Criterion 46, 1967	Testing of Emergency Core Cooling Systems Components						X			
Criterion 47, 1967	Testing of Emergency Core Cooling Systems						X			
Criterion 48, 1967	Testing of Operational Sequence of Emergency Core Cooling Systems						X			
Criterion 49, 1967	Containment Design Basis	X	X			X	X			
Criterion 52, 1967	Containment Heat Removal Systems		X							

TABLE 6.1-1

CRITERIA	TITLE	APPLICABILITY								
Engineered Safety Features		Containment Functional Design	Containment Heat Removal Systems	Containment Air Purification and Cleanup Systems	Containment Isolation System	Combustible Gas Control in Containment	Emergency Core Cooling System	Control Room Habitability System	Technical Support Center Habitability System	Auxiliary Feedwater System
Section		6.2.1	6.2.2	6.2.3	6.2.4	6.2.5	6.3	6.4.1	6.4.2	6.5
1. General Design Criteria (contd.)										
Criterion 53, 1967	Containment Isolation Valves				X					
Criterion 54, 1967	Containment Leakage Rate Testing	X								
Criterion 54, 1971	Piping Systems Penetrating Containment		X		X	X	X			X
Criterion 55, 1967	Containment Periodic Leakage Rate Testing	X								
Criterion 55, 1971	Reactor Coolant Pressure Boundary Penetrating Containment				X		X			
Criterion 56, 1971	Primary Containment Isolation		X		X	X	X			
Criterion 57, 1971	Closed System Isolation Valves				X					X
Criterion 58, 1967	Inspection of Containment Pressure-Reducing Systems		X							
Criterion 59, 1967	Testing of Containment Pressure-Reducing Systems		X							

TABLE 6.1-1

CRITERIA	TITLE	APPLICABILITY								
Engineered Safety Features		Containment Functional Design	Containment Heat Removal Systems	Containment Air Purification and Cleanup Systems	Containment Isolation System	Combustible Gas Control in Containment	Emergency Core Cooling System	Control Room Habitability System	Technical Support Center Habitability System	Auxiliary Feedwater System
Section		6.2.1	6.2.2	6.2.3	6.2.4	6.2.5	6.3	6.4.1	6.4.2	6.5
1. General Design Criteria (contd.)										
Criterion 60, 1967	Testing of Containment Spray Systems		X							
Criterion 61, 1967	Testing of Operational Sequence of Containment Pressure-Reducing Systems Components		X							
Criterion 62, 1967	Inspection of Air Cleanup Systems		X	X						
Criterion 63, 1967	Testing of Air Cleanup Systems Components		X	X						
Criterion 64, 1967	Testing of Air Cleanup Systems		X	X						
Criterion 65, 1967	Testing of Operational Sequence of Air Cleanup Systems		X	X						
Criterion 70, 1967	Control of Releases of Radioactivity to the Environment		X	X						
2. 10 CFR Part 20										
Part 20	Standards for Protection Against Radiation								X	

TABLE 6.1-1

CRITERIA	TITLE	APPLICABILITY								
Engineered Safety Features		Containment Functional Design	Containment Heat Removal Systems	Containment Air Purification and Cleanup Systems	Containment Isolation System	Combustible Gas Control in Containment	Emergency Core Cooling System	Control Room Habitability System	Technical Support Center Habitability System	Auxiliary Feedwater System
Section		6.2.1	6.2.2	6.2.3	6.2.4	6.2.5	6.3	6.4.1	6.4.2	6.5
3. <u>10 CFR Part 50</u>										
50.44	Combustible Gas Control for Nuclear Power Reactors					X				
50.46	Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Plants						X			
50.47	Emergency Plans								X	
50.49	Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants		X			X	X			X
50.55a(f)	Inservice Testing Requirements		X	X		X	X			X
50.55a(g)	Inservice Inspection Requirements		X	X		X	X			X
50.62	Requirements of Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants									X
50.63	Loss of All Alternating Current Power									X

CRITERIA	TITLE	APPLICABILITY								
Engineered Safety Features		Containment Functional Design	Containment Heat Removal Systems	Containment Air Purification and Cleanup Systems	Containment Isolation System	Combustible Gas Control in Containment	Emergency Core Cooling System	Control Room Habitability System	Technical Support Center Habitability System	Auxiliary Feedwater System
Section		6.2.1	6.2.2	6.2.3	6.2.4	6.2.5	6.3	6.4.1	6.4.2	6.5
3. <u>10 CFR Part 50 (contd.)</u>										
Appendix J, Option B	Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors	X			X					
Appendix K, Part I.A	ECCS Evaluation Models, Sources of Heat during the LOCA	X								
Appendix R	Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979							X		X
4. <u>Atomic Energy Commission (AEC) Safety Guides</u>										
Safety Guide 1, November 1970	Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps						X			

TABLE 6.1-1

CRITERIA	TITLE	APPLICABILITY								
Engineered Safety Features		Containment Functional Design	Containment Heat Removal Systems	Containment Air Purification and Cleanup Systems	Containment Isolation System	Combustible Gas Control in Containment	Emergency Core Cooling System	Control Room Habitability System	Technical Support Center Habitability System	Auxiliary Feedwater System
Section		6.2.1	6.2.2	6.2.3	6.2.4	6.2.5	6.3	6.4.1	6.4.2	6.5
5. <u>Regulatory Guides</u>										
Regulatory Guide 1.7, Revision 2, November 1978	Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident					X				
Regulatory Guide 1.52, Revision 0, June 1973	Design, Testing, and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants							X		
Regulatory Guide 1.79, June 1974	Preoperational Testing of Emergency Core Cooling Systems for Pressurized Water Reactors						X			
Regulatory Guide 1.97, Revision 3, May 1983	Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident		X			X	X	X		X

CRITERIA	TITLE	APPLICABILITY								
Engineered Safety Features		Containment Functional Design	Containment Heat Removal Systems	Containment Air Purification and Cleanup Systems	Containment Isolation System	Combustible Gas Control in Containment	Emergency Core Cooling System	Control Room Habitability System	Technical Support Center Habitability System	Auxiliary Feedwater System
Section		6.2.1	6.2.2	6.2.3	6.2.4	6.2.5	6.3	6.4.1	6.4.2	6.5
5. Regulatory Guides (contd.)										
Regulatory Guide 1.163, September 1995	Performance-Based Containment Leak-Test Program	X			X					
Regulatory Guide 1.197, Revision 0, May 2003	Demonstrating Control Room Envelope Integrity at Nuclear Power Reactors							X		
6. NRC NUREG										
NUREG-0737, November 1980	Clarification of TMI Action Plan Requirements		X		X	X	X	X	X	X
7. NRC Generic Letters										
Generic Letter 89-10, June 1989	Safety-Related Motor-Operated Valve Testing and Surveillance		X	X	X	X	X			X
Generic Letter 95-07, August 1995	Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves						X			

CRITERIA	TITLE	APPLICABILITY								
Engineered Safety Features		Containment Functional Design	Containment Heat Removal Systems	Containment Air Purification and Cleanup Systems	Containment Isolation System	Combustible Gas Control in Containment	Emergency Core Cooling System	Control Room Habitability System	Technical Support Center Habitability System	Auxiliary Feedwater System
Section		6.2.1	6.2.2	6.2.3	6.2.4	6.2.5	6.3	6.4.1	6.4.2	6.5
7. <u>NRC Generic Letters (contd.)</u>										
Generic Letter 96-06, September 1996	Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions				X		X			
Generic Letter 97-04, October 1997	Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps		X				X			
Generic Letter 98-04, July 1998	Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System after a Loss-of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment						X			

TABLE 6.1-1

CRITERIA	TITLE	APPLICABILITY								
Engineered Safety Features		Containment Functional Design	Containment Heat Removal Systems	Containment Air Purification and Cleanup Systems	Containment Isolation System	Combustible Gas Control in Containment	Emergency Core Cooling System	Control Room Habitability System	Technical Support Center Habitability System	Auxiliary Feedwater System
Section		6.2.1	6.2.2	6.2.3	6.2.4	6.2.5	6.3	6.4.1	6.4.2	6.5
7. NRC Generic Letters (contd.)										
Generic Letter 2003-01, June 2003	Control Room Habitability							X		
Generic Letter 2004-02, September 2004	Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized-Water Reactors						X			
Generic Letter 2008-01, January 2008	Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems						X			

TABLE 6.1-1

CRITERIA	TITLE	APPLICABILITY								
Engineered Safety Features		Containment Functional Design	Containment Heat Removal Systems	Containment Air Purification and Cleanup Systems	Containment Isolation System	Combustible Gas Control in Containment	Emergency Core Cooling System	Control Room Habitability System	Technical Support Center Habitability System	Auxiliary Feedwater System
Section		6.2.1	6.2.2	6.2.3	6.2.4	6.2.5	6.3	6.4.1	6.4.2	6.5
8. Bulletins										
IE Bulletin 79-06A, April 1979	Review of Operational Errors and System Misalignments Identified During the Three Mile Island Incident						X			
IE Bulletin 80-18, July, 1980	Maintenance of Adequate Minimum Flow Thru Centrifugal Charging Pumps Following Secondary Side High Energy Line Rupture						X			
NRC Bulletin 88-04, May 1988	Potential Safety-Related Pump Loss						X			
NRC Bulletin 88-08, June 1988	Thermal Stresses in Piping Connected to Reactor Coolant Systems						X			
NRC Bulletin 2003-01, June 2003	Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized-Water Reactors						X			

TABLE 6.1-1

CRITERIA	TITLE	APPLICABILITY								
Engineered Safety Features		Containment Functional Design	Containment Heat Removal Systems	Containment Air Purification and Cleanup Systems	Containment Isolation System	Combustible Gas Control in Containment	Emergency Core Cooling System	Control Room Habitability System	Technical Support Center Habitability System	Auxiliary Feedwater System
Section		6.2.1	6.2.2	6.2.3	6.2.4	6.2.5	6.3	6.4.1	6.4.2	6.5
9. Branch Technical Position										
Branch Technical Position EICSB 18, November 1975	Application of the Single Failure Criterion to Manually-Controlled Electrically-Operatred Valves						X			

TABLE 6.2-14

CONTAINMENT PRESSURE DIFFERENTIAL
ELEMENTS FOR LOOP COMPARTMENT AND PRESSURIZER ENCLOSURE
ANALYSIS MODEL

Element	Volume, ft^3	Description
1	2.860×10^4	Loop compartment
2	2.550×10^4	Loop compartment
3	2.660×10^4	Loop compartment
4	2.660×10^4	Loop compartment
5	2.550×10^4	Loop compartment
6	2.860×10^4	Loop compartment
7	2.270×10^4	Dome
8	3.525×10^4	
9	4.015×10^4	Compartments 8-12 below
10	1.251×10^4	Elevation 140 ft and above elevation
11	1.415×10^4	117 ft outside the crane wall
12	1.732×10^4	
13	2.098×10^4	
14	3.706×10^4	
15	1.650×10^4	Compartments 13-18 below elevation
16	2.497×10^4	117 ft outside the crane wall
17	1.337×10^4	
18	2.042×10^4	
19	2.312×10^3	
20	2.004×10^3	Pressurizer enclosure
21	9.69×10^2	

TABLE 6.2-15

CONTAINMENT PRESSURE DIFFERENTIAL
FLOW PATHS FOR LOOP COMPARTMENT AND PRESSURIZER ENCLOSURE ANALYSIS MODEL

Flowpath Connecting Elements	Minimum Flow Area, ft^2	Flowpath Connecting Elements	Minimum Flow Area, ft^2
1-2	790.00	10-9	212.00
1-7	130.00	11-12	212.00
2-3	790.00	12-8	212.00
2-7	34.00	12-13	40.00
3-4	110.00	13-14	270.00
3-12	20.00	13-4	20.00
4-5	790.00	14-15	270.00
4-8	20.00	14-5	20.00
5-6	790.00	15-1	20.00
5-7	34.00	15-9	40.00
6-1	300.00	16-15	270.00
6-7	130.00	16-2	20.00
7-3	130.00	17-18	270.00
7-4	130.00	17-16	254.00
8-9	212.00	18-13	48.00
8-7	40.00	7-19[a]	32.80
9-6	40.00	19-20[a]	146.00
9-7	40.00	20-21[a]	125.00
10-11	212.00	2-21[a]	4.50
		7-21[a]	25.30

a) Used only for pressurizer enclosure analysis.

TABLE 6.2-16

CONTAINMENT PRESSURE DIFFERENTIAL
LOOP COMPARTMENT ANALYSIS - MASS AND ENERGY RELEASE RATES
DOUBLE-ENDED SEVERANCE OF A REACTOR COOLANT HOT LEG

Time, sec	Mass Release Rate, lb/sec	Energy Release Rate, Btu/sec
0.	2.4704E+05	1.3834E+08
2.5100E-03	7.3494E+04	4.0804E+07
5.0300E-03	7.2355E+04	4.0173E+07
1.0040E-02	7.0343E+04	3.9080E+07
1.7530E-02	6.8460E+04	3.8082E+07
2.5040E-02	6.7699E+04	3.7715E+07
2.7520E-02	8.8473E+04	4.9400E+07
3.5010E-02	9.3921E+04	5.2531E+07
4.2540E-02	9.7912E+04	5.4828E+07
5.0070E-02	1.0044E+05	5.6284E+07
5.7580E-02	1.0147E+05	5.6886E+07
6.5080E-02	1.0154E+05	5.6946E+07
7.5120E-02	1.0044E+05	5.6349E+07
8.2570E-02	9.8810E+04	5.5451E+07
9.2510E-02	9.5936E+04	5.3861E+07
1.0001E-01	9.3090E+04	5.2281E+07
1.1759E-01	8.5296E+04	4.6953E+07
1.2751E-01	8.2263E+04	4.6293E+07
1.6002E-01	7.4507E+04	4.2074E+07
1.7507E-01	7.1563E+04	4.0472E+07
1.7755E-01	7.2357E+04	4.0943E+07
1.9512E-01	7.2090E+04	4.0899E+07
2.0253E-01	7.1718E+04	4.0734E+07
2.1751E-01	7.0525E+04	4.0151E+07
2.6007E-01	6.5426E+04	3.7447E+07
2.7512E-01	6.3890E+04	3.6590E+07
2.8508E-01	6.3182E+04	3.6185E+07
2.9760E-01	6.2740E+04	3.5916E+07
3.1011E-01	6.2704E+04	3.5876E+07
3.4008E-01	6.2969E+04	3.6010E+07
3.5251E-01	6.2882E+04	3.5980E+07
3.6752E-01	6.2621E+04	3.5848E+07
4.0501E-01	6.2062E+04	3.5553E+07
5.0013E-01	6.1329E+04	3.5205E+07
6.0028E-01	6.0879E+04	3.6029E+07
1.1003E+00	5.6031E+04	3.3016E+07
1.4003E+00	5.2485E+04	3.1512E+07
2.0002E+00	4.4871E+04	2.7839E+07
2.2002E+00	4.2601E+04	2.6645E+07
2.5000E+00	4.0314E+04	2.5338E+07
2.6000E+00	4.0156E+04	2.4941E+07
3.0000E+00	3.9109E+04	2.4386E+07

TABLE 6.2-17

CONTAINMENT PRESSURE DIFFERENTIAL
PRESSURIZER ENCLOSURE ANALYSIS - MASS AND ENERGY RELEASE RATES
PRESSURIZER SPRAY LINE RUPTURE

Time, sec	Mass Release Rate, lb/sec	Energy Release Rate, Btu/sec
0.	1	6.510×10^2
0.00101	1,843	1.201×10^6
0.00201	2,077	1.331×10^6
0.00302	2,095	1.341×10^6
0.01505	2,124	1.351×10^6
0.01605	2,143	1.362×10^6
0.02501	2,148	1.362×10^6
0.02707	2,168	1.372×10^6
0.02804	2,177	1.377×10^6
0.02907	2,182	1.380×10^6
0.03411	2,190	1.383×10^6
0.03504	2,190	1.383×10^6
0.03703	2,179	1.376×10^6
0.03906	2,165	1.368×10^6
0.04705	2,137	1.352×10^6
0.05404	2,143	1.353×10^6
0.07412	2,176	1.379×10^6
0.09005	2,151	1.357×10^6
0.09712	2,167	1.364×10^6
0.09910	2,174	1.369×10^6
0.10505	2,200	1.383×10^6
0.11017	2,218	1.387×10^6
0.11511	2,198	1.382×10^6
0.12010	2,176	1.369×10^6
0.13001	2,135	1.346×10^6
0.15015	2,161	1.368×10^6
0.15500	2,160	1.360×10^6
0.17509	2,126	1.340×10^6
0.23010	2,161	1.360×10^6
0.27005	2,141	1.349×10^6
0.30028	2,113	1.333×10^6
0.35002	2,125	1.340×10^6
0.40003	2,124	1.340×10^6
0.41001	2,116	1.335×10^6
0.52014	2,110	1.332×10^6
0.80008	2,116	1.328×10^6
1.0900	2,106	1.328×10^6
1.2701	2,100	1.323×10^6
1.7700	2,075	1.307×10^6
2.7300	2,033	1.280×10^6
3.0002	2,028	1.276×10^6

TABLE 6.2-18 Sheet 1 of 2

CONTAINMENT PRESSURE DIFFERENTIAL
ELEMENTS FOR REACTOR CAVITY ANALYSIS MODEL

	Volume, ft^3
1. Pipe annulus	3.310
2. Lower reactor cavity	8745.000
3. Break location	182.580
4. Reactor vessel annulus	25.800
5. Reactor vessel annulus	26.140
6. Reactor vessel annulus	25.160
7. Reactor vessel annulus	147.330
8. Reactor vessel annulus	24.840
9. Reactor vessel annulus	129.940
10. Reactor vessel annulus	24.510
11. Reactor vessel annulus	147.330
12. Reactor vessel annulus	24.840
13. Reactor vessel annulus	182.580
14. Reactor vessel annulus	25.160
15. Reactor vessel annulus	147.330
16. Reactor vessel annulus	24.840
17. Reactor vessel annulus	129.940
18. Reactor vessel annulus	24.510
19. Break location	147.330
20. Reactor vessel annulus	24.840
21. Lower containment	46,305.00
22. Lower containment	45,065.00
23. Lower containment	42,090.000
24. Lower containment	43,330.000
25. Pipe annulus	9.380
26. Pipe annulus	10.820
27. Pipe annulus	10.820
28. Pipe annulus	9.360
29. Pipe annulus	9.360
30. Pipe annulus	10.820
31. Pipe annulus	10.820

	Volume, ft^3
32. Upper containment	2,105,510.000
33. Reactor vessel annulus	25.460
34. Reactor vessel annulus	25.880
36. Reactor vessel annulus	26.140
35. Reactor vessel annulus	25.800
37. Reactor vessel annulus	25.460
38. Reactor vessel annulus	25.800
39. Reactor vessel annulus	10.140
40. Reactor vessel annulus	9.920
41. Reactor vessel annulus	9.700
42. Reactor vessel annulus	9.920
43. Reactor vessel annulus	10.140
44. Reactor vessel annulus	9.920
45. Reactor vessel annulus	9.700
46. Reactor vessel annulus	9.920
47. Inspection port	14.100
48. Inspection port	14.100
49. Inspection port	14.100
50. Inspection port	14.100
51. Inspection port	14.100
52. Inspection port	14.100
53. Inspection port	14.100
54. Inspection port	14.100
55. Instrumentation Tunnel	243.000
56. Instrumentation Tunnel	1086.000
57. Instrumentation Tunnel	564.000
58. Instrumentation Tunnel	2477.000
59. Instrumentation Tunnel	5953.000
60. Pipe Annulus	6.050

TABLE 6.2-19

CONTAINMENT PRESSURE DIFFERENTIAL
FLOWPATH DATA FOR REACTOR CAVITY ANALYSIS MODEL

Flow Path From -- To	K Factor	F Factor x103	Inertia Length (ft.)	Hydraulic Diameter (ft.)	Flow Area (sq. ft.)	Equivalent Length (ft.)
1—60	0.39	27	3.60	0.28	1.57	0.92
2—55	0.44	14	6.20	5.14	27.0	4.56
3—7	0.86	18	8.70	4.75	9.72	8.70
4—33	0.00	24	6.60	0.51	2.31	6.60
5—4	0.00	24	6.75	0.51	2.31	6.76
6—8	0.00	24	6.75	0.50	2.21	6.76
7—9	0.89	18	8.10	4.75	7.10	8.10
8—10	0.00	24	6.60	0.50	2.21	6.60
9—11	0.89	18	8.10	4.75	7.10	8.10
10—12	0.00	24	6.60	0.50	2.21	6.60
11—13	1.54	18	8.70	4.75	9.72	8.70
12—14	0.00	24	6.75	0.50	2.21	6.76
13—15	1.54	18	8.70	4.75	9.72	8.70
14—16	0.00	24	6.75	0.50	2.21	6.76
15—17	0.89	18	8.10	4.75	7.10	8.10
16—18	0.00	24	6.60	0.50	2.21	6.60
17—19	0.89	18	8.10	4.75	7.10	8.10
18—20	0.00	24	6.60	0.50	2.21	6.60
19—3	1.50	18	8.70	4.75	9.72	8.70
20—6	0.00	24	6.75	0.50	2.21	6.76
21—22	0.00	11	50.0	15.81	802.3	50.0
22—23	0.00	11	50.0	15.81	802.3	50.0
23—24	0.00	11	50.0	15.81	802.3	50.0
24—21	0.00	11	50.0	15.81	802.3	50.0
25—3	0.45	22	2.27	0.75	2.10	1.80
26—7	0.45	22	2.71	0.74	2.16	2.30
27—9	0.45	22	2.71	0.74	2.16	2.30
28—11	0.45	22	2.71	0.75	2.10	1.80

TABLE 6.2-19

Flow Path From -- To	K Factor	F Factor x103	Inertia Length (ft.)	Hydraulic Diameter (ft.)	Flow Area (sq. ft.)	Equivalent Length (ft.)
29—13	0.45	22	2.27	0.75	2.10	1.80
30—15	0.45	22	2.71	0.74	2.16	2.30
31—17	0.45	22	2.71	0.74	2.16	2.30
33—34	0.00	24	6.60	0.51	2.31	6.60
34—35	0.00	24	6.75	0.51	2.31	6.76
35—36	0.00	24	6.75	0.51	2.31	6.76
36—37	0.00	24	6.60	0.51	2.31	6.60
37—38	0.00	24	6.60	0.51	2.31	6.60
38—5	0.00	24	6.75	0.50	2.31	6.76
39—3	0.45	25	2.40	0.42	1.46	2.25
40—7	0.45	25	2.45	0.41	1.42	2.25
41—9	0.45	25	2.46	0.41	1.39	2.25
42—11	0.45	25	2.45	0.41	1.42	2.25
43—13	0.45	25	2.40	0.42	1.46	2.25
44—15	0.45	25	2.45	0.41	1.42	2.25
45—17	0.45	25	2.46	0.41	1.39	2.25
46—19	0.45	25	2.45	0.41	1.42	2.25
56—57	0.42	12	4.66	8.34	72.3	3.61
58—59	1.66	14	3.03	4.17	17.4	2.02
59—23	0.41	11	10.0	16.82	287	17.04
60—3	0.45	22	1.26	0.75	2.10	0.88
2—56	0.41	13	22.8	7.82	6.39	18.94
3—47	0.44	17	2.56	2.00	3.14	2.26
4—8	0.00	24	8.70	0.50	1.74	8.70
5—6	0.00	24	8.70	0.50	1.77	8.70
6—2	1.00	24	4.25	0.50	1.77	4.25
7—48	0.44	17	2.69	2.00	3.14	2.28
8—2	1.00	24	4.25	0.50	1.74	4.25
9—49	0.44	17	2.71	2.00	3.14	2.28
10—2	1.00	24	4.25	0.50	1.70	4.25
11—50	0.44	17	2.69	2.00	3.14	2.28
12—2	1.00	24	4.25	0.50	1.74	4.25

TABLE 6.2-19

Flow Path From -- To	K Factor	F Factor x103	Inertia Length (ft.)	Hydraulic Diameter (ft.)	Flow Area (sq. ft.)	Equivalent Length (ft.)
13—51	0.44	17	2.56	2.00	3.14	2.26
14—2	1.00	24	4.25	0.50	1.77	4.25
15—52	0.44	17	2.69	2.00	3.14	2.28
16—2	1.00	24	4.25	0.50	1.74	4.25
17—53	0.44	17	2.71	2.00	3.14	2.28
18—2	1.00	24	4.25	0.50	1.70	4.25
19—54	0.44	17	2.69	2.00	3.14	2.28
20—2	1.00	24	4.25	0.50	1.74	4.25
25—7	0.45	22	2.27	0.75	2.10	1.89
26—9	0.45	22	2.71	0.74	2.16	2.30
27—11	0.45	22	2.71	0.74	2.16	2.30
28—13	0.45	22	2.27	0.75	2.10	1.89
29—15	0.45	22	2.27	0.75	2.10	1.89
30—17	0.45	22	2.71	0.74	2.16	2.30
31—19	0.45	22	2.71	0.74	2.16	2.30
33—10	0.00	24	8.70	0.50	1.70	8.70
34—12	0.00	24	8.70	0.50	1.74	8.70
35—14	0.00	24	8.70	0.50	1.77	8.70
36—16	0.00	24	8.70	0.50	1.74	8.70
37—18	0.00	24	8.70	0.50	1.70	8.70
38—20	0.00	24	8.70	0.50	1.74	8.70
39—32	1.00	25	2.25	0.42	1.46	2.25
40—32	1.00	25	2.25	0.41	1.42	2.25
41—32	1.00	25	2.25	0.41	1.39	2.25
42—32	1.00	25	2.25	0.41	1.42	2.25
43—32	1.00	25	2.25	0.42	1.46	2.25
44—32	1.00	25	2.25	0.41	1.42	2.25
45—32	1.00	25	2.25	0.41	1.39	2.25
46—32	1.00	25	2.25	0.41	1.42	2.25
55—59	0.83	14	5.36	5.14	27.0	4.50
56—58	0.29	13	13.38	7.83	63.9	9.88
57—59	1.40	13	5.05	5.83	35.0	2.91

TABLE 6.2-19

Flow Path From -- To	K Factor	F Factor x103	Inertia Length (ft.)	Hydraulic Diameter (ft.)	Flow Area (sq. ft.)	Equivalent Length (ft.)
58—23	1.53	15	3.40	3.83	14.5	3.00
59—24	0.41	11	10.0	16.82	287	17.04
60—19	0.45	22	1.26	0.75	2.10	0.88
1—21	1.00	27	1.02	0.28	1.57	2.03
3—5	0.45	24	4.62	0.50	1.77	4.44
7—4	0.45	24	4.70	0.50	1.74	4.44
9—33	0.45	24	4.69	0.50	1.70	4.44
11—34	0.45	24	4.69	0.50	1.74	4.44
13—35	0.45	24	4.62	0.50	1.77	4.44
15—36	0.45	24	4.69	0.50	1.74	4.44
17—37	0.45	24	4.69	0.50	1.70	4.44
19—38	0.45	24	4.69	0.50	1.74	4.44
21—32	1.00	11	24.5	17.24	952	24.5
22—32	1.00	11	24.5	17.24	952	24.5
23—32	1.00	11	24.5	17.24	952	24.5
24—32	1.00	11	24.5	17.24	952	24.5
25—22	1.00	27	1.89	0.28	1.57	1.89
26—22	1.00	27	2.30	0.28	1.63	2.30
27—23	1.00	27	2.30	0.28	1.63	2.30
28—23	1.00	27	1.89	0.28	1.57	1.89
29—24	1.00	27	1.89	0.28	1.57	1.89
30—24	1.00	27	2.30	0.28	1.63	2.30
31—21	1.00	27	2.30	0.28	1.63	2.30
39—40	0.00	24	7.07	0.53	1.44	7.08
40—41	0.00	24	6.91	0.53	1.44	6.92
41—42	0.00	24	6.91	0.53	1.44	6.92
42—43	0.00	24	7.07	0.53	1.44	7.08
43—44	0.00	24	7.07	0.53	1.44	7.08
44—45	0.00	24	6.91	0.53	1.44	6.92
45—46	0.00	24	6.91	0.53	1.44	6.92
46—39	0.00	24	7.07	0.53	1.44	7.08
58—24	1.60	14	3.47	4.60	24.3	3.00

TABLE 6.2-20 Sheet 1 of 5

CONTAINMENT PRESSURE DIFFERENTIAL
REACTOR CAVITY ANALYSIS - TOTAL MASS AND ENERGY RELEASE RATES

115 in^2 Cold Leg Break

Time, sec	Mass Flow, lbm/sec (X10^4)	Energy Flow, Btu/sec (X10^7)
0.00000	0.00	0.000
0.00252	1.37	0.714
0.00502	1.64	0.855
0.00751	1.89	0.985
0.01002	1.97	1.030
0.01252	1.99	1.040
0.01502	2.11	1.100
0.01755	2.23	1.170
0.02004	2.15	1.130
0.02252	2.10	1.100
0.02508	2.14	1.120
0.02752	2.15	1.130
0.03009	2.20	1.150
0.03252	2.24	1.170
0.03502	2.28	1.190
0.03761	2.30	1.210
0.04004	2.32	1.210
0.04264	2.30	1.210
0.04507	2.28	1.200
0.04759	2.27	1.190
0.05013	2.26	1.180
0.05254	2.26	1.180
0.05509	2.25	1.180
0.05750	2.23	1.170
0.06005	2.19	1.140
0.06258	2.16	1.130
0.06508	2.17	1.130
0.06754	2.19	1.140
0.07012	2.21	1.160
0.07256	2.21	1.160
0.07502	2.20	1.150
0.07758	2.16	1.130
0.08001	2.12	1.110
0.08257	2.07	1.080
0.08502	2.03	1.060
0.08756	2.00	1.050
0.09009	2.00	1.040
0.09260	2.00	1.040
0.09511	2.02	1.050
0.09758	2.03	1.060

115 in^2 Cold Leg Break

Time, sec	Mass Flow, lbm/sec (X10^4)	Energy Flow, Btu/sec (X10^7)
0.10019	2.05	1.070
0.10504	2.07	1.080
0.11009	2.10	1.100
0.11503	2.10	1.100
0.12009	2.07	1.080
0.12503	2.04	1.070
0.13008	1.98	1.040
0.13512	1.93	1.010
0.14018	1.91	0.994
0.14501	1.89	0.988
0.15012	1.88	0.981
0.15519	1.88	0.978
0.16011	1.88	0.979
0.16503	1.88	0.981
0.17003	1.88	0.983
0.17507	1.89	0.986
0.18001	1.89	0.985
0.18501	1.88	0.979
0.19001	1.85	0.967
0.19504	1.83	0.953
0.20013	1.80	0.939
0.21255	1.77	0.920
0.22509	1.73	0.901
0.23766	1.71	0.892
0.25004	1.74	0.908
0.26251	1.74	0.908
0.27515	1.68	0.875
0.28762	1.68	0.874
0.30011	1.71	0.892
0.31257	1.70	0.886
0.32505	1.68	0.877
0.33752	1.69	0.883
0.35020	1.71	0.890
0.36255	1.74	0.905
0.37514	1.75	0.913
0.38753	1.74	0.907
0.40004	1.72	0.895
0.41250	1.70	0.888
0.42509	1.71	0.892
0.43765	1.72	0.897
0.45000	1.73	0.899
0.46252	1.73	0.901

115 in^2 Cold Leg Break

Time, sec	Mass Flow, lbm/sec ($X10^4$)	Energy Flow, Btu/sec ($X10^7$)
0.47500	1.73	0.902
0.48752	1.73	0.904
0.50005	1.74	0.908
0.52507	1.73	0.903
0.55015	1.76	0.917
0.57519	1.77	0.924
0.60008	1.77	0.921
0.62508	1.77	0.920
0.65002	1.78	0.927
0.67512	1.78	0.928
0.70002	1.78	0.930
0.72519	1.79	0.931
0.75011	1.79	0.934
0.77510	1.79	0.931
0.80012	1.79	0.932
0.82506	1.79	0.936
0.85014	1.80	0.937
0.87519	1.80	0.937
0.90005	1.80	0.937
0.92503	1.80	0.938
0.95016	1.80	0.938
0.97502	1.80	0.938
1.00022	1.80	0.939
1.02504	1.80	0.938
1.05007	1.80	0.937
1.07505	1.79	0.936
1.10000	1.79	0.935
1.12507	1.79	0.933
1.15014	1.78	0.931
1.17511	1.78	0.930
1.20010	1.78	0.927
1.22508	1.77	0.923
1.25002	1.77	0.922
1.27506	1.77	0.925
1.30006	1.78	0.927
1.32512	1.78	0.927
1.35007	1.78	0.928
1.37504	1.78	0.928
1.40011	1.78	0.927
1.42507	1.78	0.928
1.45006	1.78	0.929
1.47506	1.78	0.930

115 in^2 Cold Leg Break

Time, sec	Mass Flow, lbm/sec (X10^4)	Energy Flow, Btu/sec (X10^7)
1.50010	1.78	0.930
1.52505	1.78	0.930
1.55001	1.78	0.929
1.57520	1.78	0.930
1.60001	1.78	0.931
1.62512	1.78	0.931
1.65032	1.78	0.930
1.67510	1.78	0.930
1.70004	1.78	0.930
1.72505	1.78	0.931
1.75007	1.78	0.932
1.77504	1.78	0.930
1.80010	1.78	0.930
1.82506	1.78	0.930
1.85000	1.78	0.931
1.87509	1.78	0.931
1.90005	1.77	0.929
1.92500	1.77	0.929
1.95003	1.77	0.930
1.97515	1.77	0.930
2.00002	1.77	0.929
2.02515	1.77	0.929
2.05003	1.77	0.929
2.07501	1.77	0.929
2.10003	1.77	0.928
2.12501	1.77	0.928
2.15002	1.76	0.928
2.17501	1.76	0.927
2.20002	1.76	0.927
2.22502	1.76	0.926
2.25014	1.76	0.926
2.27505	1.76	0.925
2.30006	1.75	0.925
2.32509	1.75	0.924
2.35010	1.75	0.923
2.37500	1.75	0.923
2.40005	1.75	0.923
2.42502	1.75	0.923
2.45004	1.74	0.921
2.47516	1.74	0.921
2.50000	1.74	0.920

115 in^2 Cold Leg Break

Time, sec	Mass Flow, lbm/sec ($X10^4$)	Energy Flow, Btu/sec ($X10^7$)
2.52509	1.74	0.920
2.55010	1.74	0.920
2.57505	1.74	0.920
2.60005	1.74	0.920
2.62507	1.74	0.919
2.65002	1.73	0.919
2.67508	1.73	0.919
2.70000	1.73	0.919
2.72511	1.73	0.918
2.75002	1.73	0.918
2.77509	1.73	0.918
2.80013	1.73	0.917
2.82503	1.72	0.916
2.85004	1.72	0.916
2.87511	1.72	0.915
2.90023	1.72	0.914
2.92501	1.72	0.913
2.95006	1.71	0.912
2.97502	1.71	0.911
3.00003	1.71	0.911

TABLE 6.2-21

CONTAINMENT PRESSURE DIFFERENTIAL
REACTOR CAVITY ANALYSIS - CALCULATED PEAK PRESSURES

Element	Peak Pressure, psig	Element	Peak Pressure, psig
1	167.2	31	131.4
2	5.400	32	0.800
3	181.5	33	111.5
4	113.0	34	110.8
5	113.6	35	110.7
6	104.2	36	111.2
7	138.2	37	112.5
8	104.2	38	113.5
9	119.6	39	114.6
10	104.0	40	113.8
11	114.7	41	111.1
12	103.9	42	109.7
13	114.5	43	109.6
14	103.9	44	110.4
15	116.8	45	112.8
16	104.0	46	114.6
17	128.2	47	182.2
18	104.2	48	138.2
19	182.2	49	119.6
20	104.3	50	114.7
21	0.800	51	114.6
22	0.800	52	116.8
23	0.800	53	128.2
24	0.800	54	183.5
25	141.2	55	3.800
26	121.2	56	3.800
27	114.6	57	3.700
28	113.0	58	3.400
29	113.9	59	0.800
30	117.3	60	180.1

(a) Pressure still increasing 0.5 seconds after the break. The long-term pressure transient is described by analysis in Appendix 6.2D.

TABLE 6.2-22

CONTAINMENT PRESSURE DIFFERENTIAL
ELEMENTS FOR PIPE ANNULUS ANALYSIS MODEL

Element	Volume, ft^3	Vent Area, ft^2
Loop compartment 1	80,700.00	764.00
Loop compartment 2	80,700.00	804.00
Reactor coolant pipe annulus	30.00	10.25
Reactor vessel annulus	620.00	49.84
Lower reactor cavity	6,750.00	90.90

TABLE 6.2-24

CONTAINMENT PRESSURE DIFFERENTIAL
COMPARTMENT PRESSURES

Compartment	Design Differential Pressure, psi	Calculated Peak Differential Pressure, psi	Calculated Absolute Pressure At Time of Peak Differential, psia
Loop compartment	15.0	14.5	29.4
Reactor coolant pipe annulus	1,200	180.1	194.8
Reactor vessel annulus	120[(a)]	182.2	196.9
Lower reactor cavity	60	46	61
Pressurizer enclosure	4	2.6 [(c)]	17.6

(a) Refer to discussion in Section 6.2.1.2.
(b) Deleted in Revision 22.
(c) Value includes 0.1 psi penalty from Tavg coastdown effects from replacing the steam generators. Refer to Section 6.2.1.2.1.3.

TABLE 6.2-25

CONTAINMENT HEAT REMOVAL SYSTEMS DESIGN CODE REQUIREMENTS

Component	Code
Valves	ANSI B16.5-1968
Piping (including headers and spray nozzles)	
- PG&E Design Class I portions	ANSI B31.7-1969 with 1970 Addenda
- PG&E Design Class II portions	ANSI B31.1-1967
Containment Spray Pump	ASME P&V III-1968[(a)]
Refueling Water Storage Tank	AWWA D100-1967[(b)]

(a) Draft ASME Code for Pumps and Valves for Nuclear Power, November 1968.

(b) ASME BPVC Section VIII-1974, Allowable Stresses Used for Design

TABLE 6.2-26

CONTAINMENT HEAT REMOVAL SYSTEMS DESIGN PARAMETERS

Containment Spray Pump

Type	Horizontal Centrifugal
Number (per unit)	2
Design pressure, psig	275[c]
Design temperature, °F	275[c]
Design flowrate, gpm	2600
Design head, ft	450
Material	Type 316 stainless steel

Containment Spray Nozzle

Number (per unit)	343 (Unit 1)/ 342 (Unit 2)
Type	Spraco 1713A
Flow per nozzle at 40 psi Δp, gpm	15.2
Material	Type 304 stainless steel

Refueling Water Storage Tank

Number (per unit)	1
Total available tank volume (includes only usable volume)[a], gal	450,000
Minimum Technical Specifications required volume (includes usable and unusable volume), gal	455,300
Accident analysis volume (assumed), gal	350,000
Boron concentration, ppm	2300-2500
Design temperature, °F	100
Design pressure, psig	Atmospheric
Operating pressure, psig	Atmospheric
Material	Austenitic stainless steel with reinforced concrete shroud

Containment Fan Coolers

Number (per unit)	5
Fan type	Centrifugal
Bearing monitors	Vibration

Containment Fan Coolers (Continued)	Normal Mode Operation[(b)]	Accident Mode Operation[(b)]
Speed, rpm	1,200	600
Capacity, cfm	110,000	47,000
Static pressure at 0.075 lb/ft^3, in. water	7.3	3.75
Containment atmosphere pressure, psig	0	47
Containment atmosphere temperature, °F	120	271
Containment atmosphere density, lb/ft^3	0.0685	0.175
Brake horsepower	275	103
Name plate horsepower	300	100
Component cooling water flow to motor heat exchanger, gpm	50	30 (min)
Motor Assembly		
Number (per unit)	5	
Type	460 V, 3 phase, 60 Hz, two speed, single winding	
Bearing monitor	Vibration and temperature	
Winding monitor	RTDs	
Service factor	1	
Heat exchange cooling media	Component cooling water	
Cooling Coil Assembly		
Number (per unit)	5	
Type	Plate-finned	
Tube material	Copper	
Fin material	Copper	
Fins per inch	8.5	
Tube thickness, in.	0.035	
Fin thickness, in.	0.008	
Tube normal OD, in.	0.625	
Tube length, in.	114	
Vertical drain pan spacing, ft	3.25	
Pan drain diameter, in.	2	
Assembly drain diameter, in.	8	
Drain pipe, Sch	10	
Assembly frame material	Steel	
Drain pan material	Steel	

TABLE 6.2-26

Containment Fan Coolers (Continued)[(d)]

	Normal Operation[(b)]	Accident Mode Operation[(b)]
Heat removal minimum, Btu/hr	3.14×10^6	81×10^6
Steam-air flow, cfm	110,000	47,000
Steam-air inlet temperature, °F	120	271
Steam-air outlet temperature, °F	92.5	269
Total pressure, psig	0	47
Air density, lb/ft^3	0.0685	0.0677
Steam density, lb/ft^3	-	0.1073
Condensation rate, gpm	0	180.7
Air face velocity, fpm	645	275
Static pressure drop (0.075 lb/ft^3), in. water	2.0	0.3 clean, 0.74 dirty
Cooling water flow, gpm	2000	2000
Cooling water inlet temperature, °F	90	125
Cooling water outlet temperature, °F	94	212
Pressure drop, ft water	8.8	8.8
Coil tube side foul factor	0.0005	0.0005
Water velocity, fps	3.43	3.43

___

The moisture separator and HEPA filter were deleted in Revision 9.

___

(a) Usable volume includes the water above the outlet pipe. Unusable water includes the water below the outlet.

(b) CFCU data are shown for an illustration of performance at typical operating points. Design minimum CCW flow to the CFCU cooling coils is nominally 1600 gpm for both normal and limiting accident modes. Design maximum CCW flow to the CFCU cooling coils is 2500 gpm for accident modes. Temperatures, heat removal rates, and other parameters will vary dynamically according to the accident conditions.

(c) Specified values for containment spray pump design pressure and temperature are maximum values and do not designate concurrent design conditions for the pump.

(d) Values for CFCUs with Westinghouse Sturtevant coils are historical and for normal mode operation are based off a maximum flow of 110,000 CFM. Values for accident mode operation are based off a flow rate of 47,000 CFM. The operating values depend on the operating point in the acceptable range of airflow rates for both modes. Under normal conditions the range is 68,000-110,000 CFM, under accident conditions the range of airflow rates is 34,000-57,000 CFM. At airflow rates less than 47,000 CFM, the heat removal performance is still acceptable (See Westinghouse Calc. Note CN-CRA-12-5).

TABLE 6.2-27

SINGLE FAILURE ANALYSIS - CONTAINMENT HEAT REMOVAL SYSTEMS

Component	Malfunction	Comments and Consequences
A. Spray Nozzles	Clogged	Large number of nozzles precludes clogging of a significant number.
B. Pumps		
Containment spray pump	Fails to start	Two pumps provided. Operation of one required.
C. Automatically Operated Valves: (9001A/B): (Open on coincidence of two out of four high-high containment pressure signals)		
Containment spray pump discharge isolation valve	Fails to open	Two complete systems provided. Operation of one required.
D. Valves Operated From Control Room for Spray Recirculation, if Used (9003A/B):		
Containment spray header isolation valve from residual heat exchanger discharge	Fails to open	Two complete systems provided. Operation of spray recirculation not required.
E. Containment Fan Coolers	Fails to start	Five fan coolers provided. Two required for minimum safety feature operation.

TABLE 6.2-29

SPRAY ADDITIVE SYSTEM DESIGN PARAMETERS

Eductors	
Quantity	2
Eductor Inlet (motive)	
Operating fluid	Borated Water
Operating temperature	Ambient
Eductor Suction fluid	
NaOH concentration, wt%	30
Specific gravity	~ 1.3
Viscosity (design), cp	~ 10
Operating temperature	Ambient
Spray Additive Tank	
Number	1
Total Volume (nominal), gal.	4000
NaOH Concentration, wt%	30
Design Temperature, °F	300
Internal Design Pressure, psig	14
Operating Temperature, °F	100
Operating Pressure, psig	5[a]
Material	Stainless Steel

(a) During normal operating and test conditions, the tank is pressurized with nitrogen at 5 psig. During preoperational testing or following a postulated accident, the nitrogen supply system will supply sufficient nitrogen to maintain this pressure as the tank empties. In the postulated event that the nitrogen supply system is inoperative, the tank pressure would fall below atmospheric pressure as the tank empties. Vacuum breakers are provided for this occurrence.

TABLE 6.2-30

SPRAY ADDITIVE SYSTEM - CODES USED IN SYSTEM DESIGN

Spray Additive Tank	ASME B&PV, Section VIII Code Class 3
Valves	ANSI B16.5
Piping (including headers and spray nozzles)	
Design Class I portions	ANSI B31.7
Design Class II portions	ANSI B31.1
Eductors	ASME B&PV, Section III

TABLE 6.2-36

PARAMETERS AND RESULTS FOR SPRAY IODINE REMOVAL ANALYSIS DURING INJECTION PHASE OPERATION[(a)]

Parameter	Best Estimate	Minimum Expected	Design Case
Power, MWt	3568	3568	3568
Containment free vol, ft^3	2.6×10^6	2.6×10^6	2.6×10^6
Unsprayed volume, %	17	17	17
No. pumps operating	2	1	1
Spray pump flowrate, gpm	5300	2650	2600
Containment pressure, psig	25	25	47
Containment temperature, °F	233	233	271
Spray fall height, ft	132.75	128	128
Spray solution pH	10.2[(b)]	10.2[(b)]	9.5
Results			
Exponential removal constant for the spray system (hr-1)	92	36	31[(c)]

(a) Data provided in this table are for spray iodine removal analysis only. A different set of data used in the containment integrity analysis are provided in Appendix 6.2D.

(b) Based on 2000 ppm boron concentration in the RWST. Only the Design Case has been updated for the change to a minimum 2300 ppm boron concentration in the RWST.

(c) Although a subsequent safety evaluation showed that the Design Case coefficient of 31 hr^{-1} (for 2600 gpm spray header flow) should be reduced to approximately 29 hr^{-1} (for 2466 gpm spray header flow), the potential offsite dose increase due to this change is extremely small and can be considered insignificant (Reference 50).

TABLE 6.2-37

SPRAY FALL HEIGHTS IN THE CONTAINMENT

Area[(a)], ft^2	Drop Fall Height[(b)], ft
1,075	58
1,400	93
100	105
225	122
9,900	128
150	145
2,550	177

(a) Area represents portion of operating deck covered by spray nozzles located at a particular elevation above the operating deck.

(b) Measured from 268 ft minimum average nozzle elevation. Average spray fall height: 128 ft.

TABLE 6.2-38

SPRAY ADDITIVE SYSTEM SINGLE FAILURE ANALYSIS

Component	Malfunction	Comments and Consequences
Automatically Operated Valves: (Open on coincidence of two-out-four high-high signals)		
Spray additive tank outlet isolation valve	Fails to open	Two parallel provided (8994A/B). Operation of one required.

TABLE 6.2-39

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
1	Feedwater	57	Yes	1 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	(NE/SA)				A	FW-FCV-438	Gte	Mtr	O	C	Yes	O	As is	F	N	C	W	Hot	1,26
					B	FW-140	Gte	Man	O	D	No	O	As is	-	Y	O	W	Hot	7,26
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	W	Hot	2
2	Feedwater	57	Yes	1 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	(NE/SA)				A	FW-FCV-439	Gte	Mtr	O	C	Yes	O	As is	F	N	C	W	Hot	1,26
					B	FW-147	Gte	Man	O	D	No	O	As is	-	Y	O	W	Hot	7,26
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	W	Hot	2
3	Feedwater	57	Yes	1 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	(NE/SA)				A	FW-FCV-440	Gte	Mtr	O	C	Yes	O	As is	F	N	C	W	Hot	1,26
					B	FW-153	Gte	Man	O	D	No	O	As is	-	Y	O	W	Hot	7,26
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	W	Hot	2
4	Feedwater	57	Yes	1 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	(NE/SA)				A	FW-FCV-441	Gte	Mtr	O	C	Yes	O	As is	F	N	C	W	Hot	1,26
					B	FW-157	Gte	Man	O	D	No	O	As is	-	Y	O	W	Hot	7,26
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	W	Hot	2
5	Main	57	Yes	1 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	steam																		
	(NE/SA)				E	MS-FCV-41	-	Air	O	C	Yes	O	As is	M	N	C	G	Hot	3,4,26
					F	MS-FCV-25	Glb	Air	O	C	Yes	C	Closed	M	N	C	G	Hot	4,26
					G	MS-PCV-19	Glb	Air	O	D	Yes	C	Closed	-	N	C	G	Hot	5,26
					H	MS-RV-3, 4, 5, 6, 222	Rlf	Spr	O	D	No	C	-	-	N	C	G	Hot	6,26
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	G	Hot	2
6	Main	57	Yes	2 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	steam																		
	(NE/SA)				A	MS-FCV-42	-	Air	O	C	Yes	O	As is	M	N	C	G	Hot	3,4,26
					B	MS-FCV-24	Glb	Air	O	C	Yes	C	Closed	M	N	C	G	Hot	4,26
					C	MS-PCV-20	Glb	Air	O	D	Yes	C	Closed	-	N	C	G	Hot	5,26
					D	MS-RV-7, 8, 9, 10, 223	Rlf	Spr	O	D	No	C	-	-	N	C	G	Hot	6,26
					E	MS-FCV-37	Gte	Mtr	O	D	Yes	O	As is	R-M	Y	O	G	Hot	26
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	G	Hot	2
7	Main	57	Yes	2 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	steam																		
	(NE/SA)				A	MS-FCV-43	-	Air	O	C	Yes	O	As is	M	N	C	G	Hot	3,4,26
					B	MS-FCV-23	Glb	Air	O	C	Yes	C	Closed	M	N	C	G	Hot	4,26
					C	MS-PCV-21	Glb	Air	O	D	Yes	C	Closed	-	N	C	G	Hot	5,26
					D	MS-RV-11,12,13,14,224	Rlf	Spr	O	D	No	C	-	-	N	C	G	Hot	6,26

TABLE 6.2-39

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
					E	MS-FCV-38	Gte	Mtr	O	D	Yes	O	As is	R-M	Y	O	G	Hot	26
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	G	Hot	2
8	Main steam (NE/SA)	57	Yes	1 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					E	MS-FCV-44	-	Air	O	C	Yes	O	As is	M	N	C	G	Hot	3,4,26
					F	MS-FCV-22	Glb	Air	O	C	Yes	C	Closed	M	N	C	G	Hot	4,26
					G	MS-PCV-22	Glb	Air	O	D	Yes	C	Closed	-	N	C	G	Hot	5,26
					H	MS-RV-58,59,60,61,225	Rlf	Spr	O	D	No	C	-	-	N	C	G	Hot	6,26
					-	Closed System	Cls	-	I	D	-	-	-	-	N	-	G	Hot	2
9	Component Cooling Water to Fan Coolers (SA)	57	Yes	3 (V)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7
					H	CCW-169	But	Man	O	D	No	O	As is	-	Y	O	W	Cold	7,26
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	W	Cold	47
10	Component Cooling Water to Fan Coolers (SA)	57	Yes	3 (V)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7
					H	CCW-177	But	Man	O	D	No	O	As is	-	Y	O	W	Cold	7,26
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	W	Cold	47
11	Component Cooling Water to Fan Coolers (SA)	57	Yes	3 (V)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7
					H	CCW-469	But	Man	O	D	No	O	As is	-	Y	O	W	Cold	7,26
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	W	Cold	47
12	Component Cooling Water to Fan Coolers (SA)	57	Yes	3 (V)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7
					H	CCW-477	But	Man	O	D	No	O	As is	-	Y	O	W	Cold	7,26

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	W	Cold	47
13	Component Cooling Water to Fan Coolers (SA)	57	Yes	3 (V)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7
					H	CCW-185	But	Man	O	D	No	O	As is	-	Y	O	W	Cold	7,26
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	W	Cold	47
14	Component Cooling Water from Fan Coolers (SA)	57	Yes	3 (VI)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7
					I	CCW-176	But	Man	O	D	No	O	As is	-	Y	O	W	Cold	7,26
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	W	Cold	47
15	Component Cooling Water from Fan Coolers (SA)	57	Yes	3 (VI)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7
					I	CCW-184	But	Man	O	D	No	O	As is	-	Y	O	W	Cold	7,26
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	W	Cold	47
16	Component Cooling Water from Fan Coolers (SA)	57	Yes	3 (VI)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7
					I	CCW-476	But	Man	O	D	No	O	As is	-	Y	O	W	Cold	7,26
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	W	Cold	47
17	Component Cooling Water from Fan Coolers	57	Yes	3 (VI)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7
					I	CCW-484	But	Man	O	D	No	O	As is	-	Y	O	W	Cold	7,26

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
	(SA)				-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	W	Cold	47
18	Component Cooling Water from Fan Coolers (SA)	57	Yes	3 (VI)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7
					I	CCW-192	But	Man	O	D	No	O	As is	-	Y	O	W	Cold	7,26
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	W	Cold	47
19	Component Cooling Water to Reactor Coolant Pumps (ES)	55	Yes	4 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	CCW-FCV-356	But	Mtr	O	A	Yes	O	As is	P	N	C	W	Cold	-
					B	CCW-585	Chk	-	I	A	No	O	-	-	N	C	W	Cold	-
20	Component Cooling Water from Reactor Coolant Pumps (ES)	55	Yes	4 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					F	CCW-FCV-363	But	Mtr	O	A	Yes	O	As is	P	N	C	W	Cold	-
					E	CCW-FCV-749	But	Mtr	I	A	Yes	O	As is	P	N	C	W	Cold	-
					H	CCW-581	Chk	-	I	A	No	O	-	-	N	C	W	Cold	-
21	Component Cooling Water from Reactor Coolant Pumps (ES)	55	Yes	4 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					C	CCW-FCV-750	Glb	Mtr	I	A	Yes	O	As is	P	N	C	W	Hot	-
					D	CCW-FCV-357	Glb	Mtr	O	A	Yes	O	As is	P	N	C	W	Hot	-
					G	CCW-670	Chk	-	I	A	No	O	-	-	N	C	W	Hot	-
22	CCW to Excess Letdown	57	No	4 (IV)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8
					I	CCW-695	Chk	-	O	C	No	C	-	-	N	C	W	Cold	8

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
	Heat Exchanger (NE)				-	Closed System	Cls	-	I	C	-	-	-	-	N	-	W	Cold	-
23	CCW from Excess Letdown Heat Exchanger (NE)	57	Yes	4 (V)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					J	CCW-FCV-361	But	Air	O	C	Yes	C	Closed	T	N	C	W	Cold	-
					-	Closed System	Cls	-	I	C	-	-	-	-	N	-	W	Cold	-
24	Residual Heat Removal No. 1 Cold Leg Injection (SA)	55	Yes	5 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	SI-8818A	Chk	-	I	B	No	C	-	-	Y	C	W	Hot	26
					B	SI-8818B	Chk	-	I	B	No	C	-	-	Y	C	W	Hot	26
					C	SI-8809A	Gte	Mtr	O	B	Yes	O	As is	R-M	Y	C	W	Hot	7,9,26, 40
					M	SI-8885A (U1)	Glb	Air	I	E	-	C	Closed	-	N	C	W	Hot	22,26, 41
						Closed System	Cls	-	O	B	-	-	-	-	Y	-	W	Hot	10
25	Residual Heat Removal No. 2 Cold Leg Injection (SA)	55	Yes	5 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					I	SI-8818C	Chk	-	I	B	No	C	-	-	Y	C	W	Hot	26
					J	SI-8818D	Chk	-	I	B	No	C	-	-	Y	C	W	Hot	26
					K	SI-8885B (U1)	Glb	Air	I	E	-	C	Closed	-	N	C	W	Hot	22,26, 41
					L	SI-8809B	Gte	Mtr	O	B	Yes	O	As is	R-M	Y	C	W	Hot	7,9,26, 40
					-	Closed System	Cls	-	O	B	-	-	-	-	Y	-	W	Hot	10
26	Residual Heat Removal Hot Leg Injection (SA)	55	Yes	5 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					D	RHR-8716A	Gte	Mtr	O	B	Yes	O	As is	R-M	Y	C	W	Hot	7,9,26, 40
					G	RHR-8716B	Gte	Mtr	O	B	Yes	O	As is	R-M	Y	O	W	Hot	7,9,26, 40
					H	RHR-8703	Gte	Mtr	I	B	Yes	C	As is	R-M	Y	O	W	Hot	7,11, 26
					-	Closed System	Cls	-	O	B	-	-	-	-	Y	-	W	Hot	10

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
27	Reactor Coolant System Loop 4 Recirculation (SA)	55	Yes	6 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	RHR-8701	Gte	Mtr	I	D	Yes	C	As is	R-M	N	C	W	Hot	7,11, 26
					H	RHR-1012	Glb	Man	O	D	No	C	-	-	N	C	W	Hot	11,26,45
					I	RHR-1014	Glb	Man	O	D	No	C	-	-	N	C	W	Hot	11,26,45
					B	SI-8980	Gte	Mtr	O	D	Yes	O	As is	R-M	Y	C	W	Hot	11,7, 26
					C	RHR-8700A	Gte	Mtr	O	D	Yes	O	As is	R-M	Y	C	W	Hot	11,7, 26
					D	RHR-8700B	Gte	Mtr	O	D	Yes	O	As is	R-M	Y	C	W	Hot	11,7, 26
28	Containment Sump Recirculation (SA)	56	Yes	6 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					E	SI-8982A	Gte	Mtr	O	D	Yes	C	As is	-	Y	O	W	Hot	12,26
					-	Closed System	Cls	-	O	D	-	-	-	-	Y	-	W	Hot	10
29	Containment Sump Recirculation (SA)	56	Yes	6 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					F	SI-8982B	Gte	Mtr	O	D	Yes	C	As is	-	Y	O	W	Hot	12,26
					-	Closed System	Cls	-	O	D	-	-	-	-	Y	-	W	Hot	10
30	Containment Spray System (SA)	56	Yes	7 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	CS-9011B	Chk	-	I	D	No	C	-	-	Y	C	W	Cold	-
					B	CS-9001B	Gte	Mtr	O	D	Yes	C	As is	R-M	Y	C	W	Cold	11,13
					C	CS-32	Glb	Man	O	E	No	C	-	-	N	C	W	Cold	
					D	CS-9003B	Gte	Mtr	O	D	Yes	C	As is	R-M	Y	C	W	Cold	7,11, 26,48
31	Containment Spray System (SA)	56	Yes	7 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					E	CS-9011A	Chk	-	I	D	No	C	-	-	Y	C	W	Cold	-
					F	CS-9003A	Gte	Mtr	O	D	Yes	C	As is	R-M	Y	C	W	Cold	7,11, 26,48
					G	CS-9001A	Gte	Mtr	O	D	Yes	C	As is	R-M	Y	C	W	Cold	11,13
					H	CS-31	Glb	Man	O	E	No	C	-	-	N	C	W	Cold	

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
32	Spare	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26
33	Safety Injection System (SA)	55	Yes	8 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					B	SI-8835	Gte	Mtr	O	D	Yes	O	As is	R-M	Y	C	W	Cold	7,11, 26
					G	SI-8823 (U1)	Glb	Air	I	E	-	C	Closed	-	N	C	W	Cold	22,26,41
34	Safety Injection System (SA)	55	Yes	8 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					D	SI-8801A, 8801B	Gte	Mtr	O	D	Yes	C	As is	S	Y	O	W	Cold	11,14,26
					I	SI-8969	Glb	Man	O	E	No	C	-	-	N	C	W	Cold	26,48
35	Regenerative Heat Exchanger to Letdown Heat Exchanger (NE)	55	Yes	9 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	CVCS-8149A	Glb	Air	I	A	Yes	O	Closed	T	N	C	W	Hot	-
					B	CVCS-8149B	Glb	Air	I	A	Yes	O	Closed	T	N	C	W	Hot	-
					C	CVCS-8149C	Glb	Air	I	A	Yes	O	Closed	T	N	C	W	Hot	-
					D	CVCS-8152	Glb	Air	O	A	Yes	O	Closed	T	N	C	W	Hot	-
36	Normal Charging to Regenerative Heat Exchanger (SA)	55	Yes	9 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	34
					E	CVCS-8378C	Chk	-	I	A	No	O	-	-	N	C	W	Cold	26
					F	CVCS-8107	Gte	Mtr	O	A	Yes	O	As is	S	N	C	W	Cold	26
37	Steam Generator Blowdown (NE)	57	Yes	1 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					J	MS-FCV-151	Glb	Air	O	C	Yes	O	Closed	T	N	C	W	Hot	26,55
					I	MS-FCV-760	Glb	Air	I	C	Yes	O	Closed	M	N	C	W	Hot	2,4, 26,48
					-	Closed System	Cls	-	I	C	-	-	-	-	-	-	W	Hot	2
38	Steam	57	Yes	1 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
	Generator Blowdown (NE)				J	MS-FCV-154	Glb	Air	O	C	Yes	O	Closed	T	N	C	W	Hot	26,55
					I	MS-FCV-761	Glb	Air	I	C	Yes	O	Closed	M	N	C	W	Hot	2,4, 26,48
					-	Closed System	Cls	-	I	C	-	-	-	-	-	-	W	Hot	2
39	Steam Generator Blowdown (NE)	57	Yes	1 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					J	MS-FCV-157	Glb	Air	O	C	Yes	O	Closed	T	N	C	W	Hot	26,55
					I	MS-FCV-762	Glb	Air	I	C	Yes	O	Closed	M	N	C	W	Hot	2,4, 26,48
					-	Closed System	Cls	-	I	C	-	-	-	-	-	-	W	Hot	2
40	Steam Generator Blowdown (NE)	57	Yes	1 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					J	MS-FCV-160	Glb	Air	O	C	Yes	O	Closed	T	N	C	W	Hot	26,55
					I	MS-FCV-763	Glb	Air	I	C	Yes	O	Closed	M	N	C	W	Hot	2,4, 26,48
					-	Closed System	Cls	-	I	C	-	-	-	-	-	-	W	Hot	2
41	Reactor Coolant Pump Seal Water Supply (ES)	55	Yes	10 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	CVCS-8368A	Chk	-	I	B	No	O	-	-	Y	O	W	Cold	-
					-	Closed System	Cls	-	O	B	-	-	-	-	Y	-	W	Cold	10
42	Reactor Coolant Pump Seal Water Supply (ES)	55	Yes	10 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	CVCS-8368B	Chk	-	I	B	No	O	-	-	Y	O	W	Cold	-
					-	Closed System	Cls	-	O	B	-	-	-	-	Y	-	W	Cold	10
43	Reactor Coolant Pump Seal Water Supply	55	Yes	10 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	CVCS-8368C	Chk	-	I	B	No	O	-	-	Y	O	W	Cold	-
					-	Closed System	Cls	-	O	B	-	-	-	-	Y	-	W	Cold	10

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Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
	(ES)																		
44	Reactor Coolant Pump Seal Water Supply (ES)	55	Yes	10 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	CVCS-8368D	Chk	-	I	B	No	O	-	-	Y	O	W	Cold	-
					-	Closed System	Cls	-	O	B	-	-	-	-	Y	-	W	Cold	10
45	Reactor Coolant Pump Seal Water Return (NE)	55	Yes	10 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					B	CVCS-8112	Gte	Mtr	I	A	Yes	O	As is	T	N	C	W	Cold	-
					C	CVCS-8109	Chk	-	I	A	No	O	-	-	Y	O	W	Cold	-
					D	CVCS-8100	Gte	Mtr	O	A	Yes	O	As is	T	N	C	W	Cold	-
46	Refueling Canal Recirculat ion (NE)	56	Yes	3 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					C	LWS-8796	Dia	Man	I	E	No	C	-	-	N	C	W	Cold	-
					D	LWS-8787	Dia	Man	O	E	No	C	-	-	N	C	W	Cold	-
47	Refueling Canal Return (NE)	56	Yes	3 (IV)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					F	LWS-8795	Dia	Man	I	E	No	C	-	-	N	C	W	Cold	-
					G	LWS-8767	Dia	Man	O	E	No	C	-	-	N	C	W	Cold	-
48	Spare	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26
49	Containm ent Sump Discharge (NE)	56	Yes	3 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	LWS-FCV-500	Bal	Air	I	A	Yes	O	Closed	T	N	C	W	Cold	-
					B	LWS-FCV-501	Bal	Air	O	A	Yes	O	Closed	T	N	C	W	Cold	-
50	Reactor Coolant Drain Tank Discharge (NE)	56	Yes	12 (IV)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					G	LWS-FCV-254	Bal	Air	O	A	Yes	O	Closed	T	N	C	W	Hot	-
					H	LWS-FCV-253	Bal	Air	I	A	Yes	O	Closed	T	N	C	W	Hot	-

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Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
51A	Nitrogen Supply Header to Accumulators (NE)	56	Yes	8 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					E	SI-8880	Glb	Air	O	A	Yes	O	Closed	T	N	C	G	Cold	-
					F	SI-8916	Chk	-	I	A	No	O	-	-	N	C	G	Cold	-
51B	Safety Injection System Test Line (NE)	55	Yes	13 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	SI-8871	Glb	Air	I	A	Yes	C	Closed	T	N	C	W	Cold	-
					B	SI-8883	Glb	Air	O	A	Yes	C	Closed	T	N	C	W	Cold	-
					C	SI-8961	Glb	Air	O	A	Yes	C	Closed	T	N	C	W	Cold	-
					D	SI-161	Glb	Man	O	E	No	C	-	-	N	C	W	Cold	48
51C	Reactor Coolant Drain Tank Vent (NE)	56	Yes	12 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					C	LWS-FCV-256	Bal	Air	O	A	Yes	O	Closed	T	N	C	G	Cold	-
					D	LWS-FCV-255	Bal	Air	I	A	Yes	O	Closed	T	N	C	G	Cold	-
51D	Reactor Coolant Drain Tank to Gas Analyzer (NE)	56	Yes	12 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					E	LWS-FCV-257	Bal	Air	O	A	Yes	C	Closed	T	N	C	W	Cold	-
					F	LWS-FCV-258	Bal	Air	I	A	Yes	O	Closed	T	N	C	W	Cold	-
52A	Pressurizer Relief Tank Makeup (NE)	55	Yes	14 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					E	RCS-8029	Bal	Air	O	A	Yes	O	Closed	T	N	C	W	Cold	-
					F	RCS-8046	Chk	-	I	A	No	O	-	-	N	C	W	Cold	-
52B	Pressurizer Relief Tank Nitrogen Supply (NE)	55	Yes	14 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					C	RCS-8047	Chk	-	I	A	No	O	-	-	N	C	G	Cold	-
					D	RCS-8045	Dia	Air	O	A	Yes	O	Closed	T	N	C	G	Cold	-
52C	Steam Generator	56	Yes	2 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

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Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
	Nitrogen Supply				F	MS-902	Gte	Man	O	E	No	C	-	-	N	C	G	Cold	26
	(NE)				G	MS-5200	Chk	-	I	E	No	C	-	-	N	C	G	Cold	26
52D	Reactor Coolant	56	Yes	12 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Drain Tank				A	LWS-FCV-260	Bal	Air	O	A	Yes	O	Closed	T	N	C	G	Cold	-
	Nitrogen Supply (NE)				B	LWS-60	Chk	-	I	A	No	O	-	-	N	C	G	Cold	-
52E	Containment H_2	56	Yes	24 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Monitor Supply				A	VAC-FCV-235	Glb	Sol	I	E	Yes	C	Closed	-	Y	O	G	Cold	28,29
	(NE)				B	VAC-FCV-236	Glb	Sol	O	E	Yes	C	Closed	-	Y	O	G	Cold	28,29
52F	Containment H_2	56	Yes	24 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Monitor Return				C	VAC-FCV-237	Glb	Sol	O	E	Yes	C	Closed	-	Y	O	G	Cold	28,29
	(NE)				D	VAC-252	Chk	-	I	E	No	C	-	-	Y	O	G	Cold	29
52G	Containment	56	Yes	15 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Pressure PT-937				A	Sealed Bellows	Sbl	-	I	-	-	-	-	-	-	-	G	Cold	16
	(SA)				B	Sealed Instrument	Sin	-	O	-	-	-	-	-	-	-	G	Cold	16
52H	Containment	56	Yes	15 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Pressure PT-932				A	Sealed Bellows	Sbl	-	I	-	-	-	-	-	-	-	W	Cold	16
	(SA)(abandon in place)				B	Sealed Instrument	Sin	-	O	-	-	-	-	-	-	-	W	Cold	16
53A	Steam Generator 1	57	Yes	1 (IV)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Blowdown				K	MS-FCV-250	Glb	Air	O	C	Yes	O	Closed	T	N	C	W	Hot	26,55
	Sample (NE)				I	MS-FCV-760	Glb	Air	I	C	Yes	O	Closed	M	N	C	W	Hot	2,4, 26,48
					-	Closed System	Cls	-	I	C	-	-	-	-	-	-	W	Hot	2

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
53B	Steam Generator 2 Blowdown Sample (NE)	57	Yes	1 (IV)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					K	MS-FCV-248	Glb	Air	O	C	Yes	O	Closed	T	N	C	W	Hot	26,55
					I	MS-FCV-761	Glb	Air	I	C	Yes	O	Closed	M	N	C	W	Hot	2,4, 26,48
					-	Closed System	Cls	-	I	C	-	-	-	-	-	-	W	Hot	2
53C	Steam Generator 3 Blowdown Sample (NE)	57	Yes	1 (IV)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					K	MS-FCV-246	Glb	Air	O	C	Yes	O	Closed	T	N	C	W	Hot	26,55
					I	MS-FCV-762	Glb	Air	I	C	Yes	O	Closed	M	N	C	W	Hot	2,4, 26,48
					-	Closed System	Cls	-	I	C	-	-	-	-	-	-	W	Hot	2
53D	Steam Generator 4 Blowdown Sample (NE)	57	Yes	1 (IV)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					K	MS-FCV-244	Glb	Air	O	C	Yes	O	Closed	T	N	C	W	Hot	26,55
					I	MS-FCV-763	Glb	Air	I	C	Yes	O	Closed	M	N	C	W	Hot	2,4, 26,48
					-	Closed System	Cls	-	I	C	-	-	-	-	-	-	W	Hot	2
54	Instrument Air Header (NE)	56	Yes	16 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	AIR-I-587	Chk	-	I	A	No	O	-	-	N	C	G	Cold	-
					B	FCV-584	Bal	Air	O	A	Yes	O	Closed	T	N	C	G	Cold	-
					E	AIR-I-585	Dia	Man	O	E	No	C	-	-	N	C	G	Cold	48
55	Spare		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26
56	Service Air Header (NE)	56	Yes	16 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					C	AIR-S-114	Chk	-	I	E	No	C	-	-	N	C	G	Cold	-
		-			D	AIR-S-200	Bal	Man	O	E	No	C	-	-	N	C	G	Cold	-
57	Containment External H_2 Recombiners (SA)	56	Yes	24 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					E	VAC-FCV-669	Gte	Mtr	O	E	Yes	C	As is	-	Y	C	G	Cold	28,38
					F	VAC-FCV-659	Gte	Mtr	I	E	Yes	C	As is	-	Y	C	G	Cold	28,38

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
58	Mini-Equipment Hatch (NE)	-	-	-	-	Not a piping penetration	-	-	-	-	-	-	-	-	-	-	-	-	-
59A	Pressurizer Liquid Sample (NE)	55	Yes	17 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					C	NSS-9355A	Glb	Air	I	A	Yes	O	Closed	T	N	C	W	Hot	-
					D	NSS-9355B	Glb	Air	O	A	Yes	O	Closed	T	N	C	W	Hot	-
59B	Hot Leg Sample (NE)	55	Yes	17 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					E	NSS-9356A	Glb	N_2	I	A	Yes	O	Closed	T	Y	C	W	Hot	-
			-		F	NSS-9356B	Glb	N_2	O	A	Yes	O	Closed	T	Y	C	W	Hot	-
59C	Accumulator Sample (NE)	55	Yes	17 (IV)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					G	NSS-9357A	Glb	Air	I	A	Yes	C	Closed	T	N	C	W	Cold	-
					H	NSS-9357B	Glb	Air	O	A	Yes	C	Closed	T	N	C	W	Cold	-
59D	Containment Pressure Transmitter PT-938 (SA)	56	Yes	15 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	Sealed Instrument	Sin	-	I	-	-	-	-	-	-	-	W	Cold	16
					B	Sealed Bellows	Sbl	-	O	-	-	-	-	-	-	-	W	Cold	16
59E	RV Level Instrumentation Transmitter LIS-1310 (SA)	55	Yes	25 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	Sealed Bellows	Sbl	-	I	-	-	-	-	-	-	-	W	Cold	16
					B	Hydraulic Isolators	Hys	-	O	-	-	-	-	-	-	-	W	Cold	16
59F	RV Level Instrumentation Transmitter LIS-1311 (SA)	55	Yes	25 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	Sealed Bellows	Sbl	-	I	-	-	-	-	-	-	-	W	Cold	16
					B	Hydraulic Isolators	Hys	-	O	-	-	-	-	-	-	-	W	Cold	16

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
59G	RV Level Instrumentation Transmitter LIS-1312 (SA)	55	Yes	25 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	Sealed Bellows	Sbl	-	I	-	-	-	-	-	-	-	W	Cold	16
					B	Hydraulic Isolators	Hys	-	O	-	-	-	-	-	-	-	W	Cold	16
59H	Containment Pressure Transmitters PT-933 & PT-935 (SA)	56	Yes	15 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	Sealed Instrument	Sin	-	I	-	-	-	-	-	-	-	W	Cold	16
					B	Sealed Bellows	Sbl	-	O	-	-	-	-	-	-	-	W	Cold	16
60	Mini-Equipment Hatch (NE)	-	-	-	-	Not a piping penetration	-	-	-	-	-	-	-	-	-	-	-	-	-
61	Containment Purge Supply (NE)	56	Yes	18 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					D	VAC-FCV-660	But	Air	I	A	Yes	C	Closed	T	N	C	G	Cold	18
					E	VAC-FCV-661	But	Air	O	A	Yes	C	Closed	T	N	C	G	Cold	18
62	Containment Purge Exhaust (NE)	56	Yes	18 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					F	VAC-RCV-11	But	Air	I	A	Yes	C	Closed	T	N	C	G	Cold	18
					G	VAC-RCV-12	But	Air	O	A	Yes	C	Closed	T	N	C	G	Cold	18
63	Containment Pressure and Vacuum Relief (NE)	56	Yes	18 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	VAC-FCV-662	But	Air	I	A	Yes	C	Closed	T	N	C	G	Cold	18
					B	VAC-FCV-663	But	Air	O	A	Yes	C	Closed	T	N	C	G	Cold	18
					C	VAC-FCV-664	But	Air	O	A	Yes	C	Closed	T	N	C	G	Cold	18
					J	Spectacle Flange	Spf	-	O	A	-	N/A	-	-	N/A	N/A	G	Cold	26
64	Fuel Transfer	-	-	3 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
	Tube (NE)					Not a piping penetration	-	-	-	-	-	-	-	-	-	-	-	-	-
65	Personnel Hatch (NE)	-	-		-	Not a piping penetration	-	-	-	-	-	-	-	-	-	-	-	-	-
66	Emergenc y Personnel Hatch (NE)	-	-		-	Not a piping penetration	-	-	-	-	-	-	-	-	-	-	-	-	-
67	Equipmen t Hatch	-	-		-	Not a piping penetration	-	-	-	-	-	-	-	-	-	-	-	-	-
	(NE)	-	-		-		-	-	-	-	-	-	-	-	-	-	-	-	-
68	Containm ent Air Sample (NE)	56	Yes	19 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					C	VAC-FCV-679	Bal	Air	O	A	Yes	O	Closed	T	N	C	G	Cold	18
					D	VAC-FCV-678	Bal	Air	I	A	Yes	O	Closed	T	N	C	G	Cold	18
69	Containm ent Air Sample (NE)	56	Yes	19 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	VAC-FCV-681	Bal	Air	O	A	Yes	O	Closed	T	Y	C	G	Cold	18
					B	VAC-21	Chk	-	I	A	No	O	-	-	Y	C	G	Cold	-
70	Auxiliary Steam Supply (NE)	56	Yes	20 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	AXS-26	Gte	Man	O	E	No	C	-	-	N	C	G	Hot	-
					B	AXS-208	Chk	-	I	E	No	C	-	-	N	C	G	Hot	-
71	Relief Valve (NE) Header	56	Yes	14 (IV)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					G	RCS-8028	Chk	-	I	E	No	C	-	-	N	C	G	Hot	-
					H	CVCS-RV-8125,	Rlf	-	O	E	No	C	-	-	N	C	G	Hot	20,26
					H	SI-RV-8851,8853A,8853B,	Rlf	-	O	E	No	C	-	-	N	C	G	Hot	20,26
					H	8856A,8856B,8858	Rlf	-	O	E	No	C	-	-	N	C	G	Hot	20,26
					H	CS-RV-9007A,9007B	Rlf	-	O	E	No	C	-	-	N	C	G	Hot	20,26

TABLE 6.2-39

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
					I	RCS-512	Glb	Man	O	E	No	C	-	-	N	C	G	Hot	-
72	Spare	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26
73	Spare	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26
74	Spare	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26
75	Safety Injection Pump 2 Discharge (SA)	55	Yes	21 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	SI-8802B	Gte	Mtr	O	D	Yes	C	As is	R-M	Y	O	W	Cold	7,11, 26
76A	Pressurizer Steam Sample	55	Yes	17 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	NSS-9354A	Glb	Air	I	A	Yes	C	Closed	T	Y	C	G	Hot	-
					B	NSS-9354B	Glb	Air	O	A	Yes	C	Closed	T	Y	C	G	Hot	-
76B	Pressurizer Relief Tank Gas Analyzer (NE)	55	Yes	14 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	RCS-8034B	Glb	Air	O	A	Yes	C	Closed	T	N	C	G	Cold	-
					B	RCS-8034A	Glb	Air	I	A	Yes	C	Closed	T	N	C	G	Cold	-
76C	Deadweight Tester (Abandoned in place. Tester removed.) (NE)	55	Yes	22 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	Sealed Bellows	Sbl	-	I	-	-	-	-	-	-	-	W	Cold	16
					B	U1: 1-07P-8085B	Glb	Man	O	E	No	C	-	-	N	C	W	Cold	26
					-	U2: 1/4" Instrument cap	-	-	O	-	-	-	-	-	-	-	-	-	16
76D	Containment Pressure Transmitter PT-934 (SA)	56	Yes	15 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	Sealed Bellows	Sbl	-	I	-	-	-	-	-	Y	-	W	Cold	16
					B	Sealed Instrument	Sin	-	O	-	-	-	-	-	Y	-	W	Cold	16
76E	Spare Connectio	56	Yes	11 (III)															
					-	U1: 3/8" Inst Cap	-	-	I	-	-	-	-	-	-	-	-	-	26

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
	n				-	U1: 3/8" Inst Cap	-	-	O	-	-	-	-	-	-	-	-	-	26
		-	-		-	U2: 1" Welded Pipe Cap	-	-	-	-	-	-	-	-	-	-	-	-	26
77	Safety Injection Pump 1 Discharge (SA)	55	Yes	21 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					E	SI-8802A	Gte	Mtr	O	D	Yes	C	As is	R-M	Y	O	W	Cold	7,11, 26
78A	Containment H$_2$ Monitor Supply (SA)	56	Yes	24 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	VAC-FCV-238	Glb	Sol	I	E	Yes	C	Closed	-	Y	O	G	Cold	28,29
					B	VAC-FCV-239	Glb	Sol	O	E	Yes	C	Closed	-	Y	O	G	Cold	28,29
78B	Containment H$_2$ Monitor Return (SA)	56	Yes	24 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					C	VAC-FCV-240	Glb	Sol	O	E	Yes	C	Closed	-	Y	O	G	Cold	28,29
					D	VAC-253	Chk	-	I	E	No	C	-	-	Y	O	G	Cold	29
78C	Containment Pressure Transmitter PT-936 (SA)	56	Yes	15 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	Sealed Bellows	Sbl	-	I	-	-	-	-	-	-	-	W	Cold	16
					B	Sealed Instrument	Sin	-	O	-	-	-	-	-	-	-	W	Cold	16
78D	Spare Connection	56	Yes	11 (III)															
					-	U1: 3/8" Inst Plug	-	-	I	-	-	-	-	-	-	-	-	-	26
					-	U1: 3/8" Inst Plug	-	-	O	-	-	-	-	-	-	-	-	-	26
		-	-		-	U2: 1" Welded Pipe Cap	-	-	-	-	-	-	-	-	-	-	-	-	26
78E	Spare Connection	-	-		-	1" Welded Pipe Cap	-	-	-	-	-	-	-	-	-	-	-	-	26
78F	Spare Connection	-	-		-	1" Welded Pipe Cap	-	-	-	-	-	-	-	-	-	-	-	-	26

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
78G	Spare Connection	-	-	-	-	1" Welded Pipe Cap	-	-	-	-	-	-	-	-	-	-	-	-	26
78H	Spare Connection	-	-		-	1" Welded Pipe Cap	-	-	-	-	-	-	-	-	-	-	-	-	26
79	Fire Water (NE)	56	Yes	23 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	FP-FCV-633	Glb	Air	O	A	Yes	O	Closed	T	N	C	W	Cold	-
					B	FP-180(U1),FP-867(U2)	Chk	-	I	A	No	O	-	-	N	C	W	Cold	-
80A	Spare Instrument	56	Yes	11 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(U1)	Test Line (Unit-1)				-	Instrument Plug	-	-	I	E	No	-	-	-	N	-	G	Cold	26
					-	VAC-301	Glb	Man	O	E	No	C	-	-	N	C	G	Cold	26
80A	Spare Instrument	56	Yes	11 (IV)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(U2)	Test Line (Unit-2)				-	VAC-303	Glb	Man	I	E	No	C	-	-	N	C	G	Cold	26
					-	VAC-301	Glb	Man	O	E	No	C	-	-	N	C	G	Cold	26
80B	Spare Instrument	56	Yes	11 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(U1)	Test Line (Unit-1)				-	Instrument Plug	-	-	I	E	No	-	-	-	N	-	G	Cold	26
					-	VAC-302	Glb	Man	O	E	No	C	-	-	N	C	G	Cold	26
80B	Spare Instrument	56	Yes	11 (IV)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(U2)	Test Line (Unit-2)				-	VAC-304	Glb	Man	I	E	No	C	-	-	N	-	G	Cold	26
					-	VAC-302	Glb	Man	O	E	No	C	-	-	N	C	G	Cold	26
80C	Spare Instrument	56	Yes	11 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
	Test Line				-	Instrument Plug	-	-	I	E	No	-	-	-	N	C	G	-	26
					-	Instrument Plug	-	-	O	E	No	-	-	-	N	C	G	-	26
80D	Containment Pressure Transmitter PT-939 (SA)	56	Yes	15 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	Sealed Bellows	Sbl	-	I	-	-	-	-	-	-	-	W	Cold	16
					B	Sealed Instrument	Sin	-	O	-	-	-	-	-	-	-	W	Cold	16
80E	RV Level Instrumentation Transmitter LIS-1320 (SA)	55	Yes	25 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	Sealed Bellows	Sbl	-	I	-	-	-	-	-	-	-	W	Cold	16
					B	Hydraulic Isolators	Hys	-	O	-	-	-	-	-	-	-	W	Cold	16
80F	RV Level Instrumentation Transmitter LIS-1321 (SA)	55	Yes	25 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	Sealed Bellows	Sbl	-	I	-	-	-	-	-	-	-	W	Cold	16
					B	Hydraulic Isolators	Hys	-	O	-	-	-	-	-	-	-	W	Cold	16
80G	RV Level Instrumentation Transmitter LIS-1322 (SA)	55	Yes	25 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	Sealed Bellows	Sbl	-	I	-	-	-	-	-	-	-	W	Cold	16
					B	Hydraulic Isolators	Hys	-	O	-	-	-	-	-	-	-	W	Cold	16
81	Containment External H_2 Recombiners (SA)	56	Yes	24 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					E	VAC-FCV-668	Gte	Mtr	O	E	Yes	C	As is	-	Y	C	G	Cold	28,38
					F	VAC-FCV-658	Gte	Mtr	I	E	Yes	C	As is	-	Y	C	G	Cold	28,38
82A	Post-Accident	56	Yes	25 (IV)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
	Sampling System				G	LWS-FCV-697	Glb	Sol	O	A	Yes	C	Closed	-	Y	C	W	Cold	28,29
	Reactor Cavity Sump (NE)				H	LWS-FCV-696	Glb	Sol	I	A	Yes	C	Closed	-	Y	C	W	Cold	28
82B	Post-Accident	56	Yes	25 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Sampling System Containment Air				C	VAC-FCV-698	Glb	Sol	I	A	Yes	C	Closed	-	Y	C	G	Cold	28,29
	Supply (NE)				D	VAC-FCV-699	Glb	Sol	O	A	Yes	C	Closed	-	Y	C	G	Cold	28,29
82C	Post-Accident	56	Yes	25 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Sampling System				E	VAC-FCV-700	Glb	Sol	O	A	Yes	C	Closed	-	Y	C	G	Cold	28,29
	Containment Air Return (NE)				F	VAC-116	Chk	-	I	A	No	C	-	-	Y	C	G	Cold	29
82D	Spare Piping	56	Yes	11 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(U1)	Connection				-	Blind Flange	-	-	I	E	No	C	-	-	N	C	G	Cold	26
					-	VAC-1-680	Gte	Man	O	E	No	C	-	-	N	C	G	Cold	26
82D (U2)	Chilled Water Supply (NE) (abandon in place)	-	-	7 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	52
82E	Spare Instrument	56	Yes	11 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Test Line				-	Instrument Plug	-	-	I	E	No	-	-	-	-	-	G	Cold	26
					-	Instrument Plug	-	-	O	E	No	-	-	-	-	-	G	Cold	26

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
83A (U1)	Spare Piping Connection	56	Yes	11 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					-	Blind Flange	-	-	I	E	No	C	-	-	N	C	G	Cold	26
					-	VAC-1-681	Gte	Man	O	E	No	C	-	-	N	C	G	Cold	26
83A (U2)	Chilled Water Return (NE) (abandon in place)	-	-	7 (IV)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	52
83B	Hydrogen Purge Supply (NE)	56	Yes	11 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	VAC-200,201	Chk	-	I	E	No	C	-	-	Y	O	G	Cold	38
					B	VAC-1,2	Gte	Man	O	E	No	C	-	-	Y	C	G	Cold	38
84	Spare	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26

Notes:

1. Trip on feedwater isolation. (refer to Table 6.2-40, Item 4.)
2. Steam generator secondary side is missile-protected closed system. The closed loop system includes all pressure boundary test, vent, drain, and instrument valves; instruments; blanked flange connections; and steam generator tubes.
3. Reverse check (main steam isolation).
4. Trip on steam line isolation. (refer to Table 6.2-40, Item 3.)
5. Safety-related function. Valve trip is related to systems safety function.
6. PG&E considers the five main steam relief valves to be containment isolation valves.
7. Safety-related function demands that this valve not automatically isolate.
8. Penetration does not meet 1971 GDC but does meet the GDC 53, 1967 which was applicable at time of construction commitment.
9. This valve is not considered as the automatic isolation barrier. The barrier is provided by the closed system. The valve does have provision for remote manual isolation should the situation require it.
10. PG&E considers the closed system outside containment as an automatic isolation barrier.
11. Provision for remote manual isolation exists should the situation require it. Safety-related function demands that this valve not isolate. It conforms with the intent of the GDC as it affects maintenance of the containment boundary.

TABLE 6.2-39

CONTAINMENT PIPING PENETRATIONS AND VALVING

12. The protective chamber is considered outside containment. The motor-operated valves are the isolation valves outside containment.

13. Valve opens on containment spray signal.

14. Valve opens on SIS signal.

15. Deleted in Revision 17

16. Containment isolation effected by completely sealed instrument system. This penetration is not leak tested.

17. Deleted in Revision 22

18. Containment vent isolation trip. (refer to Table 6.2-40, Item 5)

19. The fuel transfer tube is not considered to be a piping penetration, but rather a Type B test penetration. The quick-opening hatch is double gasketed with a test connection allowing pressurization between the gaskets for Type B testing. The portion of the transfer tube inside the containment is considered to be part of the containment liner; the portion of the transfer tube outside the containment is not considered to be part of the containment boundary.

20. The relief valves are considered as normally closed containment isolation valves.

21. Deleted.

22. Administratively controlled valve which is treated in the same manner as a sealed closed valve. Control room indication is only active when the valve is not administratively cleared.

23. W = Water; G = Gas

24. Hot - over 200°F; Cold - 200°F or less

25. R-M = Remote Manual; S = Safety Injection; T = Containment Isolation Signal, Phase A; P = Containment Isolation Signal, Phase B; F = Feedwater Isolation Signal; M = Main Steam Isolation Signal.

26. Testability not required under Option B of Appendix J to 10 CFR Part 50.

27. Deleted in Revision 17.

28. This device is used for post-accident monitoring or control and must not be isolated by a containment isolation signal.

29. Multiple penetration number usage results from multiple tubes running though the guard pipe of a single penetration.

30. The following abbreviations are used:

Gte = Gate	Cls = Closed system	Sbl = Sealed bellows	Spf = Spectacle flange
Glb = Globe	Chk = Check	Blf = Blind flange	
Rlf = Relief	Dia = Diaphragm	Sin = Sealed instruments	
But = Butterfly	Bal = Ball	Hys = Hydraulic isolators	

31. The following abbreviations are used:

Man	=	Manual	Mtr	=	Motor
Air	=	Air	E/H	=	Electrohydraulic
Spr	=	Spring	Sol	=	Solenoid
N_2	=	Nitrogen			

32. "I" is used for inside and "O" for outside.

33. Safety-related priority designation for each penetration per Section 6.2.4.4.15 is as follows:
ES = Essential SA = Safety

CONTAINMENT PIPING PENETRATIONS AND VALVING

NE = Nonessential

34. Penetration 36 is not used by a safety system for accident mitigation. However, flow through this Penetration may be required to achieve safe shutdown following a Hosgri earthquake or an Appendix R fire.

35. “Normal Position” column:
    (A) C = Closed, O = Open
    (B) For check valves, position is stated open if flow passes through the check valve during normal operation, otherwise the valve is stated closed.
    (C) “Normal” configuration applies to the following plant conditions:
        (a) Modes 1-4, applicable T.S. 3.6.1 and 3.6.3.
        (b) Mode 6, applicable ECG 42.1.
    (D) If valve is normally open it is designated “Open” or if only periodically opened for fulfillment of its function during the “Normal” plant configurations, then a “Closed” designator is used.
    (E) If valve is normally closed and opened only in support of testing, under administrative control per T.S. 3.6.3, or for stroke testing of the valve itself, then a “Closed” designator is used.
    (F) Relief valves are assigned a “Closed” designator.

36. “Used After LOCA” column:
    (A) N = No, Y = Yes
    (B) For check valves, if valve passes flow at any point following the accident, then a “Yes” designator is used.
    (C) For valves that change position on a safeguards signal, this change is not considered a use, that is, the time the safeguards signal is received is not considered after the accident.
    (D) Use is principally an indicator of a valve passing flow at any point after the accident.

37. “Long Term Post-LOCA Position” column:
    (A) C = Closed, O = Open
    (B) The column pertains to a post accident condition, long term core cooling.
    (C) The assumed accident is a primary system LOCA with Containment isolation Phase A and B signals generated, system depressurization below 150 PSIG, corresponding to a RHR pump injection flow of greater than 200 GPM. The accident is assumed to progress through injection, cold leg recirculation, and to hot leg recirculation for the long term.
    (D) The hot leg injection flowpath is injection to RHR hot legs 1 & 2, SI pump hot legs 1,2,3, & 4, and Charging cold legs 1,2,3, & 4; the condition established by EOP E-1.4, (no RNOs entered).
    (E) Containment temperature has been reduced to near ambient conditions.
    (F) Containment pressure has been reduced to near atmospheric conditions.
    (G) Primary system/containment recirculation sump temperature has been reduced to below 200°F.
    (H) Although used periodically, PASS valves are considered to be normally closed.

38. Valve may be used following a LOCA only in the event of a failure of both internal hydrogen recombiners.

39. Deleted in Revision 22

40. Valve is not subject to Type C leakage tests because it is required to be in service post accident and the line pressure upstream of the CIV is greater than the post-accident pressure inside containment.

41. Deleted in Revision 22

42. Deleted in Revision 22

43. Deleted in Revision 22

44. Deleted in Revision 22.

45. This penetration does not require testing per Appendix J section II.H because the penetration does not provide a direct connection to the atmosphere during normal operation, is not required to close automatically, and is not required to operate intermittently. This penetration is filled with water from the submerged sump preventing gas escape to the outside and meets the test exception per Appendix J section II.c.3.

46. Deleted in Revision 22

47. The Containment Fan Coolers are a closed system inside containment. CCW does not communicate directly with the containment atmosphere. The closed loop system includes all pressure boundary test, vent, drain and instrument valves; instruments; blanked flange connections; and CFCU tubing.

48. Valve is included as a credited CIV because it was included on the original Tech Specs for the plant license.

49. Deleted in Revision 22

50. Deleted in Revision 22

51. This column lists the credited containment isolation valve or barrier that is used to demonstrate conformance to the PG&E Piping Group and the applicable GDC. Associated isolation devices required to maintain containment leakage integrity of penetrations and closed systems such as vent, drain test, instrumentation and branch line valves, blind flanges, caps or other passive devices are not shown They are administratively controlled to be in their proper isolation configuration by plant procedures and per TS 3.6.3.

52. This penetration is abandoned in place through the installation of welded plugs in the penetration.

53. Deleted in Revision 22

54. Deleted in Revision 22

55. The Steam Generator Blowdown System does not communicate directly with the containment atmosphere or reactor coolant pressure boundary. This valve is required to close when the auxiliary feedwater pumps are started in order to maintain steam generator inventory.

TABLE 6.2-40

OPERATING CONDITIONS FOR CONTAINMENT ISOLATION

Item No.	Functional Unit	Operating Conditions
1	Containment isolation Phase A	a. High containment pressure
		b. Pressurizer low pressure
		c. Low steamline pressure
		d. Manual
2	Containment isolation Phase B	a. High-high containment pressure
		b. Manual
3	Steam line isolation	a. Low steamline pressure
		b. High steamline pressure rate
		c. High-high containment pressure
		d. Manual
4	Feedwater line isolation	a. High containment pressure
		b. Low steamline pressure
		c. Pressurizer low pressure
		d. Steam generator high-high level
		e. Manual SIS

TABLE 6.2-40 Sheet 2 of 2

Item No.	Functional Unit	Operating Conditions
5	Containment ventilation isolation	a. Containment exhaust detectors b. Safety injection activation c. Manual Phase A or Manual Phase B or Manual Spray Actuation

TABLE 6.2-41

POST-LOCA TEMPERATURE TRANSIENT
USED FOR ALUMINUM AND ZINC CORROSION

Time Interval, sec	Temperature, °F
0 - 10	240
10 - 30	265
30 - 750	258
750 - 2000	253
2000 - 10,000	250
10,000 - 20,000	245
20,000 - 50,000	240
50,000 - 75,000	230
75,000 - 100,000	220
100,000 - 200,000	210
200,000 - 400,000	198
400,000 - 600,000	185
600,000 - 800,000	175
800,000 - 1,200,000	160
1,200,000 - 2,000,000	153
2,000,000 - 3,000,000	145
3,000,000 - 5,000,000	138
5,000,000 - 8,640,000	129

TABLE 6.2-42 Sheet 1 of 2

PARAMETERS USED TO DETERMINE HYDROGEN GENERATION

Plant Thermal Power Rating	3,425 MWt
Containment Temperature Prior to Accident	120°F
Containment Free Volume	2,550,000 ft^3
Weight Zirconium Cladding	43,300 lb
Hydrogen Recombiner Flowrate	100 scfm
Corrodible Metals	Aluminum and zinc
Core Cooling Solution Radiolysis Sources	
Percent of total halogens retained in the core	50.00
Percent of total noble gases retained in the core	0.00
Percent of other fission products retained in the core	99.00
Energy Distribution	
Percent of total decay energy - gamma	50.00
Percent of total decay energy - beta	50.00
Energy Absorption by Core Cooling Solution	
Percent of gamma energy absorbed by solution	10.00
Percent of beta energy absorbed by solution	0.00
Hydrogen Production	
Molecules H_2 produced per 100 eV energy absorbed by solution	0.50
Sump Solution Radiolysis Sources	
Percent of total halogens released to sump solution	50.00
Percent of noble gases released to sump solution	0.00
Percent of other fission products released to sump solution	1.00

TABLE 6.2-42

Energy Absorption by Sump Solution Percent of total energy (beta and gamma) which is absorbed by the sump solution	100.00
Hydrogen Production Molecules of hydrogen produced per 1000 eV of energy absorbed by the sump solution	0.50
Long-term Aluminum Corrosion Rate	200 mils/year
Aluminum Inventory in Containment (amount used in analyses)	3585 lb 15,988 ft^2
Zinc Inventory in Containment (amount used in analysis)	58,449 lb 397,000 ft^2

TABLE 6.2-43

CORE FISSION PRODUCT ENERGY AFTER
OPERATION WITH EXTENDED FUEL CYCLES

Time After Reactor Trip, days	Core Fission Product Energy[a] Energy Release Rate, watts/MWt x 10^3	Integrated Energy Release, watts days/MWt x 10^4
1	5.11	0.696
5	3.41	2.28
10	2.72	3.80
20	2.00	6.11
30	1.66	7.92
40	1.47	9.48
50	1.33	10.9
60	1.21	12.2
70	1.12	13.3
80	1.02	14.4
90	0.943	15.4
100	0.868	16.2

(a) Assumes 50% core halogens +99% other fission products and no noble gases. Values are for total (β and γ) energy.

TABLE 6.2-44

FISSION PRODUCT DECAY DEPOSITION IN SUMP SOLUTION

	Sump Fission Product Energy[a]	
Time After Reactor Trip, days	Energy Release Rate, watts/MWt x 10	Integrated Energy Release, watt-days/MWt x 10^3
1	25.6	0.535
5	8.17	1.02
10	5.35	1.35
15	3.80	1.57
20	2.91	1.75
30	2.06	1.99
40	1.69	2.18
60	1.30	2.47
80	1.04	2.70
100	0.837	2.88

(a) Considers release of 50 percent of core halogens, no noble gases, and 1 percent of other fission products to the sump solution.

TABLE 6.2-45

SUMMARY OF HYDROGEN ACCUMULATION DATA

(with no recombination)

Volume Percent Hydrogen	Time of Occurrence, days	Total Production Rate, scfm
2.09	1	10.9
2.65	2	8.18
3.09	3	6.45
3.48	4	6.23
3.83	5	5.03
4.13	6	4.90
5.10	10	3.19
5.96	15	2.62
6.68	20	2.42
9.77	50	1.66
11.54	75	1.22
12.95	100	1.11

TABLE 6.2-47

CONTAINMENT REFLECTIVE INSULATION[a]

Line No.	Size, in.	Length, ft.	Line Designation
1	29	19	Reactor Coolant Out Loop 1
2	29	19	Reactor Coolant Out Loop 2
3	29	19	Reactor Coolant Out Loop 3
4	29	19	Reactor Coolant Out Loop 4
5	31	22	Reactor Coolant PP Suction Loop 1
6	31	22	Reactor Coolant PP Suction Loop 2
7	31	13	Reactor Coolant PP Suction Loop 3
8	1	3	Reactor Coolant PP Suction Loop 4
9	27-1/2	21	Reactor Coolant PP Discharge Loop 1
10	27-1/2	4	Reactor Coolant PP Discharge Loop 2
11	27-1/2	23	Reactor Coolant PP Discharge Loop 3
12	27-1/2	23	Reactor Coolant PP Discharge Loop 4
13	4	111	Loop 1 spray line
14	4	84	Loop 2 spray line
15	4	96	Pressurizer spray line
16	14	65	Pressurizer surge line
24	3	38	Letdown Line Loop 2
50	3	9	Charging Line Loop 3
109	14	45	Hot Leg Recirc. Before V-8702
235	6	13	Safety Injection Loop 1 Hot Leg
236	6	10	Safety Injection Loop 2 Hot Leg
237	6	8	Safety Injection Loop 3 Hot Leg
238	6	11	Safety Injection Loop 4 Hot Leg
246	3	6	Charging Line Loop 4
253	10	41	Accumulator Injection Loop 1
254	10	35	Accumulator Injection Loop 2
255	10	14	Accumulator Injection Loop 3
256	10	30	Accumulator Injection Loop 4
958	2	4	Loop 1 cold leg drain RCDT
959	2	6	Loop 2 cold leg drain RCDT
960	2	2	Loop 3 cold leg drain RCDT
961	2	3	Loop 4 cold leg drain RCDT
1665	14	21	Loop 4 hot leg before V 8701
1992	1-1/2	3	Boron Inj Tk. Out Loop 2 cold
1993	1-1/2	3	Boron Inj Tk. Out Loop 3 cold

Line No.	Size, in.	Length, ft.	Line Designation
3844	6	35	RHR PP 1-1 Inj Cold Leg 1
3845	6	48	RHR PP 1-1 Inj Cold Leg 2
3846	6	48	RHR PP 1-1 Inj Cold Leg 3
3847	6	48	RHR PP 1-1 Inj Cold Leg 4
3855	2	4	SI PPS Cold Leg Loop 1 recirc.

(a) The information contained in this table is "representative" of Units 1 and 2. Data reflecting actual conditions for any individual line may be somewhat different than that presented, or may change with plant modifications. This table will not be revised to reflect these individual conditions or changes.

TABLE 6.2-48

CONTAINMENT CONVENTIONAL INSULATION

Line No.	Insul.	Size, in.	Length, ft.	Line Designation
23	IV	12	45	Pressurizer relief header
50	IV	3	64	Charging Line Loop 3
51	IV	2	77	Charging line auxiliary spray
63	V	1	218	Excess Letdown Loop 2
214	V	3/4	3	Loop 1 hot leg sample
215	V	3/4	1	Loop 4 hot leg sample
225	V	28	94	Steam Gen. 1-4 steam outlet
226	V	28	96	Steam Gen. 1-3 steam outlet
227	V	28	96	Steam Gen. 1-2 steam outlet
228	V	28	94	Steam Gen. 1-1 steam outlet
246	IV	3	115	Charging Line Loop 4
508	III	8	226	RHR PP 1-1 Inj Cold Leg 1 + 2
509	III	8	77	RHR PP 1-1 Inj Cold Leg 3 + 4
528	III	2-1/2	123	Reactor coolant drain tk. PP disch.
554	IV	16	54	Steam Gen. 1 feedwater supply
555	IV	16	57	Steam Gen. 2 feedwater supply
556	IV	16	53	Steam Gen. 4 feedwater supply
557	IV	16	54	Steam Gen. 3 feedwater supply
692	III	3/4	4	Cold Leg Loop 3 + 4 test line
927	III	14	33	Loop 4 hot leg to RHR PPS
1012	V	2	3	Steam Gen. 1 blowdown out N/S
1017		2	3	Steam Gen. 2 blowdown out N/S
1020	V	2	14	Steam Gen. 3 blowdown out N/S
1038	V	2	8	Steam Gen. 4 blowdown out N/S
1040	V	2-1/2	235	Steam Gen. 1-1 blowdown tank hdr.
1041	V	2-1/2	189	Steam Gen. 1-2 blowdown tank hdr.
1042	V	2-1/2	85	Steam Gen. 1-3 blowdown tank hdr.
1043	V	2-1/2	116	Steam Gen. 1-4 blowdown tank hdr.
1059	V	2	32	Steam Gen. 1 blowdown out S/N
1060	V	2	17	Steam Gen. 2 blowdown out S/N
1061	IV	2	3	Steam Gen. 3 blowdown out S/N
1062	V	2	15	Steam Gen. 4 blowdown out S/N
1167	III	4	51	RHR hot leg RV outlet
1169	V	3/4	7	Loop 1 spray line bypass
1170	V	3/4	7	Loop 2 spray line bypass
1675	V	3/8	51	Loop 1 hot leg sample
1676	V	3/8	6	Loop 4 hot leg sample

TABLE 6.2-48

Line No.	Insul.	Size, in.	Length, ft.	Line Designation
1901	III	1	8	Loop 2 V8076 + V8074B Lkoff. H
1999	III	3/4	10	SIS Accum. 1 test
2000	III	3/4	13	SIS Accum. 2 test
2001	III	3/4	60	SIS Accum. 3 test
2002	III	3/4	28	SIS Accum. 4 test
2158	IV	3/4	12	Regen. hx. channel temp. relief
2176	III	1	35	Leakoff header line to PRT
2385	III	4	202	SIS RV outlet header to PRT
2523	III	1/2	4	RHR Suction Vlv. 2 Loop 4 leakoff
2524	III	1/2	18	RHR Suction Vlv. 1 Loop 4 leakoff
2638	III	1	57	Cont. aux. steam supply to el. 91
2766	III	1/2	2	PCV-455 A leakoff line
2773	III	1/2	4	PCV-455 B leakoff line
2998	III	4	4	SIS RV outlet header to PRT
2999	III	4	5	SIS RV outlet header to PRT
3094	V	3/4	5	RHR Loop 4 V-8702 8702 therm
3095	III	3/4	5	RHR Loop 4 V-8701 8702 therm
3214	I	2	73	Incore chiller chill wtr. sup.
3215	I	2	73	Incore chiller chill wtr. ret.
3407	III	1/2	6	Loop 2 Letdown V-8076 leakoff
3729	III	2-1/2	14	REAC Clnt. Dr. PPS Disch. Header
3844	II	6	70	RHR PP 1-1 inj cold leg 1
3845	II	6	59	RHR PP 1-1 inj cold leg 2
3900	III	1	174	Reactor head aux. steam
3936	I	2	2	Incore chiller chill wtr. ret.
4399	III	1/2	1	
4400	III	1/2	7	
4402	III	1/2	5	
4406	III	1	4	
4407	III	1	2	

(a) This line is contained completely within the hot leg insulation.

(b) The information contained in this table is "representative" of Units 1 and 2. Data reflecting actual conditions for any individual line may be somewhat different than that presented, or may change with plant modifications. This table will not be revised to reflect these individual conditions or changes.

TABLE 6.2-55

MAXIMUM PRESSURE DIFFERENTIAL ACROSS STEAM GENERATOR

Break Type	Location	Maximum Pressure Differential, psi	Between Compartments	Compressibility
DEHL	1	5.50 @ .0185 sec	1-2	yes
DEHL	2	5.26 @ .0144 sec	2-1	yes
DEHL	3	6.04 @ .0184 sec	3-2	yes
DEHL	4	5.98 @ .0184 sec	4-5	yes
DEHL	5	5.26 @ .0144 sec	5-6	yes
DEHL	6	5.45 @ .0185 sec	6-5	yes
DEHL	3	6.00 @ .0184 sec	3-2	no
DECL	3 (worst case)	4.46 @ .0215 sec	3-2	no
DECL	3 (worst case)	4.48 @ .0215 sec	3-2	yes

TABLE 6.2-56

COMPARISON OF RCS CONDITIONS FOR SHORT-TERM SPRAY LINE BREAK MASS AND ENERGY RELEASES

	RCS Temperature (°F)	
	Original Design Basis	**RSG Analysis[(1)]**
Cold Leg	545.16	526.8
	RCS Pressure (psia) [(1)]	
Cold Leg	2332.4	2344.2

[(1)] A 4.8°F temperature uncertainty has been subtracted from the DCPP Unit 1 replacement steam generator project nominal temperature conditions and 42.0 psi has been added to the cold-leg pressure of 2302.4 psia Note that Unit 1 bounds Unit 2 for short-term LOCA mass and energy applications.

TABLE 6.3-1

EMERGENCY CORE COOLING SYSTEM
COMPONENT PARAMETERS

Accumulators	Number (per unit)	4
	Design Pressure, psig	700
	Design Temperature, °F	300
	Operating Temperature, °F	50-150
	Normal Operating Pressure, psig	621.5
	Minimum Operating Pressure, psig [c]	579
	Total Volume, ft^3	1,350 each
	Nominal Water Volume, ft	850
	Boric Acid Concentration	
	Nominal, ppm	2,350
	Minimum, ppm	2,200
	Relief Valve Setpoint, psig	700
Centrifugal Charging Pumps (CCP1 and 2)	(Design parameters for these pumps are given in Table 9.3-5.)	
Safety Injection Pumps	Number (per unit)	2
	Design Pressure, psig	1,700
	Design Temperature, °F	300
	Design Flowrate, gpm	425
	Design Head, ft	2,500
	Max Flowrate, gpm	675
	Head at Max Flowrate, ft	1,500
	Discharge Pressure at Shutoff Head, psig	1,520
	Motor Rating, hp[a]	400
Residual Heat Removal Pumps	(Design parameters for these pumps are given in Table 5.5-10)	

Residual Heat Exchangers	(Design parameters for these heat exchangers are given in Table 5.5-10)	
Refueling Water Storage Tank	Number (per unit)	1
	Total available tank volume (includes only usable volume)[(b)], gal	450,000
	Minimum Technical Specifications required volume (includes usable and unusable volume), gal	455,300
	Accident analysis volume (assumed)	350,000
	Boron Concentration, ppm	2300-2500
	Design Pressure, psig	Atmospheric
	Operating Pressure, psig	Atmospheric
	Design Temperature, °F	100
	Material	Austenitic stainless steel with reinforced concrete shroud
Valves		
(1) All Motor-Operated Valves That Must Function on Safety Injection ("S") Signal		
(a) Up to and including 8 inches (excluding SI-8805 A&B, CVCS-8107 and CVCS-8108)	Maximum opening or closing time, sec	10
(b) CVCS-8107 and CVCS 8108	Maximum opening and closing time, sec	14

	(c) SI-8805 A&B	Maximum opening or closing time, sec	11
	(d) Over 8 inches	Minimum opening or closing rate, in./min	60
(2)	All Other Motor-Operated Gate Valves Up to and Including 8 Inches	Minimum opening or closing rate, in./min	12

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

(3) Original purchase specification leakage criteria. Inservice leakage requirements are specified in the valve Inservice Testing Program.

(a) Conventional globe valves	*Disk leakage, cc/hr/in. of nominal pipe size*	*3*
	Backseat leakage (when open), cc/hr/in. of stem diameter	*1*
(b) Gate valves	*Disk leakage, cc/hr/in. of nominal pipe size*	*3*
	Backseat leakage (when open), cc/hr/in. of stem diameter	*1*
(c) Check valves	*Disk leakage, cc/hr/in. of nominal pipe size*	*3*
(d) Diaphragm valves	*Disk leakage*	*None*
(e) Pressure relief	*Disk leakage, cc/hr/in. of nominal pipe size*	*3*
(f) Accumulator check valves	*Disk leakage, cc/hr/in. of nominal pipe size*	*3*

(a) 1.15 service factor not included.

(b) Usable volume includes the water above the outlet pipe. Unusable water includes the water below the outlet.

(c) This minimum SI accumulator pressure is the value that is used in the accident analysis in Chapter 15. (Note that more conservative values may appear in other documents such as Technical Specifications, operating procedures, etc.)

TABLE 6.3-2

EMERGENCY CORE COOLING SYSTEM
DESIGN CODE REQUIREMENTS

Component	Code
Accumulators	ASME B&PV, Section III[a] Class C
Refueling Water Storage Tank Valves	AWWA D100[c] USAS B16.5, MSS-SP-66 and ASME B&PV, Section III[a]
Piping[b]	
- Design Class I portions (excluding Code Class A and @)	ANSI B31.7
- Design Class I, Code Classes A and @ portions and Design Class II portions	ANSI B31.1
Pumps	
Charging	ASME B&PV, Section III[a]
Residual heat removal	ASME B&PV, Section III[a]
Safety injection	ASME B&PV, Section III[a]

(a) Draft Code November 1968 Edition.

(b) See Q-List (Reference 8 of Section 3.2) for piping classification.

(c) ASME B&PV Code, Section VIII, allowable stresses used for design.

TABLE 6.3-3

MATERIALS OF CONSTRUCTION
EMERGENCY CORE COOLING SYSTEM COMPONENTS

COMPONENT	MATERIAL
<u>Accumulators</u>	Carbon steel, clad with austenitic stainless steel
<u>Refueling Water Storage Tank</u>	Austenitic stainless steel with reinforced concrete shroud
<u>Pumps</u> (parts in contact with coolants)	
Centrifugal charging	Austenitic stainless steel
Safety injection	Martensitic stainless steel
Residual heat removal	Austenitic stainless steel or equivalent corrosion-resistant material
<u>Residual Heat Exchangers</u>	
Shell	Carbon steel
Shell end cap	Carbon steel
Tubes	Austenitic stainless steel
Channel	Austenitic stainless steel
Channel cover	Austenitic stainless steel
Tube sheet	Forged carbon steel with austenitic stainless steel weld overlay
<u>Valves</u>	
Motor-operated valves containing radioactive fluids and pressure-containing parts	Austenitic stainless steel or equivalent
Body-to-bonnet bolting and nuts	Low-alloy steel, austenitic stainless steel, or 17-4PH stainless
Seating surfaces	Stellite No. 6 or equivalent
Stems	Austenitic stainless steel or 17-4PH stainless

TABLE 6.3-3

COMPONENT	MATERIAL
<u>Motor-operated Valves Containing Non-radioactive, Boron-free Fluids</u>	
Body, bonnet, and flange	Carbon steel
Stems	Corrosion resistant steel
Diaphragm	Austenitic stainless steel
<u>Accumulator Check Valves</u>	
Parts contacting borated water	Austenitic stainless steel
Clapper arm shaft	Corrosion resistant steel
<u>Relief Valves</u>	
Stainless steel bodies	Stainless steel
Carbon steel bodies	Carbon steel
All nozzles, disks, spindles, and guides	Austenitic stainless steel
Bonnets for stainless steel valves without a balancing bellows	Stainless steel
All other bonnets	Carbon steel
<u>Piping</u>	
All piping in contact with borated water	Austenitic stainless steel

TABLE 6.3-5

SAFETY INJECTION TO RECIRCULATION MODE; SEQUENCE AND TIMING OF MANUAL CHANGEOVER

Action	Status	Item	Actuation Time sec	Time for Operation sec	Total Elapsed Time min
	LOCA				0:00
	Safety injection signal-all RHR, SI and charging pumps (CCP1 and CCP2) in operation				0:20
	Spray initiation				0:40
	RWST low level alarm and RHR pumps trip; initiate recirculation changeover				17:56
IMPLEMENT - Appendix EE			0	10	18:06
CUT IN - Series Contactors **		8974A, 8809A, 8982A, 8982B, 8974B, 8809B	0	10	18:16
VERIFY - Safety injection signal reset **			5	10	18:26
VERIFY - Containment isolation Phase A and Phase B reset **			5	10	18:36
CHECK - Both ASW pumps running			0	5	18:41
VERIFY - CCW heat exchanger saltwater inlet valves open **		FCV-602(603) (Note 3)	5	10	18:51
VERIFY - CCW heat exchanger CCW outlet valves open **		FCV-430(431) (Note 3)	5	10	19:01

<u>OPEN</u> - Component cooling water to RHR heat exchanger 2 **	FCV-364	10	15	19:16
<u>OPEN</u> - Component cooling water to RHR heat exchanger 1 **	FCV-365	10	15	19:31
<u>STOP</u> - Centrifugal charging pump CCP3 **		5	10	19:41
PA Announcement **		0	10	19:51
Dispatch Operators to locally close breakers for 8976 and 8980 **	52-1H/2H-20 52-1F/2F-31	0	20	20:11
<u>VERIFY</u> - RHR Pump 2 stopped		0	5	18:11
CLOSE - RHR pump suction valve from RWST	8700B	120	125	20:16
<u>VERIFY</u> - RHR Pump 1 stopped		0	5	20:21
<u>CLOSE</u> - RHR pump suction valve from RWST	8700A	120	125	22:26
<u>CLOSE</u> - RHR crosstie isolation valves	8716A 8716B	20 20	30	22:56
<u>CHECK</u> – RCS Pressure less than 1500 PSIG		0	5	23:01
<u>CLOSE</u> - SI pump miniflow block valves	8974A 8974B	10 10	20	23:21
<u>CLOSE</u> - CCP recirculation valves	8105 8106	10 10	20	23:41
<u>CHECK</u> - recirculation sump level > 92.0’	LI-940 LI-941	5 5	10	23:51
<u>CHECK</u> - RHR pump 2 stopped		0	5	23:56

CHECK - RHR P2 suction from RWST closed		8700B	0	5	24:01
OPEN – RHR P2 suction from sump		8982B	30	35	24:36
VERIFY - RHR HX 1-2 in Service per App. EE			5	5	24:41
START - RHR-P2		RHR-P2	1	15	24:56
OPEN - SI pumps suction from RHR HX2		8804B	20	25	25:21
CHECK - RCS Pressure less than 1500 PSIG			0	5	25:26
VERIFY - SI pumps running			0	5	25:31
CHECK - RHR Pump 2 motor current less than 57 amps AND stable			0	5	25:36
OPEN - Cross-connect line from SI pump 1 to charging pumps (CCP1 and CCP2)		8807A 8807B	20 20	30	26:06
VERIFY - CCP1 and CCP2 running	Changeover of a single train complete at 26:11		0	5	26:11
CHECK - RHR pump 1 stopped			0	5	26:16
CHECK - RHR P1 suction from RWST closed		8700A	0	5	26:21
OPEN - RHR P1 suction from sump		8982A	30	35	26:56
VERIFY - RHR HX 1 in Service per App. EE			5	5	27:01
START - RHR P1		RHR-P1	1	15	27:16
OPEN - SI pump suction from RHR HX1	Changeover of both trains complete at 27:41	8804A	20	25	27:41

CHECK- RCS Pressure less than 1500 PSIG			0	5	27:46
VERIFY - SI pumps running			0	5	27:51
CHECK - RHR Pump 1 motor current less than 57 amps AND stable			0	5	27:56
CHECK - at least one RHR pump running		RHR Pump	0	5	28:01
CLOSE - Charging pump suction RWST isolation		8805A 8805B	11 11	21	28:22
CLOSE - SI pump suction RWST isolation		8976	20	25	28:47
CLOSE - RHR pump suction from RWST		8980	25	30	29:17
	Receive RWST low-low level alarm				33:25
CHECK - both RHR pumps running			0	5	33:30
CHECK - PK01-18, Containment Spray Actuated On OR Cont. Pressure greater than 22 PSIG			0	10	33:40
CHECK - RWST level less than 4%		LI-920 LI-921 LI-922	5 5 5	15	33:55
RESET - Containment spray			5	10	34:05
STOP - Containment Spray (CS) pumps1 & 2		CS-P1 CS-P2	1 1	5	34:10
CLOSE - CS pump discharge to spray header valves	System in recirculation mode	9001A 9001B	10 10	20	34:30

<u>CHECK</u> - Cont. Pressure greater than 22 PSIG			0	5	34:35
<u>VERIFY</u> - Both RHR trains in service			0	5	34:40
<u>CLOSE</u> - RCS from RHR-P1	Cold leg injection terminated	8809A	20	25	35:05
<u>OPEN</u> - RHR-P1 to spray header	Recirculation sump to spray header	9003A	15	20	35:25

Notes to Table 6.3-5

1. Actuation Time: The estimated actuation time for a component to complete its function. For valves, this is the maximum expected stroke time. In some cases, where the component is already expected to be in the desired position, no actuation time is added.

2. Time for Operation: The actuation time plus the estimated operator action, if applicable.

3. If the valves are not already in the desired position the analysis assumes they are stroked concurrently while the crew continues in the procedure, since subsequent checks of ASW/CCW alignment are made at decision points further on in the procedure.

** All these steps from Appendix EE of Procedure EOP E-1.3 can be performed in parallel with the steps that follow since they add up to 125 seconds, which is less than the 295 seconds (from 18:06 to 23:01) needed before we close 8974A/B (this is the first step that depends on a step from Appendix EE).

The following assumptions are used for Table 6.3-5:

1. Double-ended reactor coolant pump suction LOCA.

2. Maximum safety features implemented:

   a. Pumps at flow limited by pipe friction
      2 RHR pumps: 7300 gpm total during injection
      1 RHR pump: 4600 gpm for 5 minutes during changeover, when assuming a single failure of one RHR pump to trip on low RWST level
      2 SI pumps: 900 gpm total
      2 Charging pumps (CCP1 and CCP2): 900 gpm total

b. 2 Containment spray pumps: 6550 gpm total during injection, assuming 20 psig in containment
6800 gpm total during changeover, assuming 0 psig in containment

c. Allowable 100 gpm leakage penalty from RWST

3. Refueling water storage tank.

a. Maximum outflow: 15,750 gpm based on 2a and 2b during injection
8,700 gpm based on 2a and 2b during changeover, no single failure

b. Volume available: 404,511 gal.

c. Low-level alarm volume: 116,812 gal.

d. Low-low level alarm volume: 0 gal.

TABLE 6.3-6

NORMAL OPERATING STATUS OF EMERGENCY CORE COOLING SYSTEM COMPONENTS FOR CORE COOLING

Number of Safety Injection Pumps Operable	2
Number of Charging Pumps Operable	2
Number of Residual Heat Removal Pumps Operable	2
Number of Residual Heat Exchangers Operable	2
Refueling Water Storage Tank Available Volume, gal	350,000
Boron Concentration in Refueling Water Storage Tank,	
Maximum, ppm	2,500
Minimum, ppm	2,300
Boron Concentration in Accumulators,	
Maximum, ppm	2,500
Minimum, ppm	2,200
Number of Accumulators	4
Minimum Accumulator Pressure, psig [(a)]	579
Nominal Accumulator Water Volume, ft^3	850
System Valves, Interlocks, and Piping Required for	
the Above Components which are Operable	All

(a) This minimum SI accumulator pressure is the value that is used in the accident analysis in Chapter 15. (Note that more conservative values may appear in other documents such as Technical Specifications, operating procedures, etc.)

TABLE 6.3-7

SEQUENCE AND DELAY TIMES FOR STARTUP OF ECCS

Accident	Actuation Signal(s)	Action Sequence (Subsystem or Component)	Delay, sec (h)	Delay, sec (i)	Delay, sec (j)	Design Performance	Minimum ECCS Performance Assumed in Analysis	References: Section FSAR	References: Figures	References: Tables
1. Major Reactor Coolant System Rupture (LOCA)								15.4.1		
a. Injection phase	(g)	Accumulator tank	(g)	(g)	(g)	4 tanks, each with 850 ft^3 of borated water @ 600 psig	Three tanks injecting into RCS; one injecting into broken loop	6.3		8.3-4
	(a)	Containment isolation valves	1	1	10	Double barrier; fast automatic valve closure upon receipt of CIS	A single active failure is allowable	6.2.4	6.2-12, 6.2-13 & 6.2-14	8.3-4
	(b) (d)	ECCS required valves	(k)	(k)	See Table 6.3-1	Rapid reliable system alignment or isolation	A single active failure is allowable	6.3.2	7.3-22, 7.3-33	8.3-4
	(b) (d)	Centrifugal charging pumps	-5	15	4-1/2	Two centrifugal charging pumps supply borated water into a single injection flowpath splitting into 4 cold leg injection lines	One pump required at design flow	6.3.2, 9.3.4	7.3-4	8.3-4
	(b) (d)	Safety injection pumps				Two pumps inject via a single path splitting into 4 cold leg injection lines	One pump delivering at design flow	6.3.2	3.2-9	
	(b) (d)	Residual heat removal pumps				Two pumps inject into 4 cold legs, via 2 lines that each split into 2 cold leg injection lines	One pump delivering at design flow	6.3.2, 5.5.6	3.2-9	
	(b) (d)	Component cooling water pumps	25/25 /30	35/35/ 40	4-1/2	Two flowpaths; each 11,500 gpm @ 130 ft	One flowpath required at design flow	9.2.2	7.3-7	8.3-4
	(e)	Auxiliary feed-water pumps	30/35	40/45	5	Two flowpaths; each 800 gpm @ 2350 ft	One flowpath required at design flow	6.5.2	7.3-8	8.3-4
	(b) (d)	Auxiliary salt-water pumps	30/35	40/45	5	Two flowpaths; each 11,000 gpm @ 115 ft	One flowpath required at design flow	9.2.7	7.3-5	8.3-4

Accident	Actuation Signal(s)	Action Sequence (Subsystem or Component)	Delay, sec (h)	Delay, sec (i)	Delay, sec (j)	Design Performance	Minimum ECCS Performance Assumed in Analysis	References: Section FSAR	References: Figures	References: Tables
	(c)	Containment spray pumps				Two flowpaths; each 2600 gpm @ 450 ft	One flowpath required at design flow		7.3-11	8.3-4
		Pump 1	26	26	1.7					
		Pump 2	22	22	1.7					
b. Recirculation phase	(f)	Operating personnel shift system alignment from injection phase	(Total switchover time is approximately 10 min. See 6.3.2)			(Design performance for ECCSA and related equipment as described in 1a above)	A single failure is allowable	6.3.2		
2. Major Seccondary System Rupture	(b)	Action sequence similar to 1a above. Operation of ESF required. Valves isolate feedwater & steam	Same as 1a above			Same as 1a above	Same as 1a above with these further notes: Accumulator and low head injection required only in the severe cases. Since no RCS rupture has occurred, all four accumu-ators are functional	15.4.2		

TABLE 6.3-7

Accident	Actuation Signal(s)	Action Sequence (Subsystem or Component)	(h) (i) (j)	Design Performance	Minimum ECCS Performance Assumed in Analysis	Section FSAR	Figures	Tables
3. Steam Generator Tube Rupture	Low pressurizer pressure	Same as 1a above although no containment spray. Additionally, automatic isolation of individual steam generator blowdown valve occurs due to SGBD liquid radiation monitor. Injection and charging flow regulated to maintain visible pressurizer water level. Auxiliary feedwater to affected SG manually isolated. Pressurizer reliefs operated to reduce RCS pressure under 1000 psia	Same as 1a above with additional isolation done within 30 minutes	Same as 1a above	Same as 1a above (but all four accumulators assumed functional). Conservative estimate of 125,000 lb of reactor coolant transferred to the secondary side of the affected steam generator	15.4.3		
4. Minor RCS Rupture which Actuates ECCS	Low pressurizer pressure, or level, or high containment pressure					15.3.1		
a. Injection phase	Same as 1a above	Same as 1a above	Same as 1a above	Same as 1a above	Same as 1a above			
b. Recirculation	Same as 1a above	Same as 1a above	Same as 1a above	Same as 1a above	Same as 1a above			

TABLE 6.3-7

(a) Initiated by means of containment isolation signal, which occurs on containment high pressure (2 of 3) or on safety injection signal (SIS).

(b) Safety injection signal actuates on any of the following: Low pressurizer pressure, high containment pressure, low steamline pressure, or manual actuation.

(c) Containment spray actuation signal, which occurs on containment high-high pressure (2 of 4), or manual actuation.

(d) Emergency diesel loading sequencer loads the diesel in accordance with the sequence shown in Tables 8.3-2 and 8.3-4. Also see Figures 8.3-9, 8.3-10, 8.3-11, and 8.3-16.

(e) Auxiliary feedwater autostart signal, which occurs with a SIS. SG low-low level or tripping of both main feedwater pumps.

(f) Water level indication and alarms on the refueling water storage tank and in the containment sump provide ample warning to terminate the injection mode and begin the recirculation mode while the operating pumps still have adequate net positive suction head. Manual switchover by operating personnel changes the ECCS from injection to recirculation mode.

(g) All valves between the accumulators and the RCS are required to be open in Modes 1, 2, and 3; consequently, the accumulators inject as soon as the RCS pressure drops below the pressure (600 psia) of the accumulators.

(h) Electrical and instrumentation delay time after "S" signal with main generator power or offsite power available. For containment spray pumps, delay time is after “P” signal.

(i) Electrical and instrumentation delay time after "S" signal using diesel generator. For containment spray pumps, delay time is after “P” signal.

(j) Equipment startup time after receipt of signal.

(k) These delay times vary.

TABLE 6.3-8

EMERGENCY CORE COOLING SYSTEM SHARED FUNCTIONS EVALUATION

Component	Normal Operating Arrangement	Accident Arrangement
Refueling water storage tank	Lined up to suction of safety injection and residual heat removal pumps	Lined up to suction of centrifugal charging, safety injection, and residual heat removal pumps. Valves for realignment meet single failure criteria.
Centrifugal charging pumps	Lined up for charging service	Lined up to charging injection header. Valves for realignment meet single failure criteria.
Residual heat removal pumps	Lined up to cold legs of reactor coolant piping	Lined up to cold legs of reactor coolant piping.
Residual heat exchangers	Lined up for residual heat removal pump operation	Lined up for residual heat removal pump operation.

TABLE 6.3-9

MAXIMUM POTENTIAL RECIRCULATION LOOP LEAKAGE EXTERNAL TO CONTAINMENT

Items	Type of Leakage Control and Unit Leakage Rate Used in the Analysis	Leakage to Atmosphere, cc/hr	Leakage to Drain Tank, cc/hr
1. Residual Heat Removal Pumps	Mechanical seal with leakoff - 10 cc/hr seal[(a)]	20	0
2. Safety Injection Pumps	Same as residual heat removal pump	40	0
3. Charging Pumps	Same as residual heat removal pump	40	0
4. Flanges:			
a. Pumps	Gasket - adjusted to zero leakage following any test; 10 drops/min/flange used(30 cc/hr). Due to leak tight flanges on pumps, no leakage to atmosphere is assumed	0	0
b. Valves bonnet to body (larger than 2 in.)		1200	0
c. Control valves		180	0
d. Heat exchangers		240	0
5. Valves - Stem Leakoffs	Backseated double-packing with leakoff - 1 cc/hr in. stem diameter used (see Table 6.3-1)	0	40
6. Misc. Small Valves	Flanged body-packed stems -1 drop/min used (3 cc/hr).	150	0
7. Misc. Large Valves (larger than 2 in.)	Double-packing 1 cc/hr/in. stem diameter used	40	0
	TOTALS	1910	40

(a) Seals are acceptance tested to essentially zero leakage.

TABLE 6.3-10

ECCS RELIEF VALVE DATA

Description	Fluid Discharged	Fluid Inlet Temp Normal, °F	Set Pressure, psig	Back Pressure Constant	Psig Build-up	Capacity
N_2 supply to accumulators	N_2	120	700	0	0	1500 scfm
SIS pump discharge	Water	100	1750	3	50	20 gpm
RHR pumps SI line	Water	120	600	3	50	400 gpm
SI pumps suction header	Water	120	220	3	50	20 gpm
Accumulator to containment	Water or N_2 gas	120	700	0	0	1500 scfm

TABLE 6.3-11

NET POSITIVE SUCTION HEADS FOR
POST-DBA OPERATIONAL PUMP[(a)]

Pump	Flow and Condition	Suction Source	Minimum Available NPSH, ft	Required NPSH, ft	Water Temp, °F
Safety injection	675 gpm runout flow	Refueling water storage tank	31	29	100 max
Centrifugal charging	560 gpm runout flow	Refueling water storage tank	44	24	100 max
Residual heat removal	4500 gpm	Refueling water storage tank	27	20	100 max
Residual heat removal	4900 gpm runout flow	Containment sump	25	24	Saturated liquid
Containment spray	3500 gpm runout flow	Refueling water storage tank	40	19	100 max

(a) NPSH conservatively calculated without considering additional static suction head of water in the RWST.

TABLE 6.3-12

ECCS MOTOR-OPERATED VALVES WITH
ELECTRIC POWER REMOVED DURING NORMAL POWER PLANT OPERATION

		Position				
Valve Identification	Service Description	Normal Operation	Injection Phase	Cold Leg Recirc Phase	Hot Leg Recirc Phase	Power Restorable From Control Room
8703	RHR pump discharge to RCS hot leg loops	Closed	Closed	Closed	Open	No
8802 A, B	SIS pump discharge to RCS hot leg loops	Closed	Closed	Closed	Open	No
8808 A, B, C, D	Accumulator isolation	Open	Open	Open	Open	No
8809 A	RHR pump discharge to RCS cold leg loops	Open	Open	Closed[b]	Closed	Yes
8809 B		Open	Open	Open	Closed	Yes
8835	SIS pump discharge to RCS cold leg loops	Open	Open	Open	Closed	No
8974 A, B	SIS pump miniflow	Open	Open	Closed	Closed	Yes
8976	RWST supply to SIS pumps	Open	Open	Closed	Closed	No
8980	RWST supply to RHR pumps	Open	Open	Closed	Closed	No
8982 A, B	Containment recirc. sump supply to RHR pumps	Closed	Closed	Open	Open	Yes

TABLE 6.3-12

Valve Identification	Service Description	Normal Operation	Position: Injection Phase	Position: Cold Leg Recirc Phase	Position: Hot Leg Recirc Phase	Power Restorable From Control Room
8992	NaOH spray additive supply	Open	Open	Open	Open	No
8701[a]	Loop 4 hot leg RHR suction valve 2	Closed	Closed	Closed	Closed	No
8702[a]	Loop 4 hot leg RHR suction valve 1	Closed	Closed	Closed	Closed	No

(a) Valve required to function for a normal RHR cooldown not for ECCS.
(b) Closed if containment spray is required.

Table 6.3-13

SINGLE ACTIVE FAILURE ANALYSIS FOR EMERGENCY CORE COOLING SYSTEM COMPONENTS

SHORT-TERM PHASE

Component	Malfunction	Comments
A. Accumulator	Deliver to broken loop	Totally passive system with one accumulator per loop. Evaluation based on one spilling accumulator.
B. Pump		
1. Centrifugal charging	Fails to start	Two provided; evaluation based on operation of one.
2. Safety injection	Fails to start	Two provided; evaluation based on operation of one.
3. Residual heat removal	Fails to start	Two provided; evaluation based on operation of one.
4. Residual heat removal	Fails to trip on RWST Low Level	Operator trips pump locally at the breaker.
C. Automatically Operated Valves		
1. Charging injection isolation		
a. Inlet	Fails to open	Two parallel lines; one valve in either line required to open
b. Outlet	Fails to open	Two parallel lines; one valve in either line required to open.
2. Centrifugal Charging Pumps		
a. Suction line from refueling water storage tank	Fails to open	Two parallel lines; only one valve in either line is required to open.

SHORT-TERM PHASE (Continued)

Component	Malfunction	Comments
b. Discharge line to the normal charging path	Fails to close	Two valves in series; only one valve required to close.
c. Minimum flow line	Fails to close	Two valves in series; only one valve required to close.
d. Suction line from volume control tank	Fails to close	Two valves in series; only one valve required to close.

LONG-TERM PHASE

Component	Malfunction	Comments
A. Valves Operated from Control Room for Recirculation		
1. Containment sump recirculation isolation	Fails to open	Two parallel lines; only one valve in either line is required to open.
2. Residual heat removal pump suction line from refueling water storage tank	Fails to close	Check valve in series with gate valve, operation of only one valve required.
3. Safety injection pump suction line from refueling water storage tank	Fails to close	Check valve in series with gate valve, operation of only one valve required.
4. Centrifugal charging pump (CCP1 and 2) suction line from refueling water storage tank	Fails to close	Check valve in series with two parallel gate valves. Operation of either the check valve or the gate valve required.

LONG-TERM PHASE (Continued)

Component	Malfunction	Comments
5. Safety injection pump suction line at discharge of residual heat exchanger No. 2	Fails to open	Separate and independent high head injection path taking suction from discharge of residual heat exchanger No. 1. A crossover line allows flow from one heat exchanger to reach both safety injection and charging pumps, if necessary.
6. Centrifugal charging pump (CCP1 and CCP2) suction line at discharge of residual heat exchanger No. 1	Fails to open	Separate and independent high head injection path taking suction from discharge of residual heat exchanger No. 2. A crossover line allows flow from one heat exchanger to reach both safety injection and charging pumps, if necessary.
7. Centrifugal charging pump (CCP1 And CCP2) crossover line to safety injection pump suction	Fails to open	Two parallel lines; only one valve in either line is required to open.
B. Pumps		
1. Residual heat removal pump	Fails to start	Two provided. Evaluation based on operation of one.
2. Charging pump	Fails to operate	Same as short-term phase
3. Safety injection pumps	Fails to operate	Same as short-term phase

Table 6.3-14

EMERGENCY CORE COOLING SYSTEM RECIRCULATION PIPING PASSIVE FAILURE ANALYSIS

LONG-TERM PHASE

Flow Path	Indication of Loss of Flow Path	Alternate Flow Path
Low Head Recirculation		
From containment sump to low head injection header via the residual heat removal pumps and the residual heat exchangers	Reduced flow in the discharge line from one of the residual heat exchangers (one flow monitor in each discharge line). Accumulation of water in a residual heat removal pump compartment or auxiliary building sump.	Via the independent identical low head flow path utilizing the second residual heat exchanger.
High Head Recirculation		
From containment sump to the high head injection header via residual heat removal pump residual heat exchanger, and the high head injection pumps	1) Increasing activity of the air exhausted from the RHR heat exchanger rooms or in the plant vent. 2) Accumulation of water in a residual heat removal pump compartment or the auxiliary building sump 3) Increasing ESF pump room temperature 4) Reduced ECCS flow rates	From containment sump to the high head injection headers via alternate residual heat removal pump, residual heat exchanger, and the alternate high head charging pump

TABLE 6.5-1

CRITERIA FOR AUXILIARY FEEDWATER SYSTEM DESIGN BASIS CONDITIONS

Condition or Transient	Classification[a]	Criteria[a]	Additional Design Criteria
Loss of Normal Feedwater (Refer to Section 15.2.8)	Condition II	AFW capable of removing stored and residual heat to prevent pressurizer liquid relief.[b]	AFW automatically initiated on low-low SG level.
Loss of Offsite Power to the Station Auxiliaries (Refer to Section 15.2.9)	Condition II	AFW capable of removing stored and residual heat to prevent pressurizer liquid relief.	AFW automatically initiated on low-low SG level.
Steamline Rupture (Mass & Energy Release – Refer to Section 6.2D.3)	Condition IV	N/A – not an AFW system design requirement.	AFW flow maximized for mass and energy release.
Major Rupture of a Main Feedwater Pipe (Refer to Section 15.4.2.2)	Condition IV	AFW to provide assured source of feedwater to SGs for decay heat removal.	AFW flow to SGs assumed in 10 minutes after reactor trip.
Loss of all ac power	N/A	AFW to provide assured source of feedwater to SGs for decay heat removal independent of ac power.	AFW system turbine-driven pump train independent of ac power.
Small-Break Loss of Coolant (Refer to Section 15.3.1)	Condition III	AFW provide 390 gpm.[d]	N/A
Natural Circulation Cooldown	Same as LONF	AFW system provides an assured source of feedwater to SGs to prevent reactor vessel head voiding	Unit 1 – Hot Standby 1 hour, 8 hour cooldown @ 25 °F per hour. Unit 2 – Hot Standby 2 hours, 4 hour cooldown @ 50 °F per hour.

(a) Ref: ANS N18.2 (This information provided for those transients analyzed in Chapter 15.)

(b) A better-estimate analysis has also been performed to demonstrate that the pressurizer does not fill with a single motor-driven auxiliary feedwater pump feeding 2 SGs a total of 390 gpm.

(c) Refer to Section 15.5 for 10 CFR 100 acceptance criteria for accident analysis dose consequences.

(d) An AFW flowrate of 97.5 gpm per SG is assumed in NOTRUMP based on 390 gpm divided evenly among 4 SGs since NOTRUMP cannot explicitly model asymmetric flow.

TABLE 6.5-2

SUMMARY OF ASSUMPTIONS
AFW SYSTEM DESIGN VERIFICATION

	Transient	Loss of Normal Feedwater (Loss of Offsite Power)	Natural Circulation Cooldown	Major Rupture of a Main Feedwater Pipe	Major Steam Line Break[b] - (Containment)	Small Break Loss of Coolant Accident
a.	Max NSSS power	102% of 3425 MW_t	102% of 3411MW_t	102% of 3425 MW_t	102% of 3425 MW_t	102% of 3411 MW_t
b.	Time delay from event to Rx trip	(Refer to Table 15.2-1)	2 sec	(Refer to Table 15.4-8)	Variable	4.7 sec
c.	AFW system actuation signal/time delay for AFW system flow	Low-low SG level 1 minute	Low-low SG Level 1 minute	Low-low SG level 10 minutes	Assumed immediately 0 sec (no delay)	Low pressurizer pressure SI signal / 60 sec
d.	SG water level at time of reactor trip.	Low-low SG level 8 % narrow range span (NRS)	Same as LOOP	Low-low SG level 0% NRS	N/A	N/A
e.	Decay heat	Figure 15.1-7	Figure 15.1-7	Figure 15.1-7	Figure 15.1-7	Figure 15.1-7
f.	AFW pump design pressure	1102 psig	1112 psia	1102 psig	N/A	1130 psig
g.	Min. No. of SGs that must receive AFW flow	4 of 4	Same as LONF/LOOP	2 of 4	N/A	4 of 4[c]
h.	Maximum AFW temperature	100 °F	100 °F	100 °F	100 °F	100 °F

TABLE 6.5-2

	Transient	Loss of Normal Feedwater (Loss of Offsite Power)	Natural Circulation Cooldown	Major Rupture of a Main Feedwater Pipe	Major Steam Line Break[(b)] - (Containment)	Small Break Loss of Coolant Accident
i.	Operator action	None	N/A	10 minutes to isolate the faulted SG	10 minutes to isolate the faulted SG	None
j.	AFW purge volume/ temperature	113 ft^3per loop/435° F	113 ft^3 per loop/435 °F	113 ft^3per loop/435° F	0.0ft^3/ based on power	N/A
k.	Normal blowdown	None assumed	None assumed	None assumed	None assumed	None assumed
l.	Sensible heat	Table 6.5-3	Table 6.5-3	Refer to cooldown	N/A	Refer to cooldown
m.	Time at standby/time to cooldown to RHR	2 hr/4 hr with offsite power available (without offsite power available refer to Natural Circulation Cooldown)	Unit 1 – 1 hr/8 hr @ 25 °F Unit 2 – 2 hr/4 hr @ 50 °F	N/A	N/A	N/A
n.	AFW flowrate	600 gpm (total) constant (minimum requirement	Variable based on maintaining SG level at lower NR level tap at SG backpressure	390 gpm (total) constant (after 10 minutes)[(a)] (minimum requirement)	569 gpm to 1588 gpm varying due to faulted SG pressure changes	390 gpm to 4 SGs[(c)]

(a) Minimum flow of 175.5 / 214.5 gpm to each of the two steam generators receiving AFW flow.

(b) A rupture of a main steam pipe inside containment does not impose any performance related requirements on the AFW system. For the accident analysis, AFW flowrates were maximized to increase the mass and energy contributions from the AFW system (Refer to Section 6.2D.3).

(c) 390 gpm to four SGs was assumed to be provided by one motor-driven AFW pump. The approved NOTRUMP model cannot model asymmetric flow, therefore the 390 gpm is assumed to be distributed equally among the four SGs

TABLE 6.5-3

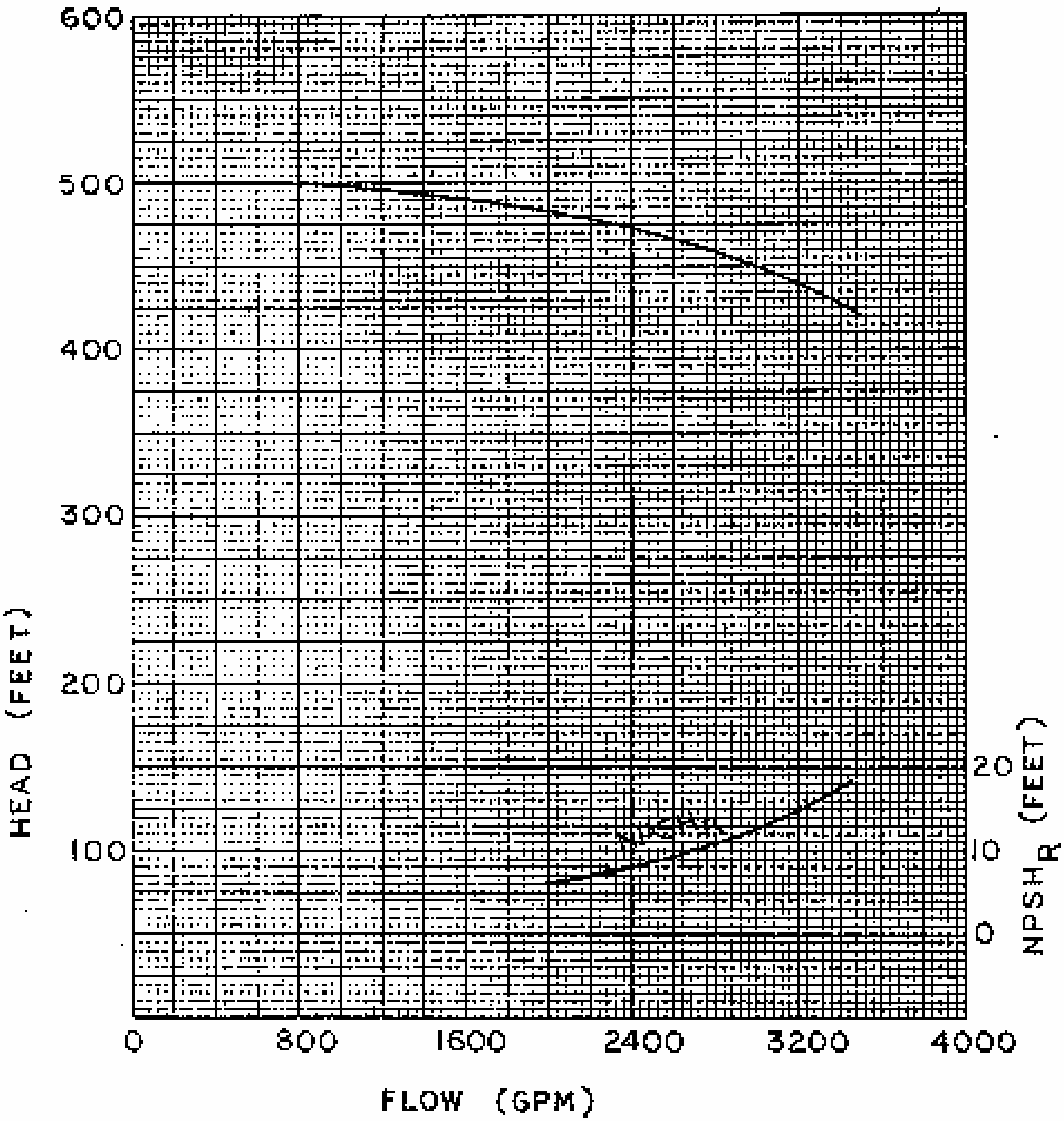
SUMMARY OF SENSIBLE HEAT SOURCES
(For Plant Cooldown by AFW system)

Primary Water Sources (initially at emergency safeguards design (ESD) power temperature and inventory)
- RCS fluid
- Pressurizer fluid (liquid and vapor)

Primary Metal Sources (initially at ESD power temperature)
- Reactor coolant piping, pumps and reactor vessel
- Pressurizer
- Steam generator tube metal and tubesheet
- Reactor vessel internals

Secondary Water Sources (initially at ESD power temperature and inventory)
- Steam generator fluid (liquid and vapor)
- Main feedwater purge fluid between steam generator and AFW system piping

Secondary Metal Sources (initially at ESD power temperature)
- All steam generator metal above tubesheet, excluding tubes



NPSH$_{AVAILABLE}$

FLOW	NPSH$_A$*
2,600 GPM	46.1 FT.
3,400 GPM	26.8 FT.

* PUMPS TAKING SUCTION FROM REFUELING WATER STORAGE TANK.

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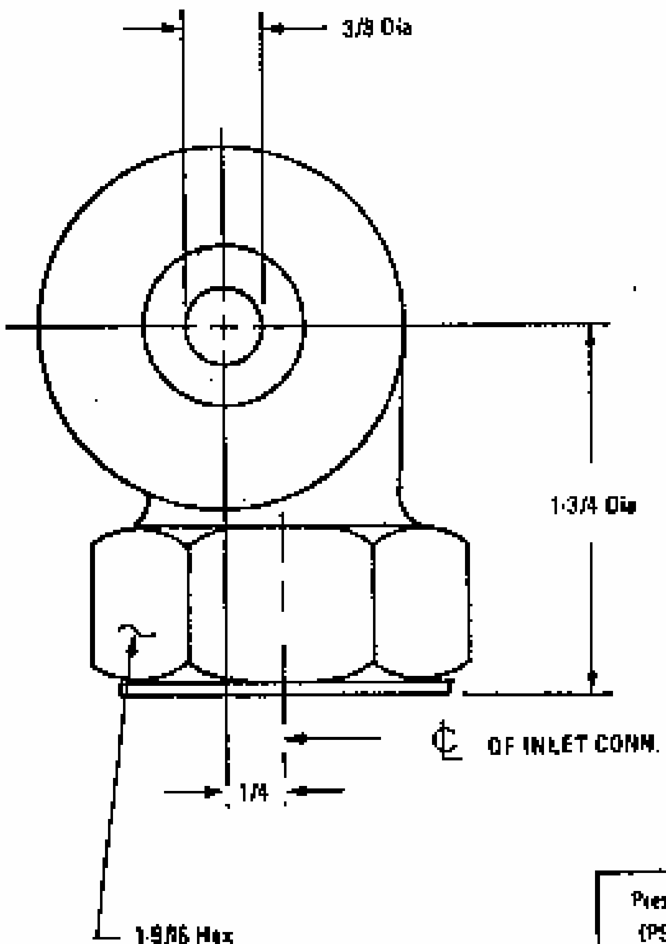
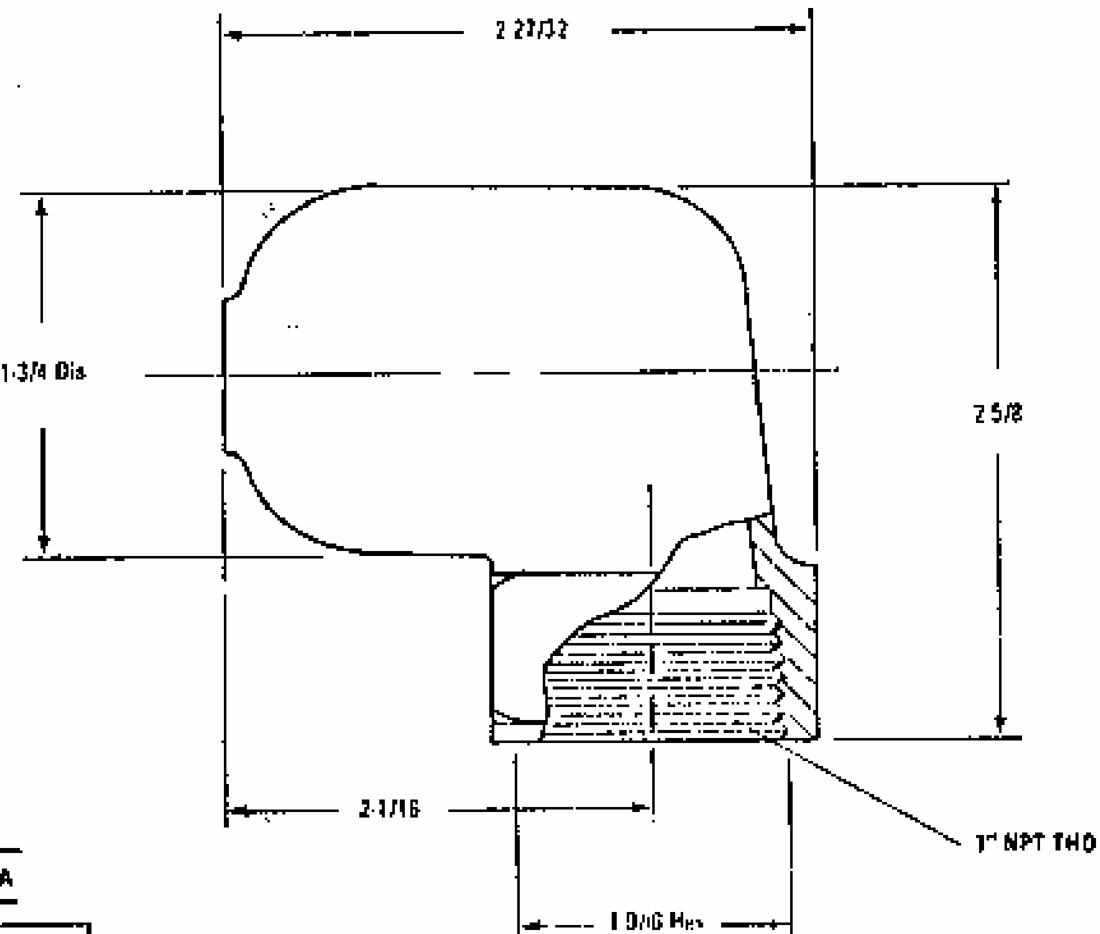
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-10
CONTAINMENT SPRAY PUMP PERFORMANCE CURVE





FLOW DATA

Pressure (PSIG)	Flow (GPM)
10	7.6
20	10.7
30	13.3
40	15.2
50	17.0

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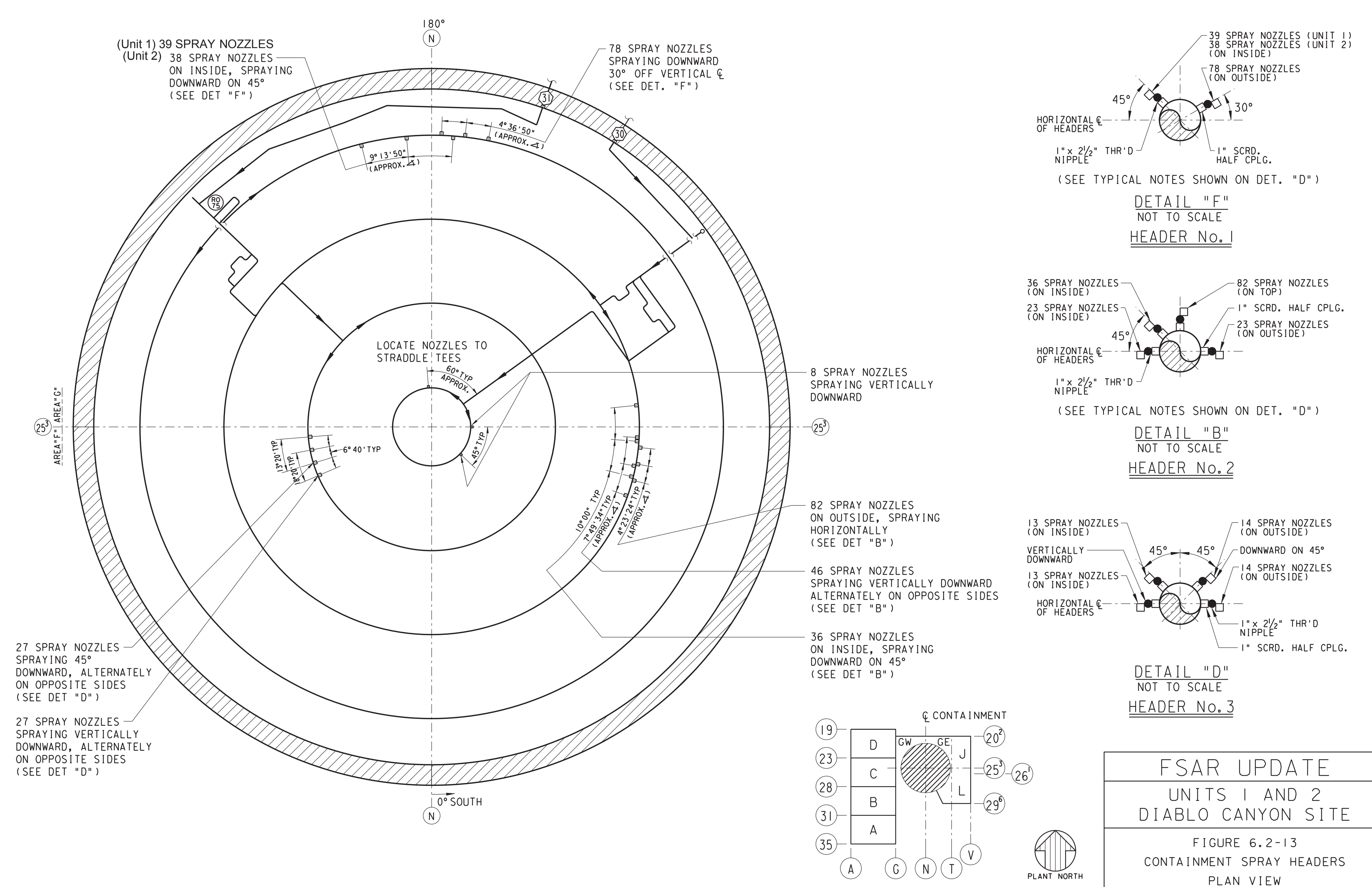
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-12

CONTAINMENT SPRAY NOZZLE CUTAWAY

Revision 11 November 1996



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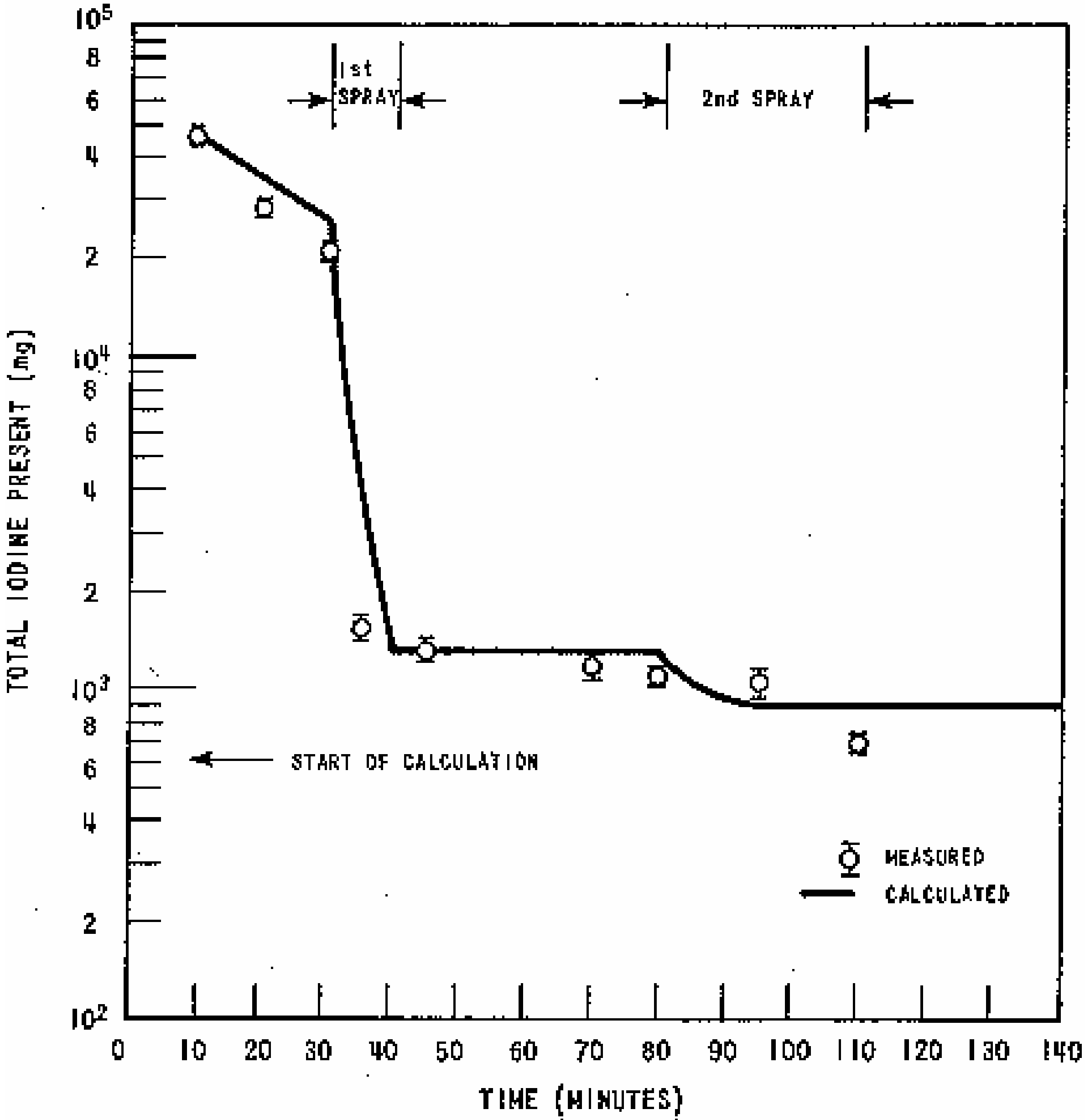
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-13
CONTAINMENT SPRAY HEADERS
PLAN VIEW



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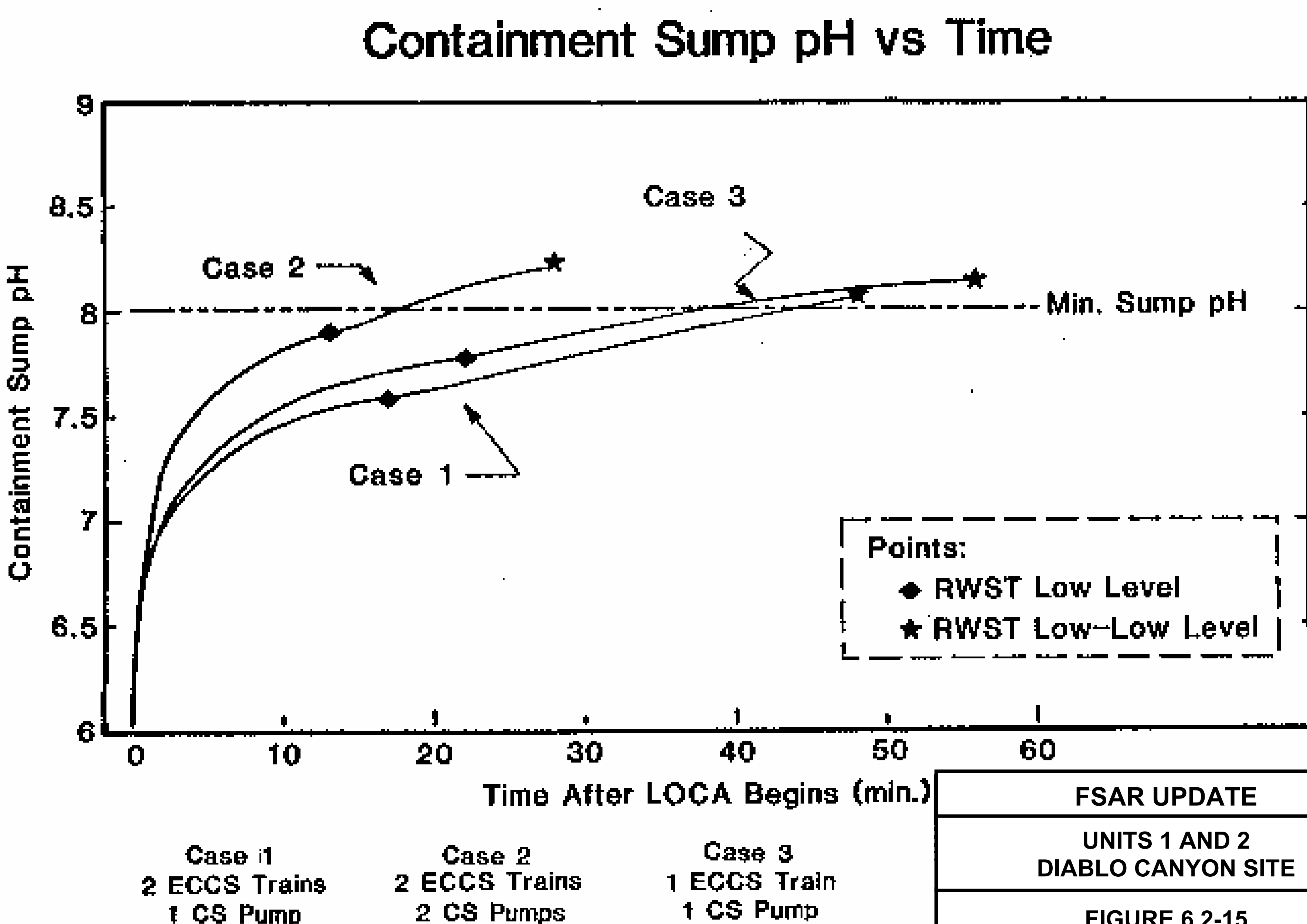
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-14
GENERIC METHODOLOGY
COMPARISON OF SPRAY REMOVAL MODEL
AND CSE RESULTS (RUN A6)



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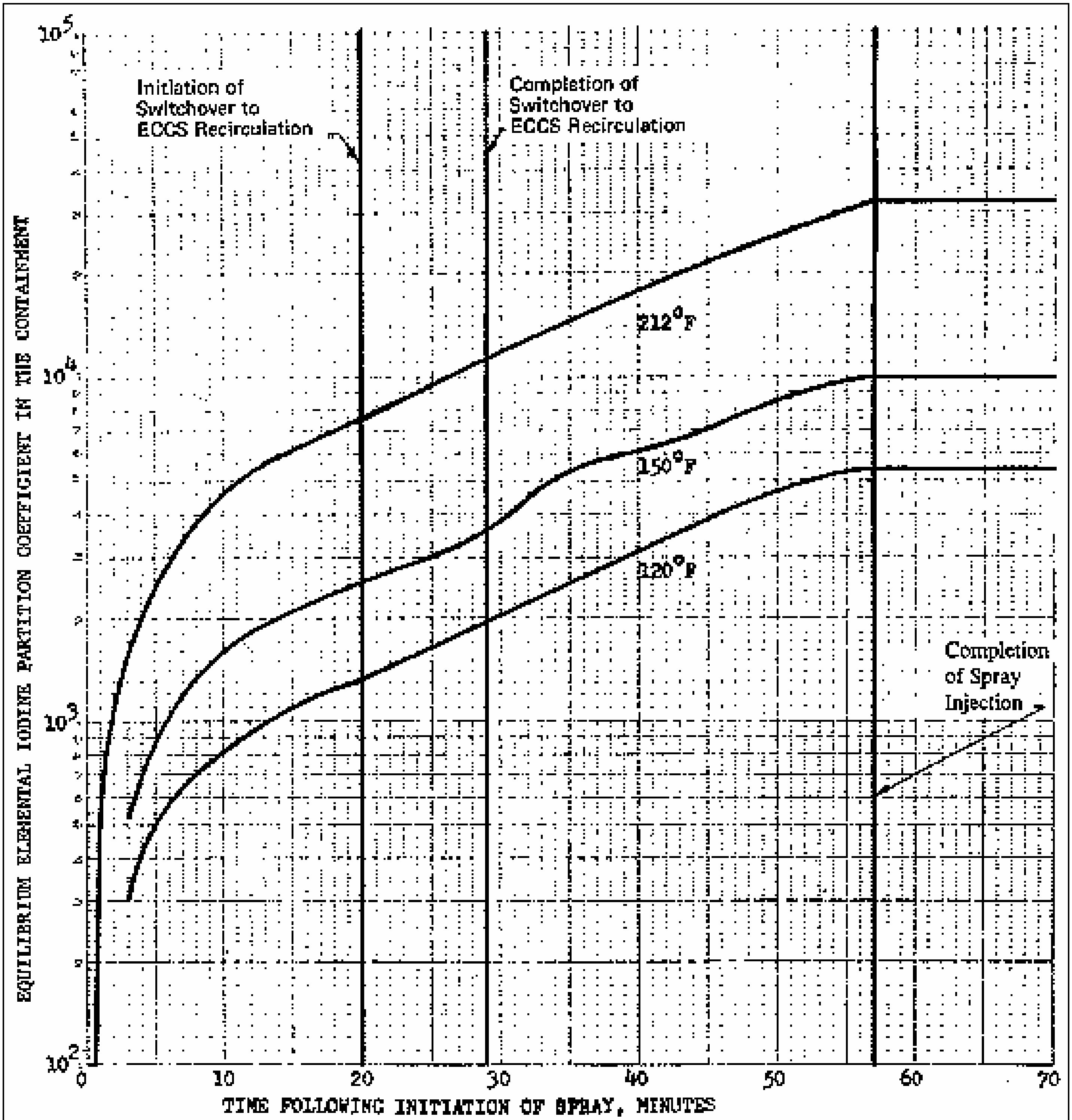
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-15 CONTAINMENT RECIRCULATION SUMP pH VERSUS TIME AFTER LOCA BEGINS



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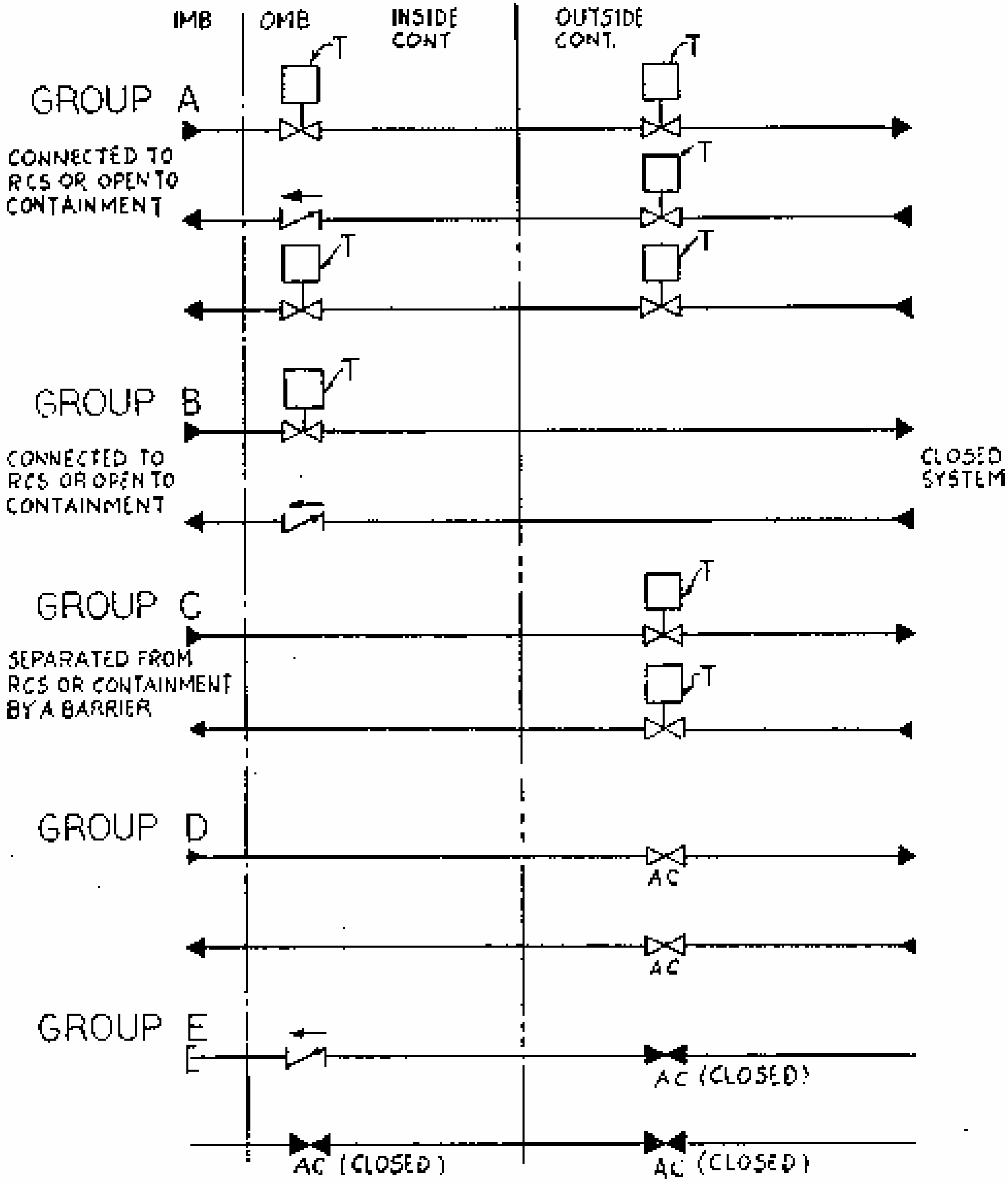
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-16
CONTAINMENT EQUILIBRIUM ELEMENTAL IODINE PARTITION COEFFICIENT VERSUS TIME FOR MINIMUM SUMP pH CASE (2 ECCS TRAINS AND 1 SPRAY TRAIN) FOR THREE TEMPERATURES



1. AC - MANUAL VALVE POSITION MAINTAINED BY ADMINISTRATIVE CONTROL
2. □T - TRIP VALVE EITHER MOTOR OR AIR OPERATED
3 ALL PENETRATION VALVES AND PIPING ARE CLASS I

CONTAINMENT ISOLATION SYSTEM

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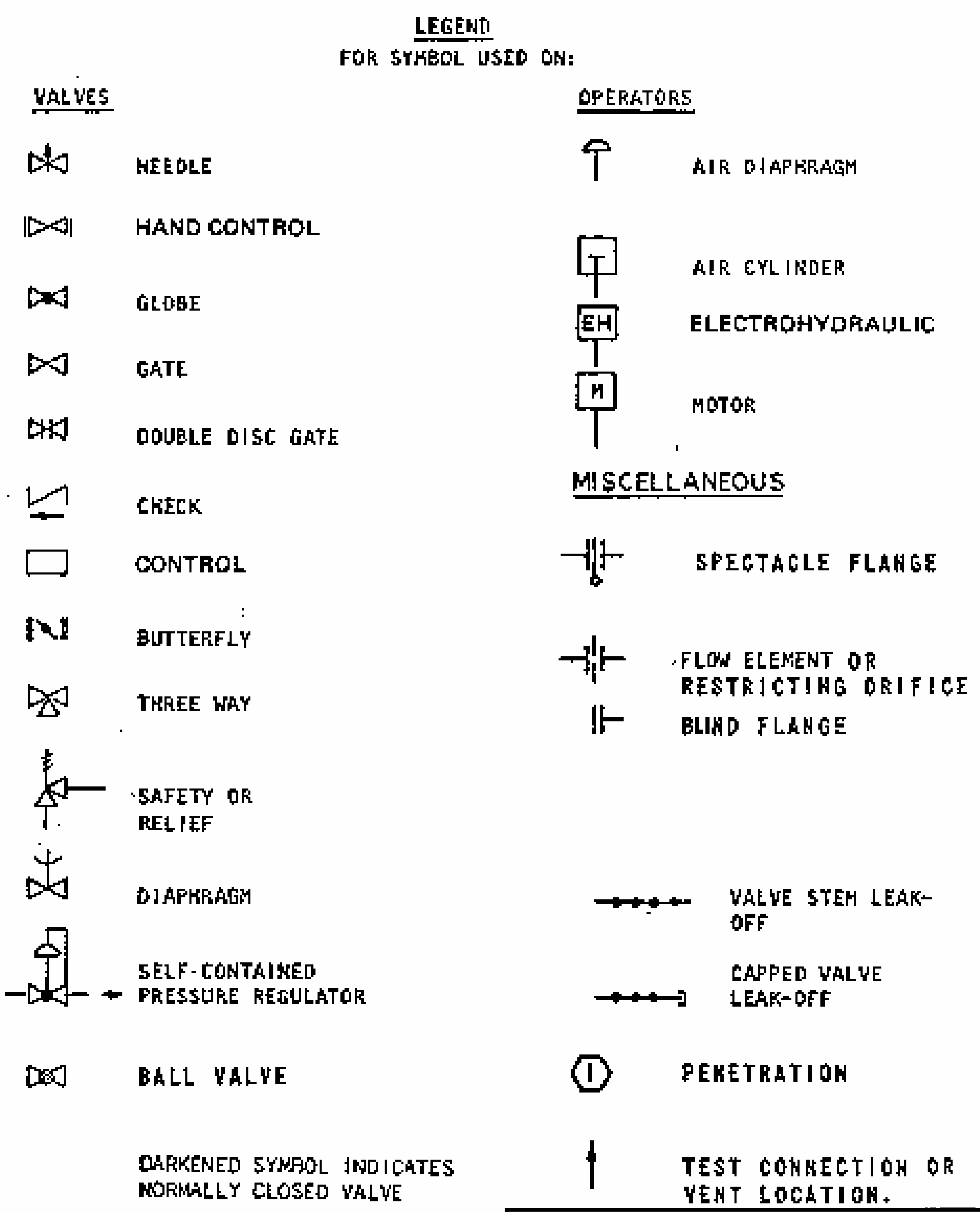
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-17 CONTAINMENT ISOLATION SYSTEM



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UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-18 (Sheet 1 of 2)
PENETRATION DIAGRAM LEGEND

NOTATION

Encircled Letter

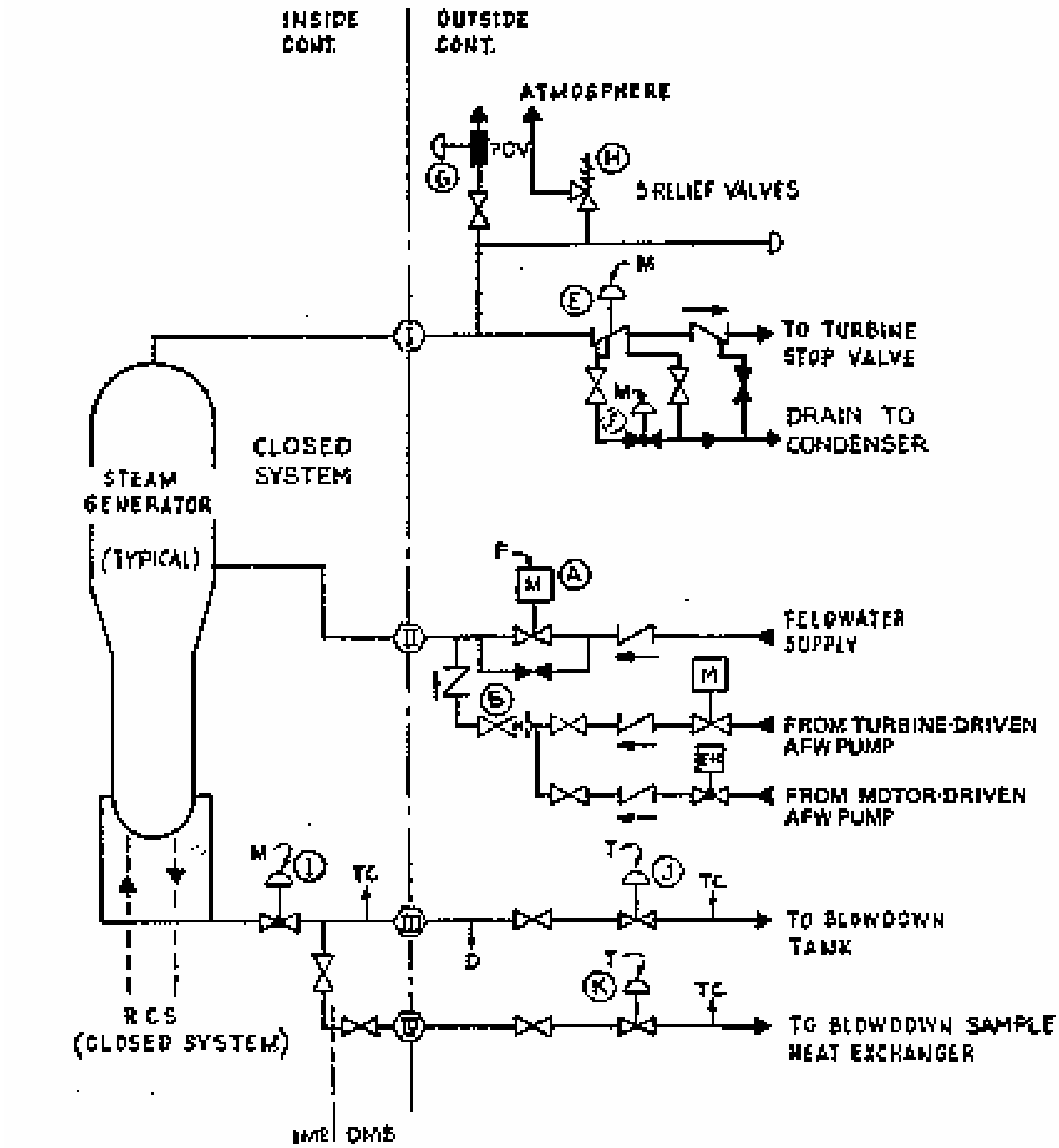
○	- VALVE DESIGNATION - SEE TABLE 6.2-39 FOR DESCRIPTION
RWST	- REFUELING WATER STORAGE TANK
DT	- REACTOR COOLANT DRAIN TANK
M	- TRIPPED BY MAIN STEAM ISOLATION SIGNAL
T	- TRIPPED BY CONTAINMENT ISOLATION SIGNAL, PHASE A
P	- TRIPPED BY CONTAINMENT ISOLATION SIGNAL, PHASE B
F	- TRIPPED BY FEEDWATER ISOLATION SIGNAL
RCS	- REACTOR COOLANT SYSTEM
CVCS	- CHEMICAL AND VOLUME CONTROL SYSTEM
CONT	- CONTAINMENT
IMB	- INSIDE MISSILE BARRIER
OMB	- OUTSIDE MISSILE BARRIER
SO	- SEALED OPEN
SC	- SEALED CLOSED
PRT	- PRESSURIZER RELIEF TANK
D	- DRAIN
V	- VENT
PCV	- PRESSURE CONTROL VALVE
TC	- TEST CONNECTION
TV	- TEST VENT
S	- SAFETY INJECTION SIGNAL
S-I	- DESIGN CLASS I

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-18 (Sheet 2 of 2)

PENETRATION DIAGRAM LEGEND



SHOWN CONFIGURATION AT PENETRATION(S) 1,2,3,4,5,6 IS GENERAL ONLY. FOR DETAILED SYSTEM CONFIGURATION, REFER TO FSAR FIGURE # AND SHEET # AS SHOWN ON CHART AT RIGHT.

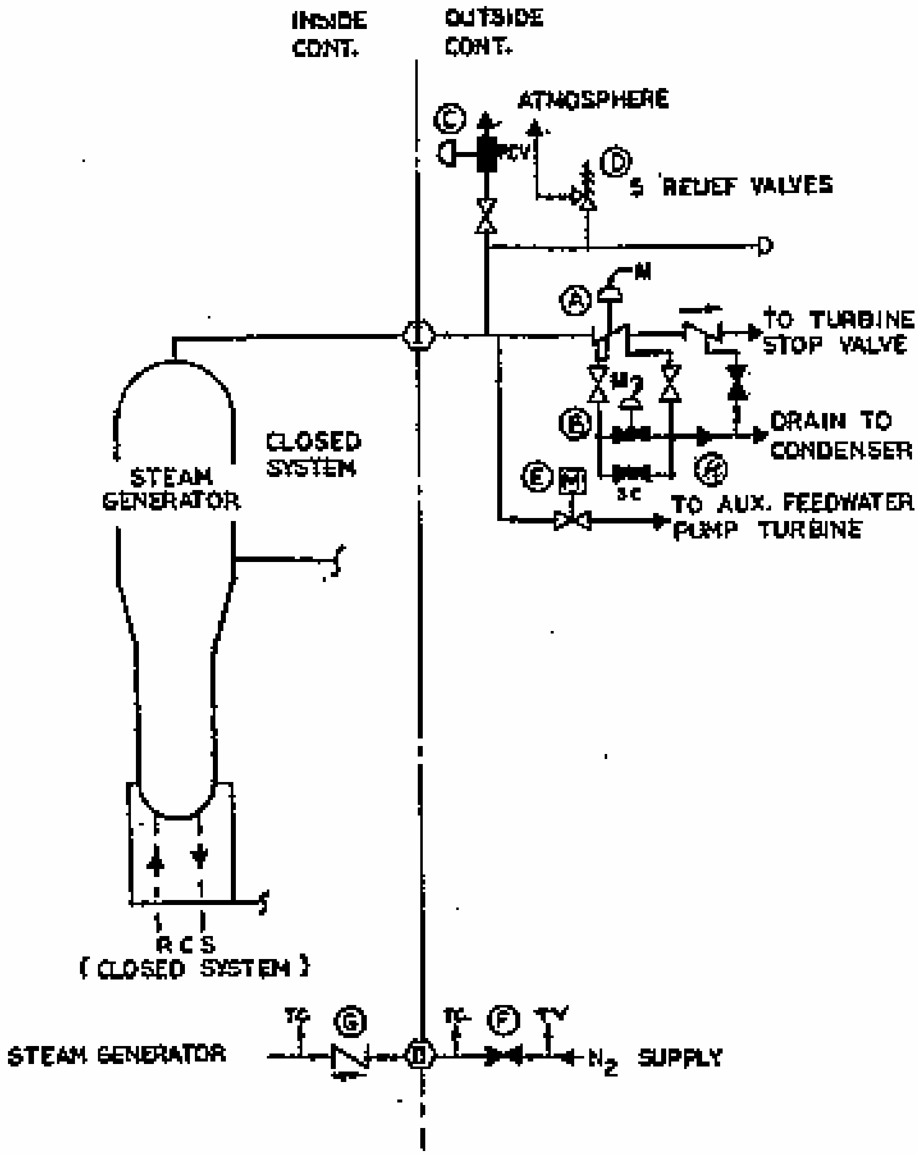
PEN #	UNIT 1		UNIT 2	
	FIG #	SHT #	FIG #	SHT #
1	3.2-03	3 of 8	3.2-03	4 of 8
2	3.2-03	3 of 8	3.2-03	4 of 8
3	3.2-03	3 of 8	3.2-03	4 of 8
4	3.2-03	3 of 8	3.2-03	4 of 8
5	3.2-04	5 of 14	3.2-04	6 of 14
6	3.2-04	1 of 14	3.2-04	2 of 14

ALL SYSTEMS ARE DESIGN CLASS I
(I) MAIN STEAM (5,6)
(II) FEEDWATER (1,2,3,4)
(III) STEAM GENERATOR BLOWDOWN (37,38,39,40)
(IV) STEAM GENERATOR BLOWDOWN SAMPLE (53) 4 LINES

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-19
PENETRATION DIAGRAM
(SHEET 1 OF 25)



SHOWN CONFIGURATION AT PENETRATION(S) 6,7 IS GENERAL ONLY. FOR DETAILED SYSTEM CONFIGURATION, REFER TO FSAR FIGURE # AND SHEET # AS SHOWN ON CHART AT RIGHT.

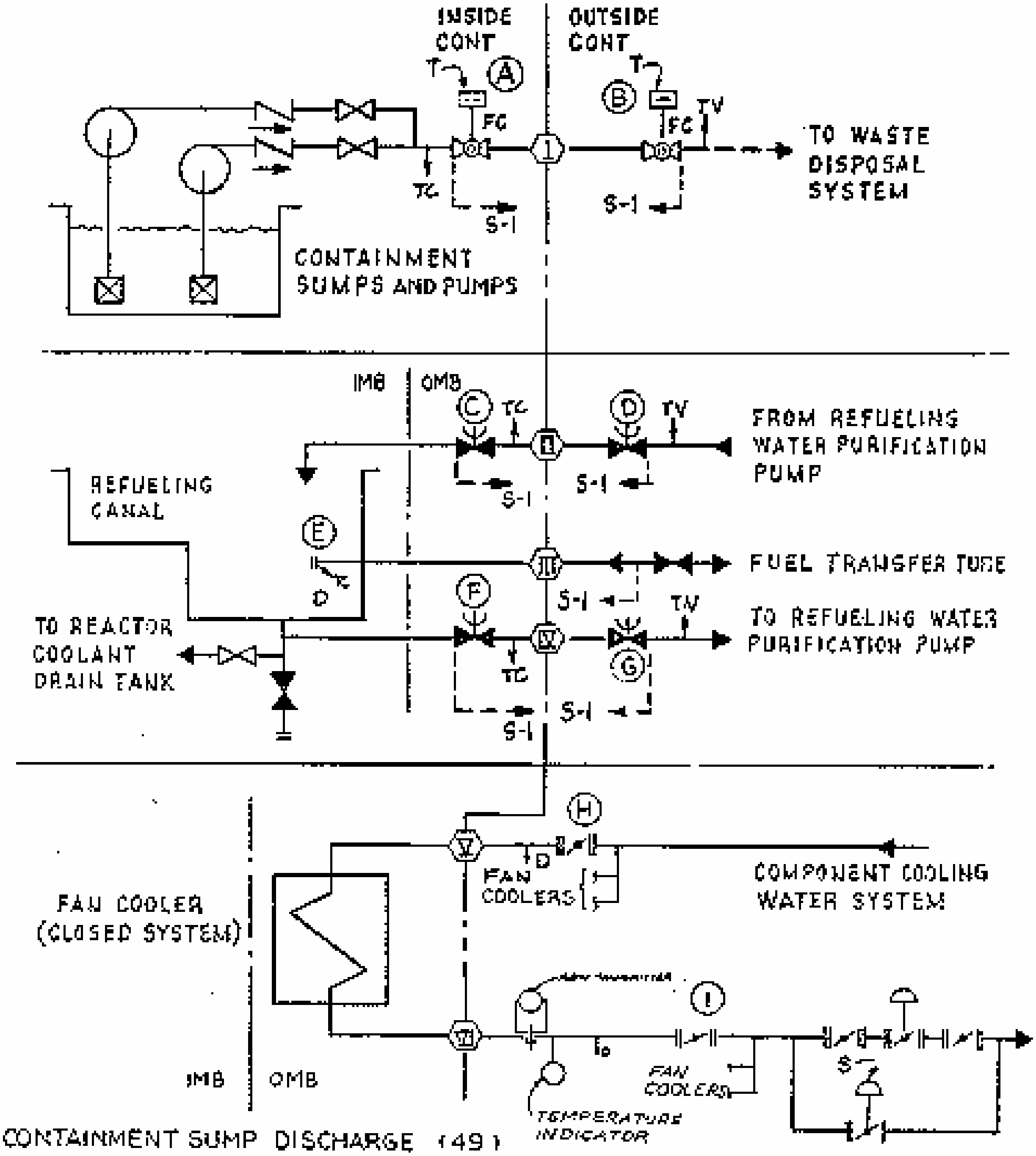
PEN #	UNIT 1 FIG #	UNIT 1 SHT #	UNIT 2 FIG #	UNIT 2 SHT #
6	3.2-04	3 of 14	3.2-04	6 of 14
7	3.2-04	1 of 14	3.2-04	2 of 14

SYSTEMS ARE DESIGN CLASS 1
(I) MAIN STEAM (6,7)
(II) STEAM GENERATOR N_2 (52)

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-19
PENETRATION DIAGRAM
(SHEET 2 OF 25)

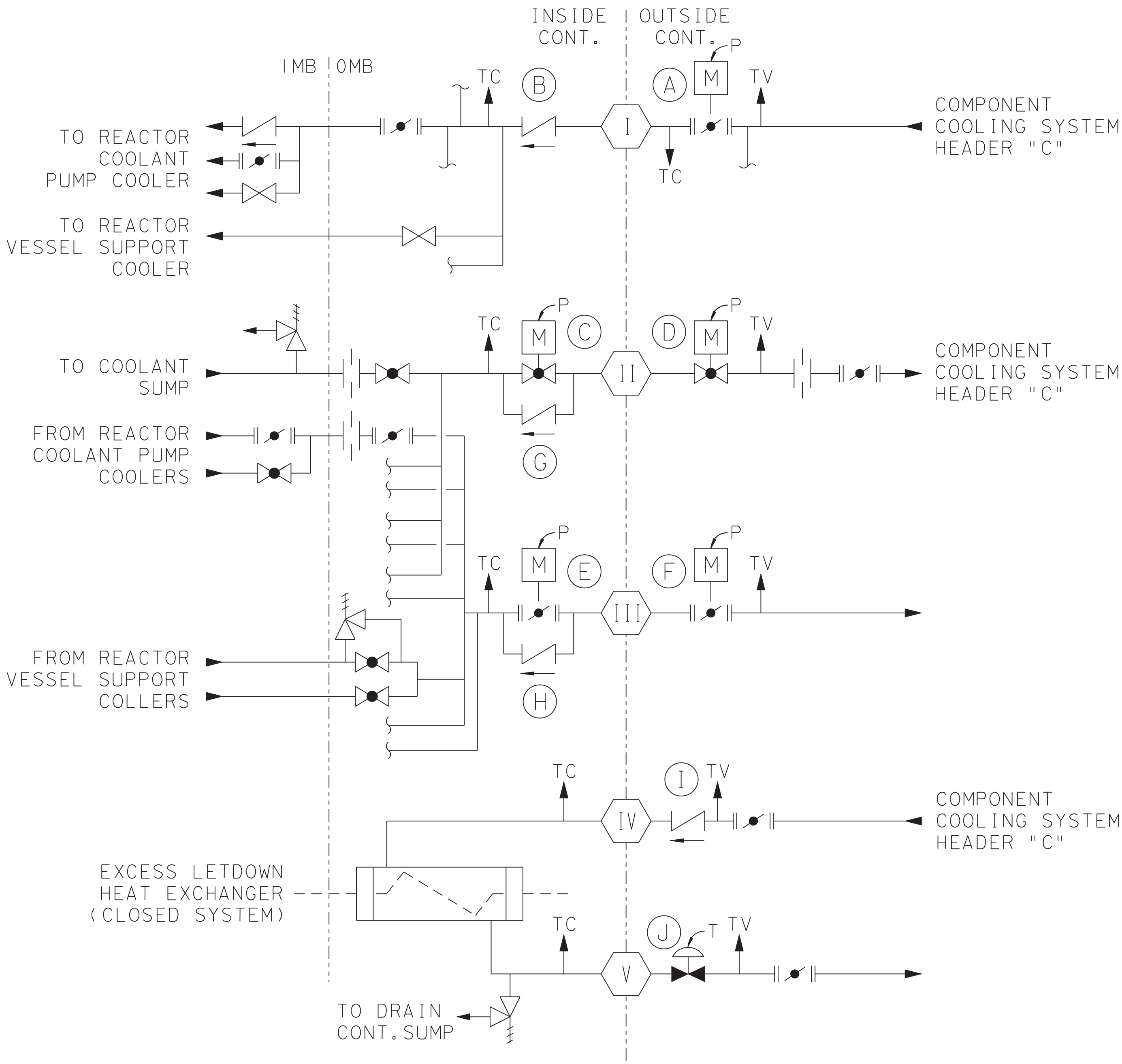


(I) CONTAINMENT SUMP DISCHARGE (49)
(II) REFUELING CANAL WATER SUPPLY (46)
(III) FUEL TRANSFER TUBE (64)
(IV) REFUELING CANAL WATER RETURN (47)
(V) FAN COOLER WATER SUPPLY (9-13)
(VI) FAN COOLER WATER RETURN (14-18)

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-19
PENETRATION DIAGRAM
(SHEET 3 OF 25)

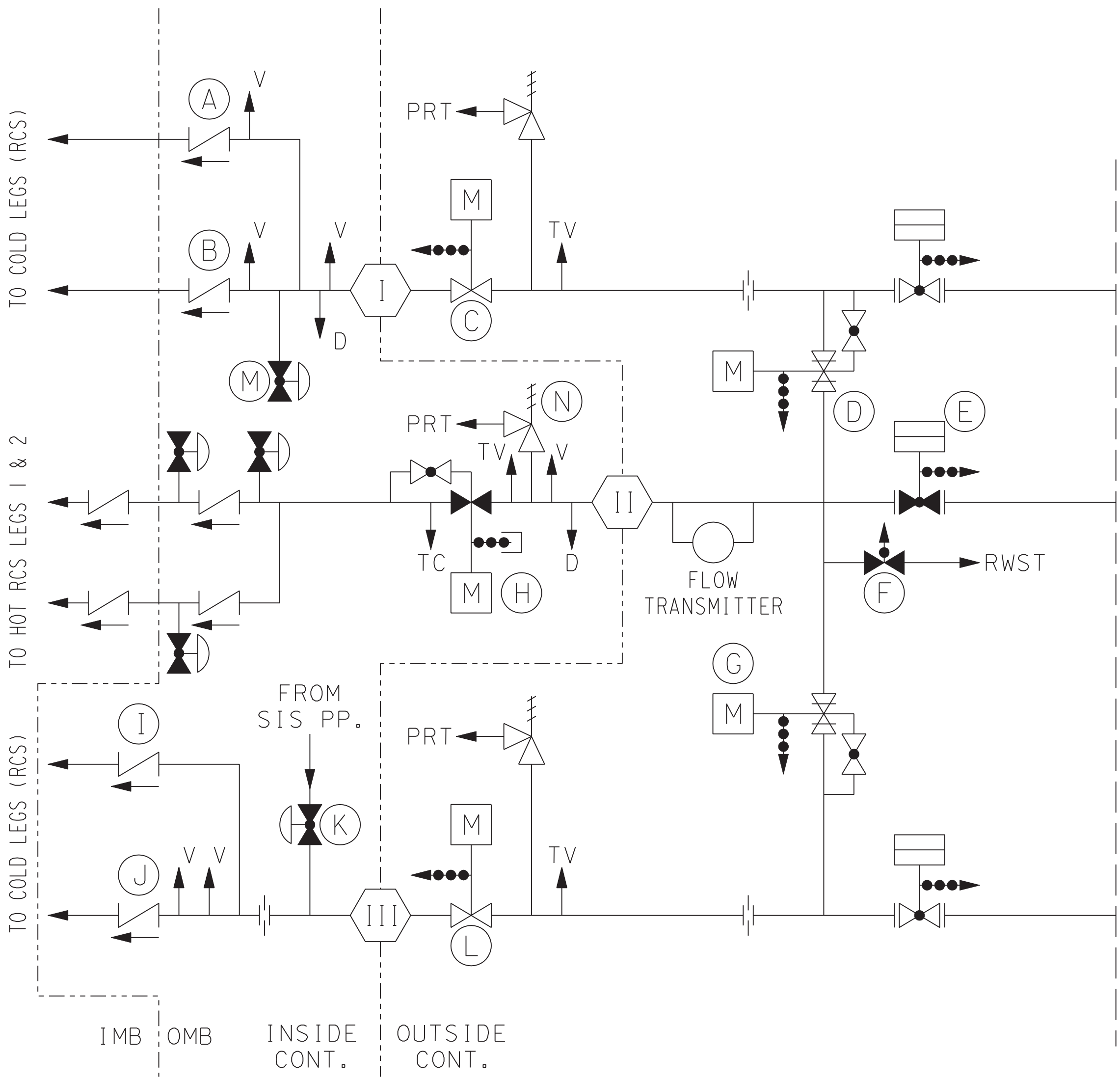


(I) CCW TO RCP (19)
(II) CCW FROM RCP (21)
(III) CCW FROM RCP (20)
(IV) CCW TO ELD HX (22)
(V) CCW FROM ELD HX (23)

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-19
PENETRATION DIAGRAM
(SHEET 4 OF 25)



(I) RHR 1 INJECTION (24)
(II) RHR HOT LEG INJECTION (26)
(III) RHR 2 INJECTION (25)

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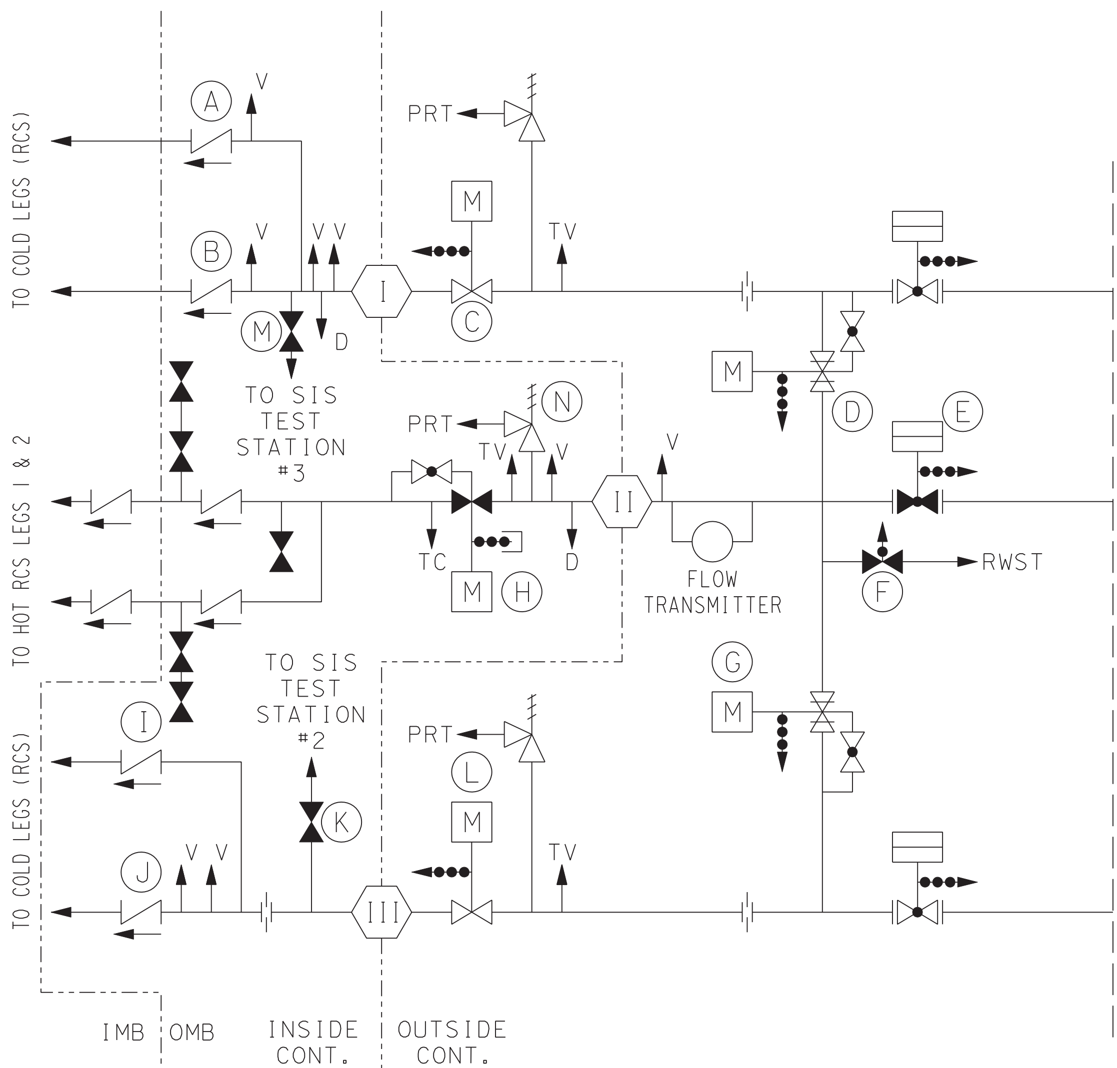
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 5 OF 25)

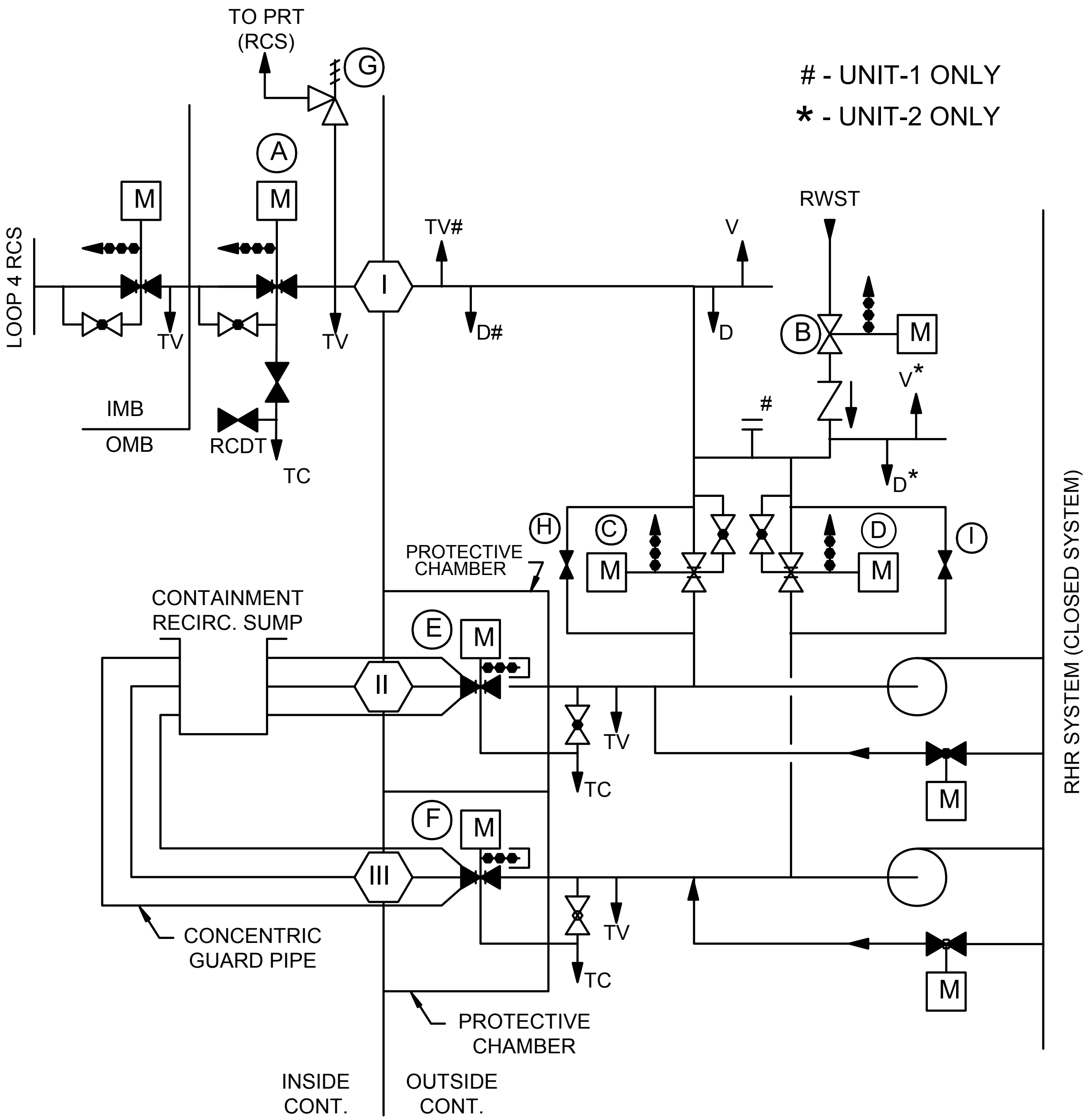


(I) RHR 1 INJECTION (24)
(II) RHR HOT LEG INJECTION (26)
(III) RHR 2 INJECTION (25)

FSAR UPDATE

UNIT 2
DIABLO CANYON SITE

FIGURE 6.2-19
PENETRATION DIAGRAM
(SHEET 5A OF 25)

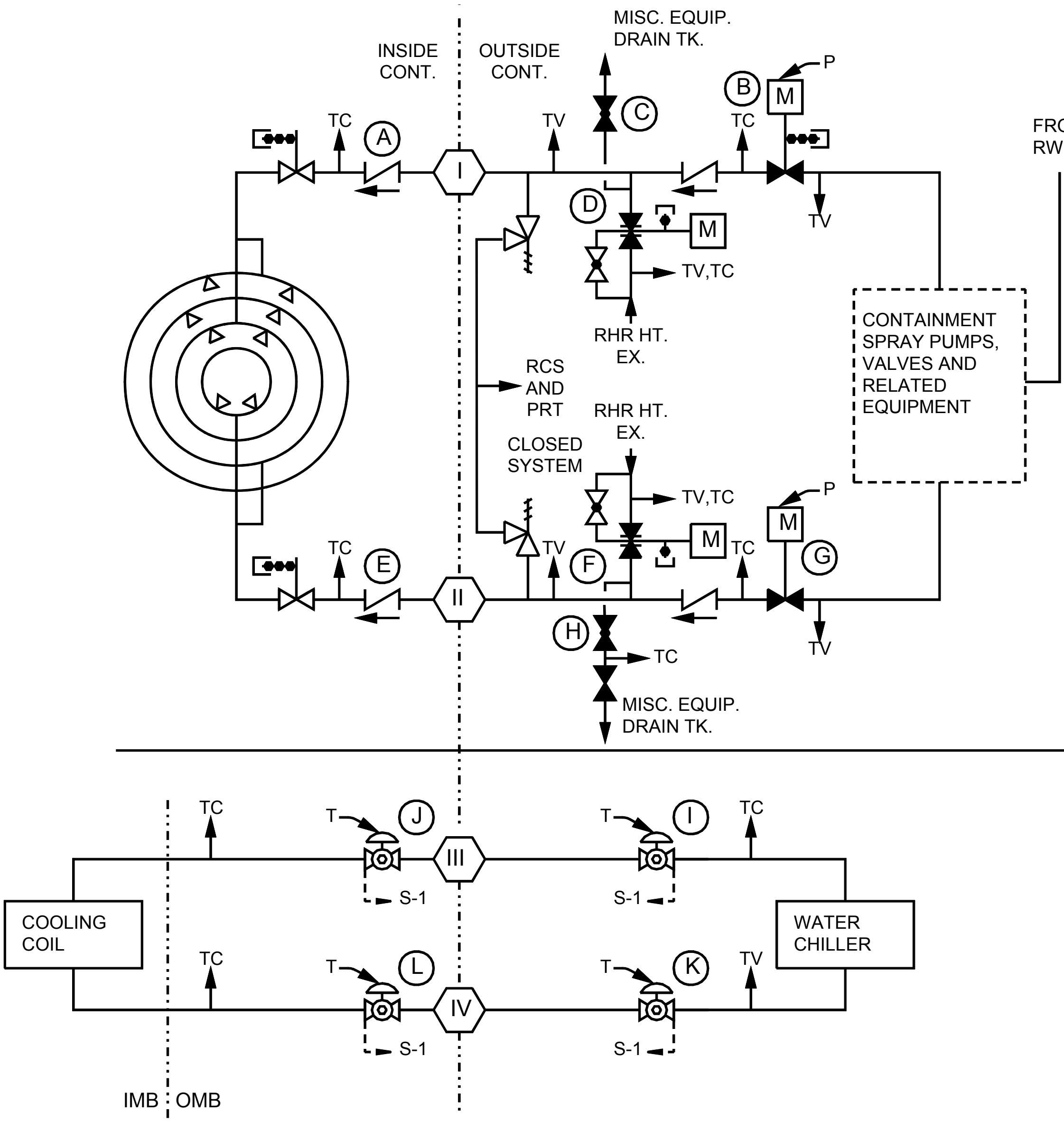


(I) RCS LOOP 4 RECIRC. (27)
(II) CONT. SUMP RECIRC. (28)
(III) CONT. SUMP RECIRC. (29)

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-19 **PENETRATION DIAGRAM (SHEET 6 OF 25)**

Revision 20 November 2011

THIS SYSTEM IS DESIGN CLASS I



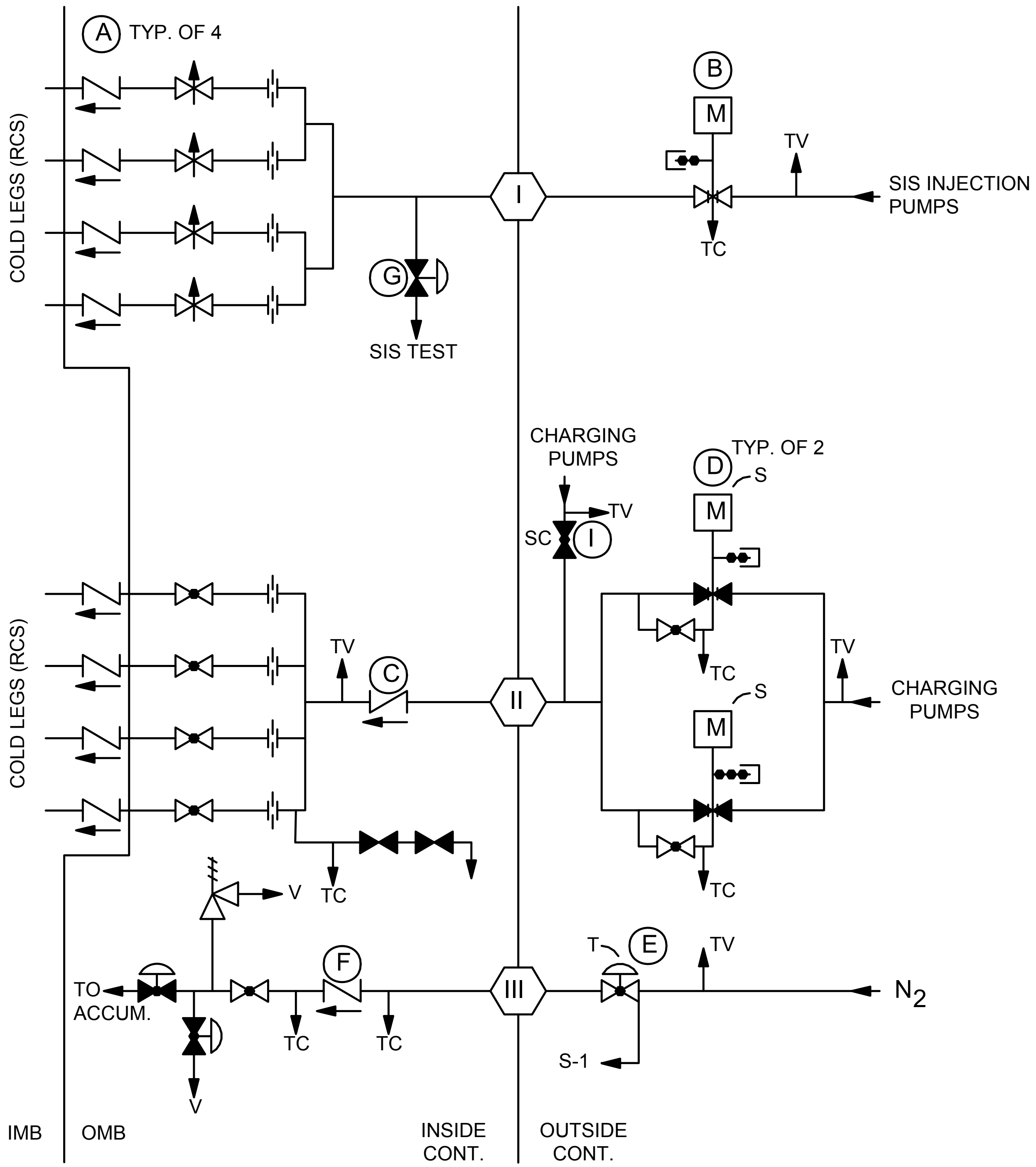
* -UNIT-2 ONLY

(I) CONTAINMENT SPRAY (30)
(II) CONTAINMENT SPRAY (31)
* (III) CHILLED WATER SUPPLY (82D)
* (IV) CHILLED WATER RETURN (83A)

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-19
PENETRATION DIAGRAM
(SHEET 7 OF 25)

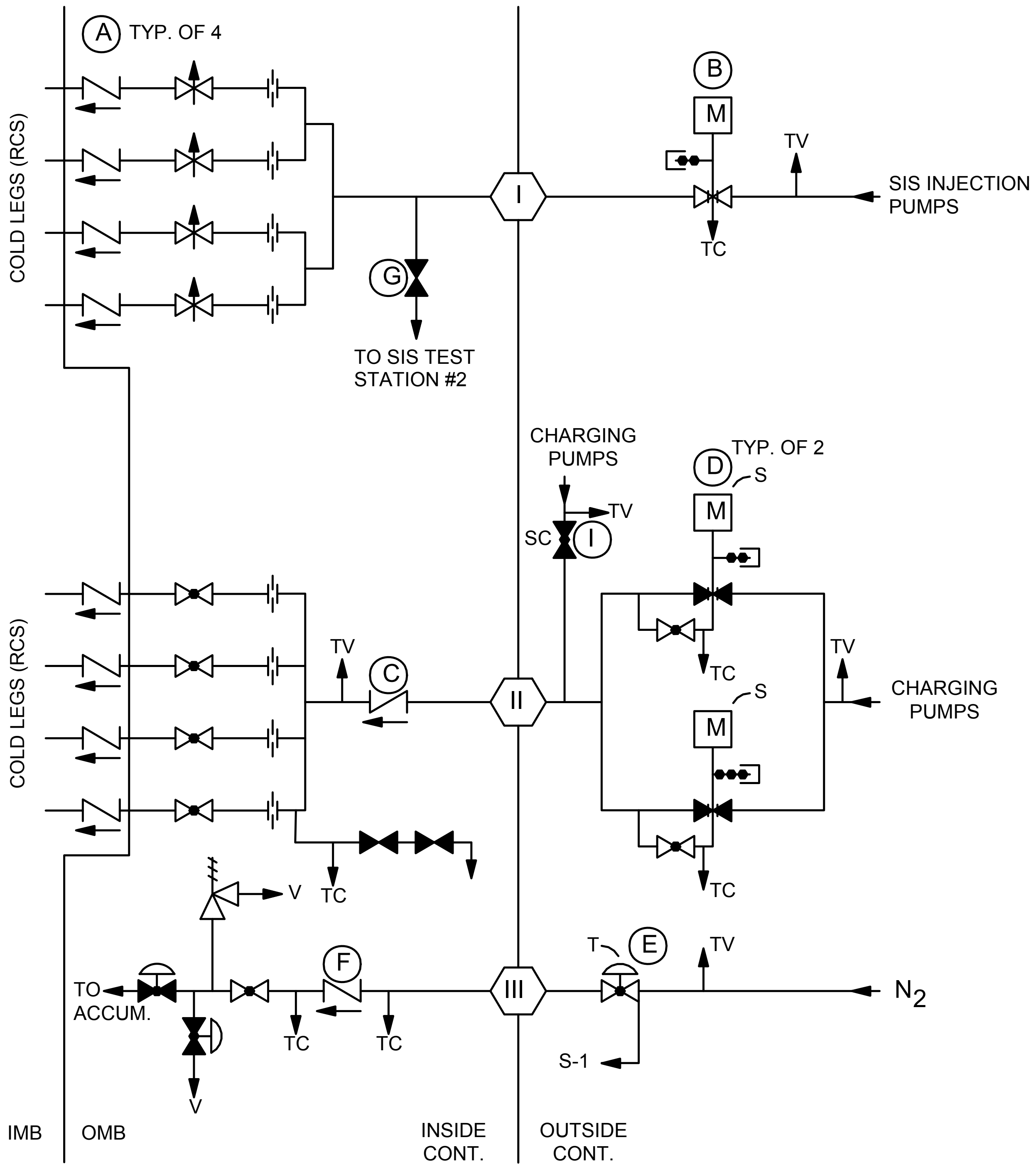


(I) SIS COLD INJECTION (33)
(II) SIS COLD INJECTION (34)
(III) N_2 SUPPLY TO ACCUM. (51A)

FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

FIGURE 6.2-19
PENETRATION DIAGRAM
(SHEET 8 OF 25)



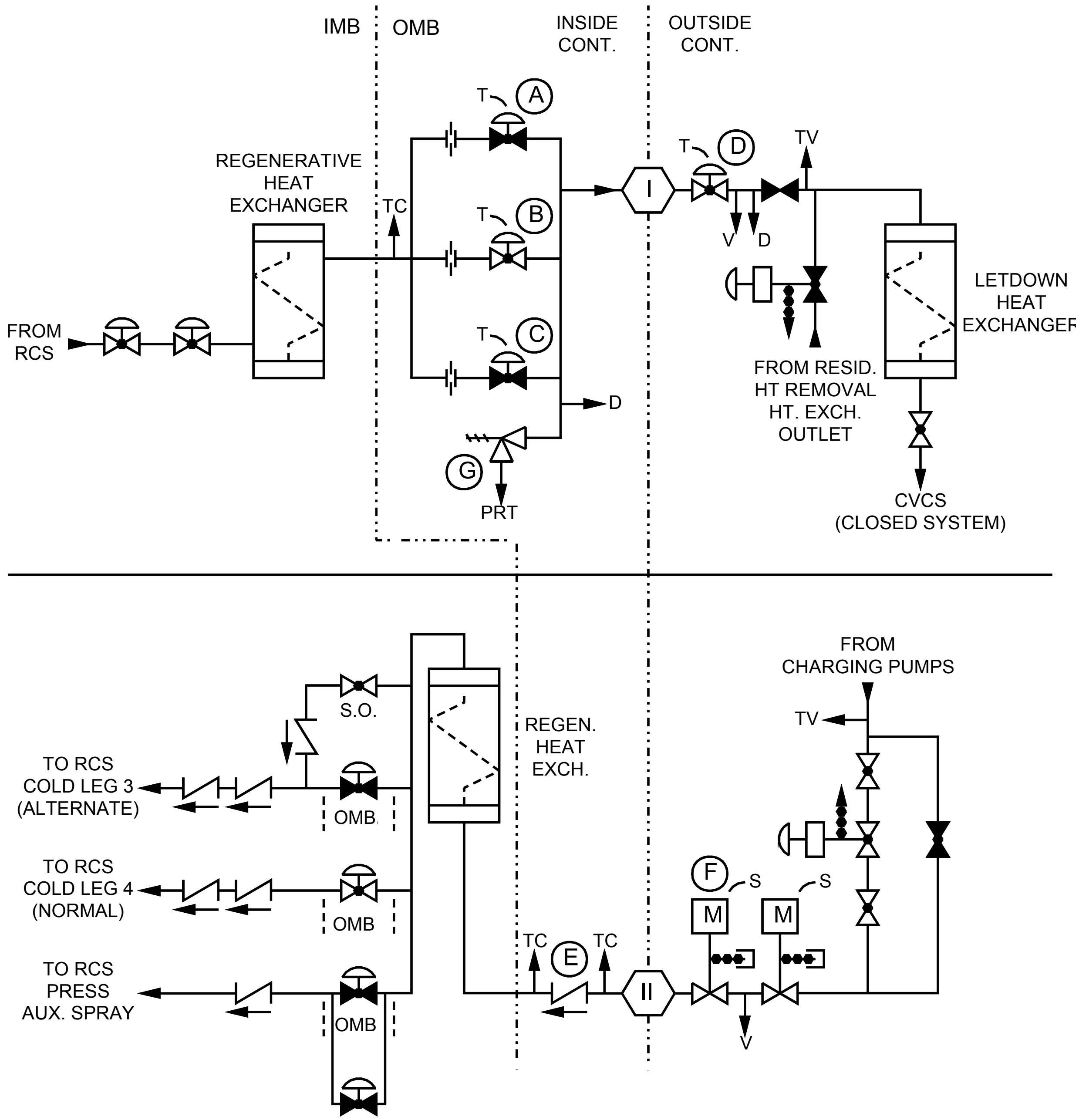
(I) SIS COLD INJECTION (33)
(II) SIS COLD INJECTION (34)
(III) N_2 SUPPLY TO ACCUM. (51A)

FSAR UPDATE

UNIT 2
DIABLO CANYON SITE

FIGURE 6.2-19
PENETRATION DIAGRAM
(SHEET 8A OF 25)

Revision 20 November 2011



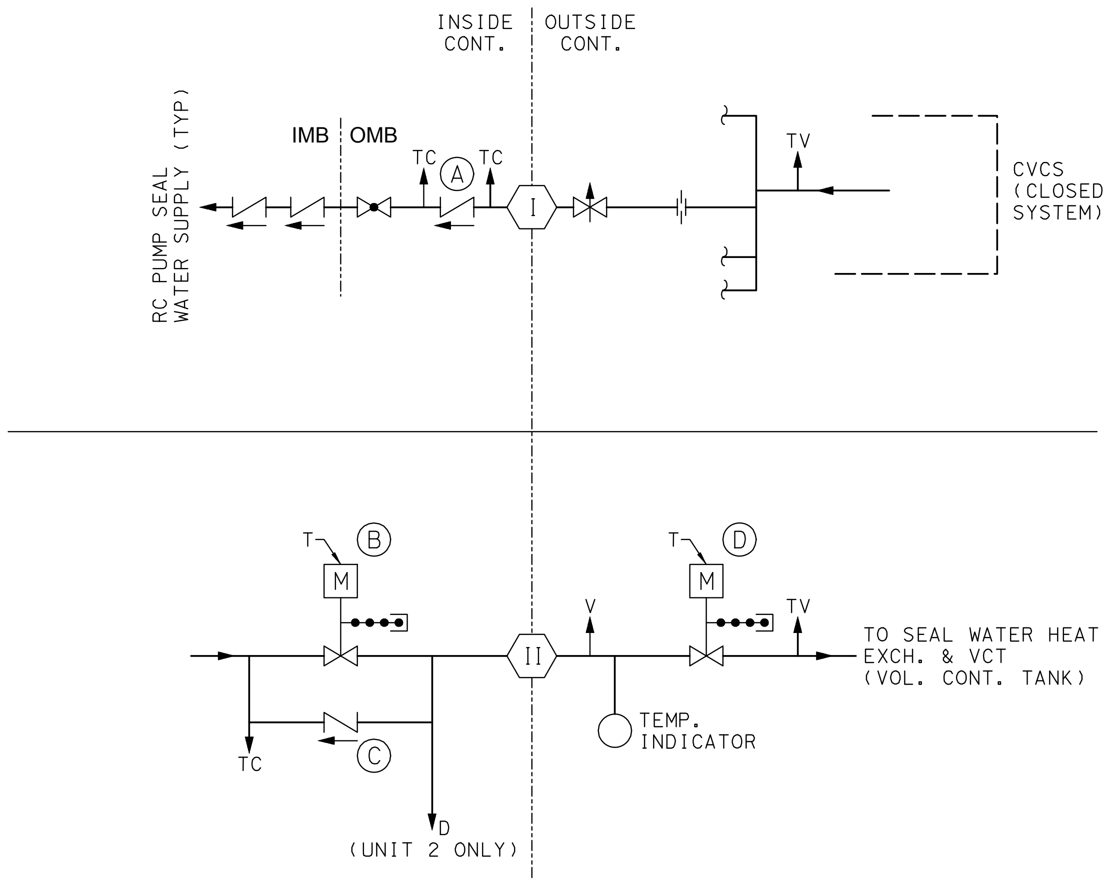
(I) LETDOWN LINE REGEN. HEAT EXCHR. TO LETDOWN HEAT EXCHR. (35)

(II) REGEN. HEAT EXCHR. CHARGING/AUX. SPRAY (36)

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-19
PENETRATION DIAGRAM
(SHEET 9 OF 25)

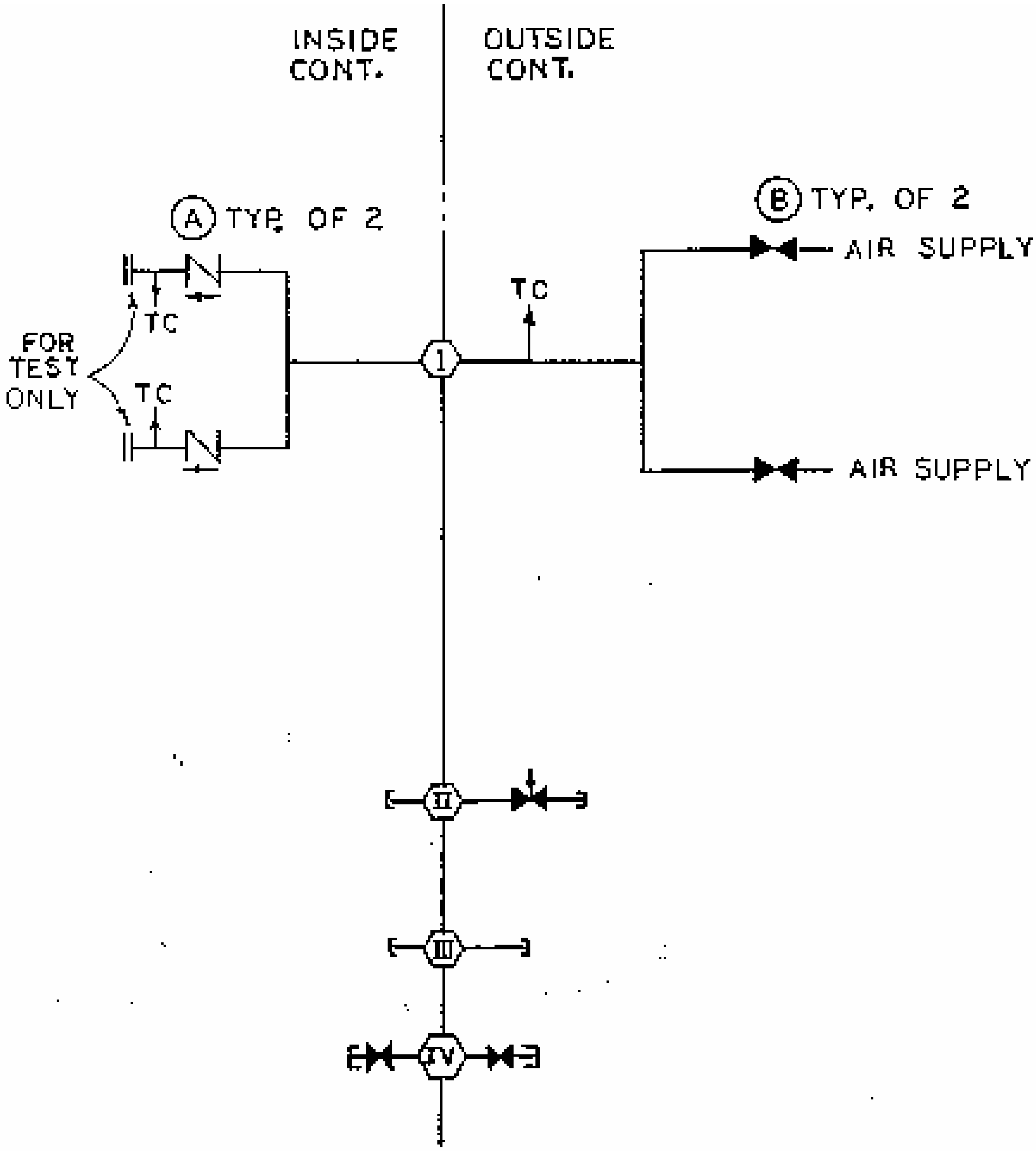


(I) SEAL WATER SUPPLY (41,42,43,44)
(II) SEAL WATER RETURN AND LETDOWN (45)

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-19
PENETRATION DIAGRAM
(SHEET 10 OF 25)



(I) H_2 PURGE SUPPLY (83)

(II) SPARE INSTRUMENT TEST LINE (80-2 LINES) UNIT 1 ONLY

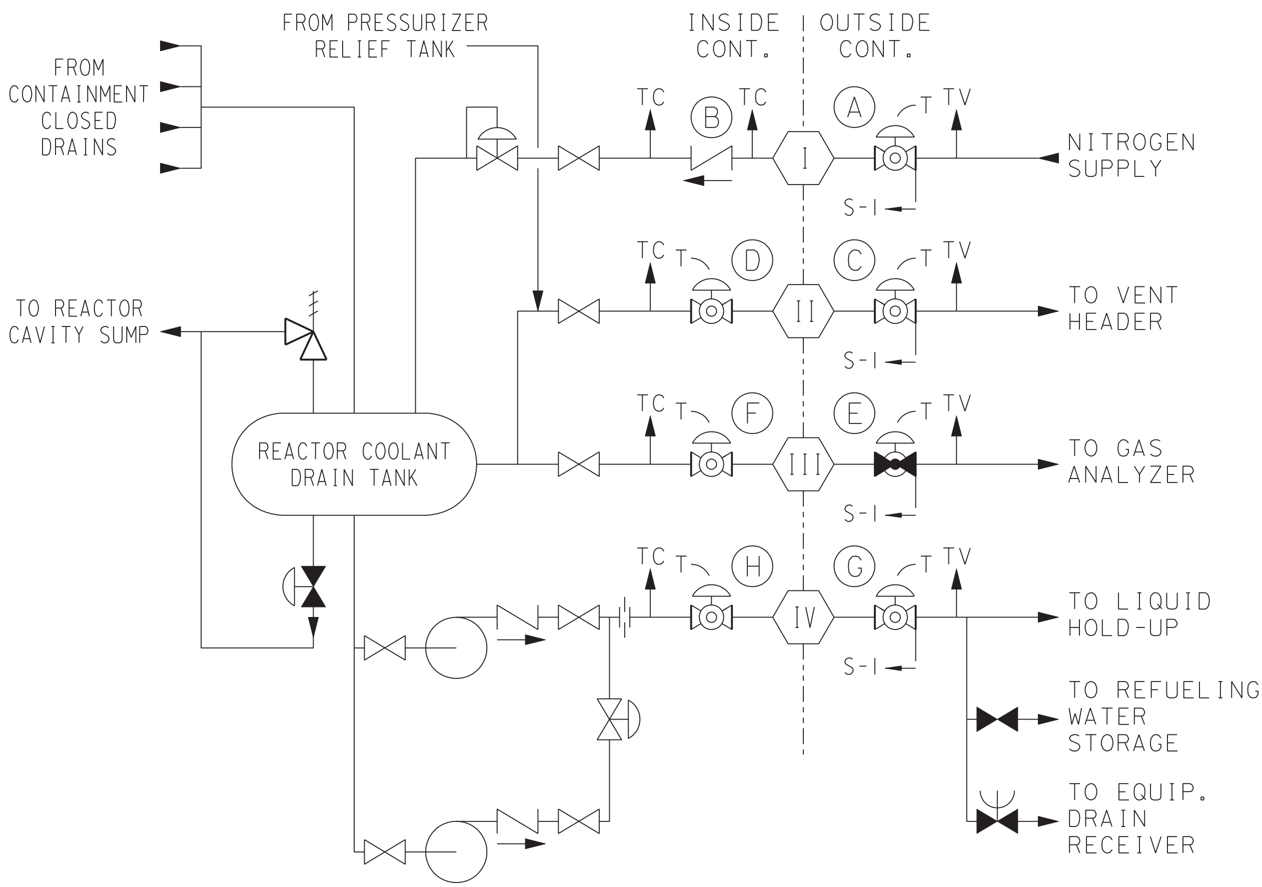
(III) SPARE INSTRUMENT TEST LINE (80,82,76,78) UNIT 1 ,LINE (80 ,82) UNIT 2

(IV) SPARE INSTRUMENT TEST LINE (80-2 LINES) UNIT 2 ONLY

FSAR UPDATE

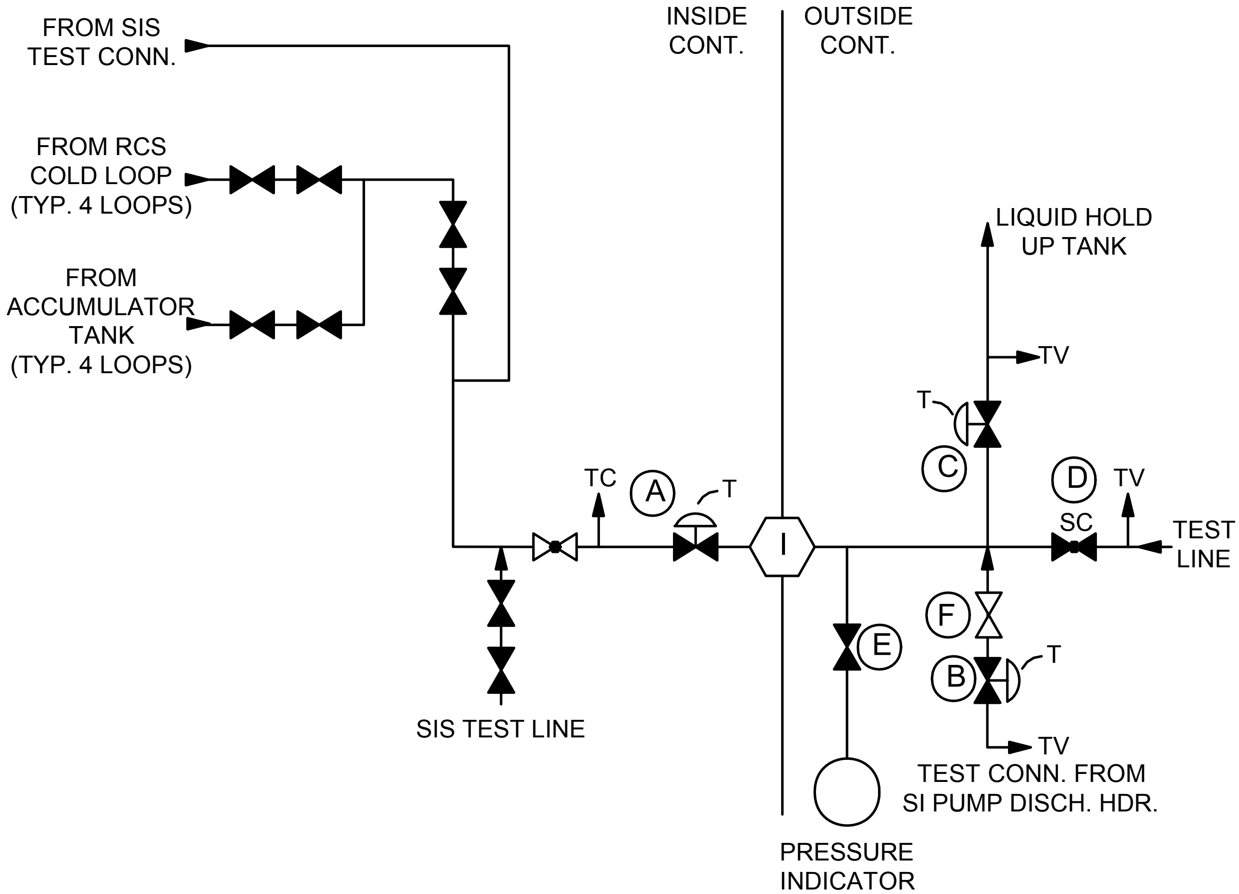
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-19
PENETRATION DIAGRAM
(SHEET 11 OF 25)



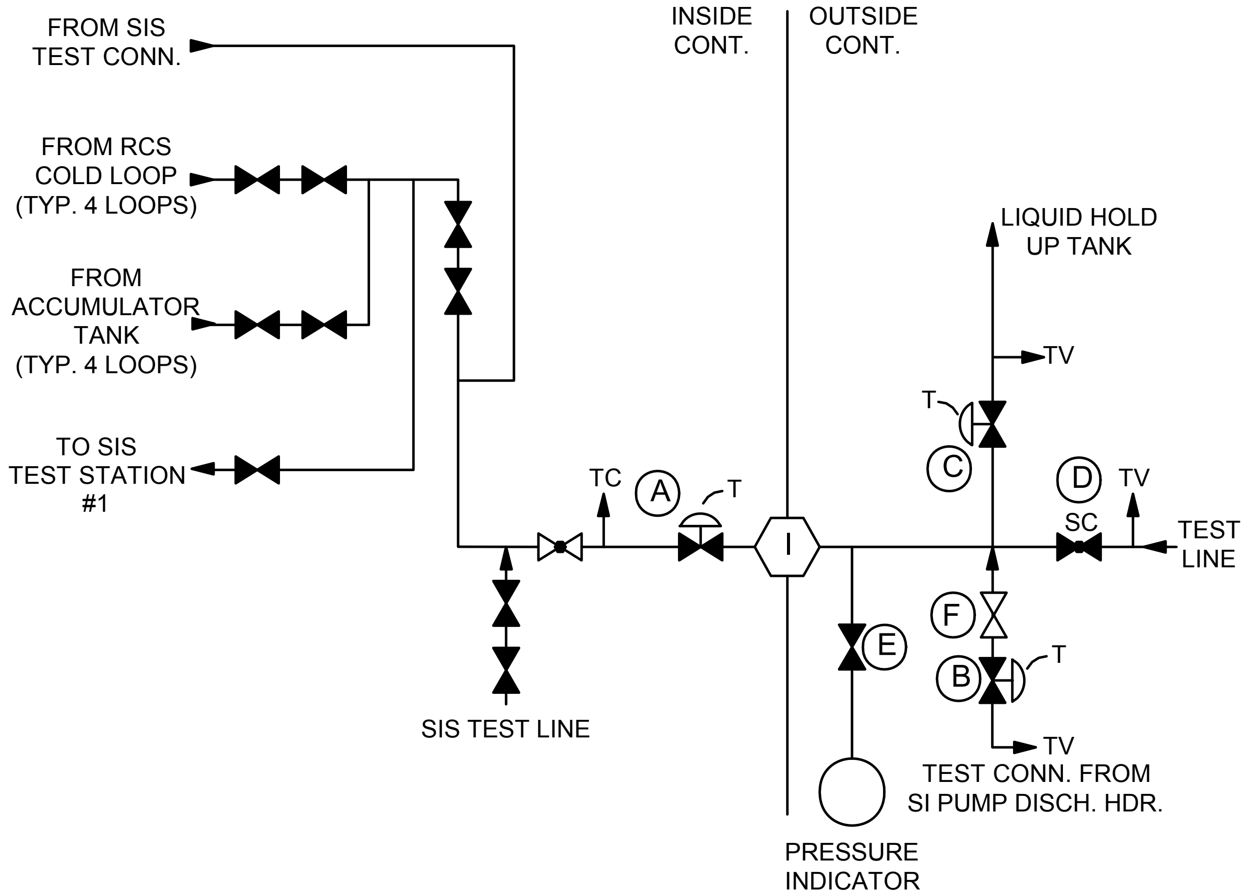
(I) REACTOR COOLANT DRAIN TANK N_2 SUPPLY (52D)
(II) REACTOR COOLANT DRAIN TANK VENT HEADER (51C)
(III) REACTOR COOLANT DRAIN TANK GAS ANALYZER (51D)
(IV) REACTOR COOLANT DRAIN TANK DISCHARGE (50)

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 12 OF 25)



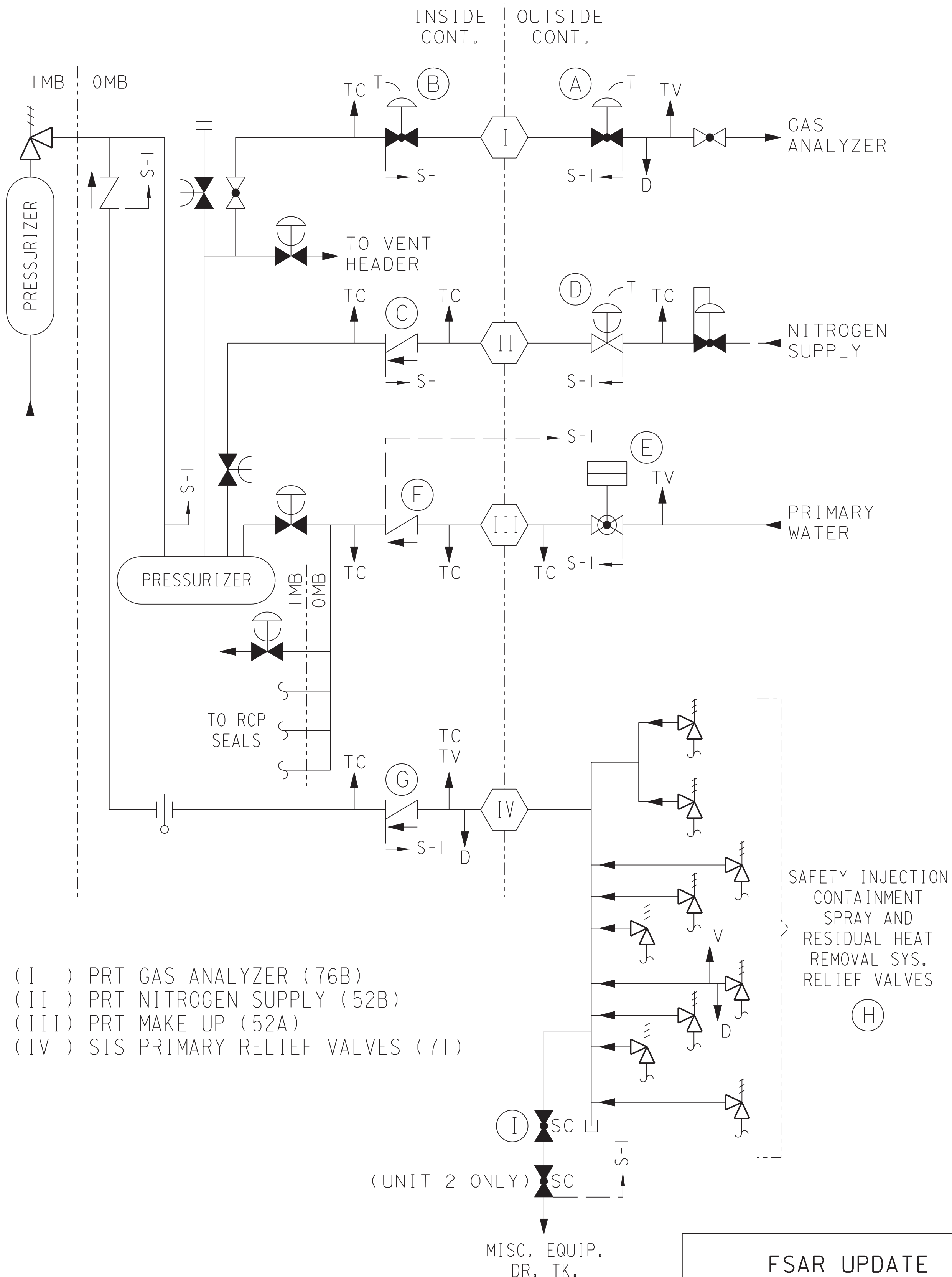
(I) TEST LINE FROM SAFETY INJECTION SYSTEM (51B)

FSAR UPDATE
UNIT 1 **DIABLO CANYON SITE**
FIGURE 6.2-19 **PENETRATION DIAGRAM** **(SHEET 13 OF 25)**



(I) TEST LINE FROM SAFETY INJECTION SYSTEM (51B)

FSAR UPDATE
UNIT 2 **DIABLO CANYON SITE**
FIGURE 6.2-19 **PENETRATION DIAGRAM** **(SHEET 13A OF 25)**

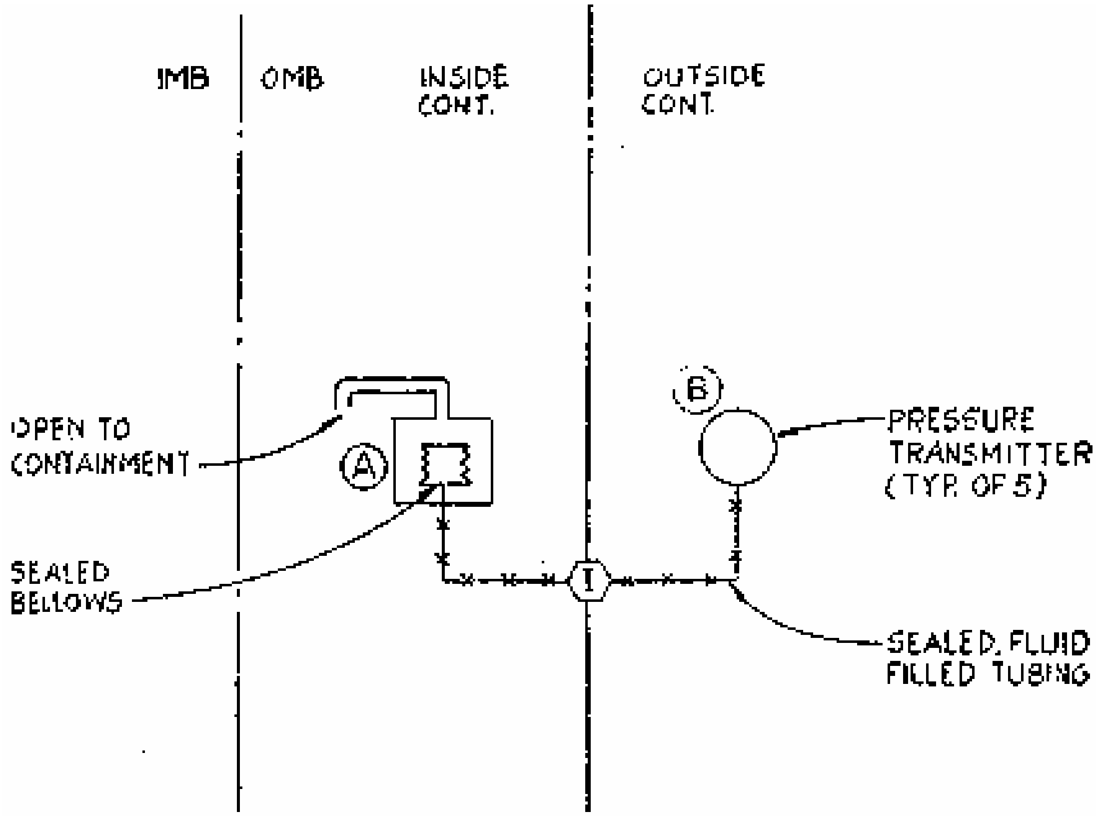


(I) PRT GAS ANALYZER (76B)
(II) PRT NITROGEN SUPPLY (52B)
(III) PRT MAKE UP (52A)
(IV) SIS PRIMARY RELIEF VALVES (71)

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-19
PENETRATION DIAGRAM
(SHEET 14 OF 25)



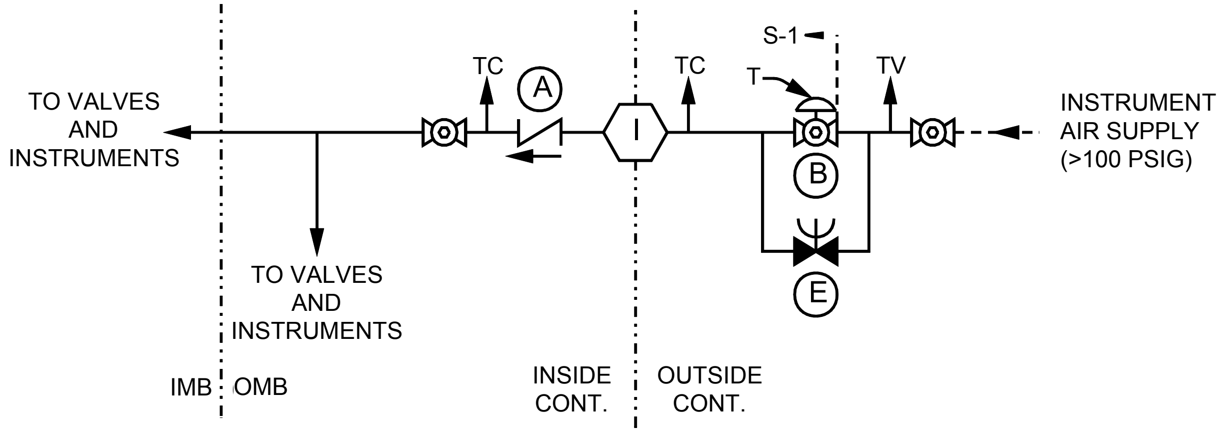
SYSTEM IS DESIGN CLASS I

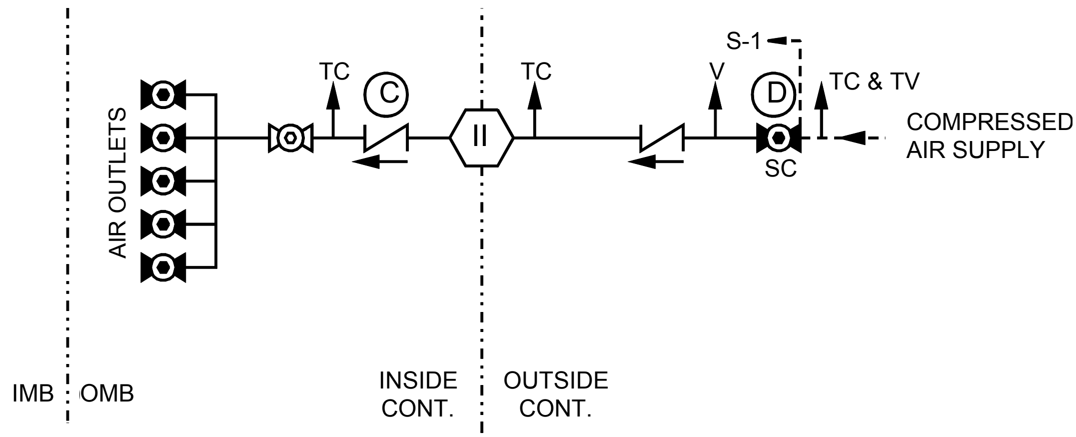
(I) CONTAINMENT PRESSURE (52&59-2 LINES; 76, 78&80-1 LINE)

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-19
PENETRATION DIAGRAM
(SHEET 15 OF 25)



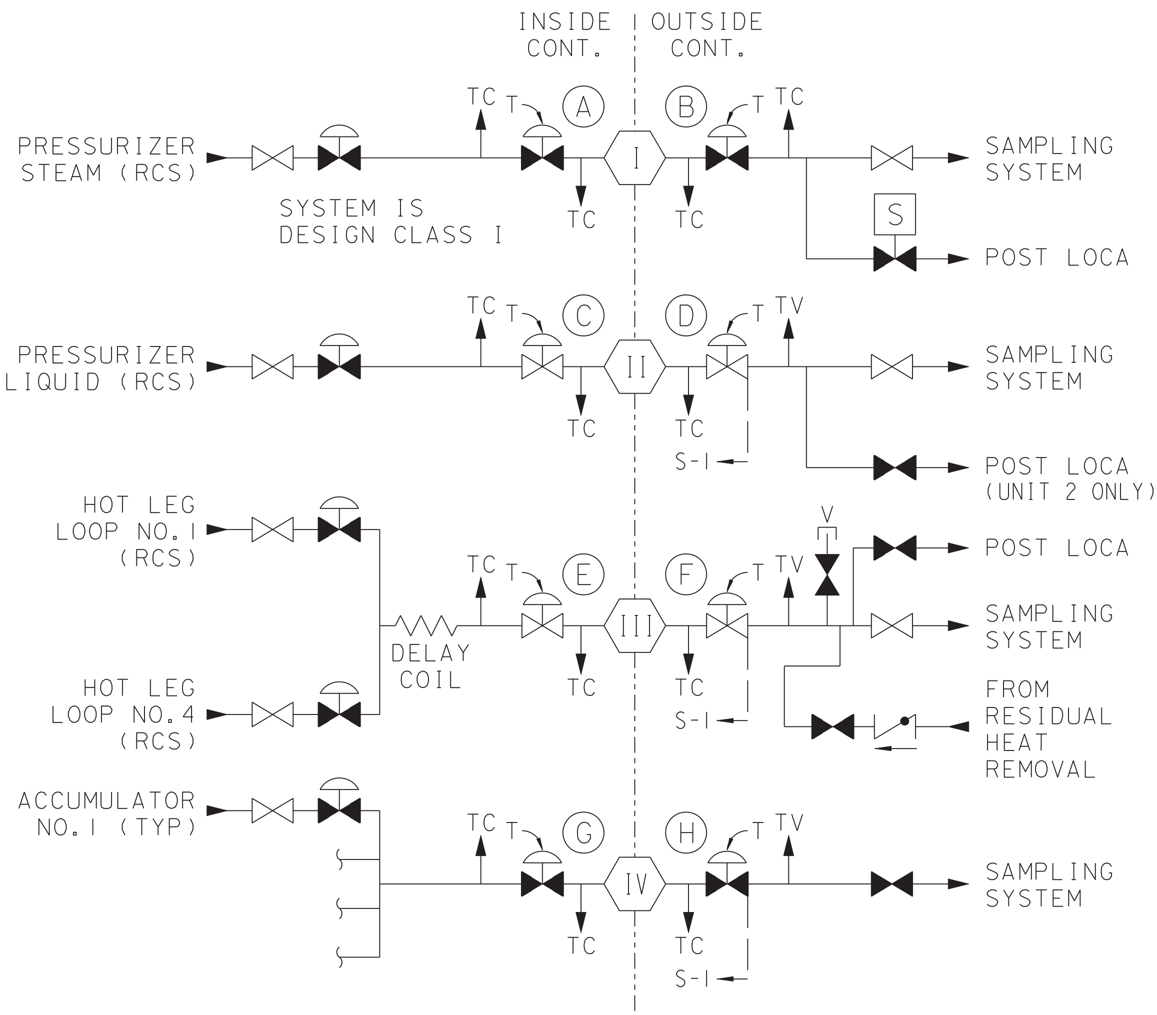


(I) INSTRUMENT AIR HEADER (54)
(II) SERVICE AIR HEADER (56)

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-19
PENETRATION DIAGRAM
(SHEET 16 OF 25)

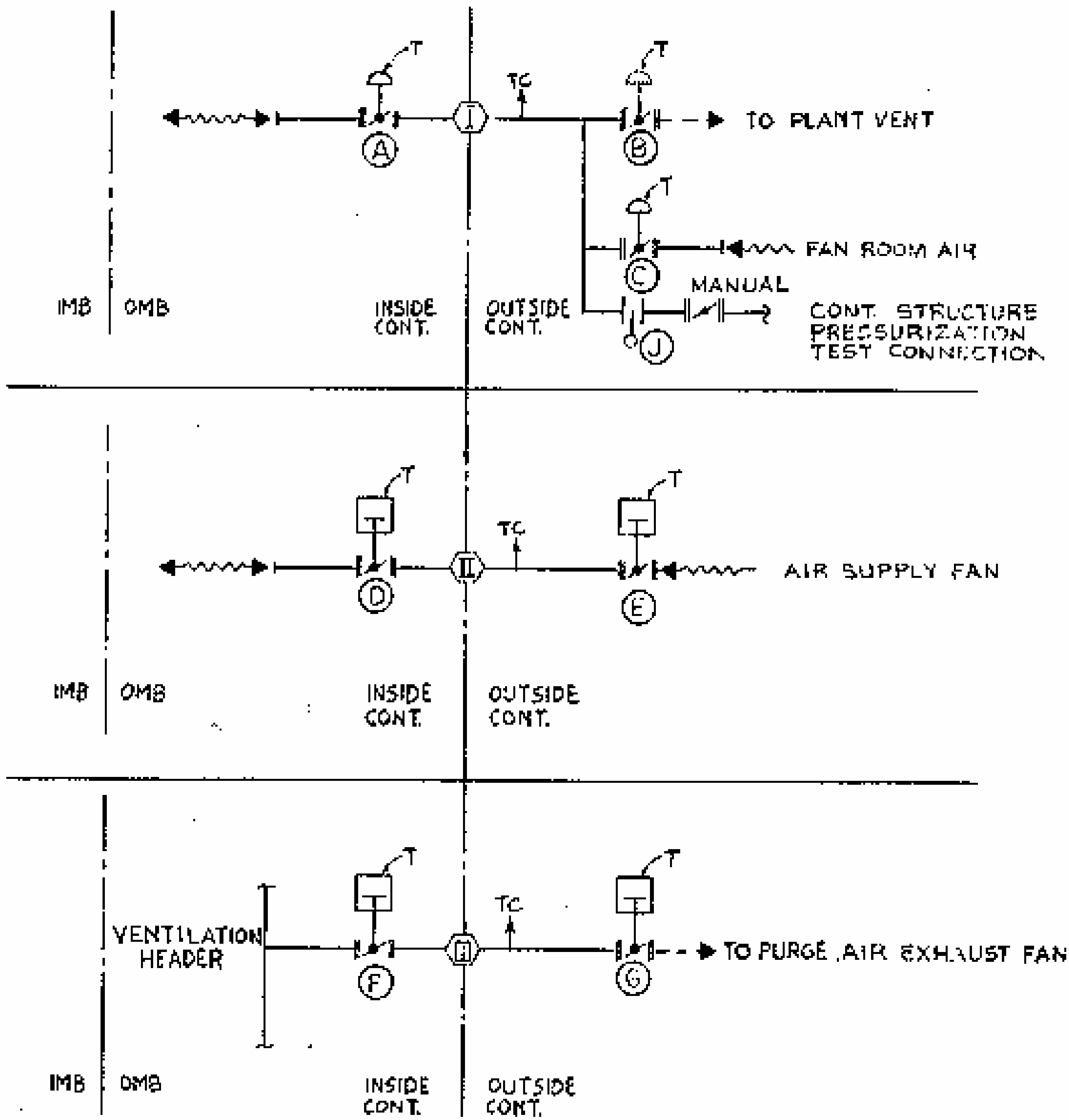


(I) PRESSURIZER STEAM SAMPLE (76A)
(II) PRESSURIZER LIQUID SAMPLE (59A)
(III) HOT LEG SAMPLE (59B)
(IV) ACCUMULATOR SAMPLE (59C)

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-19
PENETRATION DIAGRAM
(SHEET 17 OF 25)



ALL SYSTEMS ARE DESIGN CLASS I

(I) CONTAINMENT PRESSURE AND VACUUM RELIEF (63)

(II) CONTAINMENT PURGE SUPPLY DUCT (61)

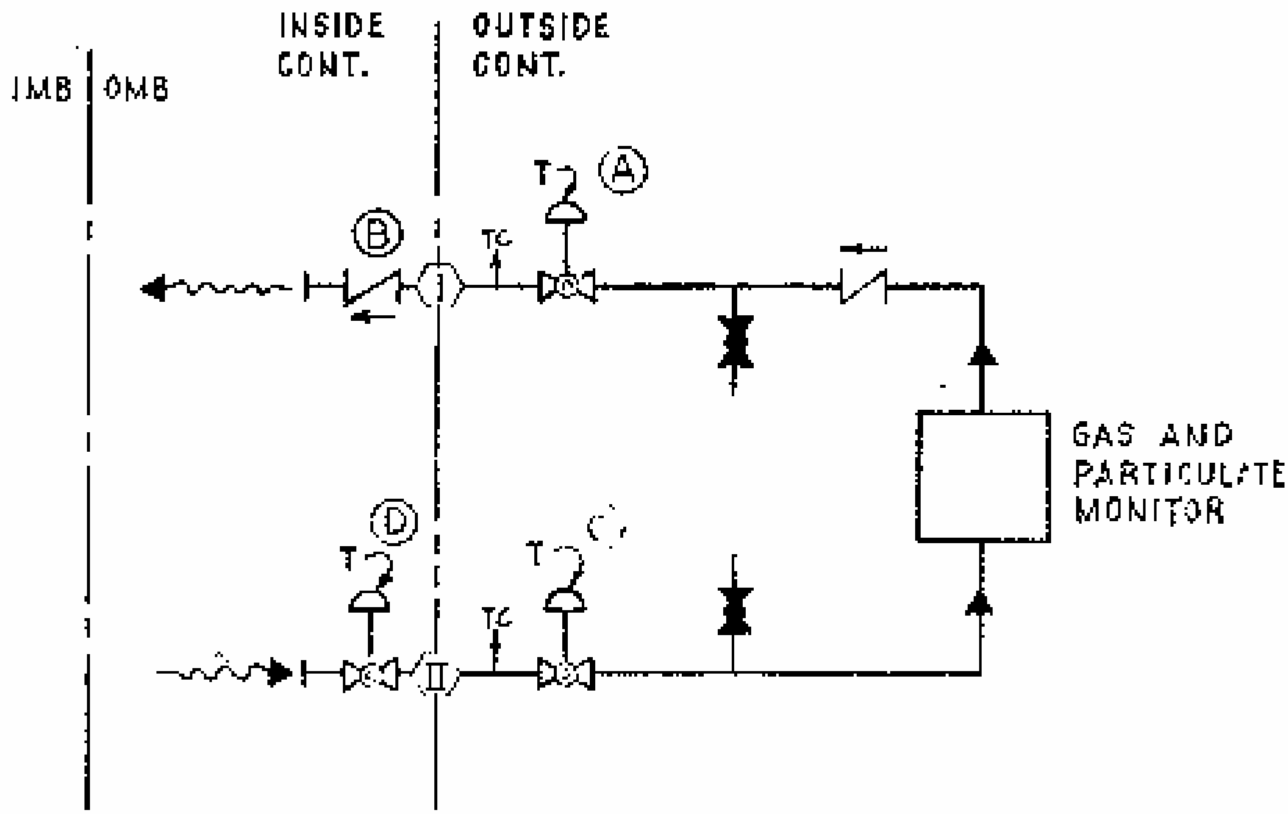
(III) CONTAINMENT PURGE EXHAUST DUCT (62)

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-19
PENETRATION DIAGRAM
(SHEET 18 OF 25)

Revision 11 November 1996

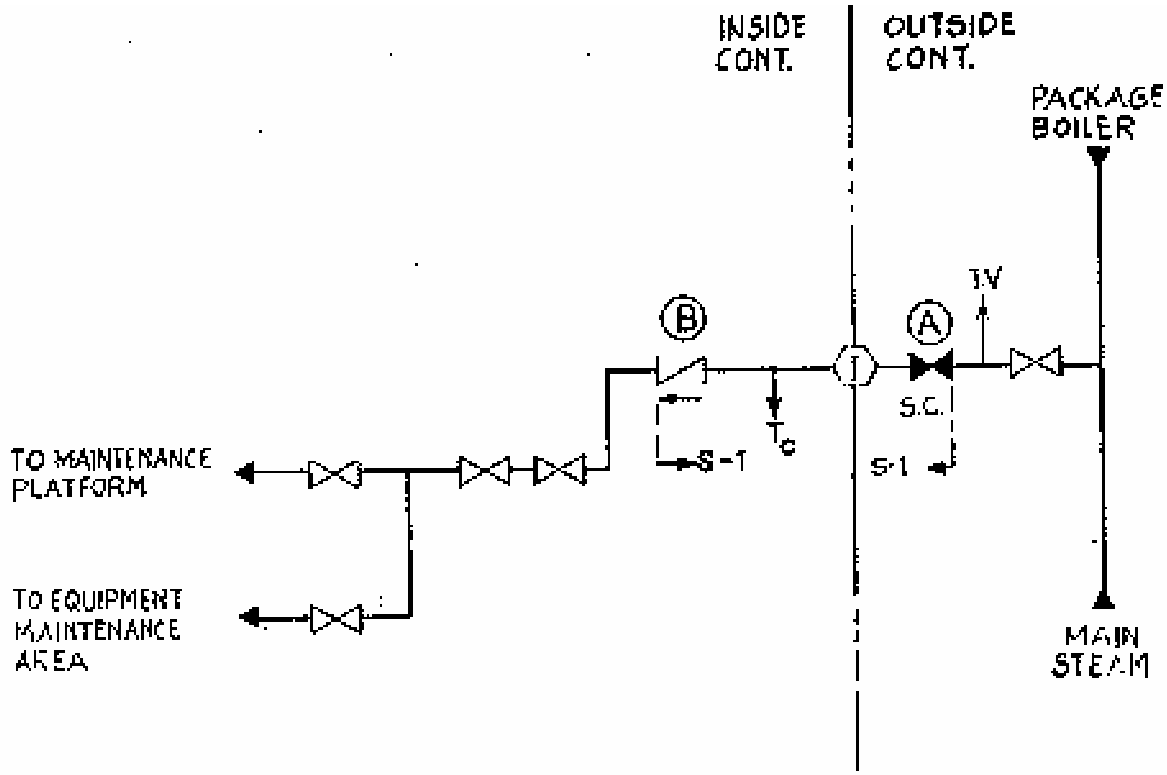


VALVES AND PIPING ARE
DESIGN CLASS I

(I) CONTAINMENT AIR SAMPLE (69)
(II) CONTAINMENT AIR SAMPLE (68)

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 19 OF 25)

Revision 11 November 1996

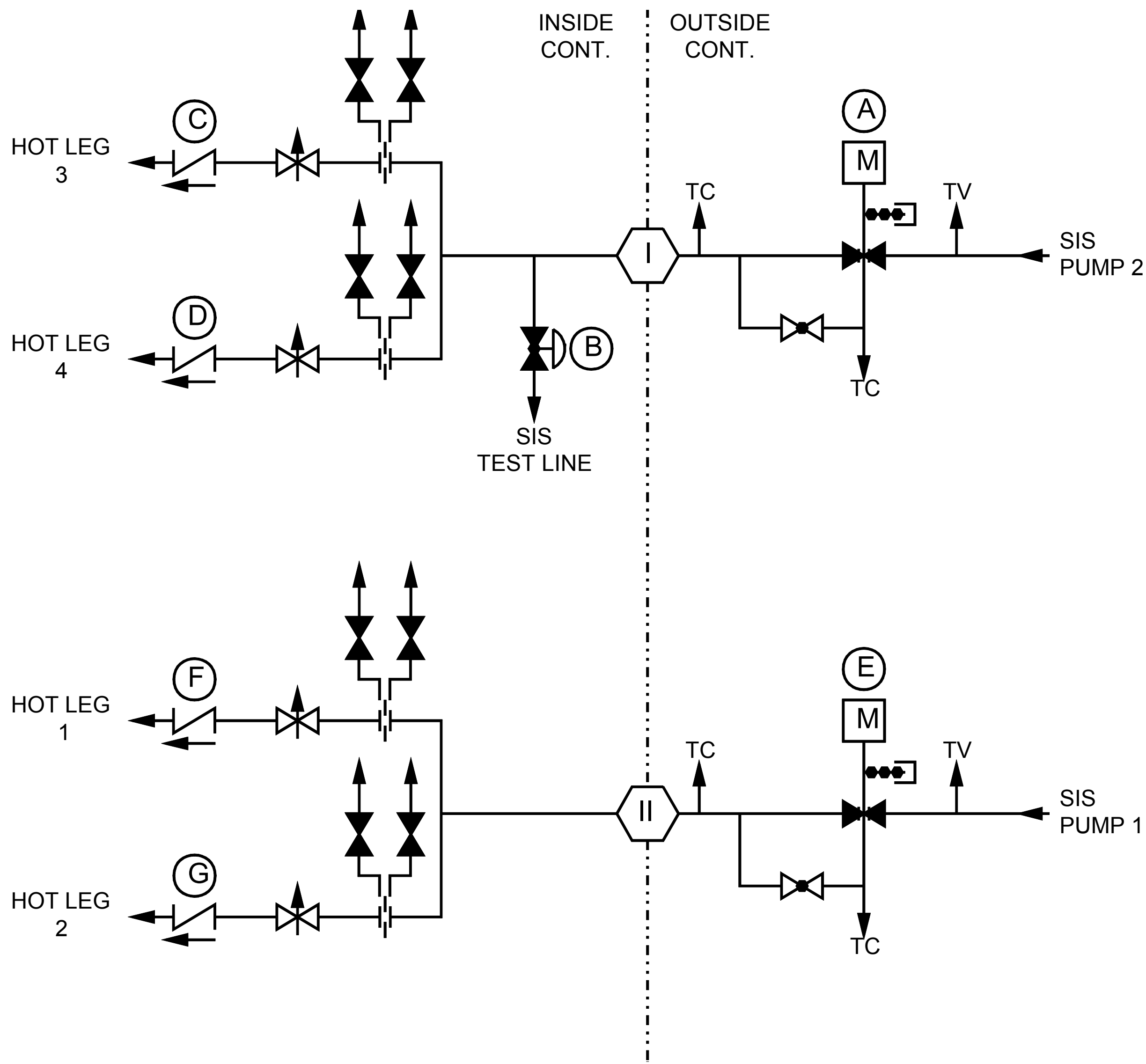


(J) AUXILIARY STEAM SUPPLY (70)

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-19
PENETRATION DIAGRAM
(SHEET 20 OF 25)



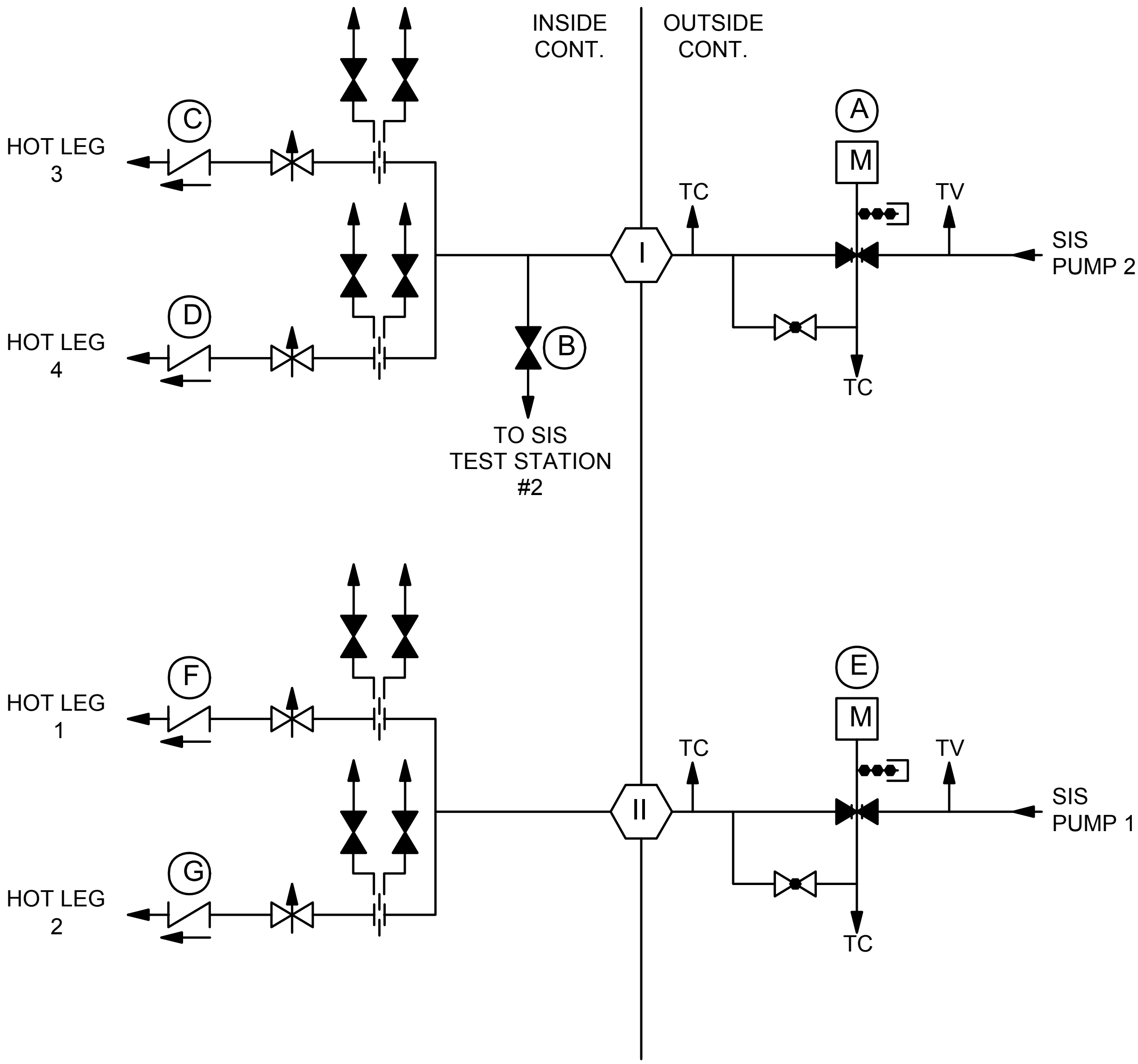
(I) SIS PUMP 2 DISCHARGE (75)
(II) SIS PUMP 1 DISCHARGE (77)

FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

FIGURE 6.2-19
PENETRATION DIAGRAM
(SHEET 21 OF 25)

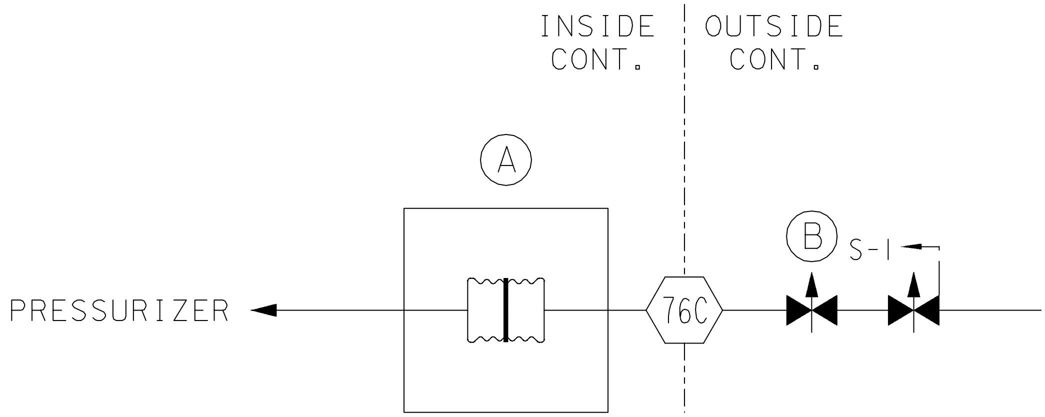
Revision 19 May 2010



(I) SIS PUMP 2 DISCHARGE (75)
(II) SIS PUMP 1 DISCHARGE (77)

FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 21A OF 25)

Revision 19 May 2010



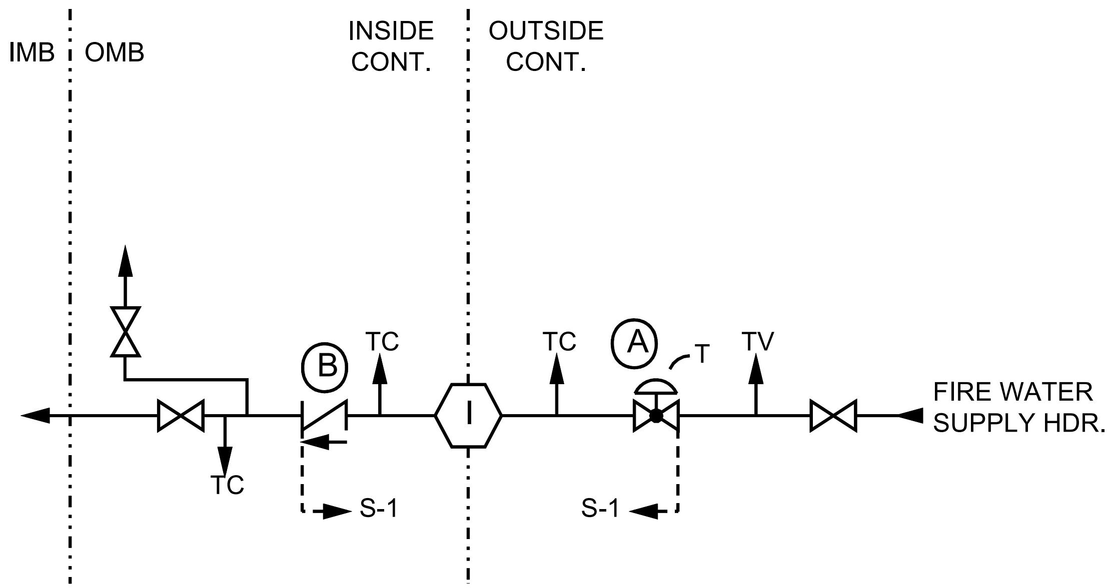
NOTES:

1. FOR UNIT 1, THE TUBING BETWEEN VALVES OUTSIDE CONTAINMENT IS REMOVED AND A CAP INSTALLED ON THE INBOARD VALVE.
2. FOR UNIT 2, THE TUBING OUTSIDE CONTAINMENT HAS BEEN REMOVED AND A CAP INSTALLED AT THE PENETRATION.

FSAR UPDATE

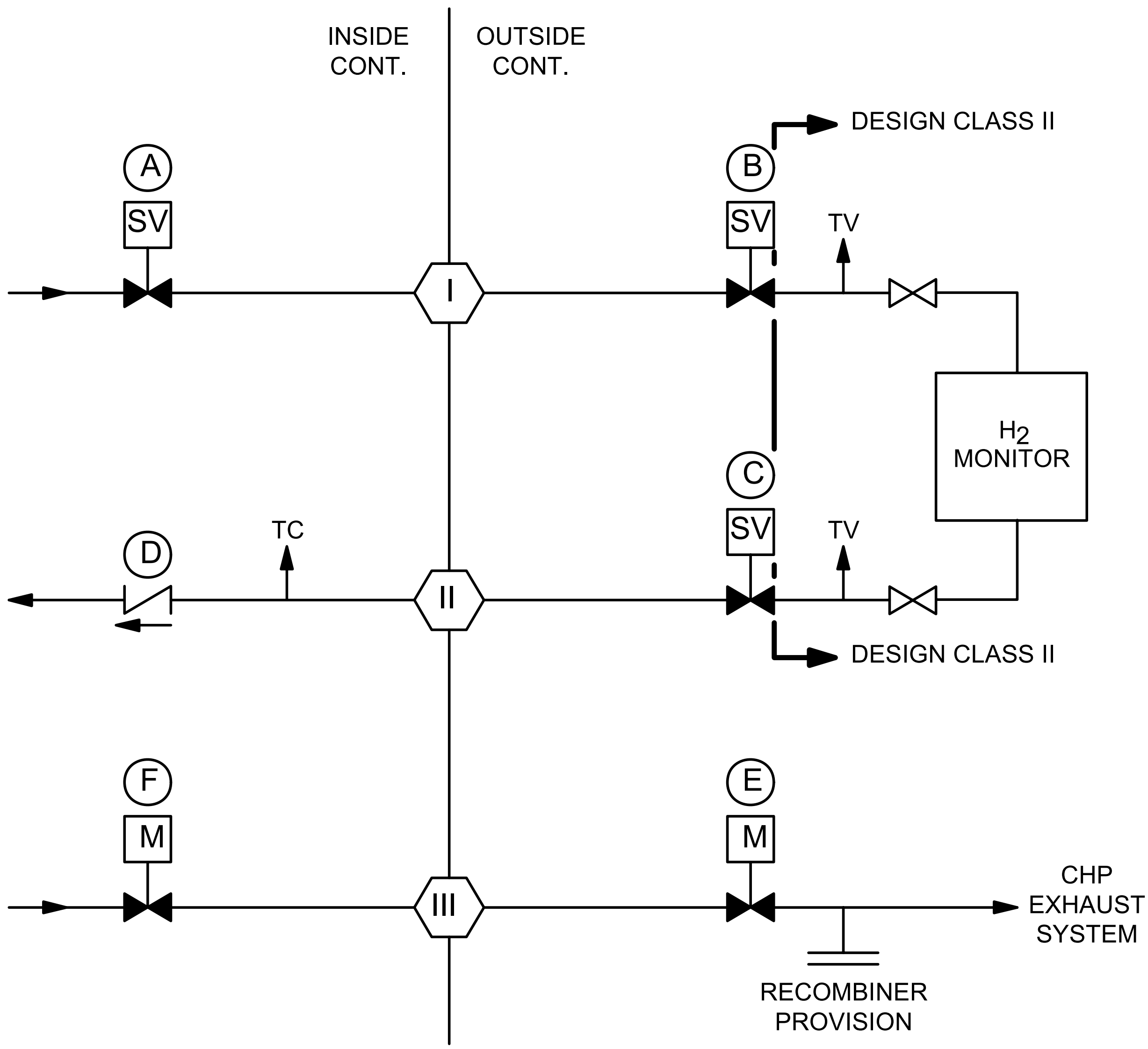
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-19
PENETRATION DIAGRAM
(SHEET 22 OF 25)



(I) FIRE WATER SUPPLY (79)

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 23 OF 25)



ALL SYSTEMS ARE DESIGN CLASS I, EXCEPT AS NOTED.

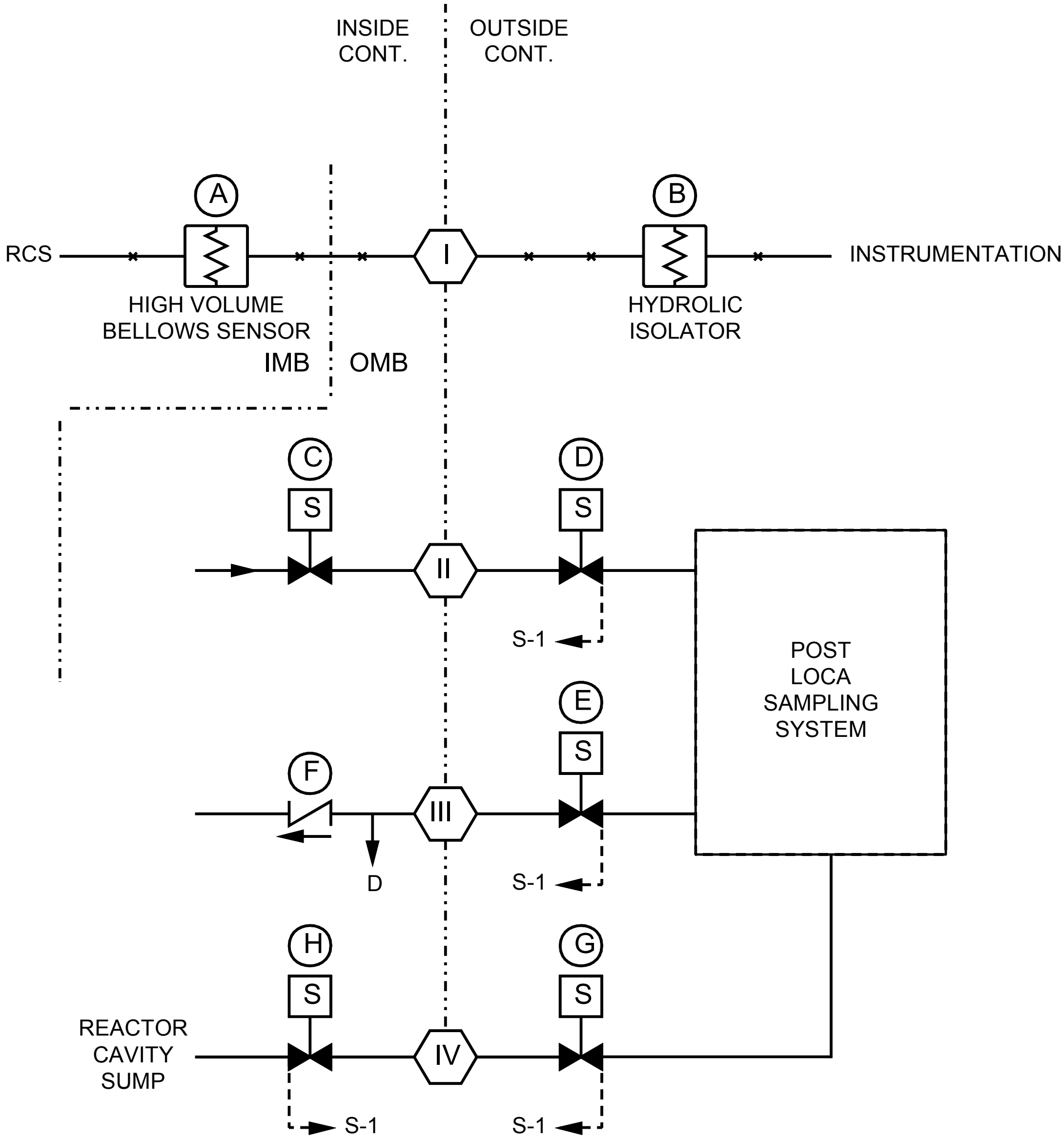
(I) CONTAINMENT H_2 MONITOR SUPPLY (52E, 78A)

(II) CONTAINMENT H_2 MONITOR RETURN (52C, 78B)

(III) CONTAINMENT H_2 EXTERNAL RECOMBINER (57, 81)

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 24 OF 25)

Revision 16 June 2005



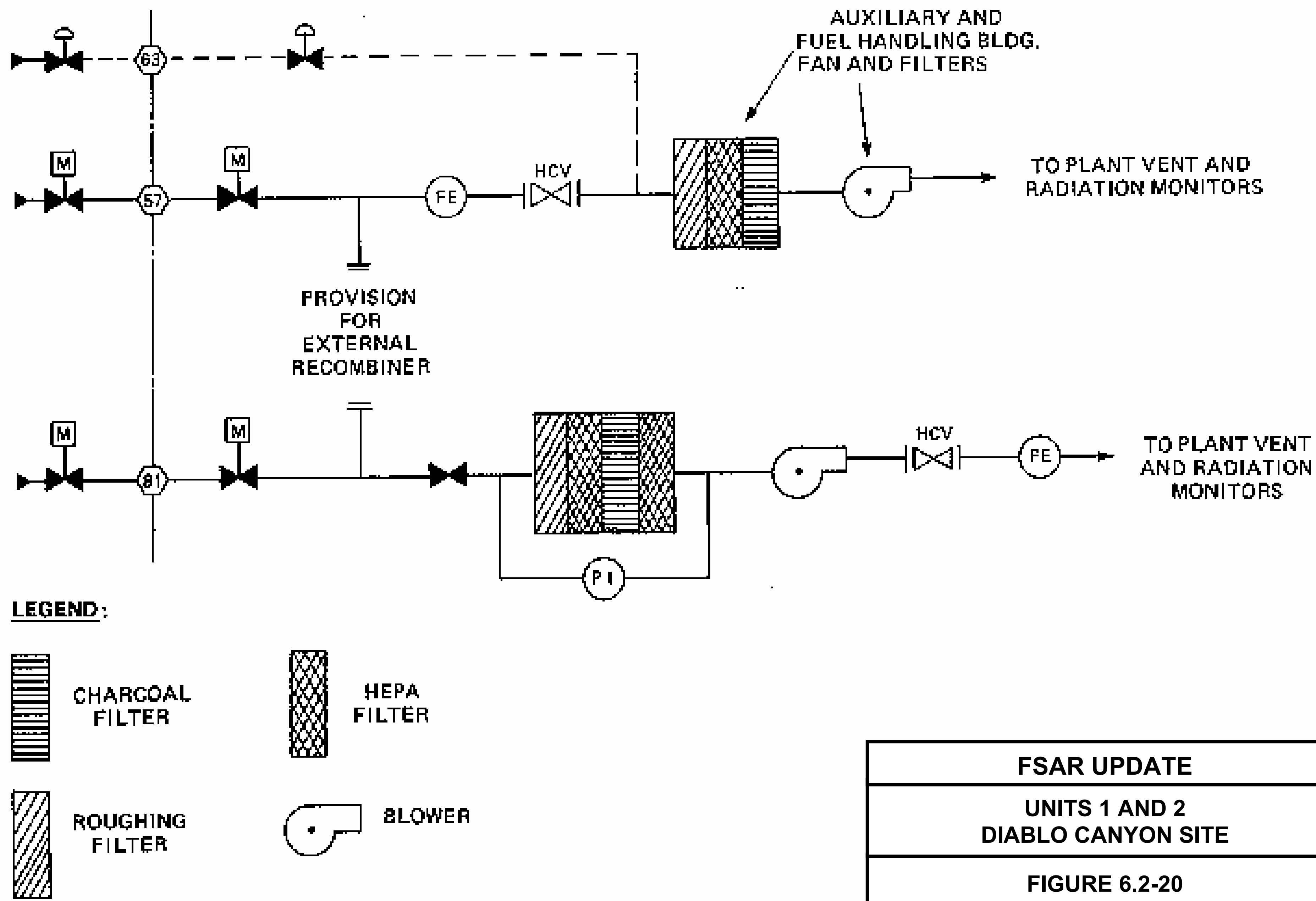
(I) REACTOR VESSEL LEVEL INSTRUMENTATION (59E,59F,59G,80E,80F,80G)

(II) POST-LOCA SAMPLING SYSTEM CONT. AIR SUPPLY (82B)

(III) POST-LOCA SAMPLING SYSTEM CONT. AIR RETURN (82C)

(IV) POST-LOCA SAMPLING SYSTEM REACTOR CAVITY SUMP (82A)

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 25 OF 25)

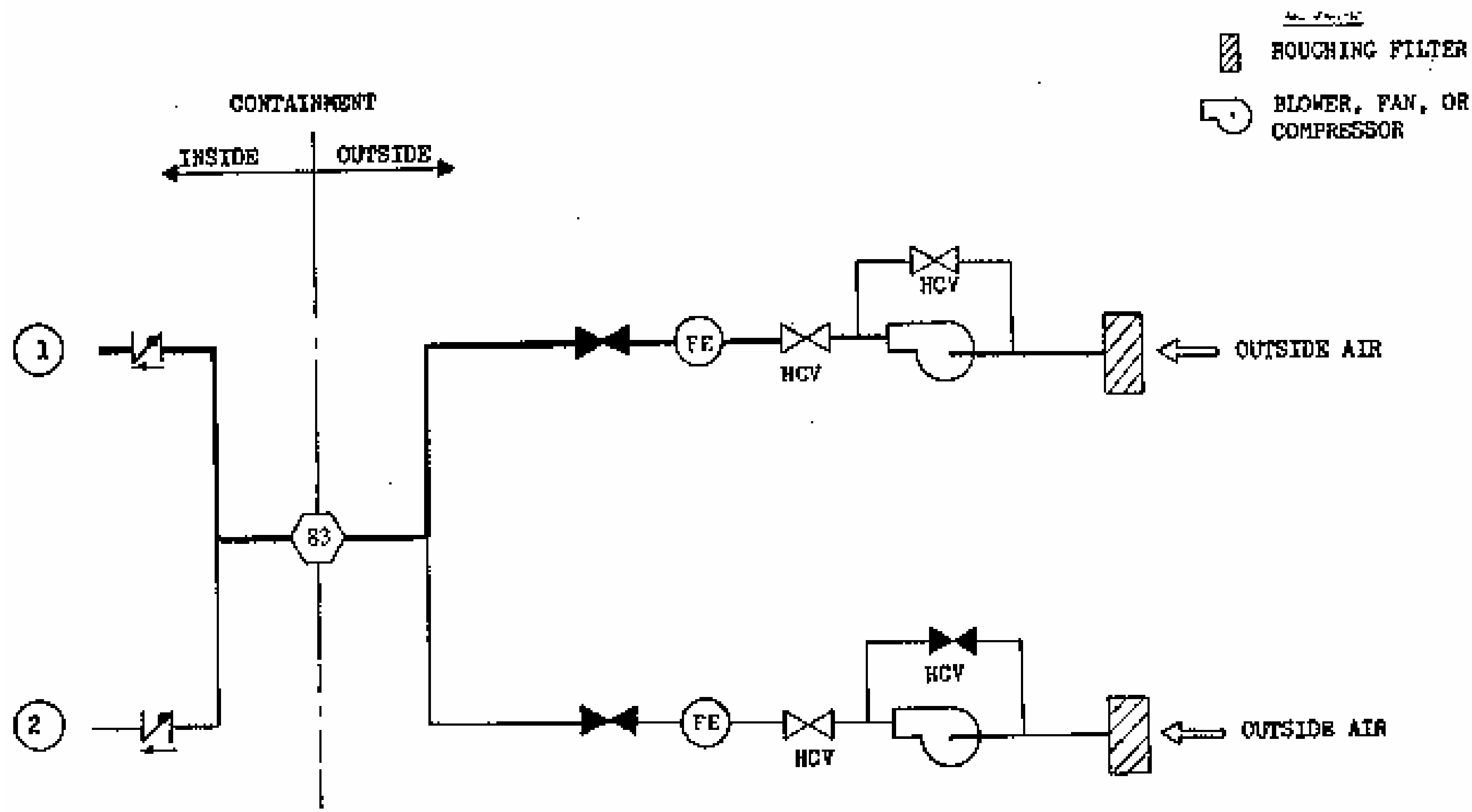


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-20
CONTAINMENT HYDROGEN PURGE SYSTEM
PURGE STREAM

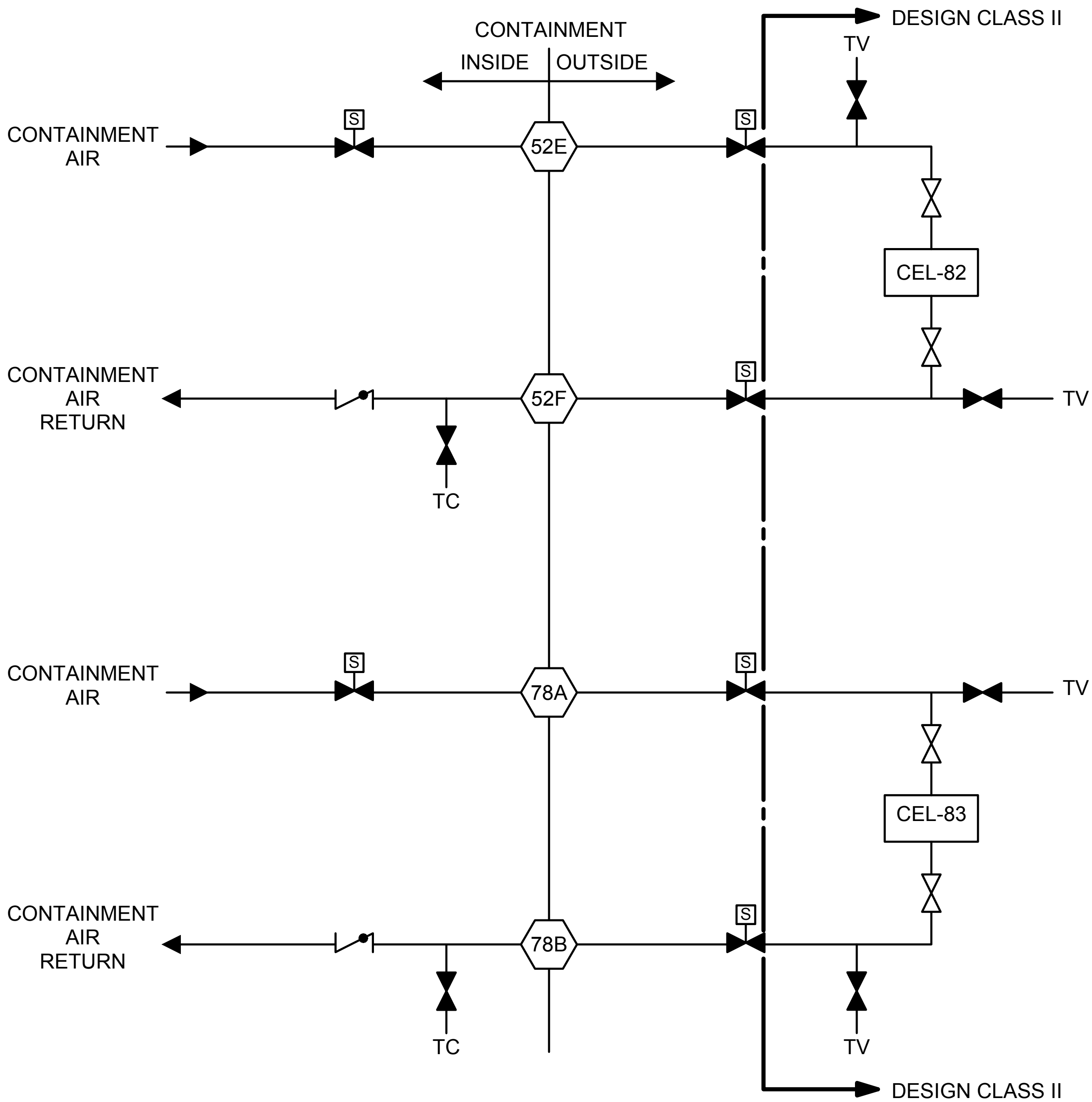
Revision 11 November 1996



NOTE

1. VALVES SHOWN IN POSITION FOR HYDROGEN DILUTION ON LINE 1
2. ALL PIPING, VALVES, FILTERS, BLOWERS, AND FLOW INSTRUMENTS ARE DESIGN CLASS I.

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-21 CONTAINMENT HYDROGEN PURGE SYSTEM SUPPLY STREAM



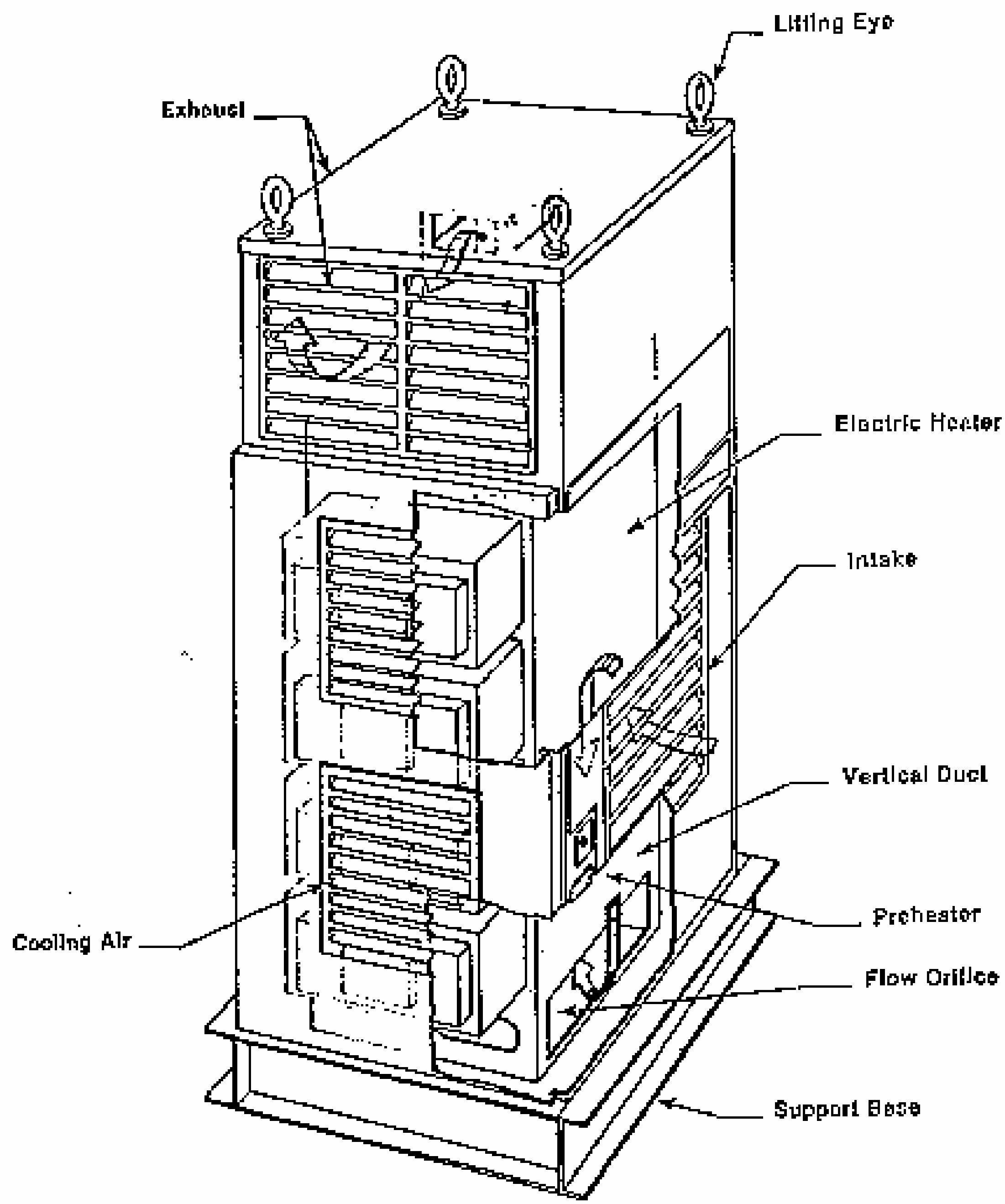
NOTES:

1. VALVES SHOWN FOR NORMAL PLANT OPERATION.
2. ALL PIPING AND VALVES ARE DESIGN CLASS I, EXCEPT AS NOTED.
3. HYDROGEN MONITORS ARE CLASS II.

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-22
CONTAINMENT HYDROGEN PURGE SYSTEM
HYDROGEN ANALYZER STREAM

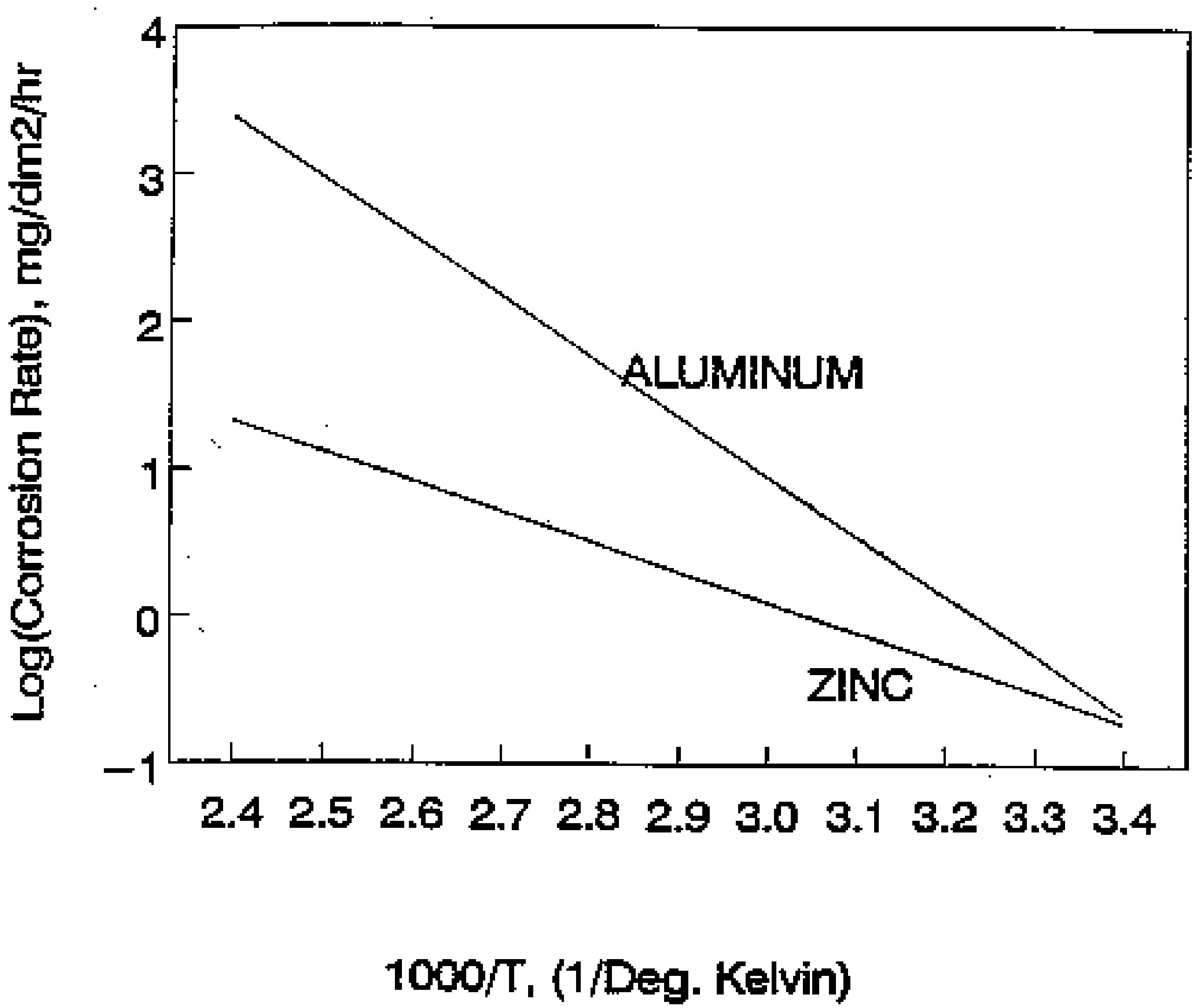


FSAR UPDATE

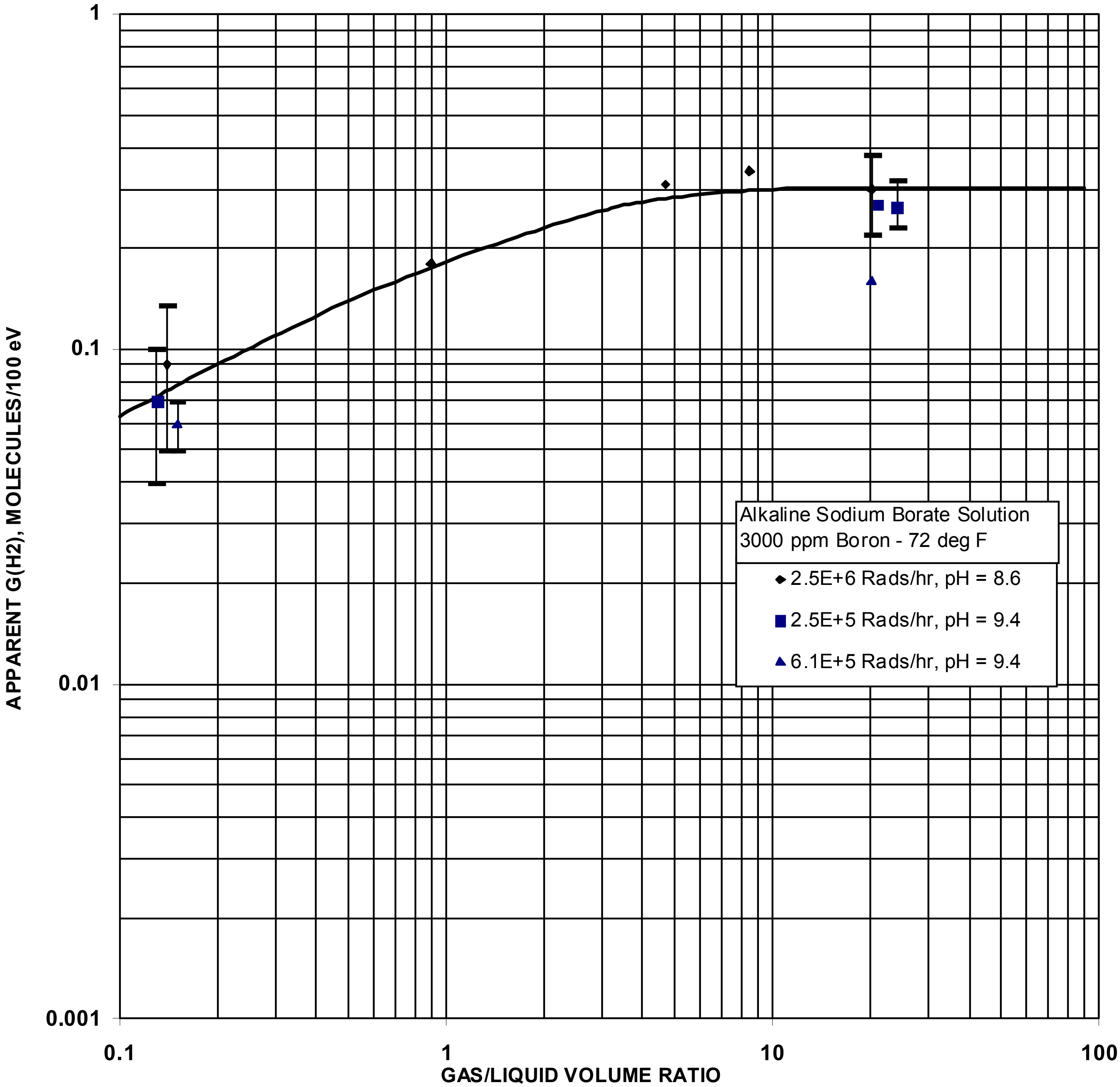
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-23
MODEL B
ELECTRIC HYDROGEN RECOMBINER
CUTAWAY

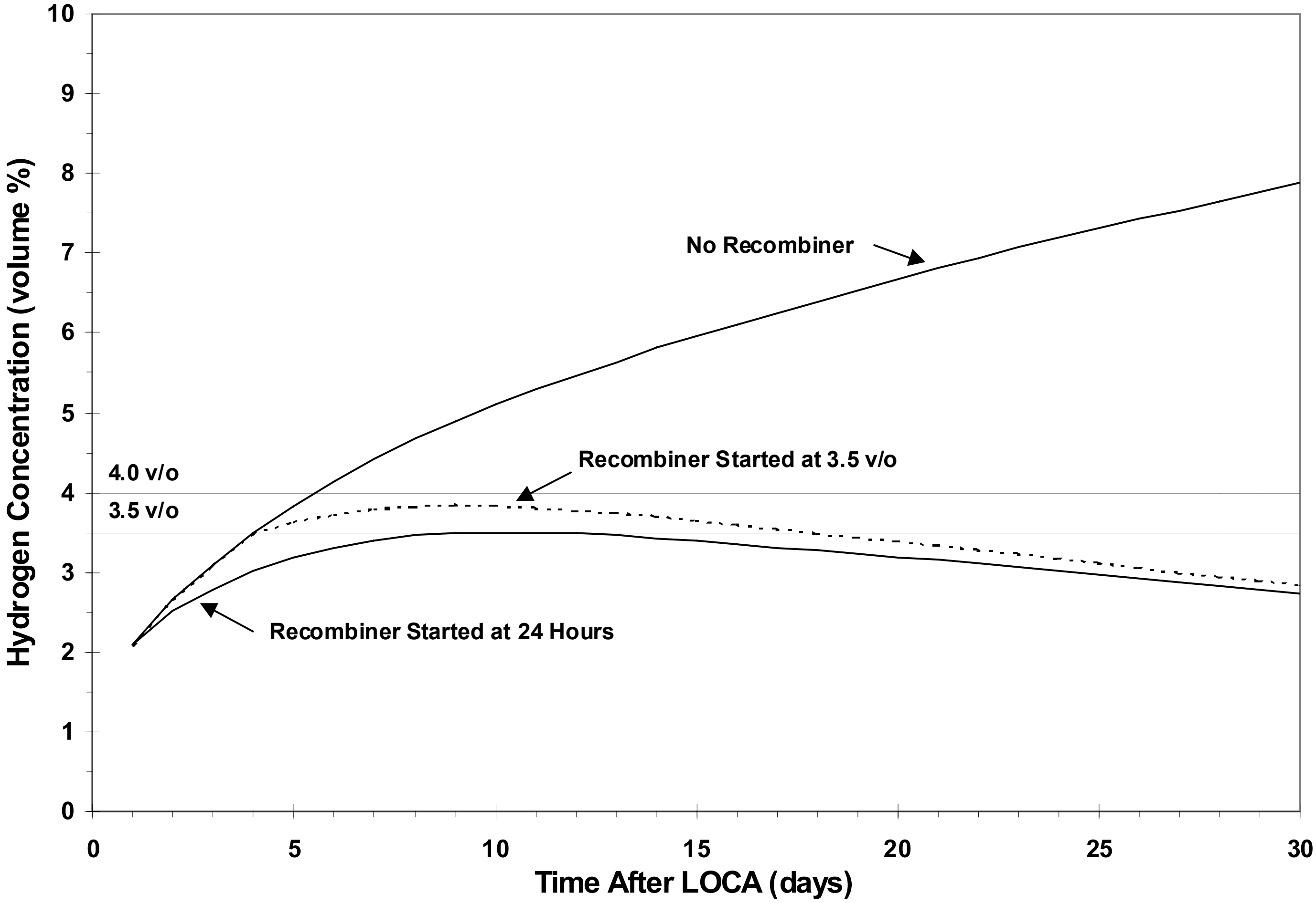
ALUMINUM AND ZINC CORROSION RATE DESIGN CURVES



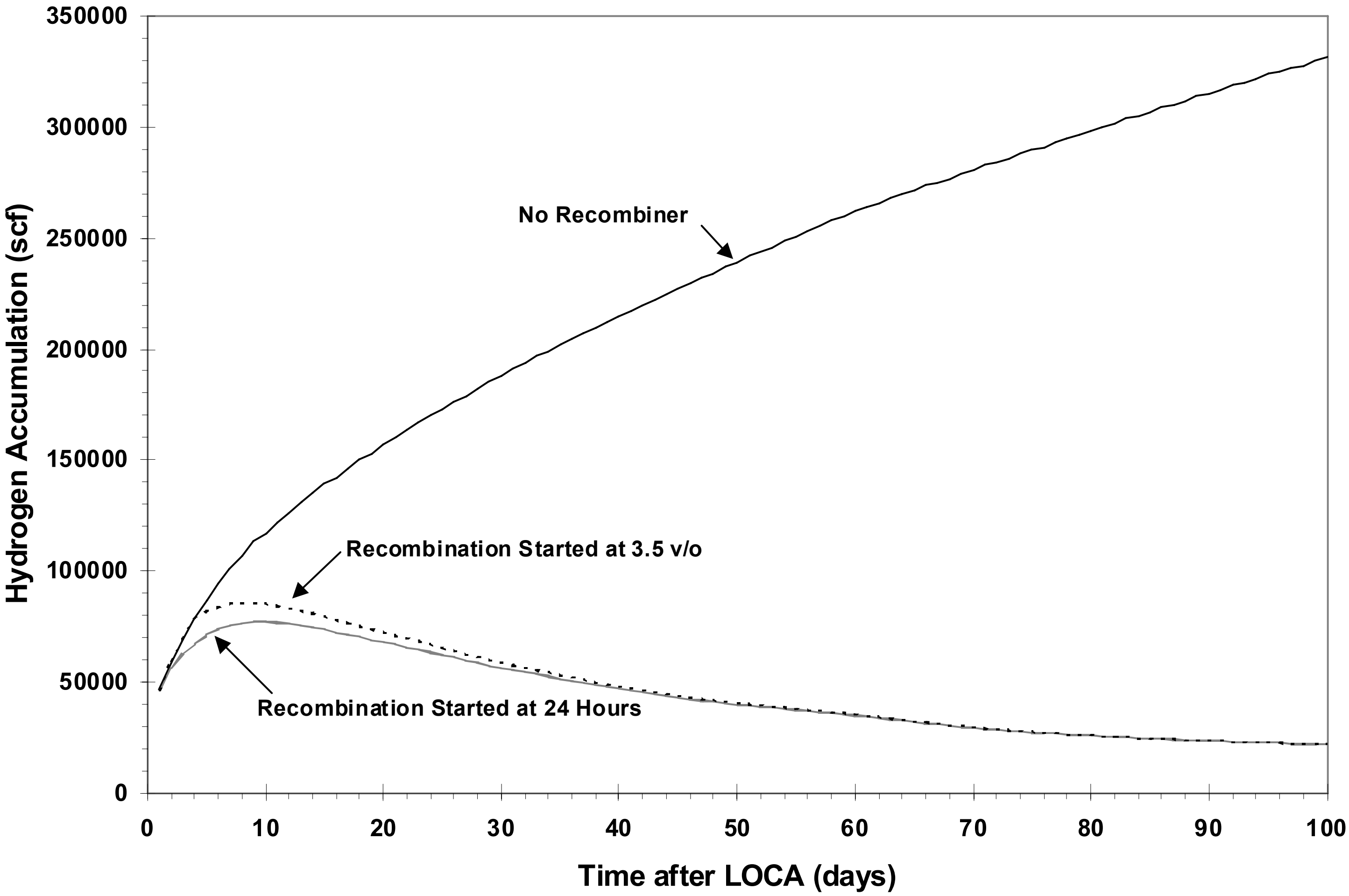
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-24 ALUMINUM AND ZINC CORROSION RATE DESIGN CURVE



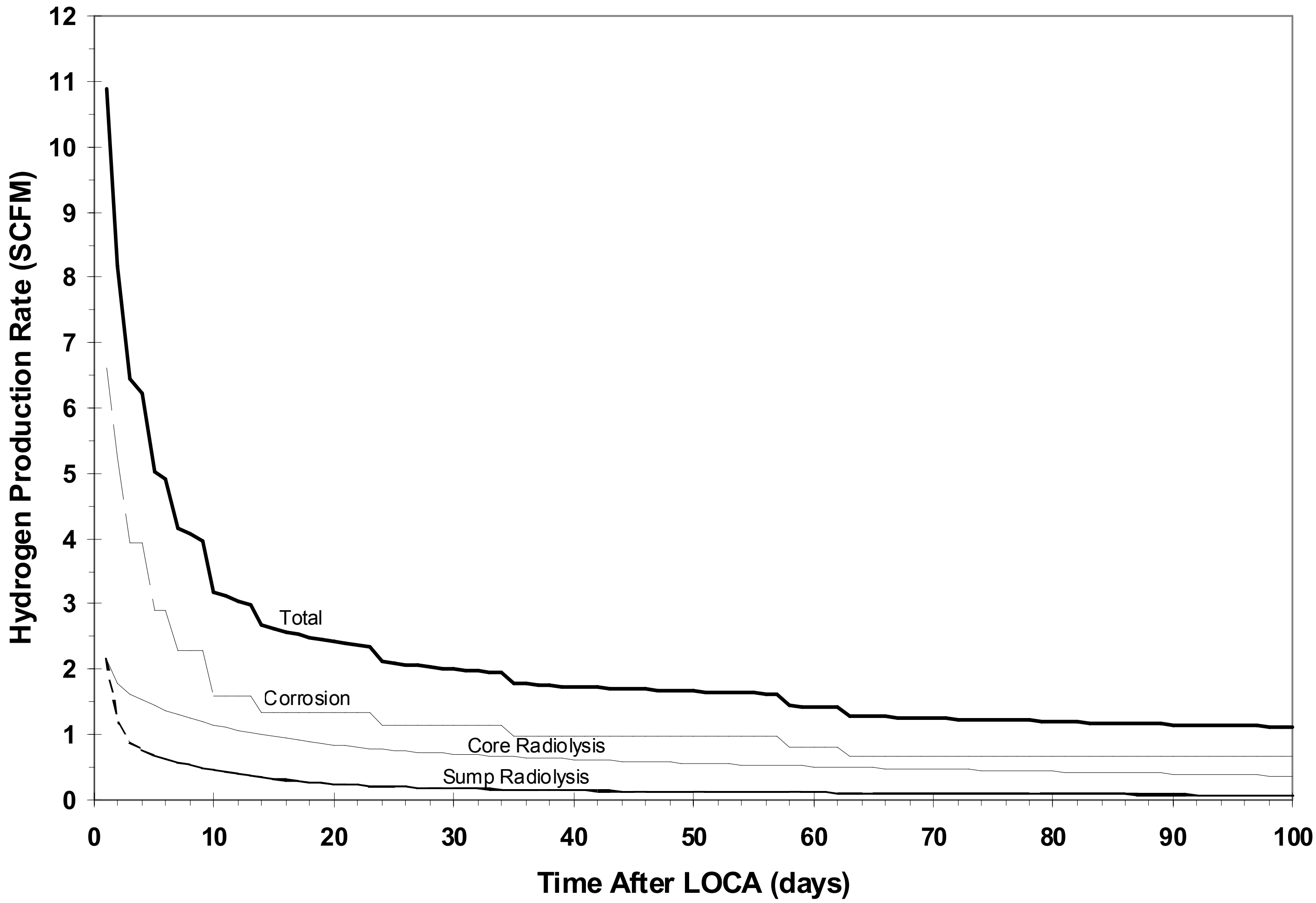
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-25 RESULTS OF WESTINGHOUSE CAPSULE IRRADIATION TESTS



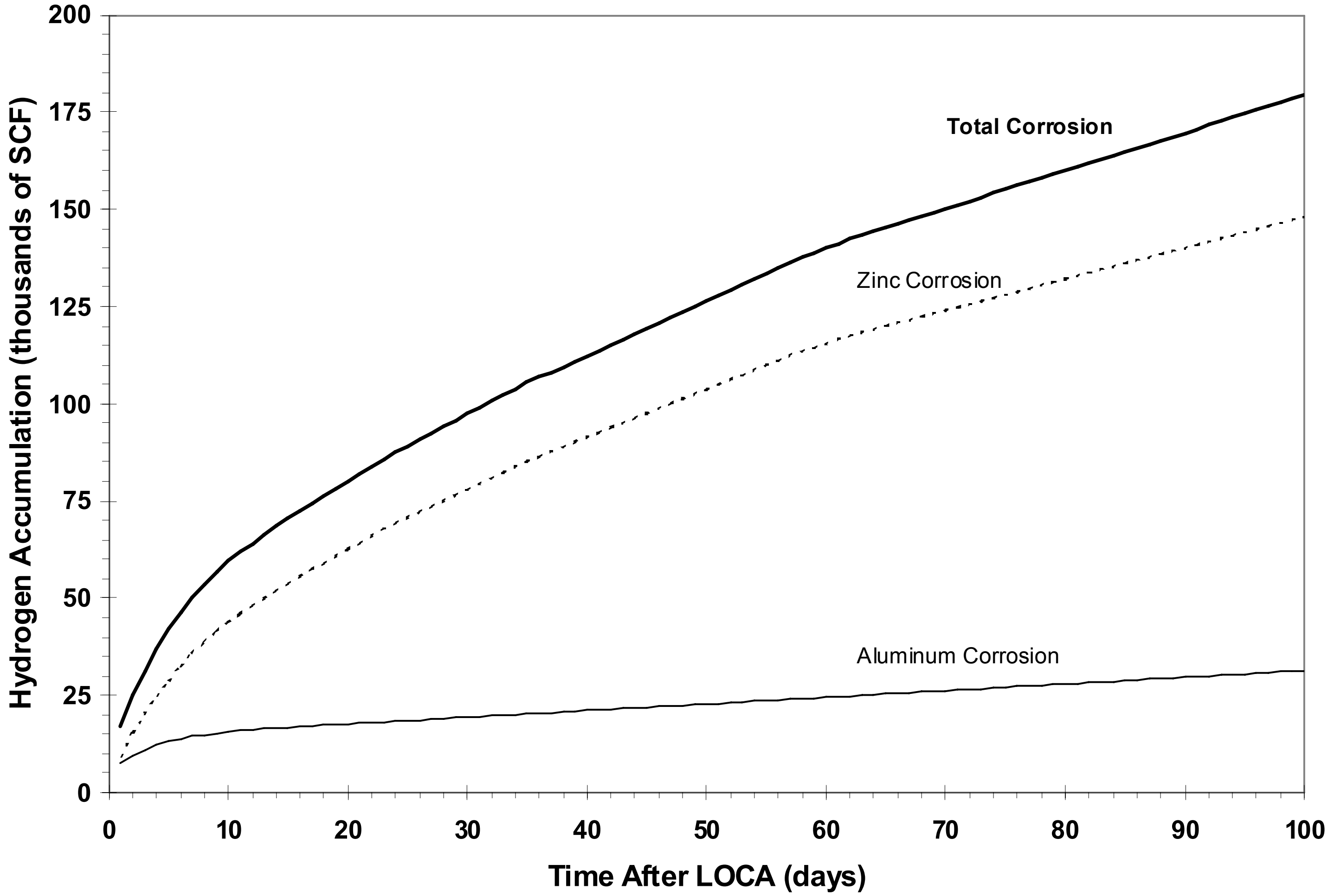
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-26 POST-LOCA CONTAINMENT HYDROGEN CONCENTRATION



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-27 POST-LOCA HYDROGEN ACCUMULATION



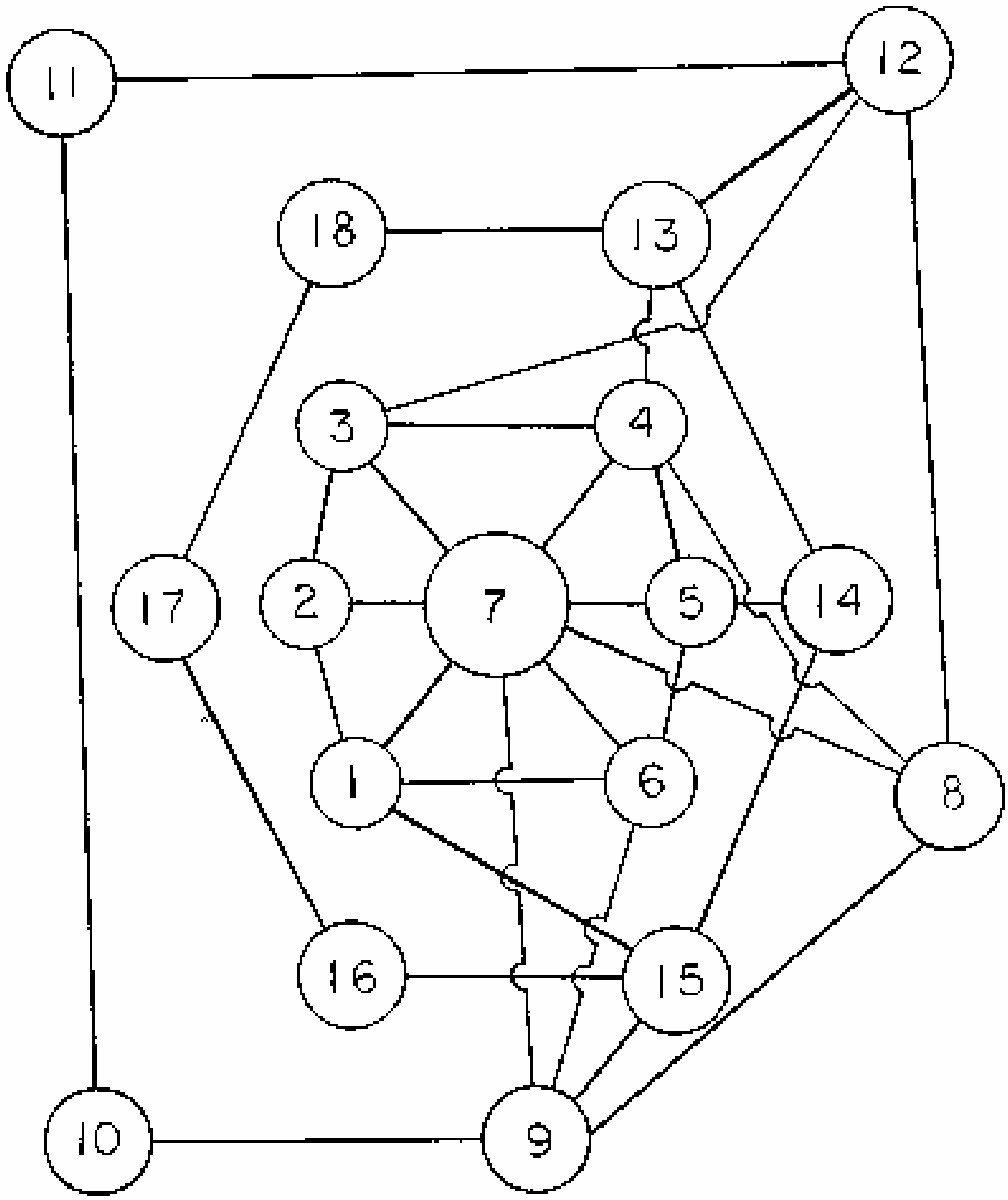
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-28 POST-LOCA HYDROGEN PRODUCTION



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-29
POST-LOCA HYDROGEN
ACCUMULATION FROM CORROSION
OF MATERIAL INSIDE CONTAINMENT
WITH NO RECOMBINER

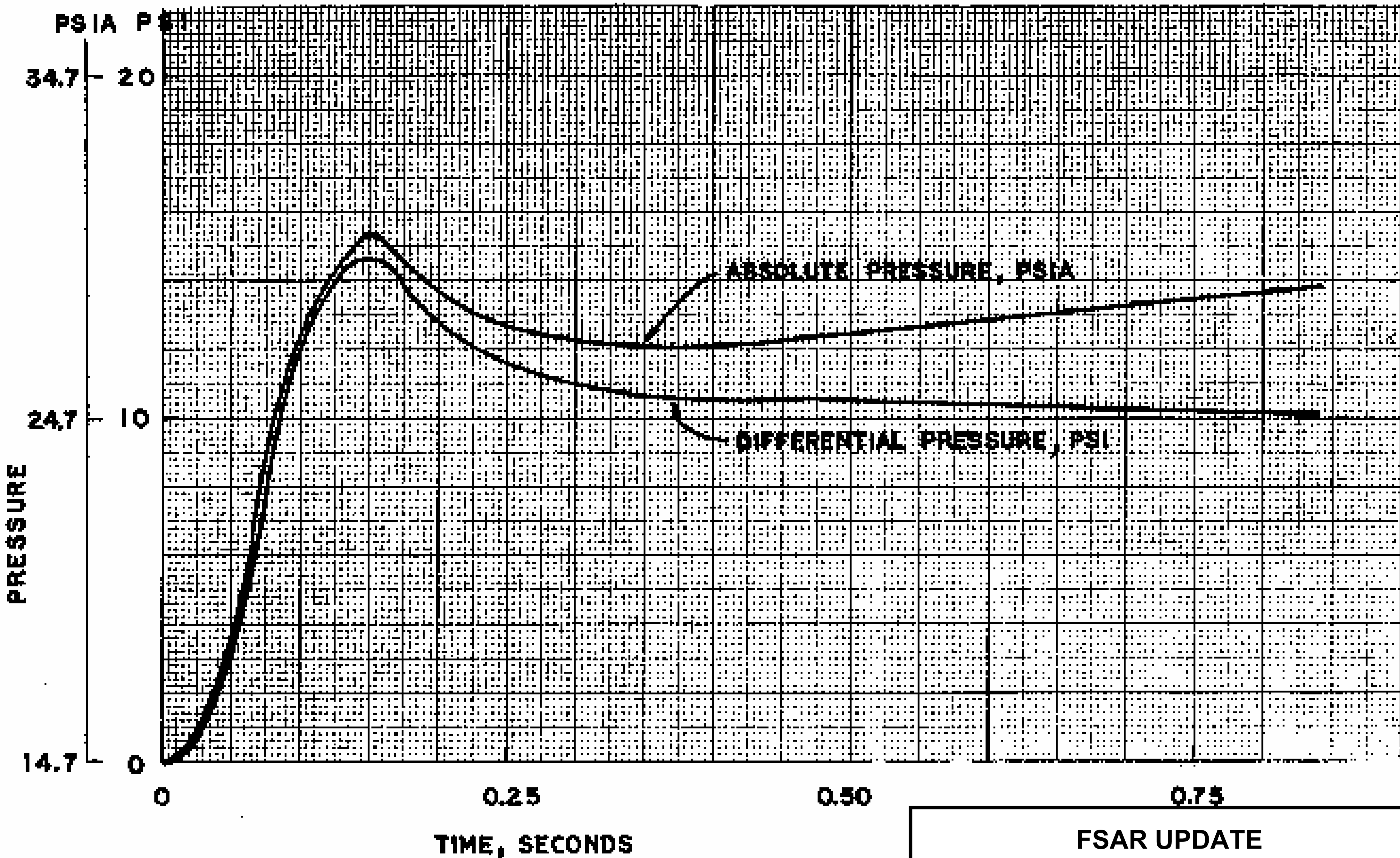


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-33

CONTAINMENT PRESSURE DIFFERENTIAL ELEMENTS AND FLOW PATHS FOR LOOP CONTAINMENT ANALYSIS MODEL

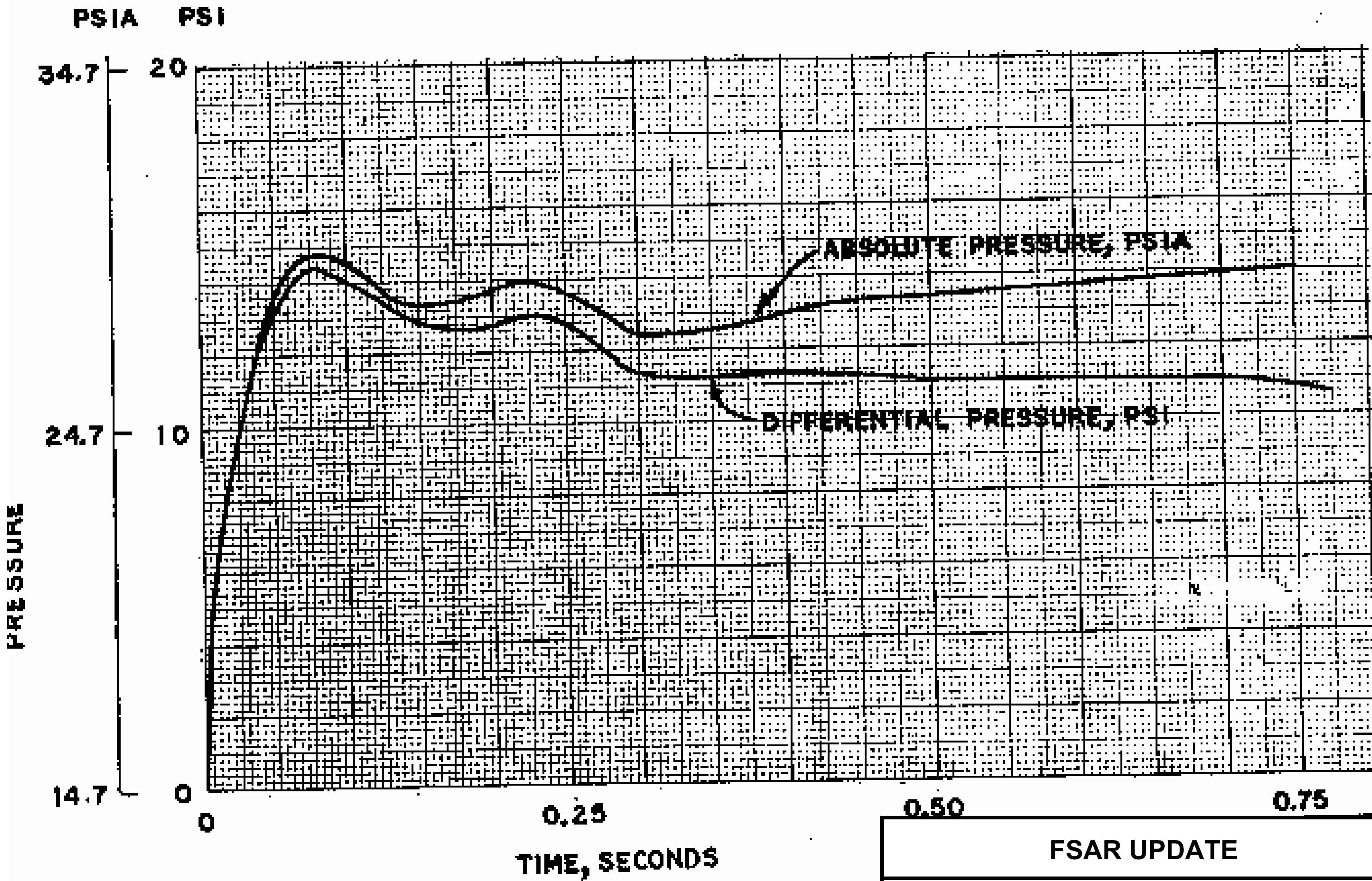


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-34

CONTAINMENT PRESSURE DIFFERENTIAL LOOP COMPARTMENT ANALYSIS ABSOLUTE AND DIFFERENTIAL PRESSURES IN LOOP COMPARTMENT 1

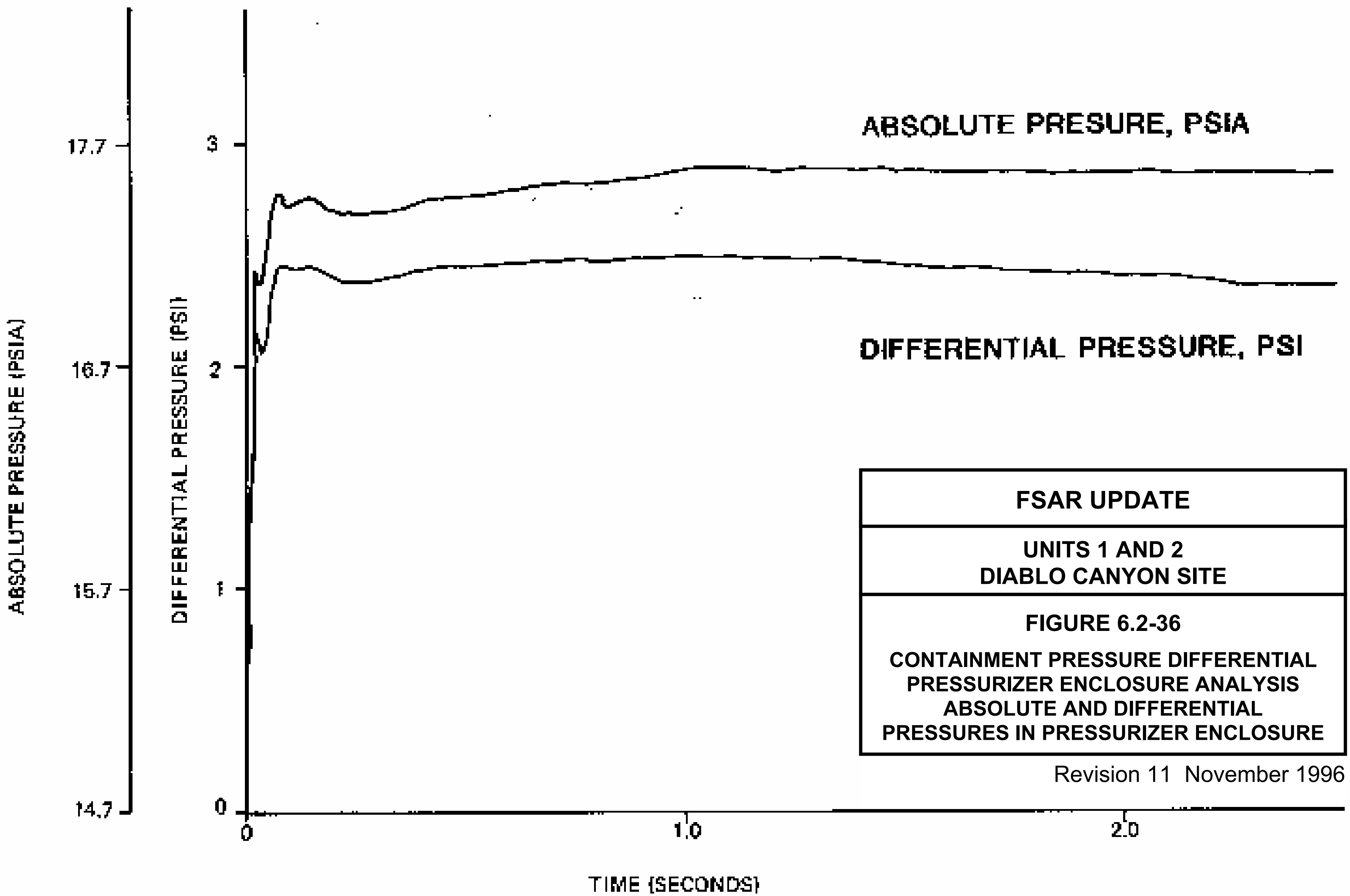


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

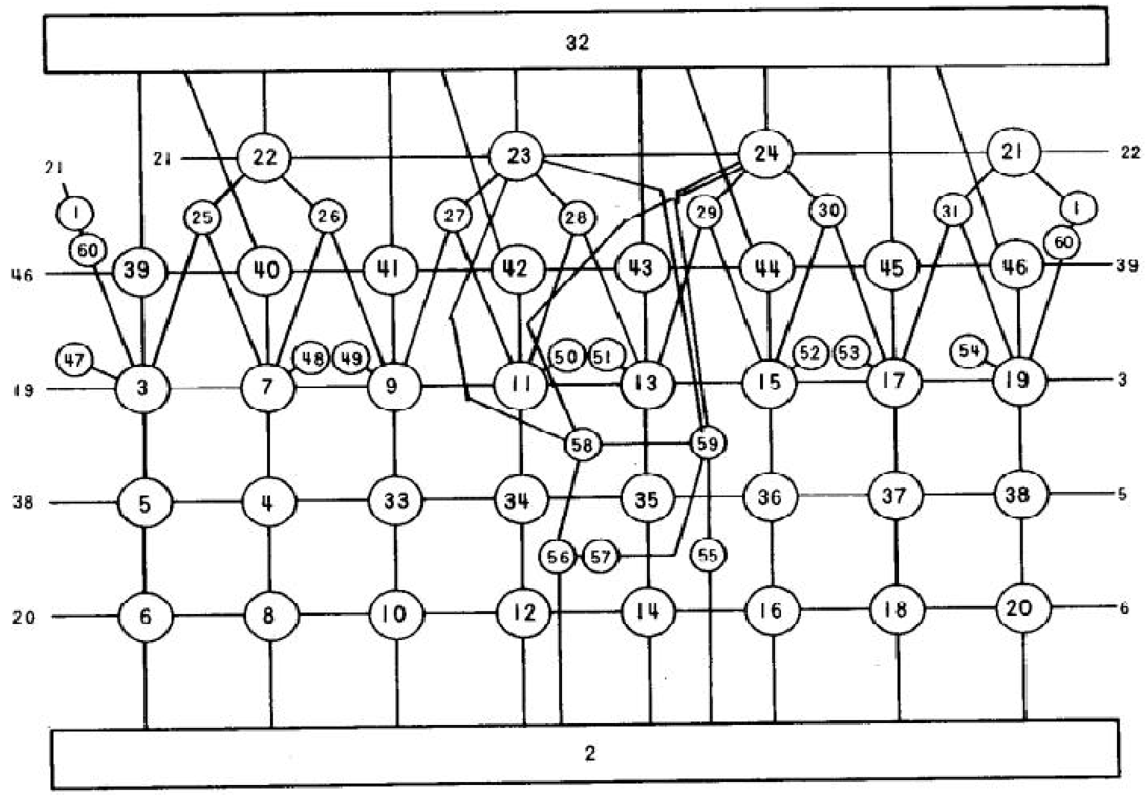
FIGURE 6.2-35

CONTAINMENT PRESSURE DIFFERENTIAL
LOOP COMPARTMENT ANALYSIS
ABSOLUTE AND DIFFERENTIAL
PRESSURES IN LOOP COMPARTMENT 2



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-36 CONTAINMENT PRESSURE DIFFERENTIAL PRESSURIZER ENCLOSURE ANALYSIS ABSOLUTE AND DIFFERENTIAL PRESSURES IN PRESSURIZER ENCLOSURE

Revision 11 November 1996



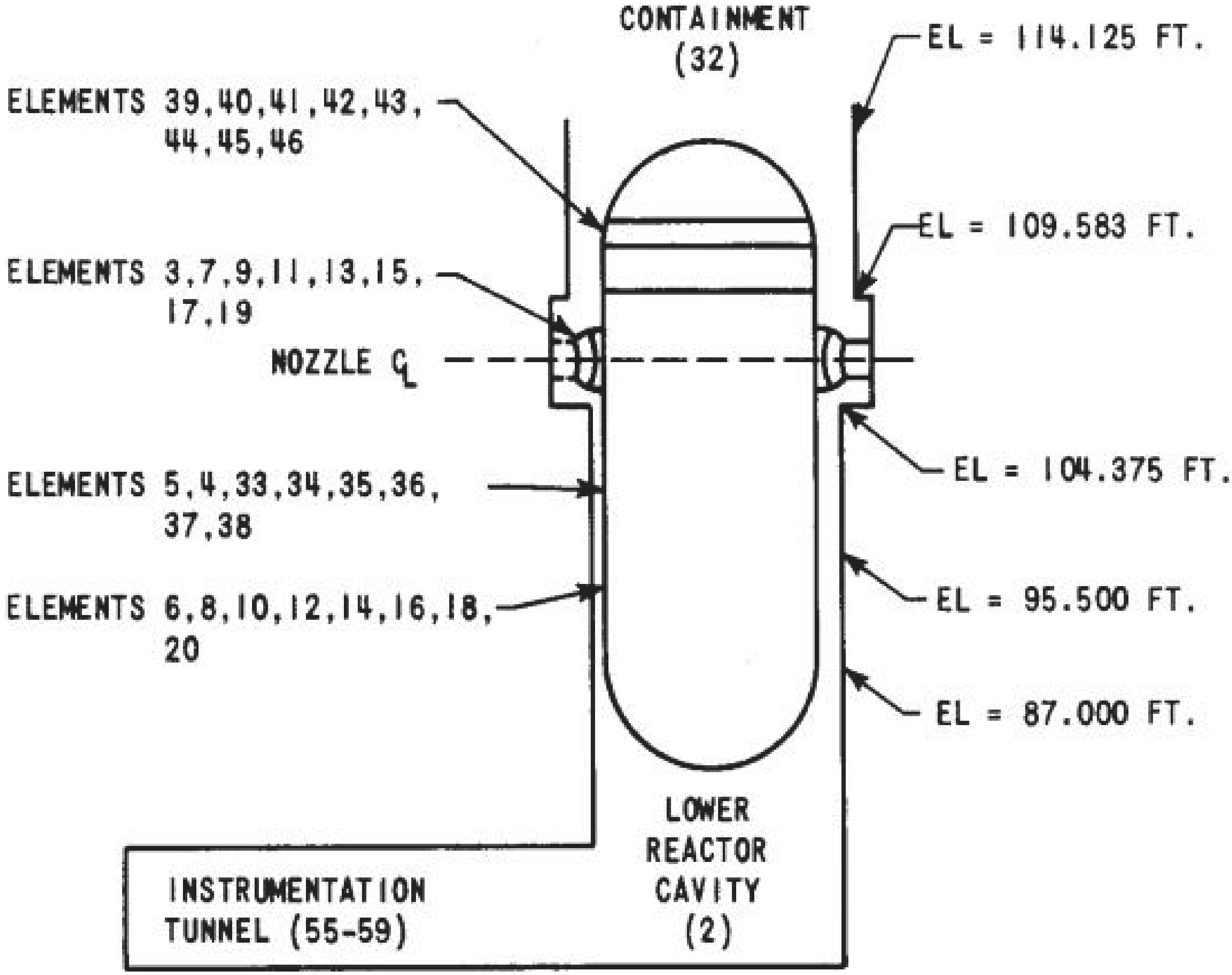
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

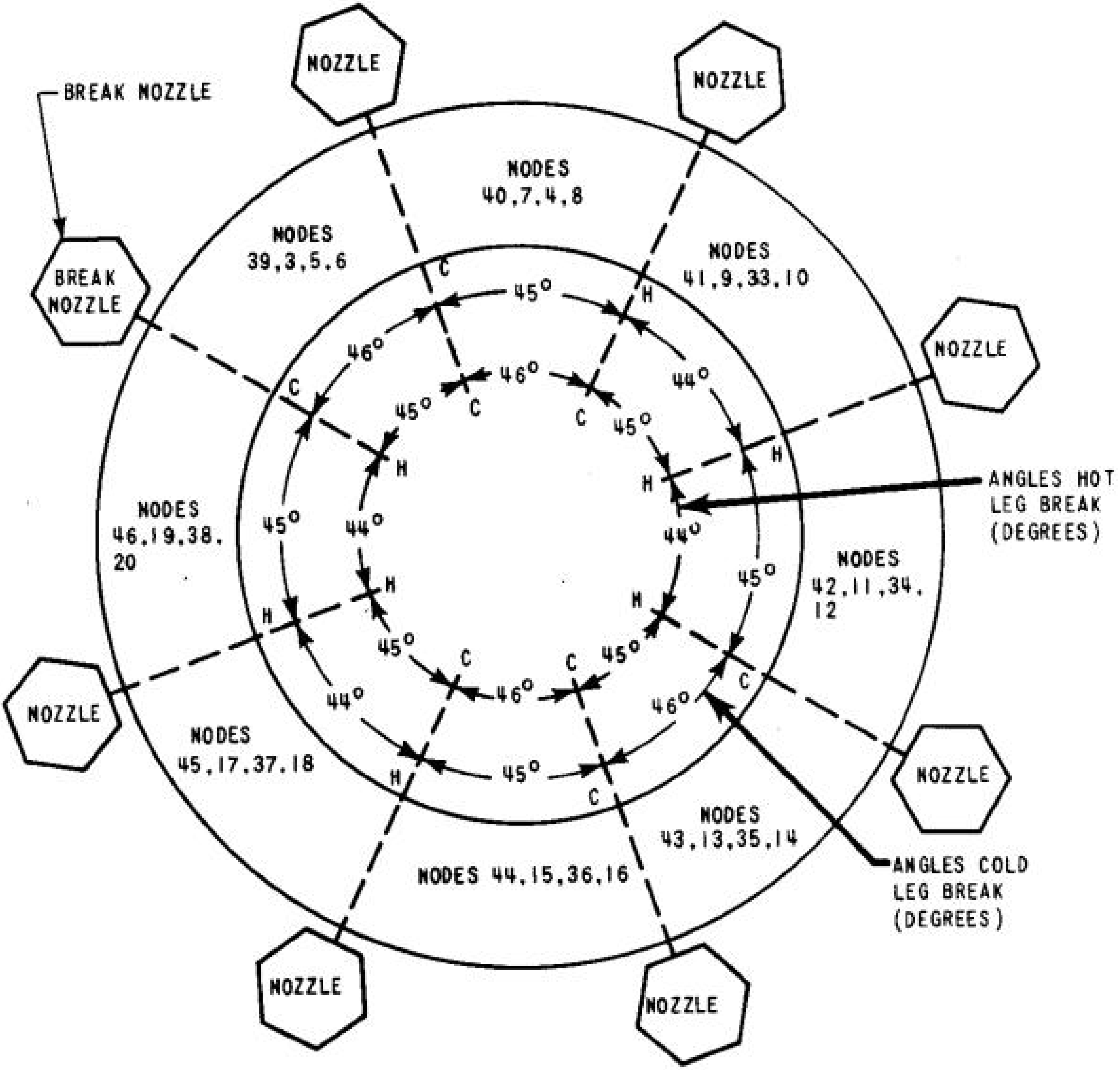
FIGURE 6.2-37

CONTAINMENT PRESSURE DIFFERENTIAL ELEMENTS AND FLOW PATHS FOR REACTOR CAVITY ANALYSIS MODEL

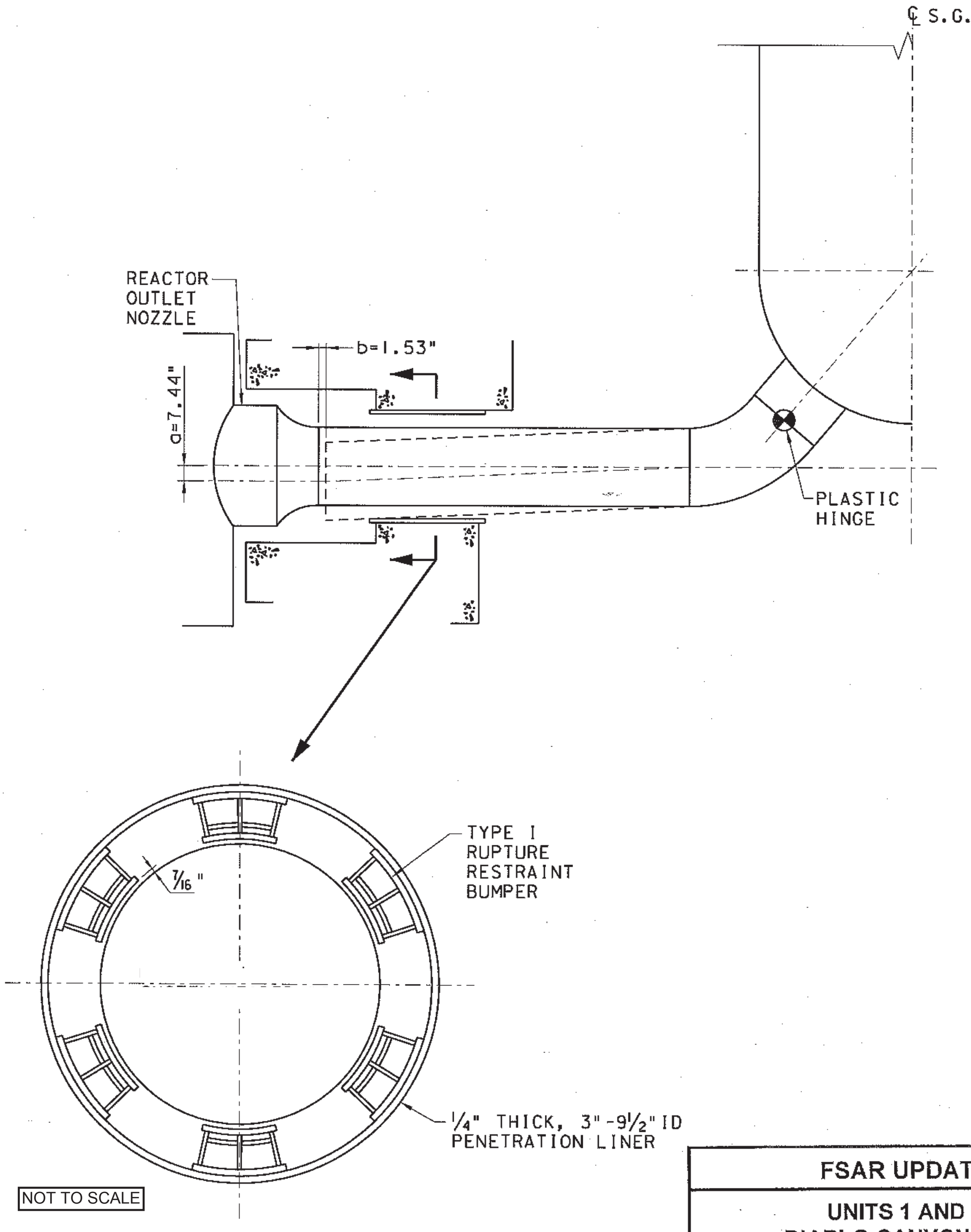
Revision 22 May 2015



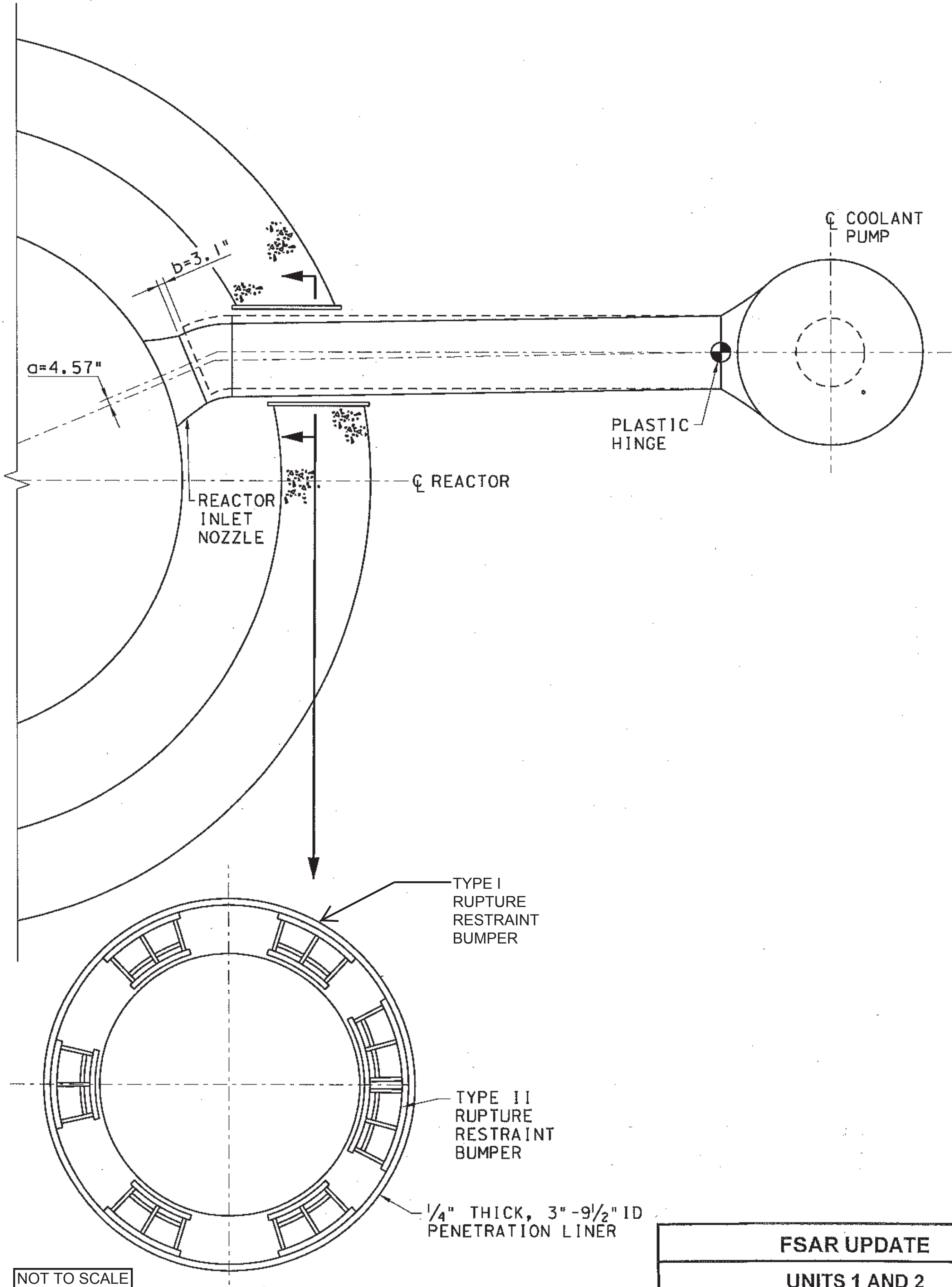
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-38 CONTAINMENT PRESSURE DIFFERENTIAL LOCATION OF ELEMENTS FOR REACTOR CAVITY ANALYSIS MODEL



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-39 CONTAINMENT PRESSURE DIFFERENTIAL LOCATION OF ELEMENTS FOR REACTOR CAVITY ANALYSIS MODEL



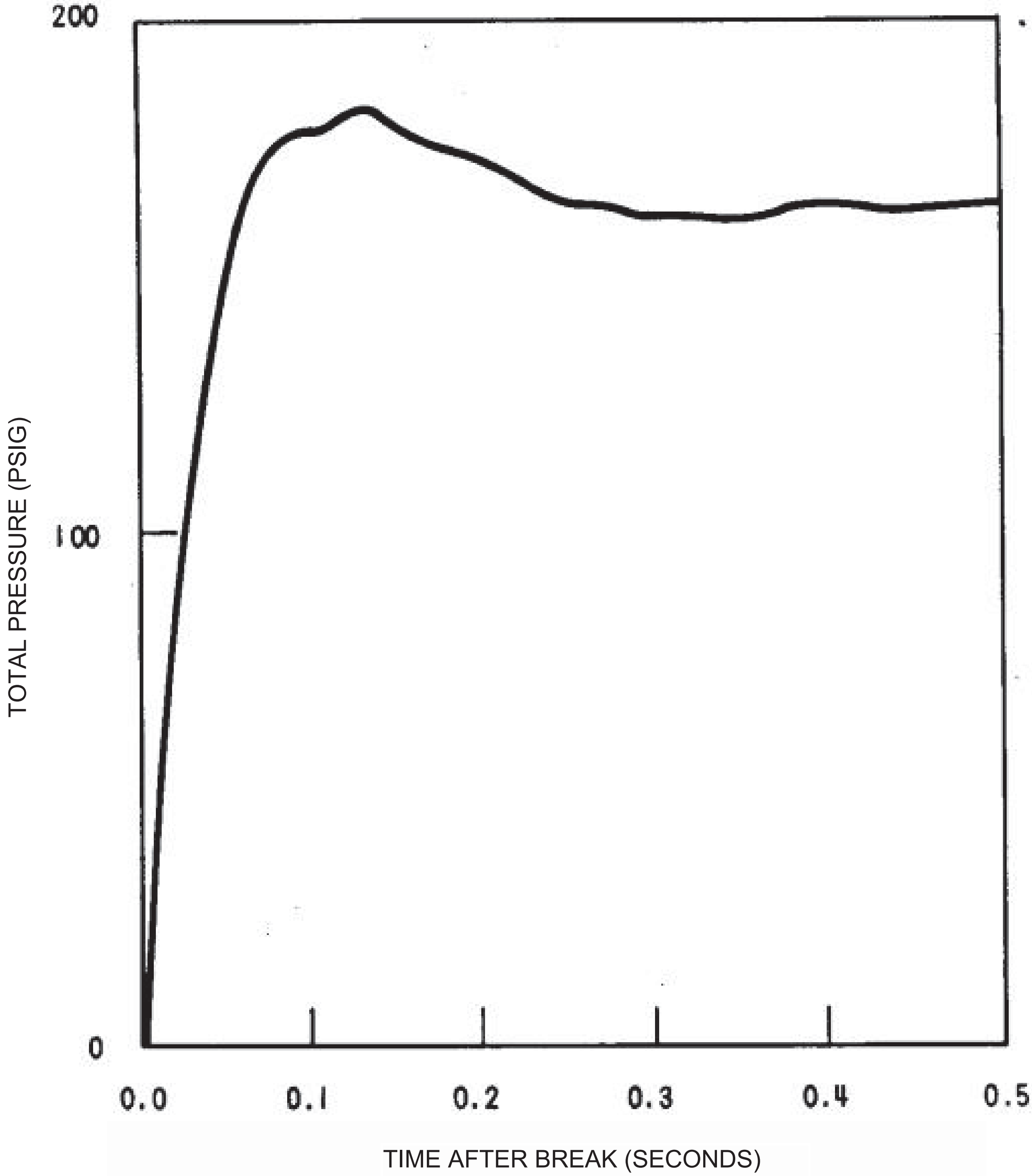
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-40 MAXIMUM DISPLACEMENTS FOR HOT LEG BREAK AT REACTOR NOZZLE



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

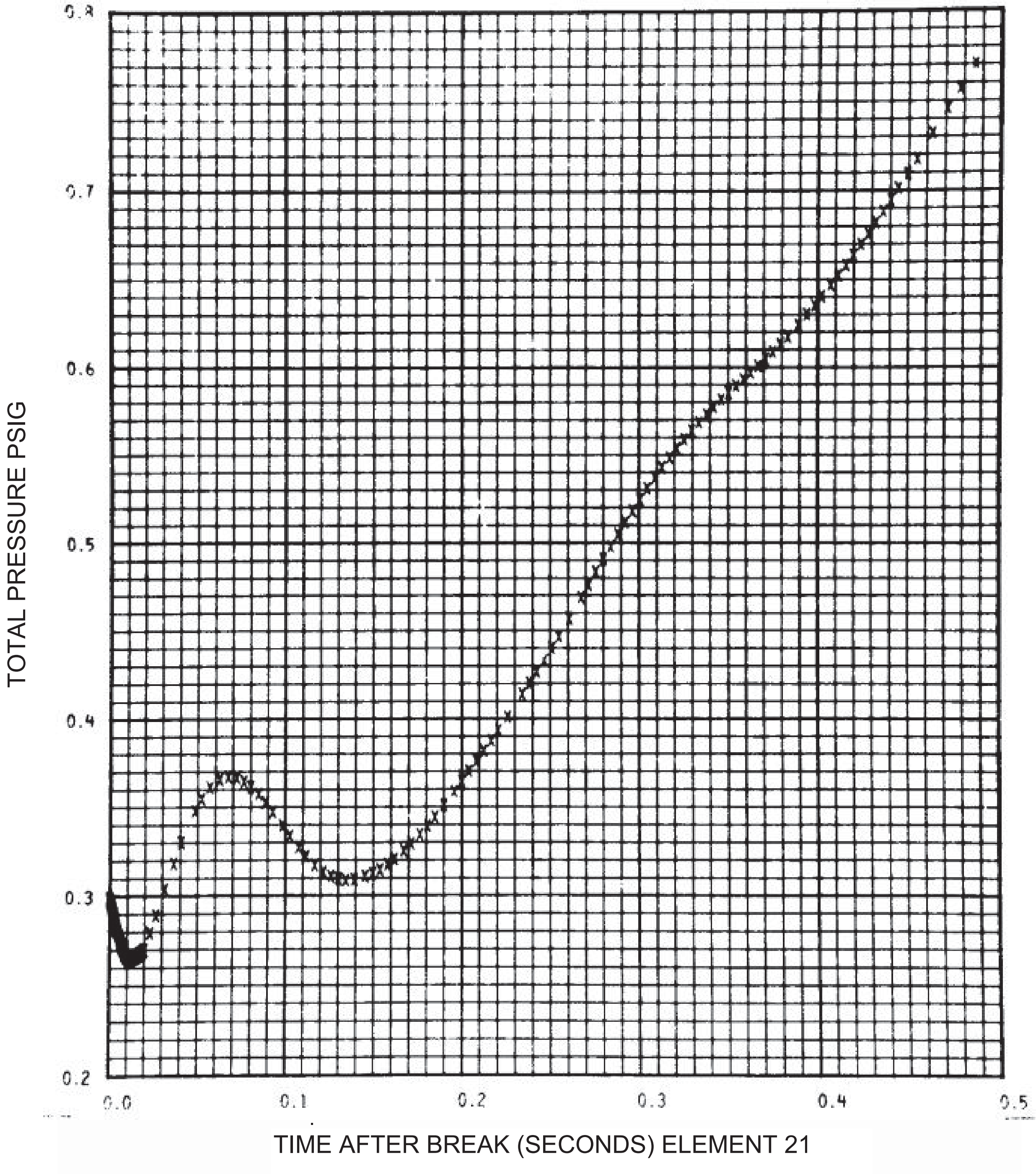
FIGURE 6.2-41
MAXIMUM DISPLACEMENTS FOR COLD LEG BREAK AT REACTOR NOZZLE



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

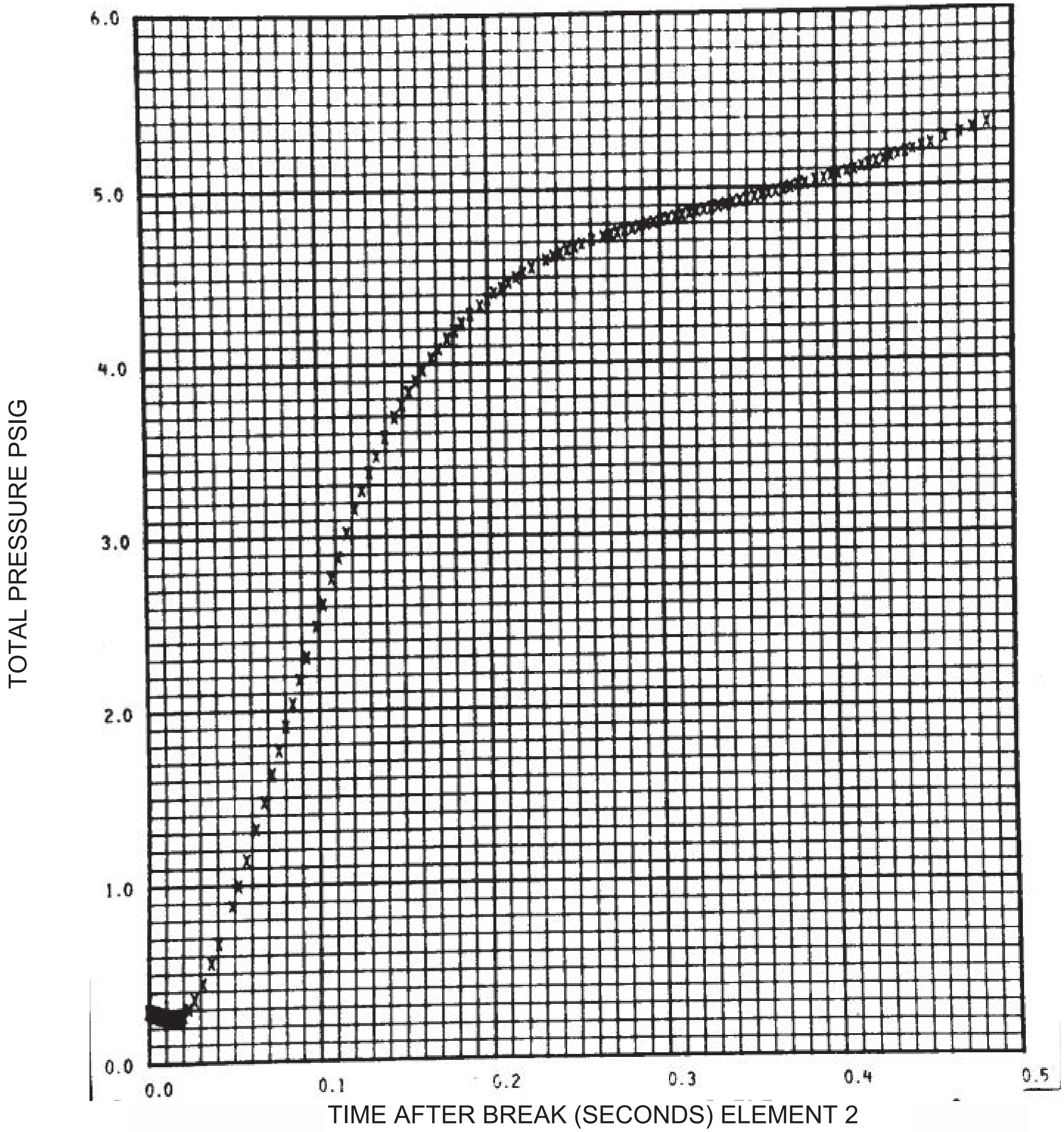
FIGURE 6.2-42
CONTAINMENT PRESSURE DIFFERENTIAL REACTOR CAVITY ANALYSIS PRESSURE IN REACTOR VESSEL ANNULUS (ELEMENT 19)



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-43
CONTAINMENT PRESSURE DIFFERENTIAL
REACTOR CAVITY ANALYSIS
PRESSURE IN LOOP COMPARTMENT
(ELEMENT 21) ADJACENT TO
REACTOR CAVITY (ELEMENT 19)

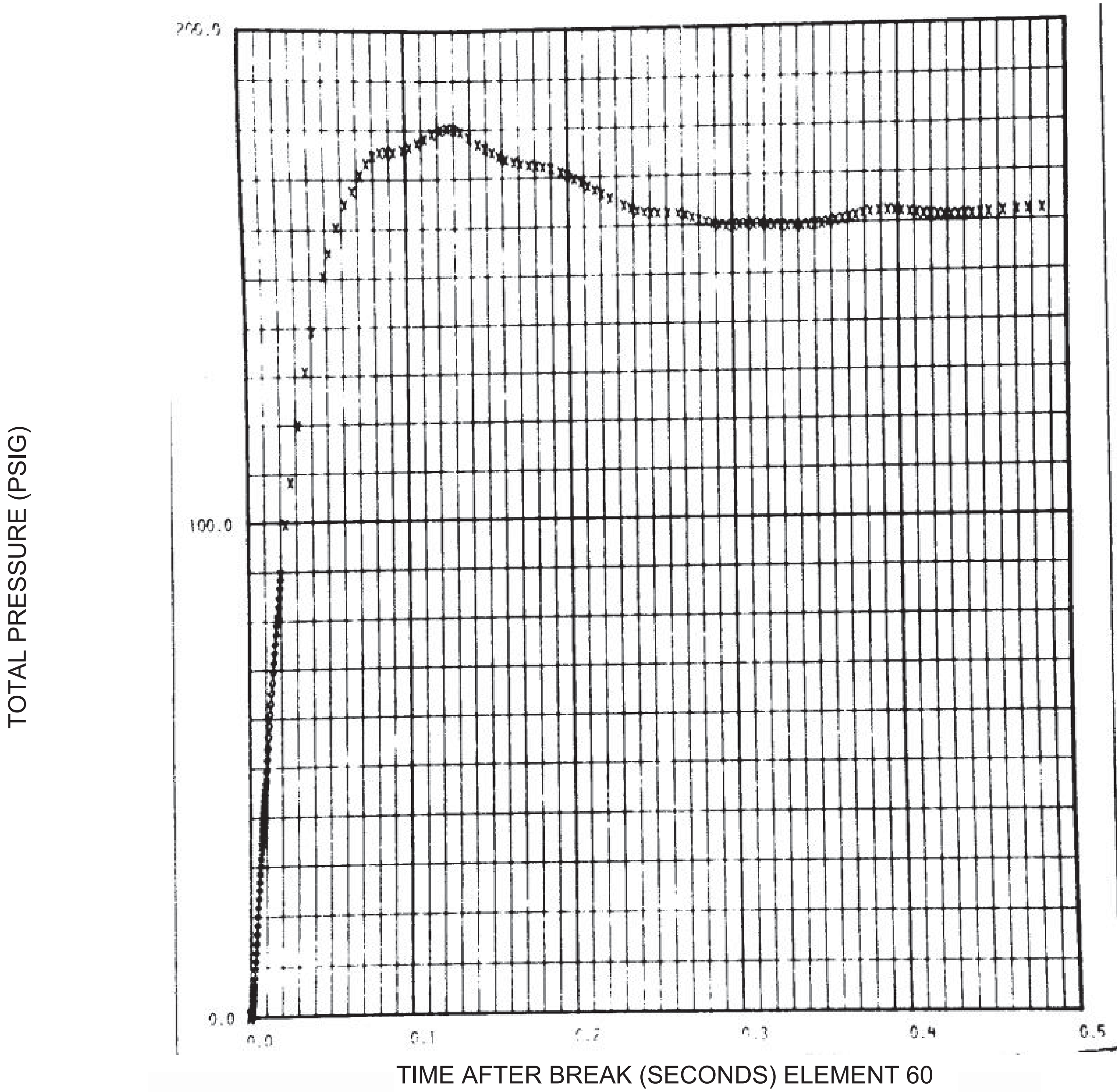


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-44

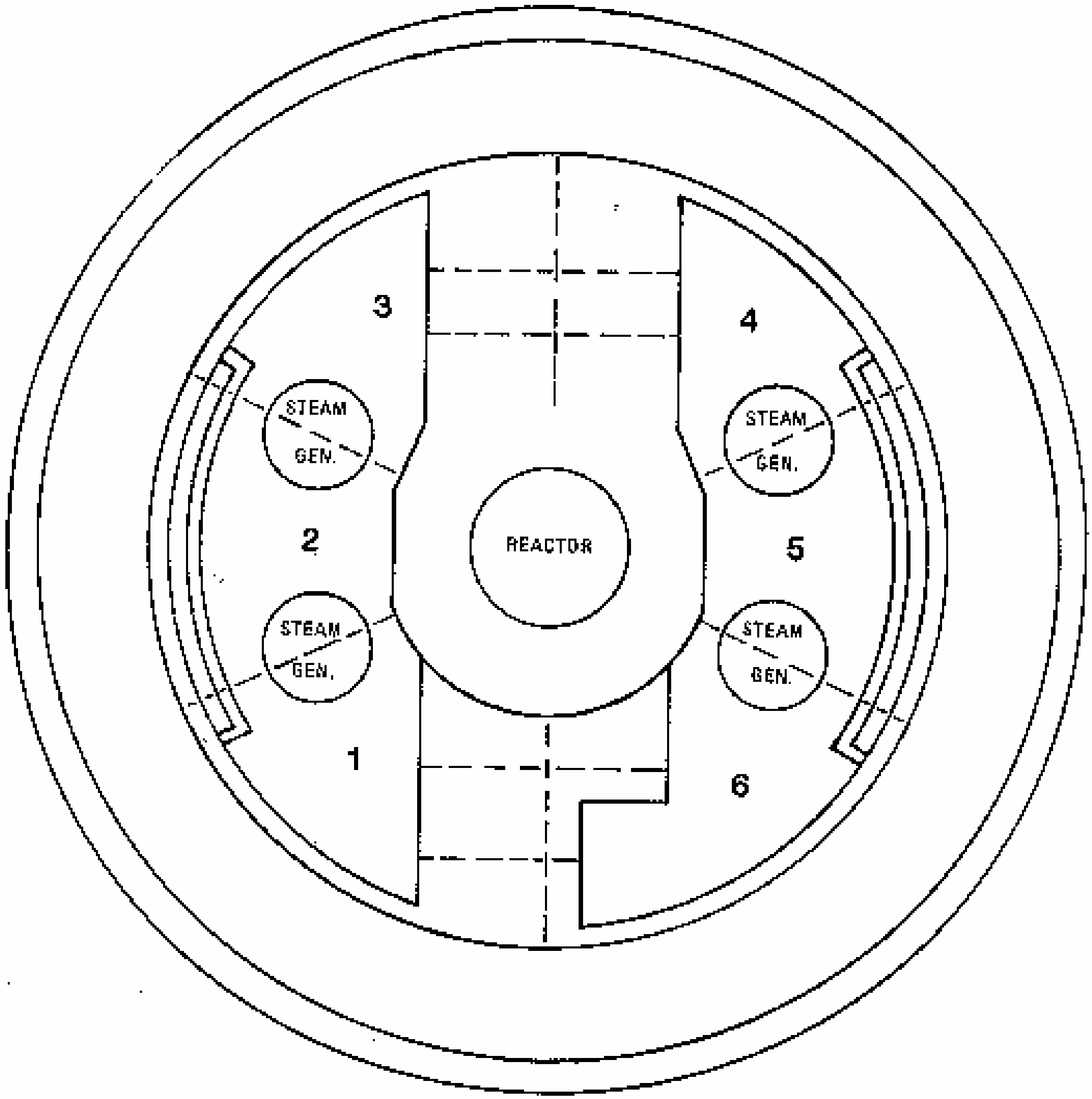
CONTAINMENT PRESSURE DIFFERENTIAL REACTOR CAVITY ANALYSIS PRESSURE IN LOWER REACTOR CAVITY (ELEMENT 2)



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-46
CONTAINMENT PRESSURE DIFFERENTIAL REACTOR CAVITY ANALYSIS PRESSURE IN COLD LEG PIPE ANNULUS (ELEMENT 60)

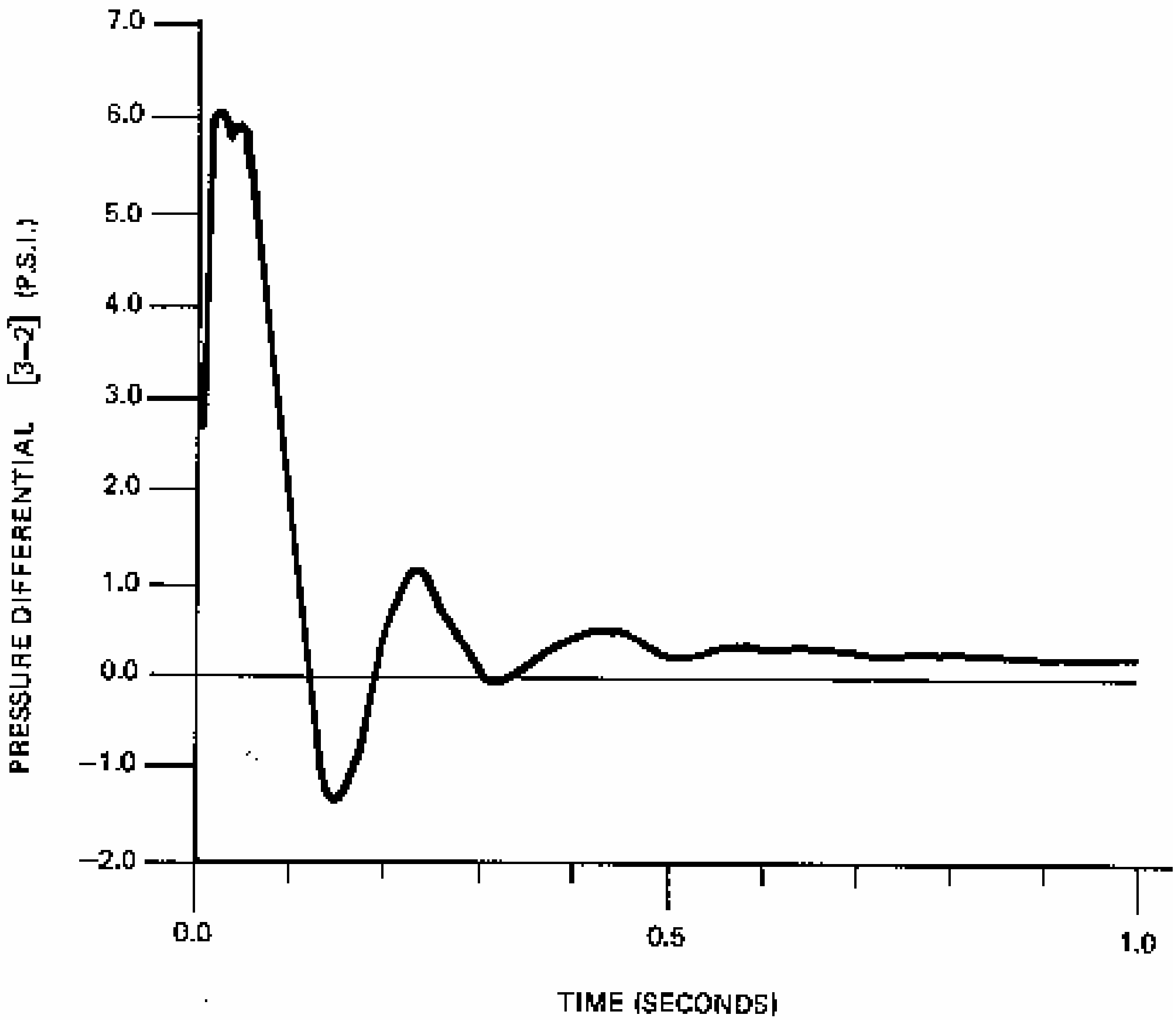


FSAR UPDATE

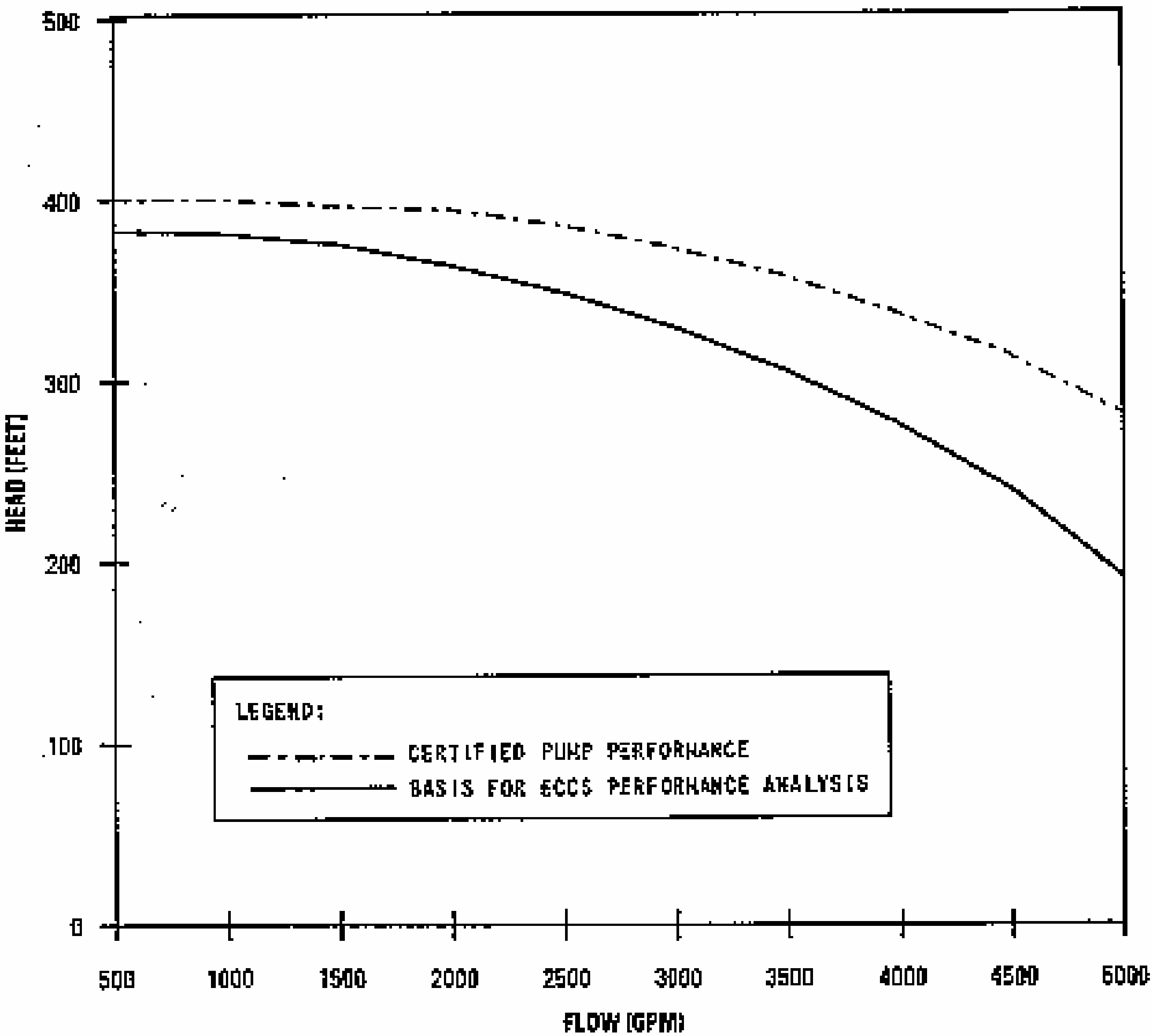
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-51
CONTAINMENT LOCATIONS USED IN CALCULATION OF DIFFERENTIAL PRESSURE ACROSS STEAM GENERATORS FROM DEHL BREAK

Revision 11 November 1996

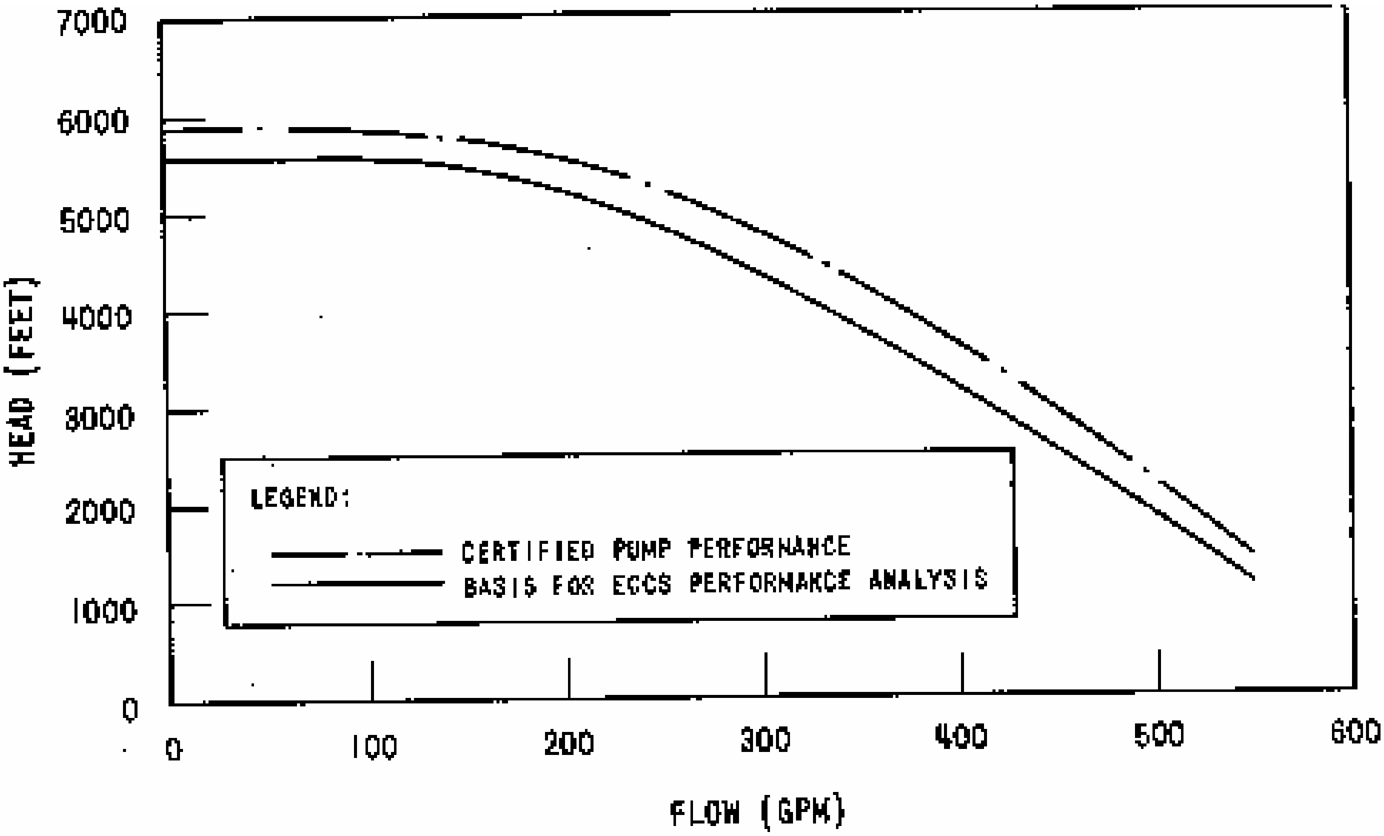


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-52 DIFFERENTIAL PRESSURE ACROSS STEAM GENERATOR (BETWEEN COMPARTMENTS 3 AND 2) RESULTING FROM A DEHL BREAK IN COMPARTMENT 3.



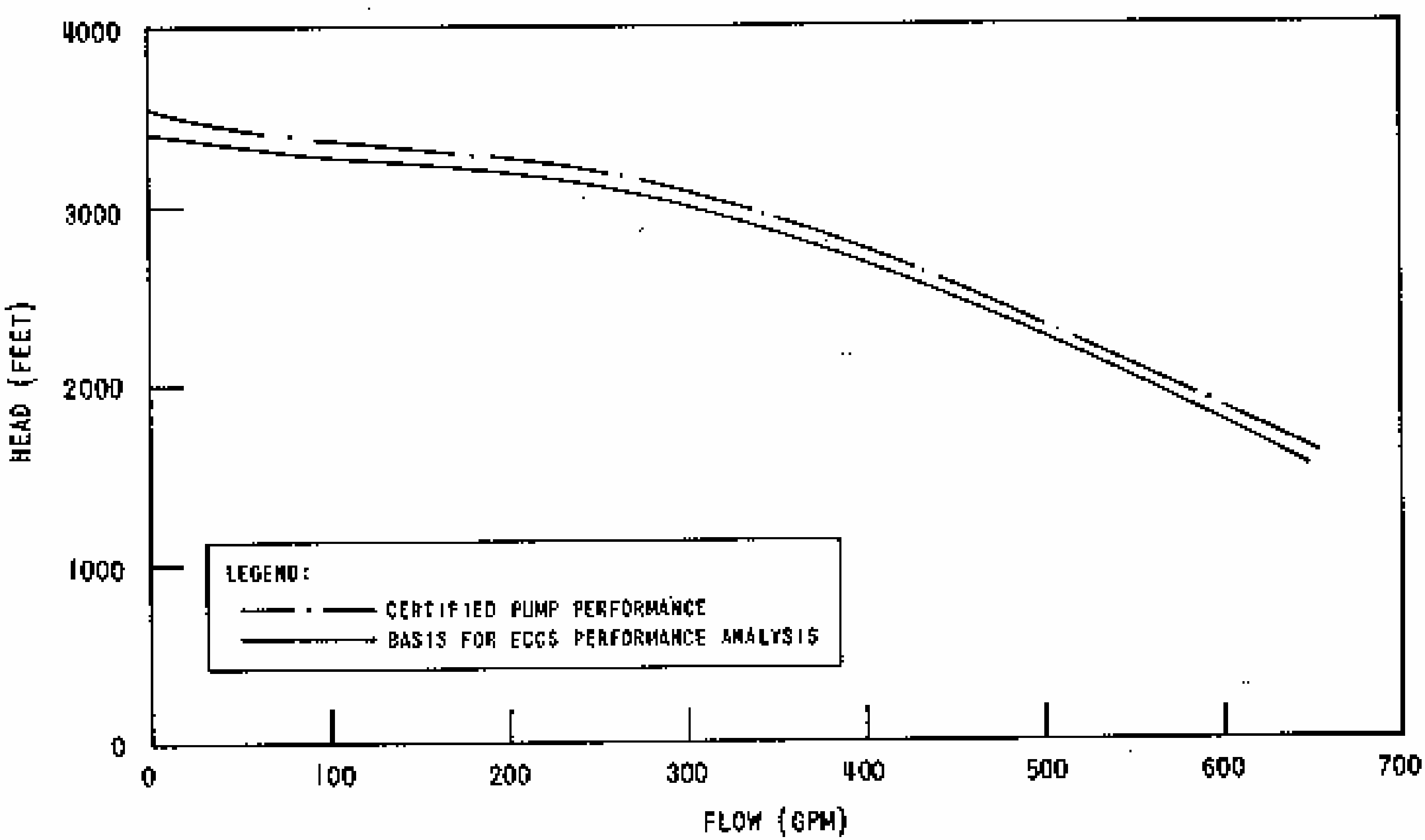
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.3-1 RESIDUAL HEAT REMOVAL PUMP PERFORMANCE CURVES (TYPICAL)

Revision 11 November 1996

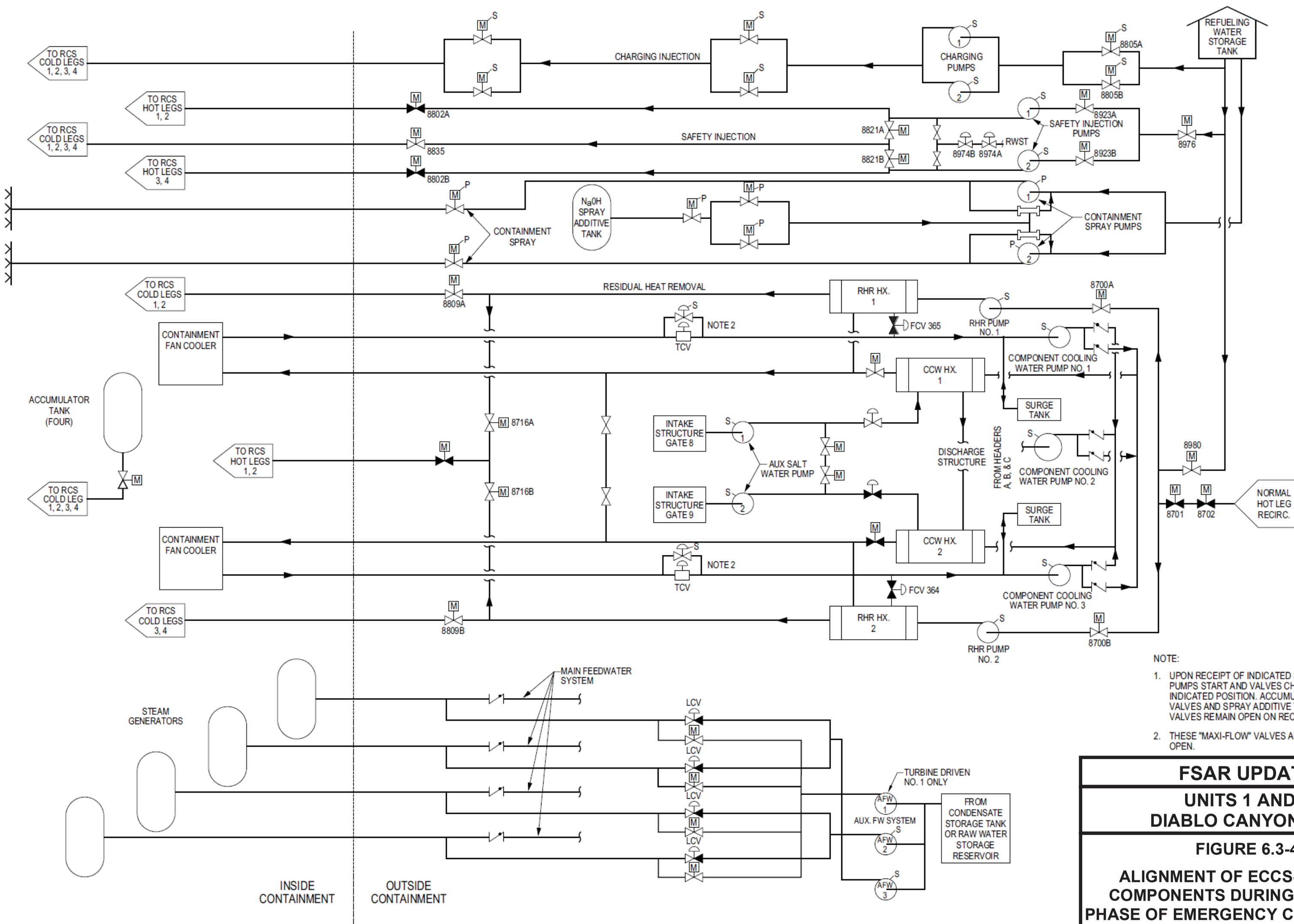


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.3-2 CENTRIFUGAL CHARGING PUMPS 1 & 2 PERFORMANCE CURVES (TYPICAL)

Revision 18 October 2008



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.3-3 SAFETY INJECTION PUMP PERFORMANCE CURVES (TYPICAL)



NOTE:

1. UPON RECEIPT OF INDICATED SIGNALS S OR P PUMPS START AND VALVES CHANGE TO INDICATED POSITION. ACCUMULATOR DISCHARGE VALVES AND SPRAY ADDITIVE TANK DISCHARGE VALVES REMAIN OPEN ON RECEIPT OF S SIGNAL.

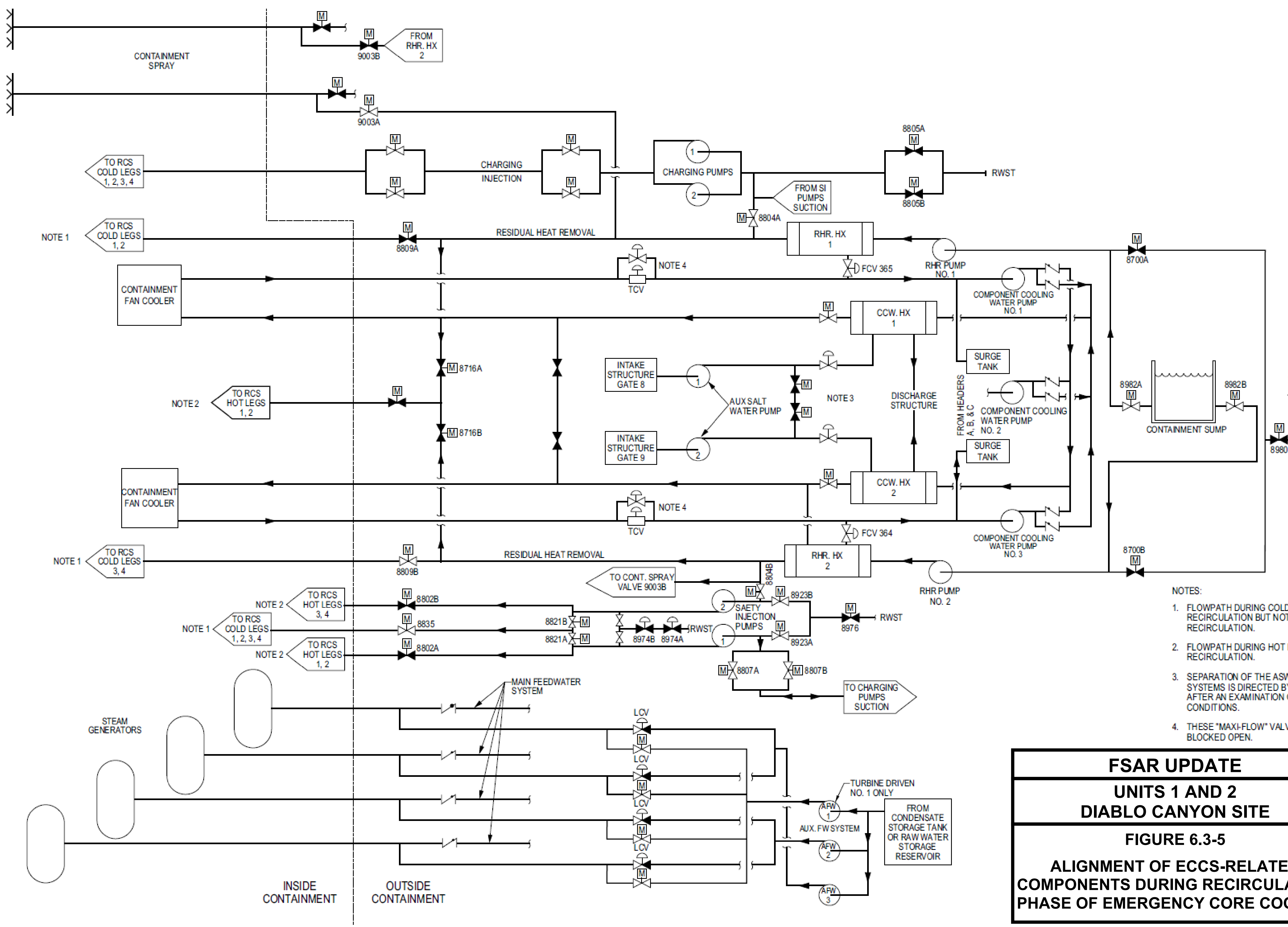
2. THESE "MAXI-FLOW" VALVES ARE BLOCKED OPEN.

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.3-4

ALIGNMENT OF ECCS-RELATED COMPONENTS DURING INJECTION PHASE OF EMERGENCY CORE COOLING



NOTES:

1. FLOWPATH DURING COLD LEG RECIRCULATION BUT NOT HOT LEG RECIRCULATION.
2. FLOWPATH DURING HOT LEG RECIRCULATION.
3. SEPARATION OF THE ASW AND CCW SYSTEMS IS DIRECTED BY THE TSC AFTER AN EXAMINATION OF PLANT CONDITIONS.
4. THESE "MAXI-FLOW" VALVES ARE BLOCKED OPEN.

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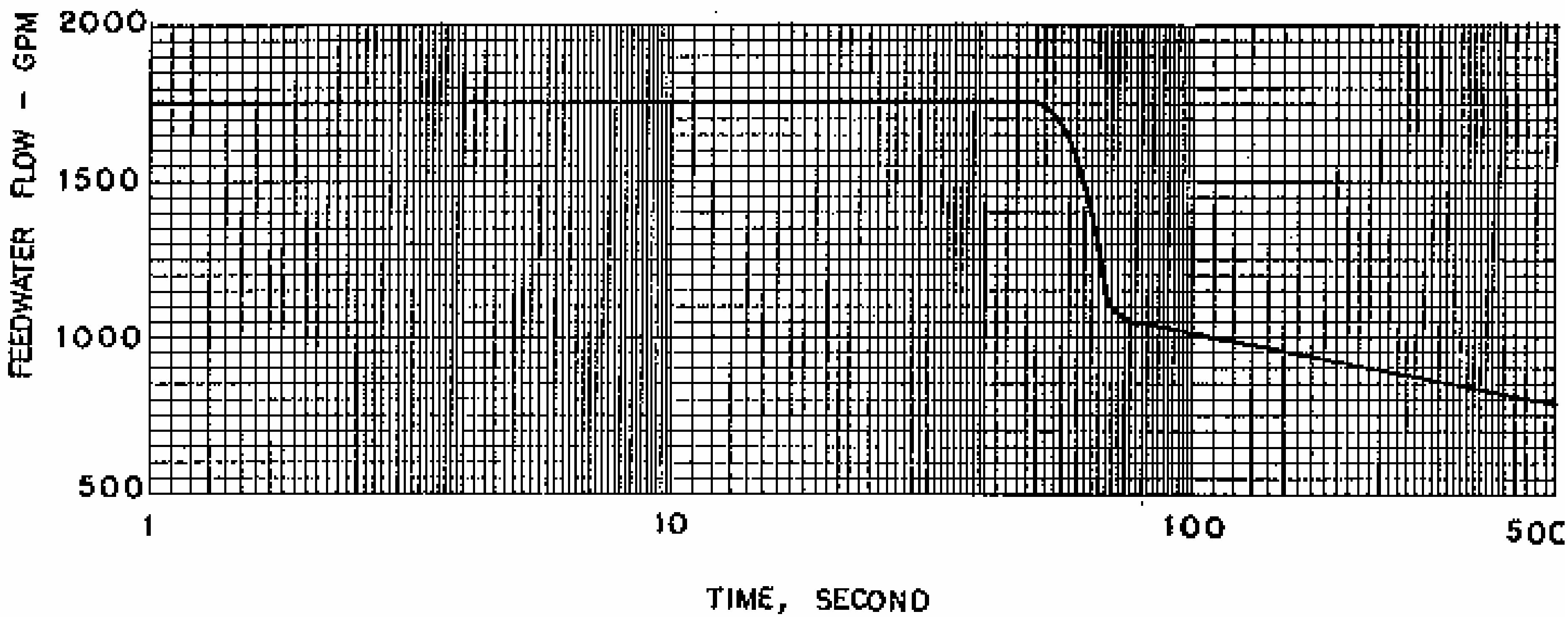
FIGURE 6.3-5

ALIGNMENT OF ECCS-RELATED COMPONENTS DURING RECIRCULATION PHASE OF EMERGENCY CORE COOLING

Revision 20 November 2011



AUXILIARY FEEDWATER FLOW FOR PLANT SHUTDOWN FROM 3568 MWT WITH ALL THREE AFW PUMPS IN OPERATION (FOR INFORMATION ONLY

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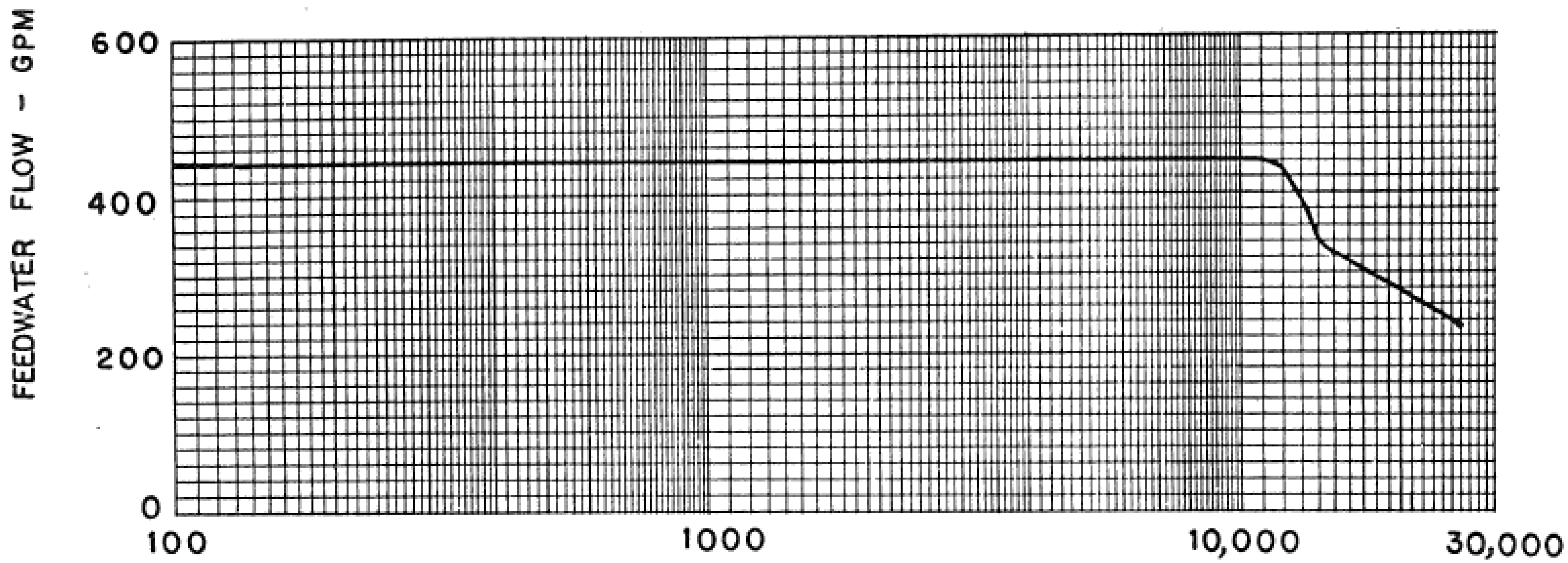
FIGURE 6.5-3 (Sheet 1) AUXILIARY FEEDWATER FLOW FOR PLANT SHUTDOWN



AUXILIARY FEEDWATER FLOW FOR PLANT SHUTDOWN FROM 3568 MWT WITH ONLY ONE 440 GPM MOTOR-DRIVEN AFW PUMP IN OPERATION (FOR INFORMATION ONLY)

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FIGURE 6.5-3 (Sheet 2) **AUXILIARY FEEDWATER FLOW FOR PLANT SHUTDOWN**

APPENDIX 6.2D

ANALYSIS OF LONG-TERM LOSS-OF-COOLANT ACCIDENTS AND MAIN STEAMLINE BREAK EVENTS

6.2D.1 INTRODUCTION

This appendix details the methodology for calculating the long-term mass and energy (M&E) releases and the resulting containment response subsequent to a hypothetical loss-of-coolant accident (LOCA) or a main steamline break (MSLB) in DCPP Unit 1 and Unit 2. Short-term LOCA-related M&E releases are used as input to the subcompartment analyses and are discussed in Section 6.2.1.

The containment system is designed such that for all break sizes, up to and including the double-ended severance of a reactor coolant pipe or secondary system pipe, the containment peak calculated pressure is less than the containment design pressure.

The M&E releases from the LOCA and MSLB analyses are used as input to the containment response analyses. The containment integrity analysis conclusions are discussed in Sections 6.2D.3.2.7 (LOCA) and 6.2D.4.2.6 (MSLB). Section 6.2.1 includes an evaluation demonstrating that the containment satisfies the applicable design requirements.

6.2D.2 COMPUTER CODES WHICH SUPPORT CURRENT ANALYSES

Computer Codes which Support Current Analyses	LOCA	MSLB
SATAN-VI	X	N/A
WREFLOOD	X	N/A
FROTH	X	N/A
EPITOME	X	N/A
RETRAN-02W (used with NRC limitations, refer to WCAP-14882-P-A)	N/A	X
GOTHIC Version 7.2	X	X

The WCAP-10325-P-A (Reference 1) M&E release evaluation model is comprised of M&E release versions of the following codes: SATAN-VI, WREFLOOD, FROTH, and EPITOME. These codes were used to calculate the long-term LOCA M&E releases for DCPP Unit 1 and Unit 2.

SATAN-VI calculates blowdown, the first portion of the thermal-hydraulic transient following break initiation, including pressure, enthalpy, density, M&E flow rates, and energy transfer between primary and secondary systems as a function of time.

The WREFLOOD code addresses the portion of the LOCA transient where the core reflooding phase occurs after the primary coolant system has depressurized (blowdown) due to the loss of water through the break and when water supplied by the ECCS refills the reactor vessel and provides cooling to the core. The most important feature of WREFLOOD is the steam/water mixing model (refer to Section 6.2D.3.1.4).

FROTH models the post-reflood portion of the transient. The FROTH code is used for the steam generator heat addition calculation from the broken and intact loop steam generators.

EPITOME continues the FROTH post-reflood portion of the transient from the time at which the secondary equilibrates to containment design pressure to the end of the transient. It also compiles a summary of data on the entire transient, including formal instantaneous M&E release tables and M&E balance tables with data at critical times.

The Westinghouse steamline break M&E release methodology was approved by the NRC (Reference 8) and is documented in WCAP-8822, “Mass and Energy Releases Following a Steam Line Rupture” (Reference 9) and WCAP-8822-S2-P-A, “Mass and Energy Releases Following a Steam Line Rupture, Supplement 2 – Impact of Steam Superheat in Mass/Energy Releases Following a Steamline Rupture of Dry and Subatmospheric Containment Designs” (Reference 11). WCAP-8822 forms the basis for the assumptions used in the calculation of the M&E releases resulting from a steamline rupture. The analysis documented herein uses the RETRAN-02W code, which is documented in WCAP-14882-P-A, “RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses” (Reference 12).

GOTHIC Version 7.2 is used to perform the containment response analyses for the LOCA and MSLB events.

6.2D.3 LONG-TERM LOSS-OF-COOLANT ACCIDENTS

6.2D.3.1 Long-Term LOCA Mass and Energy Release Analysis

6.2D.3.1.1 Acceptance Criteria

There are no direct acceptance criteria for LOCA M&E releases. The analysis methods follow the guidelines provided by the USNRC with respect to the sources of M&E during the various phases of a large break LOCA transient (refer to Section 6.2D.3.1.4).

The specific acceptance criteria for the containment response to a LOCA are discussed in Section 6.2D.3.2.1.

6.2D.3.1.2 Introduction and Background

Discussion of the short-term LOCA-related M&E releases which are used as input to the subcompartment analyses can be found in Section 6.2.1.2.

The uncontrolled release of pressurized high-temperature reactor coolant, termed a LOCA, would result in release of steam and water into the containment. This, in turn, would result in increases in the local subcompartment pressures, and an increase in the global containment pressure and temperature. Therefore, there are both long- and short-term issues relative to a postulated LOCA that must be considered at the conditions for DCPP Unit 1 and Unit 2 at the licensed core power of 3411 MWt.

The long-term LOCA M&E releases are analyzed to approximately 10^7 seconds and are utilized as input to the containment integrity analysis. The containment integrity analysis demonstrates the acceptability of the containment safeguards systems to mitigate the consequences of a hypothetical large-break LOCA. The containment safeguards systems must be capable of limiting the peak containment pressure to less than the design pressure and to limit the temperature excursion to less than the acceptance limits. Westinghouse generated the M&E releases using the March 1979 model, described in WCAP-10325-P-A (Reference 1). The Nuclear Regulatory Commission (NRC) review and approval letter is included with WCAP-10325-P-A (Reference 1). Section 6.2D.3.1 discusses the long-term LOCA M&E releases generated. The results of this analysis were provided for use in the containment integrity analysis (refer to Section 6.2D.3.2).

The M&E release rates described in this section form the basis of further computations to evaluate the containment following the postulated accident. Discussed in this section are the long-term LOCA M&E releases for the hypothetical double-ended pump suction (DEPS) rupture with minimum safeguards and maximum safeguards and double-ended hot-leg (DEHL) rupture break cases. These LOCA cases are used for the long-term containment integrity analyses in Section 6.2D.3.2.

6.2D.3.1.3 Input Parameters and Assumptions

The M&E release analysis is sensitive to the assumed characteristics of various plant systems, in addition to other key modeling assumptions. Where appropriate, bounding inputs are utilized and instrumentation uncertainties are included. For example, the RCS operating temperatures are chosen to bound the highest average coolant temperature range of all operating cases and a temperature uncertainty allowance of +5.0°F is then added. Nominal parameters are used in certain instances. For example, the RCS pressure in this analysis is based on a nominal value of 2,250 psia plus an uncertainty allowance +42.0 psi. All input parameters are chosen consistent with accepted analysis methodology.

Some of the most critical items are the RCS initial conditions, core decay heat, safety injection flow, and primary and secondary metal mass and steam generator heat release modeling. Specific assumptions concerning each of these items are discussed in the following paragraphs. Tables 6.2D-1 and 6.2D-2 present key data assumed in the analysis.

The core thermal power of 3479 MWt adjusted for calorimetric error (that is, 102 percent of 3411 MWt) was used in the analysis. As previously noted, RCS operating temperatures to bound the highest average coolant temperature range were used as bounding analysis conditions. The use of higher temperatures is conservative because the initial fluid energy is based on coolant temperatures that are at the maximum levels attained in steady-state operation. Additionally, an allowance to account for instrument error and dead-band is reflected in the initial RCS temperatures. The selection of 2,250 psia plus uncertainty as the limiting pressure is considered to affect the blowdown

phase results only, since this represents the initial pressure of the RCS. The RCS rapidly depressurizes from this value until the point at which it equilibrates with containment pressure.

The rate at which the RCS blows down is initially more severe at the higher RCS pressure. Additionally, the RCS has a higher fluid density at the higher pressure (assuming a constant temperature) and subsequently has a higher RCS mass available for releases. Thus, 2,250 psia plus uncertainty was selected for the initial pressure as the limiting case for the long-term M&E release calculations.

The selection of the fuel design features for the long-term M&E release calculation is based on the need to conservatively maximize the energy stored in the fuel at the beginning of the postulated accident (that is, to maximize the core stored energy). The core stored energy, selected to bound the 17x17 fuel product used at DCPP Unit 1 and Unit 2, was 3.50 full-power seconds (FPS). The margins in the core stored energy include a statistical uncertainty in order to address the thermal fuel model and associated manufacturing uncertainties and the time in the fuel cycle for maximum fuel densification. Thus, the analysis very conservatively accounts for the stored energy in the core.

A margin in the RCS volume of 3 percent (which is composed of a 1.6-percent allowance for thermal expansion and a 1.4-percent allowance for uncertainty) was modeled.

A uniform steam generator tube plugging level of 0 percent was modeled. This assumption maximizes the reactor coolant volume and fluid release by virtue of consideration of the RCS fluid in all steam generator tubes. During the post-blowdown period, the steam generators are active heat sources since significant energy remains in the secondary metal and secondary mass that has the potential to be transferred to the primary side. The 0 percent tube plugging assumption maximizes the heat transfer area and, therefore, the transfer of secondary heat across the steam generator tubes. Additionally, this assumption reduces the reactor coolant loop resistance, which reduces the ΔP upstream of the break for the pump suction breaks and increases break flow. Thus, the analysis conservatively accounts for the level of steam generator tube plugging.

The secondary-to-primary heat transfer is maximized by assuming conservative heat transfer coefficients. This conservative energy transfer is ensured by maximizing the initial internal energy of the inventory in the steam generator secondary side. This internal energy is based on full-power operation plus uncertainties.

Regarding safety injection flow, the M&E release calculation considered configurations/failures to conservatively bound respective alignments. The limiting case is the failure of a train of the solid state protection system (SSPS). This configuration/failure would credit minimum flow from one centrifugal charging pump (CCP1 or CCP2), one safety injection (SI) pump, and one residual heat removal (RHR)

pump (refer to Table 6.2D-2). In addition, the containment backpressure is assumed to be equal to the containment design pressure. This assumption was shown in WCAP-10325-P-A (Reference 1) to be conservative for the generation of M&E releases.

In summary, the following assumptions were employed to ensure that the M&E releases are conservatively calculated, thereby maximizing energy release to containment:

- Maximum expected operating temperature of the RCS (100-percent full-power conditions)
- Allowance for RCS temperature uncertainty (+5.0°F)
- Margin in RCS volume of 3 percent (which is composed of 1.6-percent allowance for thermal expansion and 1.4-percent allowance for uncertainty)
- Core rated power of 3411 MWt
- Allowance for calorimetric error (+2.0 percent of power)
- Conservative heat transfer coefficients (that is, steam generator primary/secondary heat transfer, and RCS metal heat transfer)
- Allowance in core stored energy for effect of fuel densification
- A margin in core stored energy (statistical uncertainty to account for manufacturing tolerances)
- An allowance for RCS initial pressure uncertainty (+42.0 psi)
- A maximum containment backpressure equal to design pressure (47.0 psig)
- Steam generator tube plugging level (0-percent uniform)
  - Maximizes reactor coolant volume and fluid release
  - Maximizes heat transfer area across the steam generator tubes
  - Reduces coolant loop resistance, which reduces the ΔP upstream of the break for the pump suction breaks and increases break flow

Thus, based on the previously discussed conditions and assumptions, an analysis of DCPP Unit 1 and Unit 2 was made for the release of M&E from the RCS in the event of a LOCA at 3479 MWt.

6.2D.3.1.4 Description of Analyses and Evaluations

The evaluation model used for the long-term LOCA M&E release calculations is described in WCAP-10325-P-A (Reference 1).

This section presents the long-term LOCA M&E releases generated in support of DCPP Unit 1 and Unit 2.

The guidance of NRC Standard Review Plan Section 6.2.1.3 was used to determine what should be addressed in the M&E release analysis for postulated LOCAs as documented in WCAP-16638-P. Criteria applicable to DCPP are contained in 10 CFR Part 50, Appendix K, Part I.A.

To meet those requirements, the following were addressed by the LOCA M&E release analysis:

- Calculation of each phase of the accident
- Break size and location
- M&E release data
- Sources of energy

These M&E releases are then subsequently used in the containment integrity analysis.

LOCA M&E Release Phases

The containment system receives M&E releases following a postulated rupture in the RCS. These releases continue over a time period, which, for the LOCA M&E analysis, is typically divided into four phases.

Blowdown – the period of time from accident initiation (when the reactor is at steady-state operation) to the time that the RCS and containment reach an equilibrium state.

Refill – the period of time when the lower plenum is being filled by accumulator and emergency core cooling system (ECCS) water. At the end of blowdown, a large amount of water remains in the cold legs, downcomer, and lower plenum. To conservatively consider the refill period for the purpose of containment M&E releases, it is assumed that this water is instantaneously transferred to the lower plenum along with sufficient accumulator water to completely fill the lower plenum. This allows an uninterrupted release of M&E to containment. Thus, the refill period is conservatively neglected in the M&E release calculation.

Reflood – begins when the water from the lower plenum enters the core and ends when the core is completely quenched.

Post-reflood – describes the period following the reflood phase. For the pump suction break, a two-phase mixture exits the core, passes through the hot legs, and is

superheated in the steam generators prior to exiting the break as steam. After the broken loop steam generator cools, the break flow becomes two phase.

Break Size and Location

Generic studies have been performed with respect to the effect of postulated break size on the LOCA M&E releases. The double-ended guillotine break has been found to be limiting due to larger mass flow rates during the blowdown phase of the transient. During the reflood and post-reflood phases, the break size has little effect on the releases.

Three distinct locations in the RCS loop can be postulated for a pipe rupture for M&E release purposes:

- Hot leg (between vessel and steam generator)
- Cold leg (between pump and vessel)
- Pump suction (between steam generator and pump)

The break locations analyzed for this program are the double-ended pump suction (DEPS) rupture with a total break area of (10.46 ft^2) and the double-ended hot leg (DEHL) rupture with a total break area of (9.17 ft^2). Break M&E releases have been calculated for the blowdown, reflood, and post-reflood phases of the LOCA for the DEPS cases. For the DEHL case, the releases were calculated only for the blowdown. The following information provides a discussion on each break location.

The DEHL rupture has been shown in previous studies to result in the highest blowdown M&E release rates. Although the core flooding rate would be the highest for this break location, the amount of energy released from the steam generator secondary is minimal because the majority of the fluid that exits the core vents directly to containment bypassing the steam generators. As a result, the reflood M&E releases are reduced significantly as compared to either the pump suction or cold-leg break locations where the core exit mixture must pass through the steam generators before venting through the break. For the hot-leg break, generic studies have confirmed that there is no reflood peak (that is, from the end of the blowdown period the containment pressure would continually decrease). Therefore, only the M&E releases for the hot-leg break blowdown phase are calculated and presented.

The cold-leg break location has also been found in previous studies to be much less limiting in terms of the overall containment energy releases. The cold-leg blowdown is faster than that of the pump suction break, and more mass is released into the containment. However, the core heat transfer is greatly reduced, and this results in a considerably lower energy release into containment. Studies have determined that the blowdown transient for the cold leg is, in general, less limiting than that for the pump suction break. During reflood, the flooding rate is greatly reduced and the energy release rate into the containment is reduced. Therefore, the cold-leg break is bounded by other breaks and no further evaluation is necessary.

The pump suction break combines the effects of the relatively high-core flooding rate, as in the hot-leg break, and the addition of the stored energy in the steam generators. As a result, the pump suction break yields the highest energy flow rates during the post-blowdown period by including all of the available energy of the RCS in calculating the releases to containment. Thus, only the DEHL and DEPS cases are used to analyze long-term LOCA containment integrity.

Application of Single-Failure Criterion

An analysis of the effects of the single-failure criterion has been performed on the M&E release rates for each break analyzed. An inherent assumption in the generation of the M&E release is that offsite power is lost. This results in the actuation of the emergency diesel generators, required to power the safety injection system. This is not an issue for the blowdown period, which is limited by the DEHL break.

Two cases have been analyzed to assess the effects of a single failure. The first case assumes minimum safeguards safety injection (SI) flow based on the postulated single failure of a train of the solid state protection system. This results in the loss of one train of safeguards equipment. The other case assumes maximum safeguards SI flow based on no postulated failures that would impact the amount of ECCS flow. The analysis of the cases described provides confidence that the effect of credible single failures is bounded.

The M&E releases for the DCPP Unit 2 cases are shown in Tables 6.2D-3 through 6.2D-9. The Unit 2 results bound the Unit 1 results.

Blowdown M&E Release Data

The SATAN-VI code is used for computing the blowdown transient. The SATAN-VI code utilizes the control volume (element) approach with the capability for modeling a large variety of thermal fluid system configurations. The fluid properties are considered uniform and thermo-dynamic equilibrium is assumed in each element. A point kinetics model is used with weighted feedback effects. The major feedback effects include moderator density, moderator temperature, and Doppler broadening. A critical flow calculation for subcooled (modified Zaloudek), two-phase (Moody), or superheated break flow is incorporated into the analysis. The methodology for the use of this model is described in WCAP-10325-P-A (Reference 1).

Table 6.2D-3 presents the calculated M&E release for the blowdown phase of the DEHL break without any pumped safety injection for DCPP Unit 2. For the hot leg break M&E release tables, break path 1 refers to the M&E exiting from the reactor-vessel side of the break; break path 2 refers to the M&E exiting from the steam-generator side of the break. Tables 6.2D-4 and 6.2D-5 present the M&E balance data for the Unit 2 DEHL case.

Table 6.2D-6 presents the calculated M&E releases for the blowdown phase of the DEPS break. For the pump suction breaks, break path 1 in the M&E release tables refers to the M&E exiting from the steam-generator side of the break. Break path 2 refers to the M&E exiting from the pump-side of the break.

Refill M&E Release Data

As noted earlier in the discussion of LOCA M&E release phases, the refill period is conservatively neglected in the M&E release calculation.

Reflood M&E Release Data

The WREFLOOD code is used for computing the reflood transient. The WREFLOOD code consists of two basic hydraulic models: one for the contents of the reactor vessel and one for the coolant loops. The two models are coupled through the interchange of the boundary conditions applied at the vessel outlet nozzles and at the top of the downcomer. Additional transient phenomena such as pumped SI and accumulators, reactor coolant pump performance, and steam generator release are included as auxiliary equations that interact with the basic models as required. The WREFLOOD code permits the capability to calculate variations during the core reflooding transient of basic parameters such as core flooding rate, core and downcomer water levels, fluid thermo-dynamic conditions (pressure, enthalpy, density) throughout the primary system, and mass flow rates through the primary system. The code permits hydraulic modeling of the two flow paths available for discharging steam and entrained water from the core to the break, that is, the path through the broken loop and the path through the unbroken loops.

A complete thermal equilibrium mixing condition for the steam and ECCS injection water during the reflood phase has been assumed for each loop receiving ECCS water. This is consistent with the usage and application of the WCAP-10325-P-A (Reference 1) M&E release evaluation model in contemporary analyses, for example, D. C. Cook Docket 50-315 (Reference 3). Even though the WCAP-10325-P-A (Reference 1) model credits steam/water mixing only in the intact loop and not in the broken loop, the justification, applicability, and NRC approval for using the mixing model in the broken loop has been documented (Reference 3). Moreover, this assumption is supported by test data and is further discussed below.

The model assumes a complete mixing condition (that is, thermal equilibrium) for the steam/water interaction. The complete mixing process, however, is made up of two distinct physical processes. The first is a two-phase interaction with condensation of steam by cold ECCS water. The second is a single-phase mixing of condensate and ECCS water. Since the steam release is the most important influence to the containment pressure transient, the steam condensation part of the mixing process is the only part that need be considered. (Any spillage directly heats only the sump.)

The most applicable steam/water mixing test data have been reviewed for validation of the containment integrity reflood steam/water mixing model. This data was generated in 1/3-scale tests (Reference 4), which were the largest scale data available in 1975 and thus most clearly simulated the flow regimes and gravitational effects that would occur in a pressurized water reactor (PWR). These tests were designed specifically to study the steam/water interaction for PWR reflood conditions.

A group of 1/3-scale tests corresponds directly to containment integrity reflood conditions. The injection flow rates for this group cover all phases and mixing conditions calculated during the reflood transient. The data from these tests were reviewed and discussed in detail in WCAP-10325-P-A (Reference 1). For all of these tests, the data clearly indicate the occurrence of very effective mixing with rapid steam condensation. The mixing model used in the containment integrity reflood calculation is, therefore, wholly supported by the 1/3-scale steam/water mixing data.

Additionally, the following justification is also noted. The post-blowdown limiting break for the containment integrity peak pressure analysis is the pump suction double-ended rupture break. For this break, there are two flow paths available in the RCS by which M&E may be released to containment. One is through the outlet of the steam generator, the other via reverse flow through the reactor coolant pump. Steam that is not condensed by ECCS injection in the intact RCS loops passes around the downcomer and through the broken loop cold leg and pump in venting to containment. This steam also encounters ECCS injection water as it passes through the broken loop cold leg, complete mixing occurs and a portion of it is condensed. It is this portion of steam that is condensed that is taken credit for in this analysis. This assumption is justified based upon the postulated break location, and the actual physical presence of the ECCS injection nozzle. A description of the test and test results are contained in WCAP-10325-P-A (Reference 1) and operating license Amendment No. 126 for D.C. Cook (Reference 3).

Table 6.2D-7 presents the calculated M&E releases for the reflood phase of the pump suction double-ended rupture with a single failure of a train of the solid state protection system (SSPS) for DCPP Unit 2. The principal parameters during reflood are given in Table 6.2D-8 for the bounding DEPS case.

<u>Post-Reflood M&E Release Data</u>

The FROTH code (Reference 5) is used for computing the post-reflood transient. The FROTH code calculates the heat release rates resulting from a two-phase mixture present in the steam generator tubes. The M&E releases that occur during this phase are typically superheated due to the depressurization and equilibration of the broken loop and intact loop steam generators. During this phase of the transient, the RCS has equilibrated with the containment pressure. However, the steam generators contain a secondary inventory at an enthalpy that is much higher than the primary side. Therefore, there is a significant amount of reverse heat transfer that occurs. Steam is produced in the core due to core decay heat. For a pump suction break, a two-phase

fluid exits the core, flows through the hot legs, and becomes superheated as it passes through the steam generator (Reference 6). Once the broken loop cools, the break flow becomes two phase. During the FROTH calculation, ECCS injection is addressed for both the injection phase and the recirculation phase. The FROTH code calculation stops when the secondary side equilibrates to the saturation temperature (T_{sat}) at the containment design pressure; after this point the EPITOME code completes the steam generator depressurization (refer to Sections 6.2D.3.1.4, Reflood Mass and Energy Release Data and 6.2D.3.1.4, Decay Heat Model for additional information).

The methodology for the use of this model is described in WCAP-10325-P-A (Reference 1). The M&E release rates are calculated by FROTH and EPITOME until the time of containment depressurization. After containment depressurization (14.7 psia), the M&E release available to containment is generated directly from core boil-off/decay heat.

Table 6.2D-9 presents the two-phase post-reflood M&E release data for the pump suction double-ended break case with a single failure of a train of the SSPS.

Decay Heat Model

ANS Standard 5.1 (Reference 7) was used in the LOCA M&E release model for DCPP Unit 1 and Unit 2 for the determination of decay heat energy. This standard was balloted by the Nuclear Power Plant Standards Committee in October 1978 and subsequently approved. The official standard (Reference 7) was issued in August 1979. Table 6.2D-10 lists the decay heat generation rate used in the DCPP M&E release analysis.

Based upon NRC staff review, (Safety Evaluation Report [SER] of the March 1979 evaluation model [Reference 1]), use of the ANS Standard-5.1, November 1979 decay heat model was approved for the calculation of M&E releases to the containment following a LOCA.

Significant assumptions in the decay heat generation rate for use in the LOCA M&E releases analysis include the following:

- The decay heat sources considered are fission product decay and heavy element decay of U-239 and Np-239.
- The decay heat power from fissioning isotopes other than U-235 is assumed to be identical to that of U-235.
- The fission rate is constant over the operating history of maximum power level.

- The factor accounting for neutron capture in fission products has been taken from Equation 11 of Reference 7 up to 10,000 seconds and from Table 10 of Reference 7 beyond 10,000 seconds.

- The fuel has been assumed to be at full power for 10^8 seconds.

- The number of atoms of U-239 produced per second has been assumed to be equal to 70 percent of the fission rate.

- The total recoverable energy associated with one fission has been assumed to be 200 MeV/fission.

- An uncertainty of two sigma (two times the standard deviation) has been applied to the fission product decay.

Steam Generator Equilibration and Depressurization

Steam generator equilibration and depressurization is the process by which secondary-side energy is removed from the steam generators in stages. The FROTH computer code calculates the heat removal from the secondary mass until the secondary temperature is the T_{sat} at the containment design pressure. After the FROTH calculations, the EPITOME code continues the FROTH calculation for steam generator cooldown removing steam generator secondary energy at different rates (that is, first- and second-stage rates). The first-stage rate is applied until the steam generator reaches T_{sat} at the user-specified intermediate equilibration pressure, when the secondary pressure is assumed to reach the actual containment pressure. Then the second-stage rate is used until the final depressurization, when the secondary reaches the reference temperature of T_{sat} at 14.7 psia, or 212°F. The heat removal of the broken loop and intact loop steam generators are calculated separately.

During the FROTH calculations, steam generator heat removal rates are calculated using the secondary side temperature, primary side temperature, and a secondary side heat transfer coefficient determined using a modified McAdam's correlation. Steam generator energy is removed during the FROTH transient until the secondary side temperature reaches T_{sat} at the containment design pressure. The constant heat removal rate used during the first heat removal stage is based on the final heat removal rate calculated by FROTH. The steam generator energy available to be released during the first stage interval is determined by calculating the difference in secondary energy available at the containment design pressure and that at the (lower) user-specified intermediate equilibration pressure, assuming saturated conditions. This energy is then divided by the first-stage energy removal rate, resulting in an intermediate equilibration time. At this time, the rate of energy release drops substantially to the second-stage rate. The second-stage rate is determined as the fraction of the difference in secondary energy available between the intermediate equilibration and final depressurization at 212°F, and the time difference from the time of the intermediate equilibration to the user-specified time of the final depressurization at 212°F. With current methodology, all

of the secondary energy remaining after the intermediate equilibration is conservatively assumed to be released by imposing a mandatory cooldown and subsequent depressurization down to atmospheric pressure at 3,600 seconds, that is, 14.7 psia and 212°F (the M&E balance tables have this point labeled as “Available Energy”).

Sources of M&E

The sources of mass considered in the LOCA M&E release analysis are given in Table 6.2D-4 for the DEHL breaks for DCPP Unit 2. The sources of mass for the DEPS break case with the SSPS failure for DCPP Unit 2 are given in Table 6.2D-11. These sources are the RCS, accumulators, and pumped SI.

The energy inventory considered in the DEHL breaks for DCPP Unit 2 is given in Table 6.2D-5. The energy inventory for the DEPS break M&E release analysis for DCPP Unit 2 is given in Table 6.2D-12. The energy sources are as follows:

- RCS water
- Accumulator water (all inject)
- Pumped SI water
- Decay heat
- Core-stored energy
- RCS metal (includes steam generator tubes)
- Steam generator metal (includes transition cone, shell, wrapper, and other internals)
- Steam generator secondary energy (includes fluid mass and steam mass)
- Secondary transfer of energy (feedwater into and steam out of the steam generator secondary)

The analysis used the following energy reference points:
Available energy: 212°F; 14.7 psia (energy available that could be released)
Total energy content: 32°F; 14.7 psia (total internal energy of the RCS)

The M&E inventories are presented at the following times, as appropriate:

- Time zero (initial conditions)
- End of blowdown time
- End of refill time
- End of reflood time
- Time of broken loop steam generator equilibration to pressure setpoint
- Time of intact loop steam generator equilibration to pressure setpoint
- Time of full depressurization (3,600 seconds)

The energy release from the metal-water reaction rate is considered as part of the WCAP-10325-P-A (Reference 1) methodology. Based on the way that the energy in the fuel is conservatively released to the vessel fluid, the fuel cladding temperature does not increase to the point where the metal-water reaction is significant. This is in contrast to

the 10 CFR 50.46 analyses, which are biased to calculate high fuel rod cladding temperatures and, therefore, a significant metal-water reaction. For the LOCA M&E release calculation, the energy created by the metal-water reaction value is small and is not explicitly provided in the energy balance tables. The energy that is determined is part of the M&E releases and is therefore already included in the overall M&E releases for DCPP.

The sequence of events for the LOCA transients is shown in Tables 6.2D-13 through 6.2D-15.

6.2D.3.1.5 Results

The consideration of the various energy sources in the long-term M&E release analysis provides assurance that all available sources of energy have been included in this analysis. The results of this analysis were provided for use in the LOCA containment integrity analysis in Section 6.2D.3.2.

6.2D.3.2 Long-Term LOCA Containment Integrity Analysis

6.2D.3.2.1 Acceptance Criteria

The containment response for design basis LOCA containment integrity is an ANS Condition IV event, an infrequent fault. The relevant requirements to satisfy NRC acceptance criteria are as follows:

- The peak calculated containment pressure should be less than the containment design pressure of 47 psig.
- The peak calculated containment average air temperature should be less than the containment design temperature of 271 °F
- The calculated pressure at 24 hours should be less than 50 percent of the peak calculated value. (This is related to the criteria for containment leakage assumptions as affecting doses at 24 hours.)

Section 6.2.1 includes an evaluation demonstrating that the containment satisfies the applicable design requirements.

6.2D.3.2.2 Introduction and Background

The purpose of the LOCA containment integrity analysis is to evaluate the bounding peak pressure and temperature of a design basis LOCA event inside containment and to demonstrate the ability of the containment heat removal systems to mitigate the accident. The impact of LOCA M&E releases on the containment pressure and temperature are assessed to ensure that the containment pressure and temperature remain below their respective design limits. The containment heat removal systems

must also be capable of maintaining the environmental qualification (EQ) parameters to within acceptable limits.

The DCPP LOCA containment response analysis considers a spectrum of cases that address differences between the individual DCPP Units, LOCA break locations, and postulated single failures (minimum and maximum safeguards). The limiting cases that address the containment peak pressure case and limiting long-term EQ temperature are presented in this section.

Calculation of the containment response following a postulated LOCA was analyzed by use of the digital computer code GOTHIC version 7.2. The GOTHIC Technical Manual (Reference 13) provides a description of the governing equations, constitutive models, and solution methods in the solver. The GOTHIC Qualifications Report (Reference 14) provides a comparison of the solver results with both analytical solutions and experimental data.

The GOTHIC containment modeling for DCPP is consistent with the NRC approved Kewaunee evaluation model (Reference 15). Kewaunee and DCPP both have large dry containment designs with similar active heat removal capabilities. The latest code version is used to take advantage of the diffusion layer model heat transfer option. This heat transfer option was approved by the NRC (Reference 15) for use in Kewaunee containment analyses with the condition that the effect of mist be excluded from what was earlier termed as the mist diffusion layer model. The GOTHIC containment modeling for DCPP has followed the conditions of acceptance placed on Kewaunee. The differences in GOTHIC code versions are documented in Appendix A of the GOTHIC User Manual Release Notes (Reference 16). Version 7.2 is used consistently with the restrictions identified in Reference 15; none of the user-controlled enhancements added to version 7.2 were implemented in the DCPP containment model. A description of the DCPP GOTHIC model is provided later in this section.

6.2D.3.2.3 Input Parameters and Assumptions

The major modeling input parameters and assumptions used in the DCPP LOCA containment evaluation model are identified in this section. The assumed initial conditions and input assumptions associated with the fan coolers and containment sprays are listed in Table 6.2D-17. The containment spray flow data used in the analysis are presented in Table 6.2D-18. The function of the residual heat removal system (RHR) during a LOCA is to remove heat from the core by way of the ECCS. The ECCS recirculation and CCW system parameters are outlined in Table 6.2D-17. The containment structural heat sink input is provided in Table 6.2D-19, and the corresponding material properties are listed in Table 6.2D-20.

The LOCA containment analysis described here uses revised input and assumptions in support of the current design, while addressing analytical conservatisms. The assumptions used in the M&E release input model and the containment pressure input model are discussed in WCAP-10325-P-A (Reference 1) and WCAP-8264-P-A Revision

1 (Reference 5). Significant assumptions contained in the LOCA containment integrity analysis include:

(1) For all the long term cases and the base hot leg cases, there is a loss of offsite power coincident with the LOCA. For the hot leg break case with safety injection, off site power is available to allow the safety injection to begin during the blowdown.

(2) In all cases, two containment fan cooler units (CFCUs), each from separate trains, are assumed to be unavailable due to maintenance

(3) The long term decay heat steaming M&E release calculation assumes that:

(a) All the decay heat is released to the containment as steam to maximize the pressure and temperature of the containment vapor region,

(b) 102% reactor power and ANS 1979 +2 sigma decay heat,

(4) The bounding auxiliary saltwater (ASW) temperature is 64 °F

(a) It should be noted that a separate set of analyses assuming a 70 °F ocean water temperature addresses operation with an elevated ultimate heat sink temperature (refer to Section 9.2.2.3.13).

The following are notable features of the current containment integrity analysis.

Decay heat steaming M&E release rates, after the end of the sensible heat release from the RCS and steam generators, are calculated each time step by GOTHIC using the transient containment pressure and recirculation safety injection water temperature.

Non-condensable accumulator gas release is modeled in the GOTHIC model (refer to Section 6.2D.3.2.5); no accumulator nitrogen gas addition due to refill is considered in the analysis.

A recirculation system model that couples the RHR, CCW, CFCUs and auxiliary saltwater systems was developed. Detailed accounting of CCW flow rates through the containment heat removal systems was used for the CFCUs, RHR heat exchangers, and miscellaneous CCW heat loads.

The DCPP LOCA containment response analysis considered a spectrum of cases. The cases address break locations, and postulated single failures (minimum and maximum safeguards) for each DCPP unit. Only the limiting cases, which address the containment peak pressure and limiting long-term EQ temperature, are presented. The LOCA pressure and temperature response analyses were performed assuming a loss of offsite power and a worst single failure (loss of one solid state protection system [SSPS]

train, i.e., loss of one containment cooling train). The active heat removal available in the long term cooling case is:

- One containment spray pump during injection-phase only
- Two containment fan cooler units
- One RHR pump and one RHR heat exchanger
- Two CCW pumps and one CCW heat exchanger
- One ASW pump.

The Unit 2 DEHL break produces the overall bounding peak pressure at the end of the blowdown. The calculation for the DEPS case was performed for a 116 day ($1x10^7$ second) transient in support of long term EQ temperatures. The sequence of events for the DEHL containment peak pressure case is shown in Table 6.2D-13 and the DEPS long term EQ temperature case for Unit 1 and Unit 2 are shown in Tables 6.2D-14 and 6.2D-15, respectively.

6.2D.3.2.4 Description of Analyses and Evaluations

Plant input assumptions (identified in Section 6.2D.3.2.3) are the same as, or slightly more restrictive, than in the original analyses performed with the COCO code (Reference 18). Benchmarking between the DCPP COCO and GOTHIC models was performed to confirm consistency in the implementation of the plant input values.

Noding Structure

The DCPP GOTHIC containment model is comprised of one control volume with separate vapor and liquid regions. M&E releases, containment spray injection, and sump water recirculation are modeled using boundary conditions. A cooler component is used to model CFCUs heat removal. Injection of accumulator nitrogen during the event is modeled with a boundary condition.

The component cooling water system model is comprised of three control volumes (CFCU cooling water, the hot side of the CCW system, and the cold side of the CCW system) and uses GOTHIC component models for the RHR and CCW heat exchangers. A heater component models the CFCU heat transfer to the CCW water. Boundary conditions model the CCW flow through the CFCUs, RHR heat exchangers, and miscellaneous CCW heat loads.

Volume Input

Values for the volume, height, hydraulic diameter, and elevation are input for each node. The containment is modeled as a single control volume. The lower bound free

volume is 2,550,000 ft^3. The hydraulic diameter, height, and floor elevation input values are 24.1 ft, 166 ft, and 91 ft, respectively.

A conservatively calculated pool surface area is used to model interfacial heat and mass transfer to liquid pools on the various floor surfaces in the containment volume. The conductor representing the floor is essentially insulated from the vapor region after the sump pool develops; however, there can still be condensation or evaporation from the surface of the liquid pools. Using this method to model the interfacial heat and mass transfer between the pools and the atmosphere was previously approved by the NRC for the Kewaunee containment DBA and equipment qualification analyses (Reference 15).

Initial Conditions

The containment initial conditions for containment integrity cases are:

- Pressure: 16.0 psia
- Relative Humidity: 18 percent
- Temperature: 120°F

The LOCA containment response model contains volumes representing the CCW system. The system volumes are water solid and assumed to be initially at 50 psia and 90°F.

Flow Paths

Flow boundary conditions linked to functions that define the M&E release model the LOCA break flow to the containment. The boundary conditions are connected to the containment control volume via flow paths. The containment spray is modeled as a boundary condition connected to the containment control volume via a flow path.

The flow rates through the flow paths are specified by the boundary conditions, so the purpose of the flow path is to direct the flow to the proper control volume. The flow path input is mostly arbitrary. Standard values are used for the area, hydraulic diameter, friction length, and inertia length of the flow path. Since this is a single volume lumped parameter model, the elevation of the break flow paths is arbitrarily set to 100 ft and the elevation of the spray flow paths is arbitrarily set to 70 ft above the containment floor.

Heat Sinks

The structural heat sinks in the containment are modeled as GOTHIC thermal conductors. The heat sink geometry data is based on conservatively low surface areas and is summarized in Table 6.2D-19. A thin air gap is assumed to exist between the steel and concrete for steel-jacketed heat sinks. A gap conductance of 10 Btu/hr-ft^2-°F is conservatively assumed between steel and concrete. The volumetric heat capacity and thermal conductivity for the heat sink materials are summarized in Table 6.2D-20.

Heat and Mass Transfer Correlation

GOTHIC has several heat transfer coefficient options that can be used for containment analyses. For the DCPP GOTHIC model, the direct heat transfer coefficient set is used with the diffusion layer model mass transfer correlation for the heat sinks inside containment. This heat transfer methodology was reviewed by the NRC and approved for use in containment DBA analyses in the Kewaunee analysis (Reference 15). The diffusion layer model correlation does not require the user to specify a revaporization input value, as was done in previous analyses using the Uchida correlation.

Split heat transfer coefficients are used for the heat sinks representing walls and floors. The split coefficient allows one thermal conductor to model heat transfer to both the water and vapor regions. The submerged portions of conductors are essentially insulated from the vapor after the pool develops. The fraction of the wall that is not submerged uses the vapor heat transfer coefficient as described above. GOTHIC calculates the fraction of the walls that are submerged in the sump water. The floors are submerged quickly.

Sump Recirculation

The calculated containment peak pressure and temperature occur before the transfer to cold leg recirculation. However, a sump recirculation model comprised of simplified RHR and CCW system models was added to the DCPP containment model for the long-term LOCA containment pressure and temperature response calculation.

ECCS recirculation is actuated after a low RWST level signal and the ECCS takes suction from the containment sump. The RHR heat exchanger cools the water before it is injected back into the reactor vessel. The RHR heat exchanger is cooled by CCW and ASW provides the ultimate heat sink, cooling the CCW heat exchangers.

Switchover to hot leg recirculation is assumed to occur at 7 hours.

6.2D.3.2.5 Boundary Conditions

M&E Release

Section 6.2D.3.1 describes the long-term LOCA M&E release. The LOCA M&E release rates are generated using the Westinghouse methodology (Reference 1). M&E releases are calculated for both sides of the double-ended break in the coolant loop: the vessel side of the break and the steam generator side of the break. The M&E releases are input to the GOTHIC containment model as mass flow rates and enthalpies via boundary conditions connected to the containment volume with flow paths.

During blowdown, the liquid portion of the break flow is released as drops with an assumed diameter of 100 microns (0.00394 inches). This is consistent with the

methodology approved for Kewaunee (Reference 15) and is based on data presented in Reference 17. After blowdown, the liquid release is assumed to be a continuous pour into the sump.

GOTHIC uses the M&E release tables from the time of accident initiation to 3,600 seconds, the time at which all energy in the primary heat structures and steam generator secondary system is assumed to be released/depressurized to atmospheric pressure, (i.e., 14.7 psia and 212°F). After primary system and secondary system energy have been released, the M&E releases to the containment are due to long-term steaming of decay heat. GOTHIC calculates the decay heat steaming M&E releases within user defined control variables. The steaming calculations incorporate the transient containment pressure and RHR recirculated ECCS enthalpy to calculate the M&E release. The calculations are essentially the same as the Westinghouse methodology previously approved by the NRC, except the calculations are performed within the GOTHIC code.

The ANS Standard 5.1 decay heat model (+2 sigma uncertainty) (Reference 7) is used to calculate the long-term boil-off from the core. All the decay heat is assumed to produce steam from the recirculated ECCS water. The remainder of the ECCS water is returned to the sump region of the containment control volume. These assumptions are consistent with the long-term M&E release methodology documented in Reference 1.

Containment Fan Coolers

The CFCUs are modeled with a GOTHIC cooler component. There are a total of five CFCUs in three trains. In all cases, two CFCUs are assumed to be out of service for maintenance. An inherent assumption in the LOCA containment analysis is that offsite power is lost with the pipe rupture. This results in the actuation of three emergency diesel generators (EDGs), powering the two trains of safeguards equipment. Startup of the EDGs delays the operation of the safeguards equipment that is required to mitigate the transient. There are two trains of the SSPS that actuate the two trains of emergency safeguards. The failure of one train of SSPS will fail one train of safeguards. A minimum of two CFCUs are available and a maximum of three CFCUs are assumed to be available based on the single failure assumptions.

Three long term cases are analyzed to assess the effects of single failures. The first case assumes minimum safeguards based on the postulated single failure of an SSPS train. This assumption results in the loss-of-one train of safeguards equipment. The operating equipment is conservatively modeled as: two CFCUs, one containment spray pump, one train of RHR, and one CCW heat exchanger. The other two cases assume maximum safeguards, in which both trains of SSPS are available. With the maximum safeguards cases, the single failure assumptions are the failure of one containment spray pump or the failure of one CFCU. The analysis of these three cases provides confidence that the effect of credible single failures is bounded.

The fan coolers in the containment evaluation model are modeled to actuate on the containment high pressure setpoint with uncertainty biased high, (5 psig), and begin removing heat from containment after a 48-second delay.

The CFCUs are cooled by CCW. The heat removal rate per containment fan cooler is calculated as a function of containment steam saturation temperature, the CCW inlet temperature and flow rate, and input to the GOTHIC cooler model. The heat removal rate is multiplied by the number of CFCUs available. The heat removed from the containment control volume is transferred to the CCW control volume receiving the flow through the CFCUs using a coupled heater model.

Containment Spray System

The containment spray is modeled with a boundary condition. DCPP has two trains of containment safeguards available, with one spray pump per train. An inherent assumption in the LOCA containment analysis is that offsite power is lost with the pipe rupture. This results in the actuation of the three EDGs powering the two trains of safeguards equipment. Startup of the EDGs delays the operation of the safeguards equipment that is required to mitigate the transient.

Relative to the single failure criterion with respect to a LOCA event, one spray pump is considered inoperable due to the SSPS failure (minimum safeguards case) or as a single failure in a maximum safeguards case. In the maximum safeguards case, in which the single failure is assumed to be one CFCU, two spray pumps are available.

The containment spray actuation is modeled on the containment high-high pressure setpoint with uncertainty biased high (24.7 psig). The sprays begin injecting 90°F water after a specified 80 second delay. The spray flow rate is a function of containment pressure and is presented in Table 6.2D-18. The containment spray is credited only during the injection phase of the transient and is terminated on a refueling water storage tank empty alarm after switchover to cold leg recirculation at a time based on the number of SI and spray pumps operating. The timing of recirculation and spray termination assumed in the LOCA containment analysis are presented in Table 6.2D-17.

Accumulator Nitrogen Gas Modeling

The accumulator nitrogen gas release is modeled with a flow boundary condition in the LOCA containment model. The nitrogen release rate was conservatively calculated by maximizing the mass available to be injected. The nitrogen gas release rate was used as input for the GOTHIC function, as a specified rate over a fixed time period. Nitrogen gas was released to the containment at a rate of 327.4 lbm/s. The release begins at 51.9 seconds, the minimum accumulator tank water depletion time.

6.2D.3.2.6 LOCA Containment Integrity Analysis Results

The containment pressure, steam temperature, and water (sump) temperature profiles of the DEHL peak pressure case are shown in Figures 6.2D-3 through 6.2D-5. Table 6.2D-13 provides the transient sequence of events for the DEHL transient.

The containment pressure, steam temperature, and water (sump) temperature profiles of the DEPS long-term EQ temperature transient are shown in Figures 6.2D-6 through 6.2D-8(The peak DEPS values are from Unit 2). The sequence of events for the Unit 1 and Unit 2 DEPS transients are presented in Tables 6.2D-14 and 6.2D-15, respectively. The peak pressure (Figure 6.2D-6) for the DEPS case occurs at 24.1 seconds after the end of the blowdown. The fans begin to cool the containment at 48.7 seconds. Containment sprays begin injecting at 88.0 seconds. The pressure comes down as the steam generators reach equilibrium with the containment environment, but spikes up again at recirculation when the CCW temperature increases and the CCW flow rate to the CFCUs decreases. The sensible heat release from the steam generator secondary system and RCS metal is completed at 3600 seconds, but at 3798 seconds, the RWST reaches a low level alarm and spray flow is terminated. The containment pressure increases for a time and then begins to decrease over the long term as the RHR heat exchangers and CFCUs remove the heat from the containment.

Table 6.2D-21 summarizes the containment peak pressure and temperature results and pressure and temperature at 24 hours for EQ support and the acceptance limits for these parameters.

A review of the results presented in Table 6.2D-21 shows that the analysis margin (analysis margin is the difference between the calculated peak pressure and temperature and the acceptance limits) is maintained for DCPP. From the GOTHIC analysis the containment peak pressure is 41.4 psig. At 24 hours, the maximum containment pressure is 8.9 psig and the maximum temperature is 167.5°F.

6.2D.3.2.7 Conclusion

The DCPP containment can adequately account for the M&E releases that would result from a LOCA. The DCPP containment systems will provide sufficient pressure and temperature mitigation capability to ensure that containment integrity is maintained.

- The peak calculated pressure is less than the containment design pressure of 47 psig

- The peak calculated containment average air temperature is less than the containment design temperature of 271 °F

- The calculated pressure at 24 hours is less than 50 percent of the peak calculated value

6.2D.4 LONG-TERM MAIN STEAMLINE BREAK INSIDE CONTAINMENT

6.2D.4.1 MSLB Mass and Energy Release Analysis

6.2D.4.1.1 Acceptance Criteria

There are no direct acceptance criteria for MSLB M&E releases. The analysis methods follow the guidelines provided by the USNRC with respect to the sources of M&E during the various phases of a MSLB transient (refer to Section 6.2D.4.1.4).

The specific acceptance criteria for the containment response to a MSLB are discussed in Section 6.2D.4.2.1.

6.2D.4.1.2 Introduction and Background

The MSLB is classified as an American Nuclear Society (ANS) Condition IV event, an infrequent fault. A MSLB occurring inside a reactor containment structure may result in significant releases of high-energy fluid to the containment environment that could produce high pressure conditions for extended periods of time. The magnitude of the releases following a MSLB is dependent upon the plant initial operating conditions and the size of the rupture as well as the configuration of the plant steam system and the containment design. There are competing effects and credible single failures in the postulated accident scenario used to determine the worst cases for containment pressure and the associated containment temperature following a MSLB.

The DCPP MSLB and containment response analysis considers a spectrum of cases that vary the initial power condition, break size, and the postulated single failure.

6.2D.4.1.3 Input Parameters and Assumptions

Major assumptions affecting the M&E releases to containment are summarized below:

<u>Initial Steam Generator Inventory</u>

A high initial steam generator mass is assumed. The initial level corresponds to 75 percent narrow range span (NRS) at all power levels. This consists of a nominal level of 65 percent NRS plus a steam generator water level control uncertainty of 10 percent NRS.

<u>Main Feedwater System</u>

The rapid depressurization that occurs following a MSLB typically results in large amounts of water being added to the steam generators through the main feedwater system. A rapid-closing main feedwater regulating valve (MFRV) near each steam generator limits this effect. The feedwater addition to the faulted steam generator is

maximized to be conservative since it increases the water mass inventory that will be converted to steam and released from the break.

Following the initiation of the MSLB, main feedwater flow is conservatively modeled by assuming that sufficient feedwater flow is provided to match or exceed the steam flow prior to reactor trip. The initial increase in feedwater flow is in response to the MFRV opening in response to the steam flow/feedwater flow mismatch and the lower backpressure on the feedwater pump as a result of the depressurizing steam generator. This maximizes the total mass addition prior to feedwater isolation. The feedwater isolation response time, following the SI signal, is assumed to be a total of 9 seconds, accounting for delays associated with signal processing plus the valve stroke time.

The feedwater in the unisolable feedline between the MFRV and faulted steam generator is also considered in the analysis. The hot main feedwater reaches saturated conditions as the steam generator and feedline depressurize. The decrease in density as flashing occurs causes most of the unisolable feedwater to enter the faulted steam generator. This unisolable feedwater line volume of 208 ft^3 is an additional source of fluid that can increase the mass discharged out of the break.

Some cases postulate the MFRV on the faulted loop failing open. Refer to Section 6.2D.3.1.4 for information on the effects of this single failure.

Auxiliary Feedwater

Within the first minute following a MSLB, an SI signal is generated. Immediately upon receipt of the SI signal, auxiliary feedwater (AFW) is initiated. Addition of AFW to the faulted steam generator will increase the secondary mass available for release to the containment. The AFW flowrate to the faulted steam generator is maximized based on flow from both motor-driven AFW pumps and the turbine-driven AFW pump. The AFW flowrate is modeled as a function of steam generator pressure, varying from 569 gpm to 1588 gpm to the faulted steam generator.

Operator action is credited to terminate the AFW flow to the faulted steam generator after 10 minutes.

Unisolable Steamline

The initial steam in the main steamline between the break and the main steamline isolation valve (MSIV) and check valve (CV) is included in the M&E released from the break. The MSIV/CV is considered a single plant component and is credited to prevent reverse flow from the main steamline header and intact steam generators for most cases. Cases that postulate the failure of the MSIV/CV are discussed in Section 6.2D.3.1.4.

Quality of the Break Effluent

The quality of the break effluent is assumed to be 1.0, corresponding to saturated steam that is all vapor with no liquid. Although it is expected that there would be a significant quantity of liquid in the break effluent for a full double-ended rupture, the all-vapor assumption conservatively maximizes the energy addition to the containment atmosphere.

Reactor Coolant System Assumptions

While the M&E released from the break is determined from assumptions that have been discussed above, the rate at which the release occurs is largely controlled by the conditions in the RCS. The major features of the primary side analysis model are summarized below:

- Continued operation of the reactor coolant pumps maintains a high heat transfer rate to the steam generators.

- The model includes consideration of the heat that is stored in the RCS metal.

- Reverse heat transfer from the intact steam generators to the RCS is modeled as the temperature in the RCS falls below the intact steam generator fluid temperature.

- Minimum flowrates are modeled from ECCS injection to conservatively minimize the amount of boron that provides negative reactivity feedback. Both the high-head and intermediate-head SI systems are considered available, with unborated purge volumes of 75.9 ft3 and 19.4 ft3, respectively. A failure of one train of ECCS is included for cases that also model a failure on a containment safeguards train (refer to Section 6.2D.3.1.4).

- The initial NSSS thermal power output assumed is 3,425 MWt, which includes the thermal power generated by the reactor coolant pumps minus heat losses to the containment and the letdown system.

- RCS average temperature is the full-power nominal value of 577.3°F (DCPP Unit 1) or 577.6°F (DCPP Unit 2) plus an uncertainty of +5.0°F.

- Core residual heat generation is assumed based on the 1979 ANS decay heat plus 2 sigma model (Reference 7).

- Conservative core reactivity coefficients (e.g. moderator temperature) corresponding to end-of-cycle conditions with the most reactive rod stuck

out of the core are assumed. This maximizes the reactivity feedback effects as the RCS cools down as a result of the MSLB.

- All cases have credited a minimum shutdown margin of 1.6 percent Δk.

6.2D.4.1.4 Description of Analyses and Evaluations

The following limitations in the NRC Safety Evaluation Report for WCAP-14882-P-A have been adhered to in the use of RETRAN-02W to analyze this event.

- The break flow model is the Moody model.
- Only steam (dry vapor) will exit the break, since perfect steam separation in the steam generators is assumed.
- The superheat in the steam released to the containment is not evaluated. Any superheated conditions will be reset to be equal to the saturation temperature.

Case Definitions and Single Failures

There are many factors that influence the quantity and rate of the M&E release from the main steamline. To encompass these factors, a spectrum of cases varies the initial power level, break size and the single failure. This section summarizes the basis of the cases that have been defined for DCPP.

The power level at which the plant is operating when the MSLB is postulated can cause different competing effects that make it difficult to pre-determine a single limiting case. For example, at higher power levels there is less initial water/steam in the steam generator, which is a benefit. However, at a higher power level there is a higher initial feedwater flowrate, higher feedwater temperature, higher decay heat, and there is a higher rate of heat transfer from the primary side, which are all penalties. Therefore, cases consider initial power levels varying from full power to zero power. The specific initial power levels that are analyzed are 100, 70, 30 and 0 percent, as presented in WCAP-8822. A calorimetric uncertainty of 2 percent is applied to the initial condition for the full power case.

Most cases consider the largest possible break, a double-ended rupture immediately downstream of the flow restrictor at the outlet of the steam generator. This break conservatively bounds the plant response to a smaller break size. The effective forward break area is limited by the 1.4 ft^2 cross-sectional area of the flow restrictor that is integral to the replacement steam generator. The actual break area is the cross-sectional area of the pipe, which is 3.67 ft^2.

A few cases also consider the effects of a smaller, split break which allows contributing steam from the main steamline header and the intact steam generators until the intact

loop MSIVs close. This break size is defined to be the largest break that does not generate a low main steamline pressure signal. Instead, split breaks have to rely on high containment pressure signals to actuate SI (and reactor trip, feedline isolation, etc.) and main steamline isolation. The split break is only considered when the faulted loop MSIV/CV is postulated as the single failure. The split breaks have the penalty of a higher integrated M&E released to the containment, but the smaller break size provides a beneficial reduction in the rate that the M&E is released.

Several single failures can be postulated that would impair the performance of various MSLB protection systems. The single failures either reduce the heat removal capacity of the containment safeguards systems or increase the energy release from the MSLB. The single failures that have been postulated for DCPP are summarized below. The analysis cases separately consider each single failure at each initial power level.

(1) Containment Safeguards Failure

This is a failure of one safeguards train. The main impact is on the containment response analysis, where the active heat removal is reduced by the loss of one train of fan coolers and one containment spray pump. This failure also causes the loss of one train of ECCS in the MSLB M&E release analysis.

(2) MFRV Failure

The MFRV is a fast-closing (7 second stroke time) valve in the feedwater system that is the preferred (fastest) method for terminating feedwater addition to the faulted steam generator during a MSLB. If the MFRV on the faulted loop fails open, the back-up main feedwater isolation valve (MFIV) is credited to close 64 seconds after an SI setpoint is reached. The slower closure time creates the possibility of additional pumped feedwater entering the faulted steam generator. Although the main feedwater pumps trip on an SI signal, the condensate pumps do not trip and can continue to provide pumped flow when the faulted steam generator depressurizes below approximately 625 psia.

(3) MSIV/CV Failure

The MSIV/CV is considered a single plant component that is credited to function when another single failure is postulated. When the MSIV/CV is postulated as the single failure, this means the failure of both the forward flow isolating function (MSIV) and the reverse flow isolation function (CV) on the faulted loop. Therefore the main steamline blowdown initially includes steam mass from the main steamline header and intact steam generators. Isolation of the break occurs due to the closure of the MSIVs on the intact steam generators.

<u>Protection Logic and Setpoints</u>

The pertinent signals and setpoints that are actuated in these analyses are summarized below.

The first SI signal is generated by a low steamline pressure signal in all double-ended rupture cases. The assumed setpoint is 458.7 psia (DCPP low steamline pressure setpoint is 600 psig), with a lead/lag of 50/5 seconds. For split rupture cases, the first SI signal that is credited in the analysis comes from the high containment pressure setpoint (5.0 psig) (DCPP high containment pressure setpoint is 3 psig). The SI signal is credited to cause:

- Start of charging, RHR and SI pumps
- Reactor trip
- Start of auxiliary feedwater pumps
- Closure of MFRVs and MFIVs
- Trip of main feedwater pumps (only credited for MFRV failure cases).

Most cases isolate the MSLB to blowdown of a single steam generator by fast closure of the passive CV, which prevents reverse flow from the intact main steamline. For cases that model the MSIV/CV failure on the faulted loop, the closure of the intact MSIVs are credited due to the low steamline pressure signal (for double-ended ruptures) or the high-high containment pressure signal (for split breaks)(DCPP high-high containment pressure setpoint is 22 psig which initiates Phase B containment isolation).

6.2D.4.1.5 MSLB Inside Containment Mass and Energy Release Results

Sixteen MSLB cases were analyzed varying the initial power level, break size and the assumed single failure.

The limiting containment pressure case is double-ended rupture MSLB initiated from 70 percent power with the faulted loop MFRV failed open. The break flowrate is shown in Figure 6.2D-1 and the break enthalpy is shown in Figure 6.2D-2. (refer to Section 6.2D.4.2 for the basis of this case being the limiting transient.) Section 6.2D.4.2 also contains the sequence of events for this case, including primary, secondary, and containment system actuations.

A sensitivity analysis was performed to consider the effects of the plant response for Unit 1 versus Unit 2. It was determined that the plant response to this event is

essentially the same for either unit. The MSLB analysis results bound the plant response for either Unit 1 or Unit 2.

The MSLB inside containment event has been analyzed with conservative assumptions to maximize the M&E release from the break. The M&E releases from this analysis are used as input to the containment integrity analysis documented in Section 6.2D.4.2.

6.2D.4.2 Long-Term MSLB Containment Integrity Analysis

6.2D.4.2.1 Acceptance Criteria

The containment response to a MSLB is analyzed to ensure that the containment pressure remains below the containment design pressure of 47.0 psig. There is no explicit design temperature limit to be met for the MSLB containment response.

6.2D.4.2.2 Introduction and Background

Containment integrity analyses are performed to ensure that pressure inside containment will remain below the containment building design pressure for a postulated secondary system pipe rupture. The M&E release analysis discussed in Section 6.2D.4.1 is input to this analysis.

6.2D.4.2.3 Input Parameters and Assumptions

This section identifies the major input values that are used in the MSLB containment response analysis. The assumed initial conditions and the input assumptions associated with the fan coolers and containment sprays are listed in Table 6.2D-22. The containment thermal conductor input is provided in Table 6.2D-19, and the corresponding material properties are listed in Table 6.2D-20.

6.2D.4.2.4 Description of Analyses and Evaluations

The containment response analysis uses the GOTHIC computer code. The GOTHIC Technical Manual (Reference 13) provides a description of the governing equations, constitutive models, and solution methods in the solver. The GOTHIC Qualifications Report (Reference 14) provides a comparison of the solver results with both analytical solutions and experimental data.

The DCPP GOTHIC containment evaluation model consists of a single lumped-parameter node; the diffusion layer model is used for heat transfer to all structures in the containment. Plant input assumptions (identified in Section 6.2D.3.2.3) are the same as, or slightly more restrictive, than in the original analyses performed with the COCO code (Reference 18). Benchmarking between the DCPP COCO and GOTHIC models was performed to confirm consistency in the implementation of the plant input values. The benchmarking results show that the GOTHIC model predicted similar transient results.

This MSLB containment response analysis uses GOTHIC version 7.2. This code version is used to take advantage of the diffusion layer model heat transfer option. This heat transfer option was approved by the NRC (Reference 19) for use in Kewaunee containment analyses with the condition that mist be excluded from what was earlier termed as the mist diffusion layer model. The GOTHIC containment modeling for DCPP has followed the conditions of acceptance placed on Kewaunee. Kewaunee and DCPP both have large, dry containments. Changes in the GOTHIC code versions are detailed in Appendix A of the GOTHIC User Manual Release Notes (Reference 16). Version 7.2 is used consistent with the restrictions identified in Reference 19; none of the user-controlled enhancements added to version 7.2 were implemented in the DCPP containment model.

6.2D.4.2.5 Results

Sixteen MSLB cases were analyzed varying the initial power level and the assumed single failure. The M&E release from the break was calculated using the RETRAN-02W code (refer to Section 6.2D.4.1.4), while the containment pressure response was determined with the GOTHIC code. The MSLB results are based on Unit 2 configuration, which was determined to be bounding for Unit 1.

The peak pressures and peak temperatures from the spectrum of cases are listed in Table 6.2D-23. The limiting peak pressure case is a MFRV failure at 70 percent power assuming a full double-ended rupture. The sequence of events for this limiting case is listed in Table 6.2D-24. The containment pressure and temperature transient for the limiting case is shown in Figures 6.2D-9 and 6.2D-10, respectively.

6.2D.4.2.6 Conclusions

The peak containment pressure is 42.8 psig, which is below the containment design pressure of 47.0 psig. The analysis performed demonstrates that the containment pressure remains below the containment design pressure throughout the transient for a postulated secondary system pipe rupture. Thus the containment integrity has been demonstrated and the applicable acceptance criteria are therefore met.

6.2D.5 REFERENCES

1. Westinghouse LOCA Mass and Energy Release Model for Containment Design - March 1979 Version, WCAP-10325-P-A (Proprietary), WCAP-10326-A (Non-Proprietary), May 1983.

2. Deleted in Revision 22.

3. License Amendment No.126 for D. C. Cook Nuclear Plant Unit 1, Operating License No. DPR-58 (TAC No. 71062), June 9, 1989.

4. Mixing of Emergency Core Cooling Water with Steam; 1/3-Scale Test and Summary, WCAP-8423, EPRI 294-2, Final Report, June 1975.

5. Westinghouse Mass and Energy Release Data for Containment Design, WCAP-8264-P-A, Rev. 1 (Proprietary), WCAP-8312-A, Rev. 2 (Non-Proprietary), August 1975.

6. Letter from Herbert N. Berkow, Director (NRC) to James A. Gresham (Westinghouse), “Acceptance of Clarifications of Topical Report WCAP-10325-P-A, ‘Westinghouse LOCA Mass and Energy Release Model for Containment Design - March 1979 Version’, (TAC No. MC7980)”.

7. ANSI/ANS-5.1 1979, “American National Standard for Decay Heat Power in Light Water Reactors”, August 29, 1979.

8. Letter from Cecil O. Thomas (NRC), “Acceptance for Referencing of Licensing Topical Report WCAP-8821(P)/8859(NP), TRANFLO Steam Generator Code Description”, and “WCAP-8822(P)/8860(NP), “Mass and Energy Release Following a Steam Line Rupture,” August 1983.

9. R. E. Land, Mass and Energy Releases Following a Steam Line Rupture, WCAP-8822 (Proprietary), WCAP-8860 (Non-Proprietary), September 1976.

10. Deleted in Revision 22

11. J. C. Butler and P. A. Lin, Mass and Energy Releases Following a Steam Line Rupture, Supplement 2 – Impact of Steam Superheat in Mass/Energy Releases Following a Steamline Rupture for Dry and Subatmospheric Containment Designs, WCAP-8822-S2-P-A (Proprietary), September 1986

12. D. S. Huegel, et al. RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, [RETRAN-02W] WCAP-14882-P-A (Proprietary), April 1999, WCAP-15234-A (Non-Proprietary), May 1999.

13. GOTHIC Containment Analysis Package Technical Manual, Version 7.2, NAI-8907-06, Rev. 15, September 2004.

14. GOTHIC Containment Analysis Package Qualification Report, Version 7.2, NAI-8907-09, Rev. 8, September 2004.

15. License Amendment No. 169 for Kewaunee Nuclear Power Plant, Operating License No. DPR-43 (TAC No. MB6408), September 29, 2003.

16. GOTHIC Containment Analysis Package User Manual, Version 7.2, NAI-8907-02, Rev. 16, September 2004.

17. Brown and York, “Sprays formed by Flashing Liquid Jets”, AICHE Journal, Volume 8, #2, May 1962.

18. F. M. Bordelon and E. T. Murphy, Containment Pressure Analysis Code (COCO), WCAP-8327 (Proprietary), WCAP-8326 (Non-Proprietary), July 1974.

19. Letter from Anthony C. McMurtray (NRC) to Thomas Coutu (NMC), “Enclosure 2, Safety Evaluation,” September 29, 2003.

TABLE 6.2D-1

SYSTEM PARAMETERS INITIAL CONDITIONS

Parameters	Unit 1 Value	Unit 2 Value
Core Thermal Power (MWt)	3479.0	Same
RCS Total Flow Rate (lbm/sec)	36888.88	37222.22
Vessel Outlet Temperature (°F)	615.1	Same
Core Inlet Temperature (°F)	549.5	550.1
Vessel Barrel-Baffle Configuration	Downflow	Upflow
Initial Steam Generator Steam Pressure (psia)	881.0	885.0
Steam Generator Design	Δ54	Same
Steam Generator Tube Plugging (%)	0	0
Initial Steam Generator Secondary Side Mass (lbm)	132953.7	Same
Assumed Maximum Containment Backpressure (psia)	61.7	Same
Accumulator		
Water volume (ft^3) per accumulator	850.0	Same
N_2 cover gas pressure (psia)	577.2	Same
Temperature (°F)	120.0	Same
SI Start Time, (sec) [total time from beginning of event which includes the maximum delay from reaching the setpoint]	31.1	31.3

Note:
Core thermal power, RCS total flow rate, RCS coolant temperatures, and steam generator secondary side mass include appropriate uncertainty and/or allowance.

TABLE 6.2D-2

SI FLOW MINIMUM SAFEGUARDS – BOTH UNITS

RCS Pressure (psig)	Total Flow (gpm)
Injection Mode (reflood phase)	
0	4805.0
20	4558.8
40	4298.6
60	4017.4
80	3710.2
100	3363.0
120	2950.4
140	2403.8
160	1386.2
180	780.6
200	775.0
Cold-Leg Recirculation Flow	3252.3
Hot-Leg Recirculation Flow	3071.7

TABLE 6.2D-3

DCPP UNIT 2 DEHL BREAK
NO SAFETY INJECTION
MASS AND ENERGY RELEASES DURING BLOWDOWN

Time (s)	Break Path No. 1 Flow[1] (lbm/s)	Break Path No. 1 Flow[1] Thousand (Btu/s)	Break Path No. 2 Flow[2] (lbm/s)	Break Path No. 2 Flow[2] Thousand (Btu/s)
0.00000	0.0	0.0	0.0	0.0
.00107	44,541.3	28,166.1	44,538.8	28,163.1
.00200	45,195.9	28,579.8	44,946.2	28,415.5
.00302	44,781.3	28,318.3	44,242.0	27,964.6
.00418	44,360.3	28,054.3	43,495.1	27,486.1
.101	45,600.3	29,180.2	26,321.8	16,611.8
.201	33,267.6	21,549.3	23,417.0	14,699.5
.301	33,305.3	21,529.4	20,822.6	12,924.1
.401	32,349.1	20,884.4	19,472.1	11,904.9
.501	31,804.9	20,519.1	18,650.5	11,227.7
.602	31,757.0	20,476.9	18,089.9	10,735.9
.702	31,718.8	20,458.2	17,658.8	10,352.6
.801	31,455.0	20,318.4	17,306.7	10,039.4
.901	31,016.0	20,083.4	17,042.1	9,796.6
1.00	30,566.3	19,853.9	16,829.2	9,599.1
1.10	30,194.1	19,683.7	16,682.1	9,451.1
1.20	30,012.3	19,646.5	16,563.2	9,328.8
1.30	29,787.6	19,586.1	16,532.9	9,262.9
1.40	29,464.4	19,457.8	16,556.7	9,232.0
1.50	29,049.3	19,264.7	16,602.4	9,217.8
1.60	28,611.9	19,048.4	16,669.3	9,219.3
1.70	28,244.6	18,870.7	16,750.0	9,232.1
1.80	27,948.9	18,737.3	16,837.1	9,251.8
1.90	27,615.3	18,573.6	16,922.4	9,274.5
2.00	27,190.2	18,341.3	16,996.3	9,294.7

Time (s)	Break Path No. 1 Flow[1] (lbm/s)	Break Path No. 1 Flow[1] Thousand (Btu/s)	Break Path No. 2 Flow[2] (lbm/s)	Break Path No. 2 Flow[2] Thousand (Btu/s)
2.10	26,704.6	18,060.0	17,058.9	9,312.3
2.20	26,248.5	17,795.4	17,110.8	9,327.0
2.30	25,856.3	17,573.9	17,152.8	9,339.0
2.40	25,474.8	17,357.3	17,183.4	9,347.1
2.50	25,053.4	17,106.9	17,198.6	9,348.9
2.60	24,613.6	16,836.3	17,199.5	9,344.8
2.70	24,173.4	16,560.2	17,188.2	9,335.3
2.80	23,762.0	16,302.1	17,166.7	9,321.5
2.90	23,395.3	16,073.1	17,137.0	9,304.3
3.00	23,030.8	15,842.8	17,099.2	9,283.3
3.10	22,655.9	15,597.7	17,053.6	9,258.9
3.20	22,292.5	15,355.4	16,999.6	9,230.3
3.30	21,967.1	15,138.0	16,941.5	9,200.0
3.40	21,653.4	14,924.6	16,878.8	9,167.5
3.50	21,350.8	14,714.2	16,810.6	9,132.3
3.60	21,080.5	14,523.9	16,738.5	9,095.2
3.70	20,822.7	14,338.3	16,663.4	9,056.7
3.80	20,571.6	14,151.8	16,583.8	9,015.9
3.90	20,351.7	13,984.8	16,500.0	8,973.0
4.00	20,153.7	13,830.5	16,414.2	8,929.1
4.20	19,801.1	13,541.5	16,233.0	8,836.8
4.40	19,519.2	13,292.3	16,033.2	8,735.2
4.60	19,303.2	13,081.5	15,810.9	8,622.3
4.80	19,162.2	12,916.1	15,558.8	8,494.2
5.00	19,122.7	12,817.9	15,224.4	8,321.8
5.20	19,126.1	12,749.9	14,778.4	8,089.6
5.40	19,183.3	12,715.2	14,482.9	7,943.1
5.60	19,316.8	12,709.4	14,186.0	7,795.0
5.80	19,474.5	12,712.1	13,737.5	7,561.1

Time (s)	Break Path No. 1 Flow(1) (lbm/s)	Break Path No. 1 Flow(1) Thousand (Btu/s)	Break Path No. 2 Flow(2) (lbm/s)	Break Path No. 2 Flow(2) Thousand (Btu/s)
6.00	19,682.3	12,746.5	13,338.0	7,354.5
6.20	19,940.9	12,802.3	12,987.3	7,174.8
6.40	20,353.0	12,926.6	12,623.2	6,986.7
6.60	15,413.8	10,752.9	12,297.6	6,819.0
6.80	15,236.0	10,624.6	11,933.0	6,628.2
7.00	15,366.6	10,592.9	11,574.0	6,440.0
7.20	15,549.9	10,645.6	11,272.2	6,283.6
7.40	15,660.1	10,597.4	10,978.5	6,130.4
7.60	15,835.3	10,627.2	10,688.2	5,978.1
7.80	15,997.0	10,640.0	10,404.4	5,828.7
8.00	16,185.1	10,713.2	10,136.6	5,687.6
8.20	16,233.3	10,663.1	9,888.1	5,556.5
8.40	16,136.2	10,576.9	9,648.3	5,429.6
8.60	16,204.4	10,541.3	9,419.9	5,308.6
8.80	16,402.5	10,584.6	9,198.7	5,191.3
9.00	16,589.7	10,625.8	8,984.6	5,077.8
9.20	16,775.4	10,670.0	8,780.3	4,969.7
9.40	16,967.2	10,719.0	8,577.6	4,862.4
9.60	17,173.4	10,778.1	8,379.4	4,757.7
9.80	17,433.2	10,867.7	8,183.1	4,654.3
10.0	17,813.1	11,020.7	7,988.2	4,551.9
10.2	18,281.7	11,239.0	7,795.5	4,451.1
10.2	18,278.9	11,236.9	7,792.7	4,449.6
10.4	18,141.9	11,119.8	7,602.8	4,350.6
10.6	17,891.2	10,932.2	7,410.7	4,250.7
10.8	16,616.9	10,228.6	7,217.2	4,150.6
11.0	14,856.4	9,279.7	7,028.4	4,053.5
11.2	14,805.8	9,211.3	6,844.7	3,959.8
11.4	14,894.8	9,221.9	6,670.8	3,872.0

Time (s)	Break Path No. 1 Flow(1)		Break Path No. 2 Flow(2)	
	(lbm/s)	Thousand (Btu/s)	(lbm/s)	Thousand (Btu/s)
11.6	15,011.3	9,254.7	6,508.6	3,790.7
11.8	15,151.7	9,305.3	6,352.9	3,712.3
12.0	15,257.5	9,338.6	6,206.3	3,638.4
12.2	15,283.8	9,332.3	6,063.8	3,566.4
12.4	15,192.4	9,266.5	5,926.0	3,496.8
12.6	14,757.1	9,024.1	5,789.2	3,427.7
12.8	13,959.1	8,596.3	5,656.8	3,361.2
13.0	13,455.7	8,317.8	5,523.9	3,294.8
13.2	13,252.4	8,192.2	5,396.1	3,231.8
13.4	13,121.4	8,106.7	5,272.7	3,171.3
13.6	12,981.4	8,020.4	5,154.8	3,114.0
13.8	12,793.3	7,912.3	5,038.8	3,057.4
14.0	12,553.5	7,780.8	4,928.6	3,003.8
14.2	12,261.1	7,624.2	4,820.7	2,951.3
14.4	11,945.6	7,457.6	4,715.3	2,900.2
14.6	11,639.3	7,297.6	4,612.4	2,850.4
14.8	11,352.9	7,150.1	4,513.9	2,803.1
15.0	11,077.4	7,010.9	4,416.2	2,756.3
15.2	10,807.5	6,886.4	4,320.6	2,710.6
15.4	10,210.4	6,711.1	4,230.6	2,668.0
15.6	9,769.8	6,599.5	4,140.3	2,625.1
15.8	9,490.9	6,539.3	4,052.4	2,583.4
16.0	9,155.4	6,429.6	3,962.8	2,540.5
16.2	8,692.4	6,230.4	3,865.8	2,494.1
16.4	7,934.8	5,863.4	3,755.1	2,441.7
16.6	7,268.8	5,557.7	3,621.9	2,381.9
16.8	6,820.5	5,382.5	3,467.5	2,316.6
17.0	6,387.0	5,228.3	3,289.7	2,245.2
17.2	5,926.6	5,068.9	3,095.5	2,169.9

Time (s)	Break Path No. 1 Flow(1)		Break Path No. 2 Flow(2)	
	(lbm/s)	Thousand (Btu/s)	(lbm/s)	Thousand (Btu/s)
17.4	5,426.2	4,819.1	2,894.0	2,092.0
17.6	4,998.7	4,529.1	2,694.5	2,011.4
17.8	4,606.2	4,282.6	2,515.6	1,935.3
18.0	4,277.5	4,080.7	2,353.4	1,861.1
18.2	3,992.8	3,904.4	2,215.5	1,796.0
18.4	3,755.7	3,736.3	2,095.1	1,738.0
18.6	3,530.4	3,573.1	1,989.3	1,686.3
18.8	3,304.6	3,398.0	1,894.0	1,639.4
19.0	3,067.7	3,219.6	1,806.3	1,598.2
19.2	2,812.8	3,037.2	1,723.1	1,560.7
19.4	2,545.3	2,842.0	1,645.9	1,525.1
19.6	2,295.3	2,643.4	1,573.2	1,491.5
19.8	2,081.2	2,445.3	1,491.9	1,459.4
20.0	1,903.0	2,267.3	1,409.8	1,432.3
20.2	1,784.9	2,158.5	1,315.3	1,401.7
20.4	1,693.8	2,068.8	1,233.2	1,369.0
20.6	1,606.7	1,966.1	1,161.9	1,328.4
20.8	1,514.8	1,860.1	1,108.9	1,289.5
21.0	1,412.8	1,741.8	1,066.0	1,253.8
21.2	1,326.1	1,642.4	1,038.9	1,230.3
21.4	1,251.3	1,553.6	1,020.0	1,211.5
21.6	1,159.5	1,444.2	997.1	1,185.2
21.8	1,075.7	1,347.6	965.6	1,153.5
22.0	1,005.6	1,260.1	923.1	1,114.2
22.2	941.1	1,183.5	848.3	1,035.1
22.4	870.9	1,094.7	762.7	935.4
22.6	805.0	1,013.1	709.1	871.9
22.8	738.8	929.4	613.2	754.7
23.0	684.6	860.9	499.5	616.6

Time (s)	Break Path No. 1 Flow(1)		Break Path No. 2 Flow(2)	
	(lbm/s)	Thousand (Btu/s)	(lbm/s)	Thousand (Btu/s)
23.2	638.5	801.5	395.6	489.6
23.4	599.6	749.4	306.5	380.7
23.6	584.4	727.4	250.3	311.9
23.8	560.9	699.3	232.4	290.3
24.0	529.0	659.3	112.5	140.9
24.0	529.0	659.2	112.2	140.5
24.2	259.5	330.9	.0	.0
24.4	.0	.0	.0	.0

Notes:
1. Mass and energy exiting from the reactor-vessel side of the break.
2. Mass and energy exiting from the steam-generator side of the break.

TABLE 6.2D-4

DCPP UNIT 2 DEHL BREAK
NO SAFETY INJECTION
MASS BALANCE

Time (Seconds)		0.00	24.40	24.40
		Mass (thousand lbm)		
Initial	In RCS and ACC	745.68	745.68	745.68
Added Mass	Pumped Injection	0.0	0.0	0.0
	Total Added	0.0	0.0	0.0
Total Available		**745.68**	**745.68**	**745.68**
Distribution	Reactor Coolant	527.43	69.55	97.56
	Accumulator	218.25	165.65	137.64
	Total Contents	745.68	235.20	235.20
Effluent	Break Flow	0.0	510.46	510.46
	ECCS Spill	0.0	0.0	0.0
	Total Effluent	0.0	510.46	510.46
Total Accountable		**745.68**	**745.66**	**745.66**

TABLE 6.2D-5

DCPP UNIT 2 DEHL BREAK
NO SAFETY INJECTION
ENERGY BALANCE

Time (s)		.00	24.40	24.40
		Energy (Million Btu)		
Initial Energy	In RCS, Accumulator, SG	905.10	905.10	905.10
Added Energy	Pumped Injection	.00	.00	.00
	Decay Heat	.00	8.44	8.44
	Heat from Secondary	.00	14.68	14.68
	Total Added	.00	23.11	23.11
***** Total Available *****		**905.10**	**928.21**	**928.21**
Distribution	Reactor Coolant	307.86	16.73	19.23
	Accumulator	19.52	14.82	12.31
	Core Stored	22.37	8.68	8.68
	Primary Metal	152.45	143.33	143.33
	Secondary Metal	110.78	108.33	108.33
	SG	292.13	308.16	308.16
	Total Contents	905.10	600.03	600.03
Effluent	Break Flow	.00	327.58	327.58
	ECCS Spill	.00	.00	.00
	Total Effluent	.00	327.58	327.58
***** Total Accountable *****		**905.10**	**927.61**	**927.61**

TABLE 6.2D-6

DCPP UNIT 2 DEPS BREAK
MASS AND ENERGY RELEASES DURING BLOWDOWN

Time (s)	Break Path No. 1 Flow(1) (lbm/s)	Break Path No. 1 Flow(1) Thousand (Btu/s)	Break Path No. 2 Flow(2) (lbm/s)	Break Path No. 2 Flow(2) Thousand (Btu/s)
0.0000	0.0	0.0	0.0	0.0
.00101	92,521.0	50,304.2	38,824.7	21,047.2
.00208	40,817.3	22,127.8	40,485.8	21,946.4
.101	40,420.4	21,973.6	21,118.6	11,441.9
.202	41,042.2	22,449.9	23,061.7	12,502.3
.301	41,804.0	23,053.4	23,229.8	12,602.7
.401	42,627.5	23,741.7	22,801.1	12,382.0
.501	43,380.7	24,427.7	21,953.7	11,929.5
.602	43,781.4	24,928.0	21,129.7	11,487.2
.702	43,657.5	25,113.9	20,481.4	11,138.0
.801	42,828.8	24,861.3	19,928.9	10,839.7
.902	41,675.6	24,398.6	19,483.7	10,599.5
1.00	40,579.4	23,952.7	19,187.2	10,440.0
1.10	39,511.3	23,520.0	19,028.5	10,355.8
1.20	38,402.3	23,065.4	18,959.7	10,319.7
1.30	37,249.5	22,584.3	18,947.5	10,314.2
1.40	36,108.9	22,098.2	18,964.3	10,324.1
1.50	35,071.0	21,648.3	18,995.3	10,341.3
1.60	34,208.0	21,281.0	19,025.0	10,357.6
1.70	33,463.9	20,972.1	19,059.7	10,376.7
1.80	32,776.6	20,693.9	19,096.3	10,396.8
1.90	32,102.6	20,421.0	19,124.8	10,412.7
2.00	31,397.6	20,128.0	19,120.1	10,410.4
2.10	30,611.5	19,775.1	19,082.7	10,390.3
2.20	29,873.7	19,448.4	19,019.5	10,356.3
2.30	29,105.8	19,092.8	18,929.6	10,307.7
2.40	28,311.7	18,711.9	18,608.0	10,132.0
2.50	27,476.0	18,296.6	18,386.7	10,012.6
2.60	26,393.3	17,705.5	18,230.6	9,928.7

Time (s)	Break Path No. 1 Flow(1)		Break Path No. 2 Flow(2)	
	(lbm/s)	Thousand (Btu/s)	(lbm/s)	Thousand (Btu/s)
2.70	24,922.5	16,832.9	18,070.0	9,842.2
2.80	22,800.1	15,489.7	17,885.8	9,742.8
2.90	20,616.3	14,089.6	17,671.8	9,627.2
3.00	20,161.2	13,878.1	17,460.5	9,513.2
3.10	20,196.4	13,958.6	17,257.3	9,403.8
3.20	19,378.6	13,416.2	17,052.9	9,293.7
3.30	18,805.8	13,055.5	16,834.1	9,175.7
3.40	18,342.4	12,765.1	16,617.5	9,059.0
3.50	17,710.2	12,348.0	16,417.2	8,951.2
3.60	17,087.6	11,936.3	16,224.1	8,847.4
3.70	16,454.6	11,515.2	16,039.6	8,748.3
3.80	15,819.4	11,091.9	15,869.2	8,657.0
3.90	15,206.0	10,683.7	15,705.2	8,569.2
4.00	14,640.1	10,307.2	15,547.3	8,484.8
4.20	13,733.4	9,708.9	15,272.4	8,338.2
4.40	13,051.6	9,255.2	15,011.2	8,199.0
4.60	12,515.4	8,894.0	14,781.2	8,076.7
4.80	12,096.1	8,603.7	14,564.4	7,961.4
5.00	11,751.9	8,356.7	14,365.1	7,855.9
5.20	11,487.0	8,156.9	14,157.9	7,745.7
5.40	11,269.7	7,982.5	13,971.9	7,647.4
5.60	11,113.2	7,843.4	13,784.2	7,547.9
5.80	10,990.7	7,722.9	13,749.7	7,536.8
6.00	10,940.3	7,646.0	15,193.0	8,329.3
6.20	10,963.9	7,614.1	14,940.2	8,192.3
6.40	11,042.5	7,615.7	14,714.6	8,072.6
6.60	11,148.5	7,634.1	14,611.4	8,018.7
6.80	11,303.9	7,684.4	14,421.8	7,918.3
7.00	11,888.5	8,015.7	14,284.5	7,847.2
7.20	11,672.0	7,866.2	14,288.9	7,854.1
7.40	10,724.4	7,593.7	14,105.8	7,755.4

Time (s)	Break Path No. 1 Flow[1] (lbm/s)	Break Path No. 1 Flow[1] Thousand (Btu/s)	Break Path No. 2 Flow[2] (lbm/s)	Break Path No. 2 Flow[2] Thousand (Btu/s)
7.60	9,379.3	7,097.2	13,887.0	7,636.4
7.80	8,896.0	6,868.3	13,719.0	7,545.6
8.00	8,893.8	6,824.3	13,627.9	7,497.5
8.20	8,962.6	6,802.8	13,510.9	7,433.6
8.40	9,023.1	6,783.7	13,356.3	7,347.3
8.60	9,101.7	6,776.5	13,202.6	7,261.4
8.80	9,211.0	6,779.6	13,064.6	7,184.5
9.00	9,333.4	6,785.3	12,918.7	7,103.5
9.20	9,480.3	6,806.0	12,767.6	7,019.6
9.40	9,640.6	6,834.0	12,616.2	6,935.4
9.60	9,778.3	6,846.9	12,467.2	6,852.5
9.80	9,868.8	6,835.7	12,324.5	6,773.2
10.0	9,896.2	6,792.3	12,186.0	6,696.0
10.2	9,829.7	6,699.2	12,053.3	6,621.8
10.4	9,687.6	6,571.8	11,933.4	6,554.7
10.6	9,527.5	6,446.8	11,819.5	6,490.8
10.8	9,364.7	6,328.9	11,702.0	6,424.7
11.0	9,196.2	6,214.5	11,590.7	6,362.3
11.2	9,033.9	6,109.0	11,483.5	6,302.3
11.4	8,872.0	6,005.4	11,371.8	6,239.7
11.6	8,702.8	5,898.5	11,264.5	6,179.6
11.8	8,537.3	5,796.3	11,161.0	6,121.7
12.0	8,369.4	5,694.7	11,054.3	6,061.9
12.2	8,200.7	5,595.0	10,952.4	6,004.9
12.4	8,034.9	5,499.8	10,852.6	5,948.9
12.6	7,865.5	5,403.7	10,750.3	5,891.6
12.8	7,702.3	5,314.2	10,655.7	5,838.6
13.0	7,551.6	5,233.9	10,550.3	5,779.5
13.2	7,401.3	5,152.3	10,453.9	5,725.6
13.4	7,259.5	5,074.6	10,354.3	5,670.0
13.6	7,123.1	4,999.2	10,256.0	5,615.0

Time (s)	Break Path No. 1 Flow(1) (lbm/s)	Break Path No. 1 Flow(1) Thousand (Btu/s)	Break Path No. 2 Flow(2) (lbm/s)	Break Path No. 2 Flow(2) Thousand (Btu/s)
13.8	6,991.0	4,926.4	10,159.5	5,561.2
14.0	6,863.0	4,856.3	10,062.4	5,507.0
14.2	6,738.6	4,788.5	9,967.0	5,453.8
14.4	6,618.4	4,722.8	9,871.9	5,401.0
14.6	6,501.7	4,658.4	9,777.2	5,348.5
14.8	6,389.5	4,596.0	9,683.6	5,296.7
15.0	6,281.6	4,535.1	9,590.3	5,245.3
15.2	6,171.6	4,472.0	9,483.3	5,186.6
15.4	6,059.9	4,407.1	9,373.4	5,126.9
15.6	5,933.8	4,330.0	9,250.0	5,060.3
15.8	5,807.6	4,251.0	9,133.7	4,998.1
16.0	5,686.8	4,172.1	9,019.7	4,937.0
16.2	5,577.9	4,096.3	8,915.3	4,881.1
16.4	5,485.7	4,026.9	8,816.4	4,828.3
16.6	5,406.5	3,963.7	8,722.4	4,778.6
16.8	5,336.4	3,906.6	8,632.6	4,731.9
17.0	5,271.2	3,854.5	8,545.6	4,687.7
17.2	5,207.5	3,806.1	8,460.9	4,645.8
17.4	5,143.9	3,761.4	8,377.4	4,605.8
17.6	5,079.6	3,719.8	8,285.9	4,562.7
17.8	5,014.2	3,681.7	8,140.2	4,490.9
18.0	4,955.8	3,652.2	8,057.0	4,457.0
18.2	4,904.4	3,630.5	7,806.7	4,348.9
18.4	4,872.1	3,641.0	7,669.6	4,296.1
18.6	4,808.6	3,669.9	7,529.6	4,210.6
18.8	4,680.8	3,696.6	7,359.4	4,084.6
19.0	4,511.3	3,716.3	7,263.6	3,984.4
19.2	4,318.7	3,730.5	7,129.8	3,851.8
19.4	4,108.5	3,737.0	7,014.4	3,723.0
19.6	3,845.2	3,697.3	6,745.6	3,510.6
19.8	3,519.3	3,593.4	6,360.4	3,244.2

Time (s)	Break Path No. 1 Flow(1) (lbm/s)	Break Path No. 1 Flow(1) Thousand (Btu/s)	Break Path No. 2 Flow(2) (lbm/s)	Break Path No. 2 Flow(2) Thousand (Btu/s)
20.0	3,194.5	3,459.0	5,982.6	3,008.7
20.2	2,897.8	3,305.1	5,627.1	2,801.6
20.4	2,631.1	3,126.0	5,288.0	2,612.5
20.6	2,389.2	2,910.7	4,972.1	2,445.3
20.8	2,164.0	2,663.0	4,675.4	2,299.6
21.0	1,987.2	2,457.6	4,393.2	2,171.1
21.2	1,849.2	2,294.1	3,859.6	1,896.8
21.4	1,720.3	2,139.3	3,457.0	1,561.0
21.6	1,610.9	2,007.2	3,529.5	1,460.3
21.8	1,490.8	1,860.9	3,728.9	1,475.2
22.0	1,378.9	1,724.3	3,561.7	1,376.2
22.2	1,271.1	1,592.1	3,703.9	1,400.4
22.4	1,173.7	1,472.6	3,088.2	1,147.5
22.6	1,090.6	1,370.2	2,670.6	986.0
22.8	1,006.2	1,265.5	2,448.0	896.1
23.0	915.2	1,153.1	2,153.7	769.6
23.2	825.6	1,041.2	2,106.1	721.4
23.4	737.3	930.7	2,412.3	787.3
23.6	656.8	829.9	2,880.0	903.1
23.8	567.9	718.1	3,225.9	980.8
24.0	486.0	615.0	2,899.2	862.5
24.2	413.5	523.7	2,569.5	752.8
24.4	359.2	455.3	2,203.3	637.6
24.6	326.3	413.8	1,836.2	525.5
24.8	302.6	384.0	1,447.8	410.3
25.0	272.7	346.2	1,028.5	289.2
25.2	232.5	295.3	573.0	160.4
25.4	188.4	239.5	139.9	39.2
25.6	140.5	178.8	.0	.0
25.8	88.5	112.8	.0	.0
26.0	30.4	38.9	.0	.0

Time (s)	Break Path No. 1 Flow[1]		Break Path No. 2 Flow[2]	
	(lbm/s)	Thousand (Btu/s)	(lbm/s)	Thousand (Btu/s)
26.2	.0	.0	.0	.0

Notes:

1. Mass and energy exiting from the steam-generator side of the break (path 1).
2. Mass and energy exiting from the pump-side of the break (path 2).

TABLE 6.2D-7

DCPP UNIT 2 DEPS BREAK
MASS AND ENERGY RELEASES DURING REFLOOD
MINIMUM SAFEGUARDS (SSPS FAILURE)

Time (s)	Break Path No. 1 Flow(1)		Break Path No. 2 Flow(2)	
	(lbm/s)	Thousand (Btu/s)	(lbm/s)	Thousand (Btu/s)
26.2	.0	.0	.0	.0
26.8	.0	.0	.0	.0
26.9	.0	.0	.0	.0
27.0	.0	.0	.0	.0
27.1	.0	.0	.0	.0
27.2	.0	.0	.0	.0
27.3	81.0	95.4	.0	.0
27.4	32.8	38.7	.0	.0
27.5	23.8	28.1	.0	.0
27.6	26.2	30.9	.0	.0
27.7	33.1	39.0	.0	.0
27.8	40.4	47.6	.0	.0
27.9	45.1	53.2	.0	.0
28.0	49.8	58.7	.0	.0
28.1	54.2	63.8	.0	.0
28.2	58.3	68.7	.0	.0
28.3	62.2	73.3	.0	.0
28.4	66.0	77.7	.0	.0
28.5	68.7	80.9	.0	.0
28.5	69.6	82.0	.0	.0
28.6	73.0	86.0	.0	.0
28.7	76.4	90.0	.0	.0
28.8	79.6	93.8	.0	.0
28.9	82.7	97.5	0	0
29.0	85.8	101.1	.0	.0
29.1	88.7	104.6	.0	.0
29.2	91.6	107.9	.0	.0

Time (s)	Break Path No. 1 Flow[1] (lbm/s)	Break Path No. 1 Flow[1] Thousand (Btu/s)	Break Path No. 2 Flow[2] (lbm/s)	Break Path No. 2 Flow[2] Thousand (Btu/s)
30.2	117.1	138.0	.0	.0
31.2	138.4	163.2	.0	.0
32.2	294.2	347.7	2,812.4	360.3
32.8	478.1	567.0	4,779.8	667.3
33.2	492.7	584.7	4,891.9	698.9
34.2	489.7	581.1	4,863.6	700.0
35.2	482.5	572.4	4,799.1	693.0
36.2	474.8	563.2	4,728.8	685.0
37.0	468.6	555.8	4,671.3	678.3
37.2	467.0	553.9	4,656.9	676.6
38.2	459.4	544.7	4,585.3	668.1
39.2	451.9	535.8	4,514.7	659.7
40.2	444.6	527.1	4,445.7	651.4
41.2	437.6	518.8	4,378.5	643.3
42.2	430.9	510.7	4,313.1	635.4
42.4	429.5	509.1	4,300.2	633.8
43.2	424.3	502.9	4,249.6	627.7
44.2	418.0	495.3	4,187.9	620.2
45.2	412.0	488.1	4,128.1	612.9
46.2	406.1	481.1	4,069.9	605.9
47.2	400.4	474.3	4,013.5	599.0
48.2	395.0	467.8	3,958.7	592.3
48.6	392.8	465.3	3,937.2	589.7
49.2	389.7	461.5	3,905.4	585.8
50.2	384.6	455.4	3,853.6	579.5
51.2	379.6	449.5	3,803.2	573.4
52.2	374.8	443.8	3,754.1	567.4
53.3	308.1	364.3	3,015.2	484.8
54.3	399.1	472.5	308.7	213.8
55.3	431.5	511.5	322.6	233.6
55.5	429.8	509.5	321.9	232.6

Time (s)	Break Path No. 1 Flow[1]		Break Path No. 2 Flow[2]	
	(lbm/s)	Thousand (Btu/s)	(lbm/s)	Thousand (Btu/s)
56.3	420.8	498.7	317.8	227.2
57.3	409.1	484.6	312.6	220.1
58.3	397.3	470.6	307.4	213.2
59.3	386.8	458.1	302.7	206.9
60.3	376.9	446.3	298.3	201.1
61.3	367.4	434.9	294.1	195.5
62.3	358.3	424.1	290.1	190.2
63.3	349.5	413.6	286.2	185.1
64.3	341.1	403.6	282.5	180.2
65.3	333.0	394.0	279.0	175.6
66.3	325.2	384.7	275.6	171.1
67.3	317.8	375.8	272.3	166.8
68.3	310.6	367.3	269.2	162.8
69.3	303.7	359.1	266.3	158.9
70.3	297.1	351.3	263.4	155.2
70.5	295.9	349.7	262.9	154.4
71.3	290.8	343.7	260.7	151.6
72.3	284.7	336.5	258.0	148.2
73.3	278.9	329.6	255.5	145.0
74.3	273.3	323.0	253.1	141.9
75.3	268.0	316.6	250.8	139.0
76.3	262.9	310.5	248.7	136.1
77.3	257.9	304.7	246.6	133.5
78.3	253.2	299.1	244.5	130.9
79.3	248.6	293.7	242.6	128.4
80.3	244.3	288.5	240.8	126.1
81.3	240.1	283.6	239.0	123.8
82.3	236.1	278.8	237.4	121.7
83.3	232.3	274.3	235.7	119.6
84.3	228.6	269.9	234.2	117.7
85.3	225.1	265.7	232.8	115.8

Time (s)	Break Path No. 1 Flow(1) (lbm/s)	Break Path No. 1 Flow(1) Thousand (Btu/s)	Break Path No. 2 Flow(2) (lbm/s)	Break Path No. 2 Flow(2) Thousand (Btu/s)
86.3	221.7	261.7	231.4	114.0
87.3	218.5	257.9	230.0	112.4
89.3	212.4	250.8	227.6	109.2
90.6	208.8	246.5	226.1	107.3
91.3	206.9	244.3	225.3	106.4
93.3	201.9	238.3	223.3	103.8
95.3	197.4	232.9	221.4	101.4
97.3	193.3	228.1	219.8	99.3
99.3	189.5	223.6	218.3	97.4
101.3	186.1	219.6	216.9	95.7
103.3	183.1	216.0	215.7	94.2
105.3	180.3	212.8	214.6	92.8
107.3	177.9	209.9	213.6	91.6
109.3	175.7	207.3	212.8	90.5
111.3	173.7	205.0	212.0	89.5
113.3	172.0	202.9	211.3	88.6
115.3	170.5	201.1	210.7	87.9
115.6	170.2	200.8	210.6	87.8
117.3	169.1	199.5	210.1	87.2
119.3	167.9	198.1	209.7	86.6
121.3	166.9	196.9	209.3	86.1
123.3	166.0	195.8	208.9	85.6
125.3	165.3	194.9	208.6	85.3
127.3	164.6	194.2	208.3	84.9
129.3	164.1	193.5	208.1	84.6
131.3	163.6	193.0	207.9	84.4
133.3	163.2	192.5	207.7	84.2
135.3	162.9	192.2	207.6	84.0
137.3	162.7	191.9	207.5	83.9
139.3	162.5	191.7	207.4	83.7
141.3	162.4	191.6	207.3	83.7

Time (s)	Break Path No. 1 Flow(1) (lbm/s)	Break Path No. 1 Flow(1) Thousand (Btu/s)	Break Path No. 2 Flow(2) (lbm/s)	Break Path No. 2 Flow(2) Thousand (Btu/s)
143.3	162.4	191.5	207.3	83.6
143.5	162.4	191.5	207.3	83.6
145.3	162.4	191.5	207.3	83.6
147.3	162.4	191.6	207.3	83.6
149.3	162.5	191.7	207.3	83.6
151.3	162.6	191.8	207.3	83.6
153.3	162.7	192.0	207.3	83.6
155.3	162.9	192.1	207.3	83.7
157.3	163.1	192.4	207.4	83.7
159.3	163.3	192.6	207.4	83.8
161.3	163.5	192.9	207.5	83.9
163.3	163.7	193.1	207.6	84.0
165.3	164.0	193.4	207.7	84.1
167.3	164.3	193.8	207.7	84.2
169.3	164.6	194.1	207.8	84.3
171.3	164.8	194.5	207.9	84.4
173.0	165.1	194.8	208.0	84.5
173.3	165.2	194.8	208.0	84.5
175.3	165.5	195.2	208.1	84.6
177.3	165.8	195.6	208.2	84.7
179.3	166.1	196.0	208.3	84.9
181.3	166.5	196.4	208.4	85.0
183.3	166.8	196.8	208.5	85.1
185.3	167.1	197.2	208.6	85.3
187.3	167.5	197.6	208.7	85.4
189.3	167.8	198.0	208.8	85.6
191.3	168.2	198.4	209.0	85.7
193.3	168.6	198.8	209.1	85.9
195.3	169.8	200.3	209.9	86.4
197.3	170.8	201.5	211.3	87.0
199.3	171.9	202.7	213.3	87.7

TABLE 6.2D-7

Time (s)	Break Path No. 1 Flow[1]		Break Path No. 2 Flow[2]	
	(lbm/s)	Thousand (Btu/s)	(lbm/s)	Thousand (Btu/s)
201.3	173.0	204.0	215.8	88.5
203.3	174.0	205.3	218.6	89.3
203.5	174.1	205.4	218.9	89.4

Notes:
1. Mass and energy exiting from the steam-generator side of the break (path 1).
2. Mass and energy exiting from the pump-side of the break (path 2).

TABLE 6.2D-8

DCPP UNIT 2 DEPS SSPS CASE
PRINCIPAL PARAMETERS DURING REFLOOD

Time (s)	Flooding		Carryover Fraction	Core Height (ft)	Downcomer Height (ft)	Flow Fraction	Total	Injection Accumulator	Spill	Enthalpy (Btu/lbm)
	Temp (°F)	Rate (in/s)					(lbm/s)			
26.2	175.3	.000	.000	.00	.00	.250	.0	.0	.0	.00
27.0	173.1	21.725	.000	.63	1.50	.000	7,491.0	7,491.0	.0	89.44
27.2	172.0	24.019	.000	1.01	1.41	.000	7,442.6	7,442.6	.0	89.44
28.5	171.4	2.536	.300	1.50	4.89	.333	7,109.7	7,109.7	.0	89.44
29.2	171.6	2.465	.393	1.60	7.08	.349	6,959.9	6,959.9	.0	89.44
32.8	172.5	4.749	.623	2.00	16.11	.602	6,184.5	5,667.9	.0	86.82
34.2	172.9	4.514	.666	2.19	16.12	.599	5,914.4	5,402.7	.0	86.72
37.0	174.0	4.132	.702	2.50	16.12	.596	5,596.9	5,079.5	.0	86.54
42.4	176.7	3.734	.725	3.00	16.12	.585	5,110.3	4,582.8	.0	86.20
48.6	180.5	3.444	.733	3.50	16.12	.574	4,669.1	4,132.5	.0	85.83
53.3	183.5	2.922	.734	3.85	16.12	.530	3,606.1	3,050.1	.0	84.60
54.3	184.2	3.468	.738	3.91	16.03	.591	537.6	.0	.0	58.05
55.3	185.0	3.614	.739	3.99	15.78	.596	525.9	.0	.0	58.05
55.5	185.1	3.600	.739	4.01	15.72	.596	526.2	.0	.0	58.05
63.3	192.0	3.000	.738	4.56	14.08	.582	544.4	.0	.0	58.05

TABLE 6.2D-8

Time (s)	Flooding		Carryover Fraction	Core Height (ft)	Downcomer Height (ft)	Flow Fraction	Total	Injection Accumulator	Spill	Enthalpy (Btu/lbm)
	Temp (°F)	Rate (in/s)					(lbm/s)			
70.5	199.2	2.606	.736	5.00	13.09	.568	555.0	.0	.0	58.05
80.3	209.4	2.231	.735	5.52	12.31	.550	563.2	.0	.0	58.05
90.6	219.5	1.975	.733	6.00	11.98	.532	568.0	.0	.0	58.05
103.3	229.6	1.788	.734	6.53	11.98	.515	571.2	.0	.0	58.05
115.6	237.7	1.692	.735	7.00	12.23	.506	572.7	.0	.0	58.05
129.3	245.4	1.640	.738	7.50	12.66	.500	573.4	.0	.0	58.05
143.5	252.3	1.618	.743	8.00	13.18	.499	573.6	.0	.0	58.05
159.3	259.0	1.612	.748	8.54	13.79	.500	573.5	.0	.0	58.05
161.3	259.7	1.612	.749	8.61	13.87	.501	573.5	.0	.0	58.05
173.0	264.0	1.614	.753	9.00	14.33	.502	573.4	.0	.0	58.05
189.3	269.3	1.620	.758	9.54	14.97	.505	573.2	.0	.0	58.05
203.5	273.4	1.645	.764	10.00	15.49	.512	572.5	.0	.0	58.05

TABLE 6.2D-9

DCPP UNIT 2 DEPS BREAK
MASS AND ENERGY RELEASES DURING POST-REFLOOD
SSPS FAILURE

	Break Path No. 1 Flow(1)		Break Path No. 2 Flow(2)	
Time (s)	(lbm/s)	Thousand (Btu/s)	(lbm/s)	Thousand (Btu/s)
203.5	208.3	260.1	372.5	127.9
208.5	207.4	259.1	373.3	127.9
213.5	207.5	259.2	373.2	127.6
218.5	206.7	258.2	374.1	127.7
223.5	205.9	257.2	374.9	127.7
228.5	206.0	257.2	374.8	127.4
233.5	205.1	256.2	375.7	127.5
238.5	205.2	256.2	375.6	127.2
243.5	204.3	255.2	376.5	127.3
248.5	204.3	255.2	376.5	127.0
253.5	203.4	254.1	377.3	127.1
258.5	203.4	254.1	377.3	126.9
263.5	202.5	253.0	378.2	126.9
268.5	202.5	252.9	378.3	126.7
273.5	201.6	251.8	379.2	126.7
278.5	201.5	251.7	379.3	126.5
283.5	200.6	250.5	380.2	126.5
288.5	200.5	250.4	380.3	126.4
293.5	199.6	249.2	381.2	126.4
298.5	199.4	249.1	381.3	126.2
303.5	199.3	248.9	381.5	126.0
308.5	198.3	247.7	382.5	126.1
313.5	198.1	247.5	382.6	125.9

Time (s)	Break Path No. 1 Flow(1)		Break Path No. 2 Flow(2)	
	(lbm/s)	Thousand (Btu/s)	(lbm/s)	Thousand (Btu/s)
318.5	197.1	246.2	383.7	126.0
323.5	196.9	246.0	383.9	125.8
328.5	196.7	245.7	384.1	125.7
333.5	195.6	244.4	385.1	125.7
338.5	195.4	244.0	385.4	125.6
343.5	195.1	243.7	385.7	125.4
348.5	194.8	243.3	386.0	125.3
353.5	193.7	241.9	387.1	125.4
358.5	193.3	241.5	387.5	125.2
363.5	192.9	241.0	387.8	125.1
368.5	192.5	240.5	388.2	125.0
373.5	192.1	240.0	388.7	124.9
378.5	191.7	239.4	389.1	124.8
383.5	191.2	238.8	389.6	124.7
388.5	190.6	238.1	390.1	124.6
393.5	190.1	237.4	390.7	124.6
398.5	189.5	236.7	391.3	124.5
403.5	189.0	236.1	391.8	124.4
408.5	188.5	235.4	392.3	124.3
413.5	188.0	234.8	392.8	124.2
418.5	187.4	234.1	393.4	124.2
423.5	186.8	233.3	394.0	124.1
428.5	186.1	232.5	394.7	124.1
433.5	185.4	231.6	395.3	124.0
438.5	184.7	230.7	396.1	124.0
443.5	184.6	230.5	396.2	123.8

Time (s)	Break Path No. 1 Flow(1)		Break Path No. 2 Flow(2)	
	(lbm/s)	Thousand (Btu/s)	(lbm/s)	Thousand (Btu/s)
448.5	183.7	229.5	397.0	123.8
453.5	183.5	229.2	397.3	123.7
458.5	183.1	228.8	397.6	123.6
463.5	182.1	227.5	398.7	123.6
468.5	181.6	226.9	399.1	123.5
473.5	181.1	226.2	399.7	123.4
478.5	180.4	225.3	400.4	123.4
483.5	180.2	225.1	400.6	123.2
488.5	179.3	224.0	401.5	123.2
493.5	178.9	223.4	401.9	123.1
498.5	178.3	222.7	402.5	123.1
503.5	177.5	221.7	403.3	123.1
508.5	177.0	221.1	403.7	123.0
513.5	176.3	220.3	404.4	122.9
518.5	175.9	219.7	404.9	122.8
523.5	185.6	231.9	395.1	124.5
528.5	185.4	231.6	395.4	124.3
533.5	184.5	230.4	396.3	124.3
538.5	184.2	230.1	396.6	124.2
543.5	183.4	229.0	397.4	124.1
548.5	182.7	228.2	398.1	124.1
553.5	182.0	227.4	398.7	124.0
558.5	181.4	226.5	399.4	123.9
563.5	180.7	225.7	400.1	123.9
568.5	86.7	108.3	494.1	148.4
829.2	86.7	108.3	494.1	148.4

Time (s)	Break Path No. 1 Flow[1]		Break Path No. 2 Flow[2]	
	(lbm/s)	Thousand (Btu/s)	(lbm/s)	Thousand (Btu/s)
829.3	87.3	108.3	493.4	143.1
833.5	87.3	108.2	493.5	142.9
1,677.9	87.3	108.2	493.5	142.9
1,678.0	75.7	93.8	340.8	165.3
1,717.8	75.7	93.8	340.8	165.3
1,717.9	73.1	84.1	343.4	75.0
2,000.0	70.0	80.5	346.5	75.6
2,000.1	70.0	80.5	346.5	75.2
2,500.0	67.0	77.1	349.5	75.7
2,500.1	67.0	77.1	349.5	75.3
3,000.0	64.0	73.6	352.5	75.8
3,000.1	64.0	73.6	352.5	74.9
3,500.0	61.0	70.1	355.5	75.5
3,500.1	61.0	70.1	355.5	74.4
3,600.0	60.4	69.5	356.1	74.5

Notes:

1. Mass and energy exiting from the steam-generator side of the break (path 1).
2. Mass and energy exiting from the pump-side of the break (path 2).

TABLE 6.2D-10

LOCA MASS AND ENERGY RELEASE ANALYSIS CORE DECAY HEAT RATE

Time (sec)	Decay Heat Generation Rate (Btu/Btu)
10	0.053876
15	0.050401
20	0.048018
40	0.042401
60	0.039244
80	0.037065
100	0.035466
150	0.032724
200	0.030936
400	0.027078
600	0.024931
800	0.023389
1000	0.022156
1500	0.019921
2000	0.018315
4000	0.014781
6000	0.013040
8000	0.012000
10000	0.011262
15000	0.010097
20000	0.009350
40000	0.007778
60000	0.006958
80000	0.006424
100000	0.006021
150000	0.005323
200000	0.004847
400000	0.003770
600000	0.003201
800000	0.002834
1000000	0.002580

TABLE 6.2D-11

DCPP UNIT 2 DEPS SSPS CASE – MASS BALANCE

Time (s)		**.00**	**26.20**	**26.20**	**203.49**	**829.34**	**1,717.82**	**3,600.00**
Mass (thousand lbm)								
Initial	In RCS and ACC	745.68	745.68	745.68	745.68	745.68	745.68	745.68
Added Mass	Pumped Injection	.00	.00	.00	96.92	460.40	946.60	1,753.68
	Total Added	.00	.00	.00	96.92	460.40	946.60	1,753.68
***** Total Available *****		**745.68**	**745.68**	**745.68**	**842.61**	**1,206.09**	**1,692.29**	**2,499.37**
Distribution	Reactor Coolant	527.43	46.67	76.70	138.09	138.09	138.09	138.09
	Accumulator	218.25	169.81	139.77	.00	.00	.00	.00
	Total Contents	745.68	216.48	216.48	138.09	138.09	138.09	138.09
Effluent	Break Flow	.00	529.19	529.19	693.62	1,057.10	1,566.55	2,350.37
	ECCS Spill	.00	.00	.00	.00	.00	.00	.00
	Total Effluent	.00	529.19	529.19	693.62	1,057.10	1,566.55	2,350.37
***** Total Accountable *****		**745.68**	**745.67**	**745.67**	**831.72**	**1,195.19**	**1,704.65**	**2,488.46**

TABLE 6.2D-12

DCPP UNIT 2 DEPS SSPS FAILURE ENERGY BALANCE

Time (s)		**.00**	**26.20**	**26.20**	**203.49**	**829.34**	**1,717.82**	**3,600.00**
Energy (million Btu)								
Initial Energy	In RCS, ACC, SG	905.10	905.10	905.10	905.10	905.10	905.10	905.10
Added Energy	Pumped Injection	.00	.00	.00	5.63	26.73	62.65	181.64
	Decay Heat	.00	8.47	8.47	29.33	83.58	145.18	250.96
	Heat from Secondary	.00	15.91	15.91	15.91	15.91	15.91	15.91
	Total Added	.00	24.38	24.38	50.87	126.21	223.74	448.52
***** Total Available *****		**905.10**	**929.48**	**929.48**	**955.97**	**1,031.31**	**1,128.84**	**1,353.62**
Distribution	Reactor Coolant	307.86	10.53	13.22	36.37	36.37	36.37	36.37
	Accumulator	19.52	15.19	12.50	.00	.00	.00	.00
	Core Stored	22.37	11.66	11.66	4.85	4.37	4.03	3.33
	Primary Metal	152.45	145.03	145.03	120.11	80.86	60.54	48.23
	Secondary Metal	110.78	110.04	110.04	101.22	74.90	51.21	40.06
	Steam Generator	292.13	314.16	314.16	285.60	204.80	135.89	105.39
	Total Contents	905.10	606.60	606.60	548.15	401.30	288.04	233.39
Effluent	Break Flow	.00	322.30	322.30	398.33	620.52	821.40	1,106.39
	ECCS Spill	.00	.00	.00	.00	.00	.00	.00
	Total Effluent	.00	322.30	322.30	398.33	620.52	821.40	1,106.39
***** Total Accountable *****		**905.10**	**928.90**	**928.90**	**946.48**	**1,021.83**	**1,109.45**	**1,339.77**

TABLE 6.2D-13

DOUBLE-ENDED HOT-LEG BREAK SEQUENCE OF EVENTS

Time (sec)	Event Description
0.0	Break Occurs
1.1	Reactor Trip Occurs on Compensated Pressurizer Pressure Setpoint of 1859.7 psia and SG Throttle Valves Closed
4.0	Low Pressurizer Pressure SI Setpoint = 1694.7 psia Reached (Safety Injection begins after a 27 second delay and feedwater control valve starts to close)
13.0	Main Feedwater Regulating Valve Fully Closed
15.5	Broken Loop Accumulator Begins Injecting Water
15.6	Intact Loop Accumulator Begins Injecting Water
24.4	End of Blowdown Phase - Transient Modeling Terminated

TABLE 6.2D-14

DIABLO CANYON UNIT 1 DOUBLE-ENDED PUMP SUCTION BREAK
SEQUENCE OF EVENTS
(MINIMUM SAFEGUARDS)

Time (s)	Event Description
0.0	Break Occurs and Loss-of-Offsite Power is Assumed
1.0	Reactor Trip Occurs on Compensated Pressurizer Pressure Setpoint of 1,859.7 psia and SG Throttle Valves Closed
4.0	Low Pressurizer Pressure SI Setpoint = 1,694.7 psia Reached (SI begins after a 27-second delay and feedwater control valve starts to close)
13.0	Main Feedwater Regulating Valve Closed
16.4	Broken-Loop Accumulator Begins Injecting Water
16.8	Intact-Loop Accumulator Begins Injecting Water
25.6	End of Blowdown Phase
31.1	Pumped Safety Injection Begins
48.7	CFCUs On
51.9	Broken Loop Accumulator Water Injection Ends
53.2	Intact Loop Accumulator Water Injection Ends
87.6	Containment Sprays Begin Injecting
193.7	End of Reflood for Minimum Safeguards Case
508.8	Mass and Energy Release Assumption: Broken-Loop SG Equilibration to 61.7 psia
889.2	Mass and Energy Release Assumption: Broken-Loop SG Equilibration to 40.7 psia
1,495.2	Mass and Energy Release Assumption: Intact-Loop SG Equilibration to 61.7 psia
1,678.0	Cold-Leg Recirculation Begins
1,695.6	Mass and Energy Release Assumption: Intact-Loop SG Equilibration to 39.7 psia
3,600.0	End of Sensible Heat Release from RCS and SGs
3,798.0	Containment Sprays Terminated
25,200.0	Switchover to Hot-Leg Recirculation

TABLE 6.2D-15

DIABLO CANYON UNIT 2 DOUBLE-ENDED PUMP SUCTION BREAK SEQUENCE OF EVENTS (MINIMUM SAFEGUARDS)

Time (sec)	Event Description
0.0	Break Occurs and Loss-of-offsite Power is assumed
1.2	Reactor Trip Occurs on Compensated Pressurizer Pressure Setpoint of 1859.7 psia and SG Throttle Valves Closed
4.2	Low Pressurizer Pressure SI Setpoint = 1694.7 psia Reached (Safety Injection begins after a 27 second delay and feedwater control valve starts to close)
13.2	Main Feedwater Regulating Valve Closed
18.1	Broken Loop Accumulator Begins Injecting Water
18.6	Intact Loop Accumulator Begins Injecting Water
26.2	End of Blowdown Phase
31.3	Pumped Safety Injection Begins
48.7	CFCUs On
52.7	Broken Loop Accumulator Water Injection Ends
53.7	Intact Loop Accumulator Water Injection Ends
88.0	Containment Sprays Begin Injecting
203.5	End of Reflood for Minimum Safeguards Case
568.5	Mass and Energy Release Assumption: Broken Loop SG Equilibration to 61.7 psia
829.3	Mass and Energy Release Assumption: Broken Loop SG Equilibration to 40.7 psia
1,536.5	Mass and Energy Release Assumption: Intact Loop SG Equilibration to 61.7 psia
1,678.0	Cold-Leg Recirculation Begins
1,717.8	Mass and Energy Release Assumption: Intact Loop SG Equilibration to 39.7 psia
3,600.0	End of Sensible Heat Release from Reactor Coolant System and Steam Generators
3,798.0	Containment Sprays Terminated
25,200.0	Switchover to Hot-Leg Recirculation

TABLE 6.2D-17 Sheet 1 of 2

DIABLO CANYON CONTAINMENT LOCA INTEGRITY ANALYSIS PARAMETERS

Parameter	Value
Auxiliary Saltwater Temperature (°F)	64
RWST Water Temperature (°F)	90
Initial Containment Temperature (°F)	120
Initial Containment Pressure (psia)	16.0
Initial Relative Humidity (%)	18
Net Free Volume (ft^3)	2,550,000
Reactor Containment Fan Coolers	
Total CFCUs	5
Analysis Maximum	3
Analysis Minimum	2
High Containment Pressure Setpoint (psig)	5.0
Delay Time (sec) Without Offsite Power	 48.0
CCW Flow to the CFCUs (gpm) During Injection During Recirculation	 8,000 7,450
Containment Spray Pumps	
Total CSPs	2
Analysis Maximum	2
Analysis Minimum	1
Flowrate (gpm) During Injection During Recirculation	 Table 6.2.D-18 0
High-High Containment Pressure Setpoint (psig)	24.7
Spray Delay Time (sec) Without Offsite Power	 80
Containment Spray Termination Time, (sec) Minimum Safeguards Maximum Safeguards (1 CSP) Maximum Safeguards (2 CSPs)	 3,798 3,018 1,824

Parameter	Value
ECCS Recirculation	
ECCS Cold-Leg Recirculation Switchover, sec Minimum Safeguards Maximum Safeguards (1 CSP) Maximum Safeguards (2 CSPs)	 1,678 1,033 829
Containment ECCS Cold-Leg Recirculation Flow, (gpm) Minimum Safeguards (1 RHR train) Maximum Safeguards (2 RHR trains)	 3,252.3 8,082.4
ECCS Hot-Leg Recirculation Switchover, sec	25,200
Containment ECCS Hot-Leg Recirculation Flow, (gpm) Minimum Safeguards (1 RHR train) Maximum Safeguards (2 RHR trains)	 3,071.7 4,576.8
Component Cooling Water System	
Total CCW Heat Exchangers	2
Analysis Maximum	2
Analysis Minimum	1
CCW Flow Rate to RHR Heat Exchanger (gpm per available HX)	4,800
ASW Flow Rate to CCW Heat Exchanger (gpm per available HX)	10,300
CCW Misc. Heat Loads (MBTU/hr) During Injection During Recirculation	 1.0 2.0
CCW Flow Rate to Misc. Heat Loads (gpm) During Injection During Recirculation	 2,500 500

TABLE 6.2D-18

CONTAINMENT SPRAY FLOW RATES
AS A FUNCTION OF CONTAINMENT PRESSURE

Containment Pressure (psig)	1 CSP Spray Flow Rate (gpm)	2 CSPs Spray Flow Rate (gpm)
0	3036	6142
10	2926	5922
20	2806	5692
30	2686	5442
40	2546	5182
47	2456	4992

TABLE 6.2D-19

GOTHIC THERMAL CONDUCTOR MODELING

No.	Description	Materials	Surface Area (ft^2)	Thickness (in)	Initial Temp (°F)
1	Concrete Interior Walls	Paint Concrete	79965	0.0075 12	120
2	Concrete Floor	Paint Concrete	13012	0.0075 24	120
3	SS Fuel Transfer Tube	Stainless Steel	8852	0.144	120
4	SS Structures	Stainless Steel	857	0.654	120
5	CS Structures	Paint Carbon Steel	48024	0.0075 0.0815	120
6	CS Structures	Paint Carbon Steel	60941	0.0075 0.133	120
7	CS Lined Containment Concrete Shell	Paint Carbon Steel HGap = 10 Concrete	90560	0.0075 0.375 0.0168 35.6007	120
8	CS Structures	Paint Carbon Steel	42517	0.0075 0.567	120
9	CS Structures	Paint Carbon Steel	56494	0.0075 0.738	120
10	CS Structures	Paint Carbon Steel	31902	0.0075 1.355	120
11	CS SG Snubbers	Paint Carbon Steel	522	0.0075 3.0	120
12	CS RCP Motors	Paint Carbon Steel	1610	0.0075 6.99	200

TABLE 6.2D-20

MATERIAL PROPERTIES FROM THE GOTHIC MODEL (REFERENCE 15)

Material	**Thermal Conductivity (BTU/hr-ft-°F)**	**Vol. Heat Capacity (BTU/ft^3-°F)**
Paint	0.2083	35.91
Carbon Steel	28	58.8
Air Gap	0.0148	0.018
Concrete	1.04	23.4
Stainless Steel	8.6	58.8

TABLE 6.2D-21

SUMMARY OF LOCA PEAK CONTAINMENT PRESSURE AND TEMPERATURES

Break Location	**Peak Pressure (psig)**	**Time (sec)**	**Peak Air Temp (°F)**	**Time (sec)**	**Press @ 24 hours (psig)**	**Temp @ 24 hours (°F)**
DEHL	41.4	23.8	261.8	23.4	-	-
DEPS min SI	39.8	24.1	259.3	24.1	8.9	167.5
Acceptance Criteria	<47 (Containment Design Pressure)	-	<271 (Containment Design Temperature)	-	<50% of peak pressure	-

TABLE 6.2D-22

INITIAL CONTAINMENT CONDITIONS, FAN COOLER AND CONTAINMENT SPRAY PUMP ASSUMPTIONS

Parameter	**Value**		
Containment net free volume (ft^3)	2,550,000		
Initial containment temperature (°F)	120.0		
Initial containment pressure (psia)	16.0		
Initial relative humidity (%)	18		
Number of fan coolers - All - Analysis maximum - Containment safeguards failure	 5 3 2		
High containment pressure setpoint (psig)	5.0		
Delay (sec) from high containment pressure setpoint to start of fan coolers	38.0		
Containment fan cooler heat removal (MBTU/hr) vs. Component Cooling Water (CCW) Flow rate (gpm) assuming T_{sat} = 271°F and T_{CCW} = 125°F	Flow	Heat Removal	
	1000	59.12	
	1500	73.18	
	2000	82.47	
	2500	89.03	
	3000	93.93	
	3250	95.90	
	3500	97.73	
Containment fan cooler air flowrate (ft^3/min per fan cooler)	47,000		
Number of spray pumps - All - Containment safeguards failure	 2 1		
High-high containment pressure setpoint (psig)	24.7		
Delay (sec) from high-high containment pressure setpoint to start of containment sprays	74.5		
Containment spray flowrate (gpm) vs. containment pressure (psig)	Press	Flow 1 Pump	Flow 2 Pumps
	0	3036	6142
	10	2926	5922
	20	2806	5692
	30	2686	5442
	40	2546	5182
	47	2456	4992
RWST/containment spray water temperature (°F)	90.0		

TABLE 6.2D-23

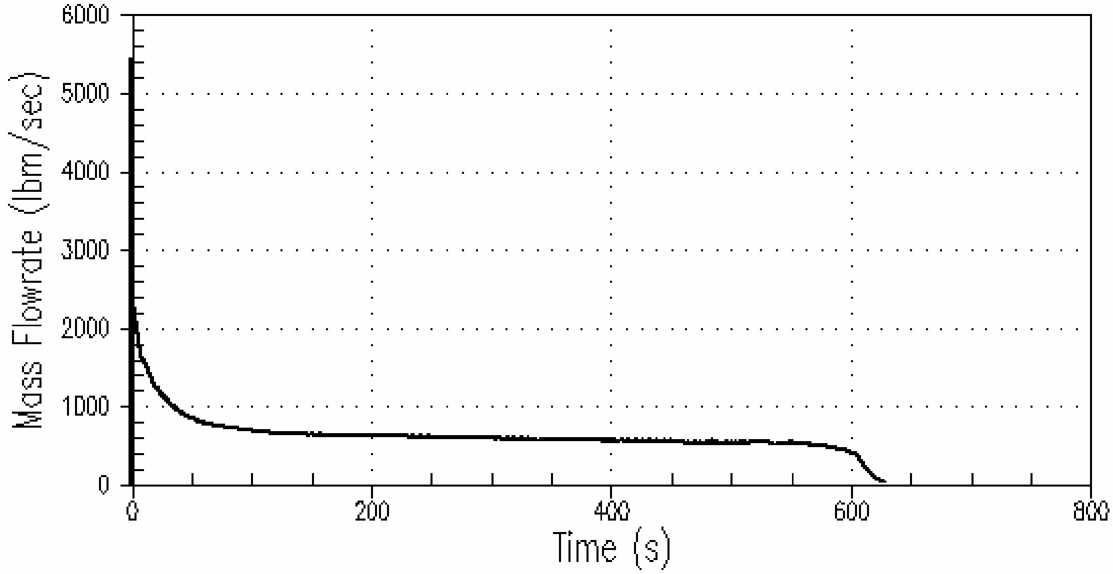
PEAK PRESSURES AND TEMPERATURES FOR
CONTAINMENT RESPONSE TO MAIN STEAMLINE BREAKS

Case	Description			Peak Pressure (psig @ sec)	Peak Temperature (°F @ sec)
	Break	Initial Power	Failure		
1a	1.4 ft^2 DER	102%	containment safeguards	29.7 @ 234	281.8 @ 225
2a	1.4 ft^2 DER	70%	containment safeguards	30.5 @ 615	281.8 @ 239
3a	1.4 ft^2 DER	30%	containment safeguards	32.7 @ 614	278.8 @ 252
4a	1.4 ft^2 DER	0%	containment safeguards	32.9 @ 611	277.9 @ 260
1b	1.4 ft^2 DER	102%	MFRV	37.3 @ 466	280.7 @ 226
2b	1.4 ft^2 DER	70%	MFRV	42.8 @ 608	280.6 @ 239
3b	1.4 ft^2 DER	30%	MFRV	40.5 @ 693	277.4 @ 263
4b	1.4 ft^2 DER	0%	MFRV	31.8 @ 415	275.6 @ 265
1c	1.4 ft^2 DER	102%	MSIV/CV	31.4 @ 253	309.9 @ 26
2c	1.4 ft^2 DER	70%	MSIV/CV	32.8 @ 296	310.4 @ 26
3c	1.4 ft^2 DER	30%	MSIV/CV	33.4 @ 403	311.2 @ 25
4c	1.4 ft^2 DER	0%	MSIV/CV	34.5 @ 419	312.1 @ 24
5c	0.73 ft^2 Split Break	102%	MSIV/CV	34.0 @ 631	295.2 @ 118
6c	0.87 ft^2 Split Break	70%	MSIV/CV	34.4 @ 667	301.1 @ 104
7c	0.94 ft^2 Split Break	30%	MSIV/CV	33.4 @ 724	302.2 @ 98
8c	0.90 ft^2 Split Break	0%	MSIV/CV	31.3 @ 726	296.6 @ 109

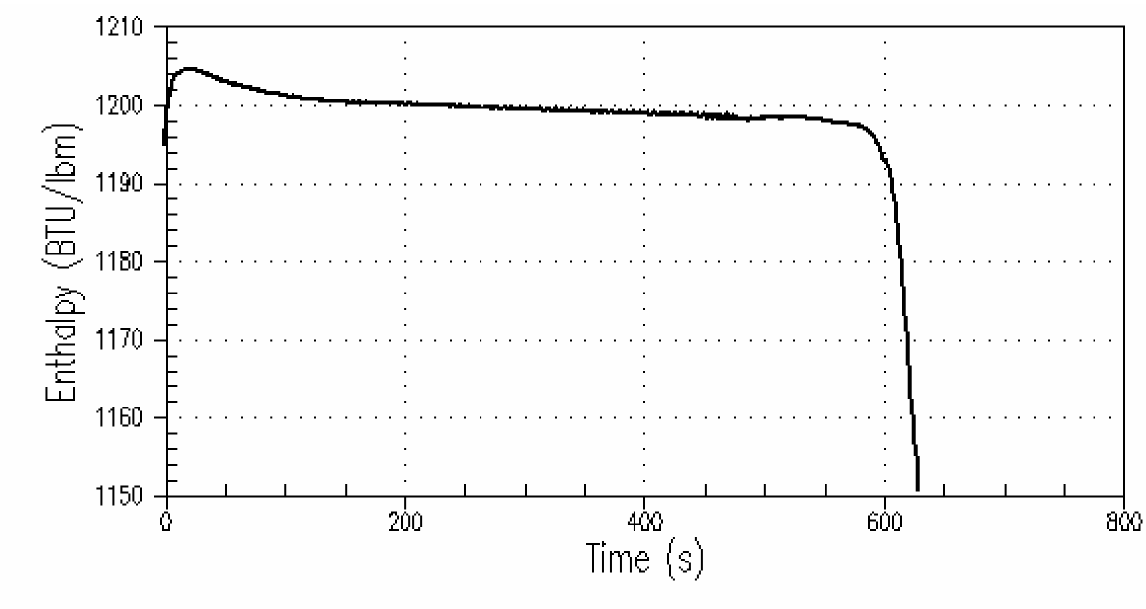
TABLE 6.2D-24

SEQUENCE OF EVENTS
MAIN STEAMLINE BREAK, MFRV FAILURE, 70% POWER

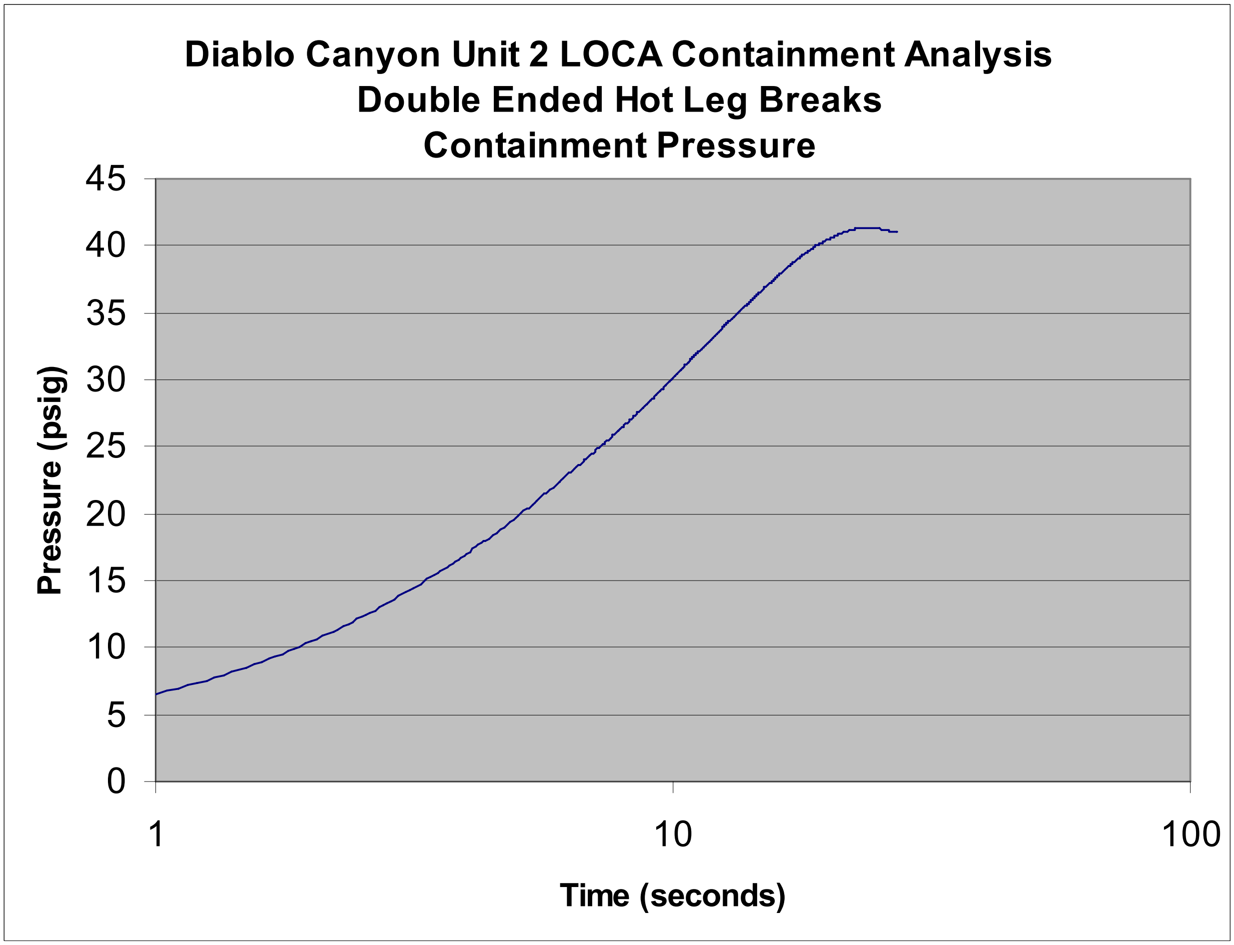
Event	Time (sec)
SI Low Steamline Pressure Setpoint Reached	0.051
AFW Initiation	0.051
Closure of Steamline CV on Faulted Loop	0.1
Reactor Trip – Start of Rod Motion	2.1
Faulted Loop MFRV Fully Closed	Failed Open
High Containment Pressure Setpoint Reached	5.7
SI Flow Starts	27.1
Fan Coolers Start	43.7
Faulted Loop Backup MFIV Fully Closed	64.1
SI Boron Reaches Core	148
High-High Containment Pressure Setpoint Reached	164.2
Containment Sprays Start	239.2
Accumulator Injection	n/a
AFW Re-aligned from Faulted SG	600
Peak Containment Pressure Occurs	608
Mass Release Terminated	630



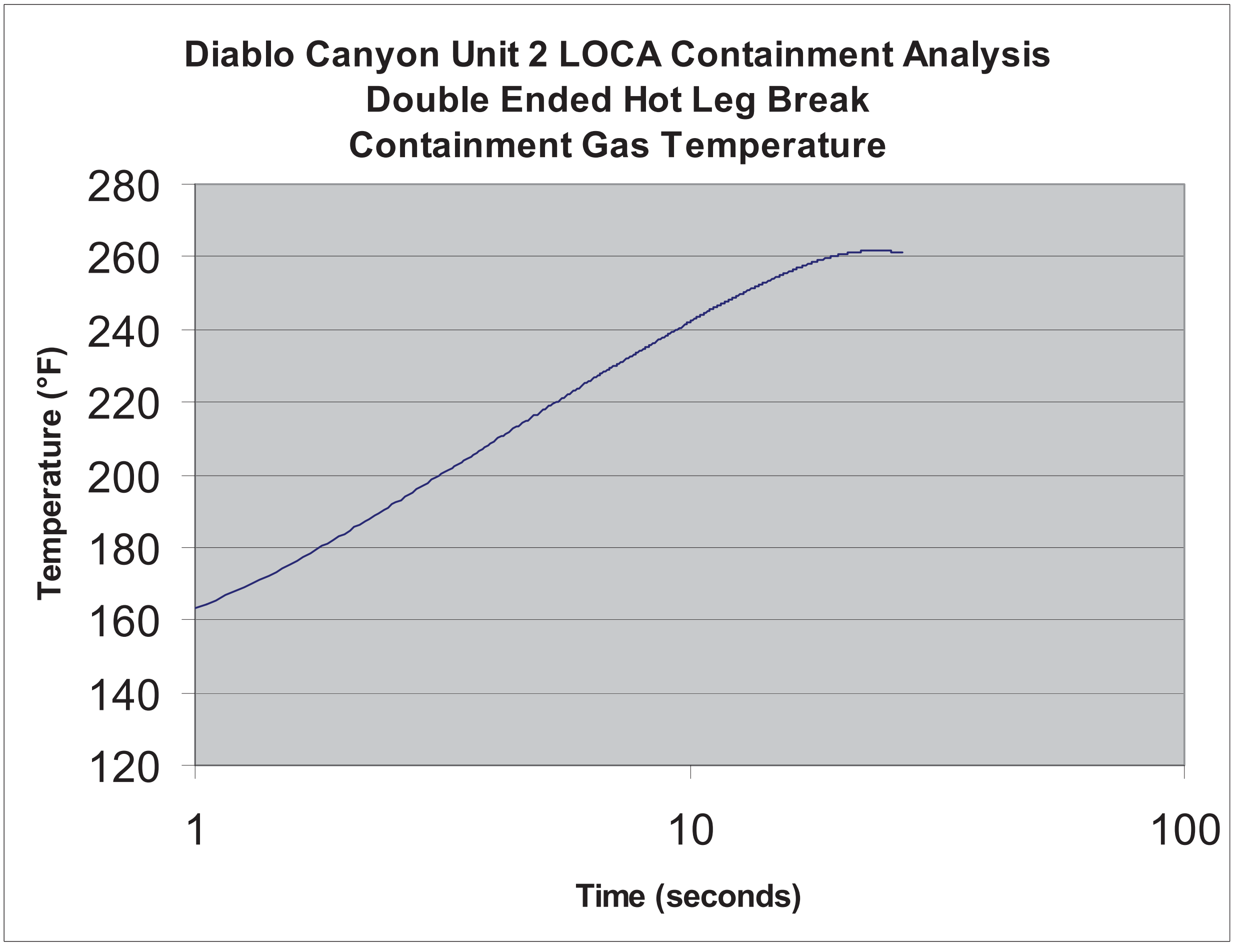
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2D-1 STEAMLINE BREAK MASS RELEASE TO CONTAINMENT 1.4 ft^2 DER. 70% POWER, FRV FAILURE



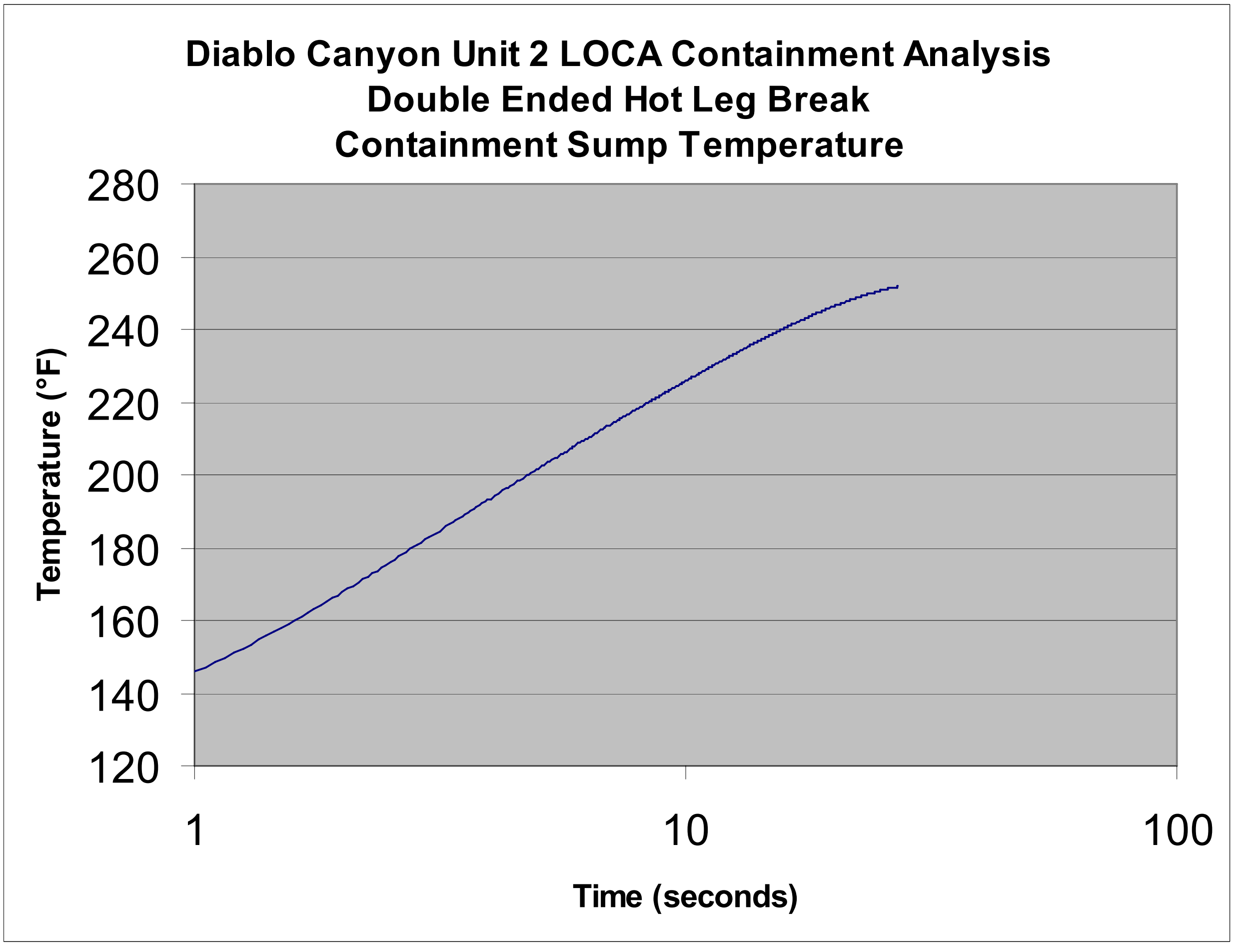
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2D-2 STEAMLINE BREAK ENTHALPY OF BREAK EFFLUENT 1.4 ft^2 DER. 70% POWER, FRV FAILURE



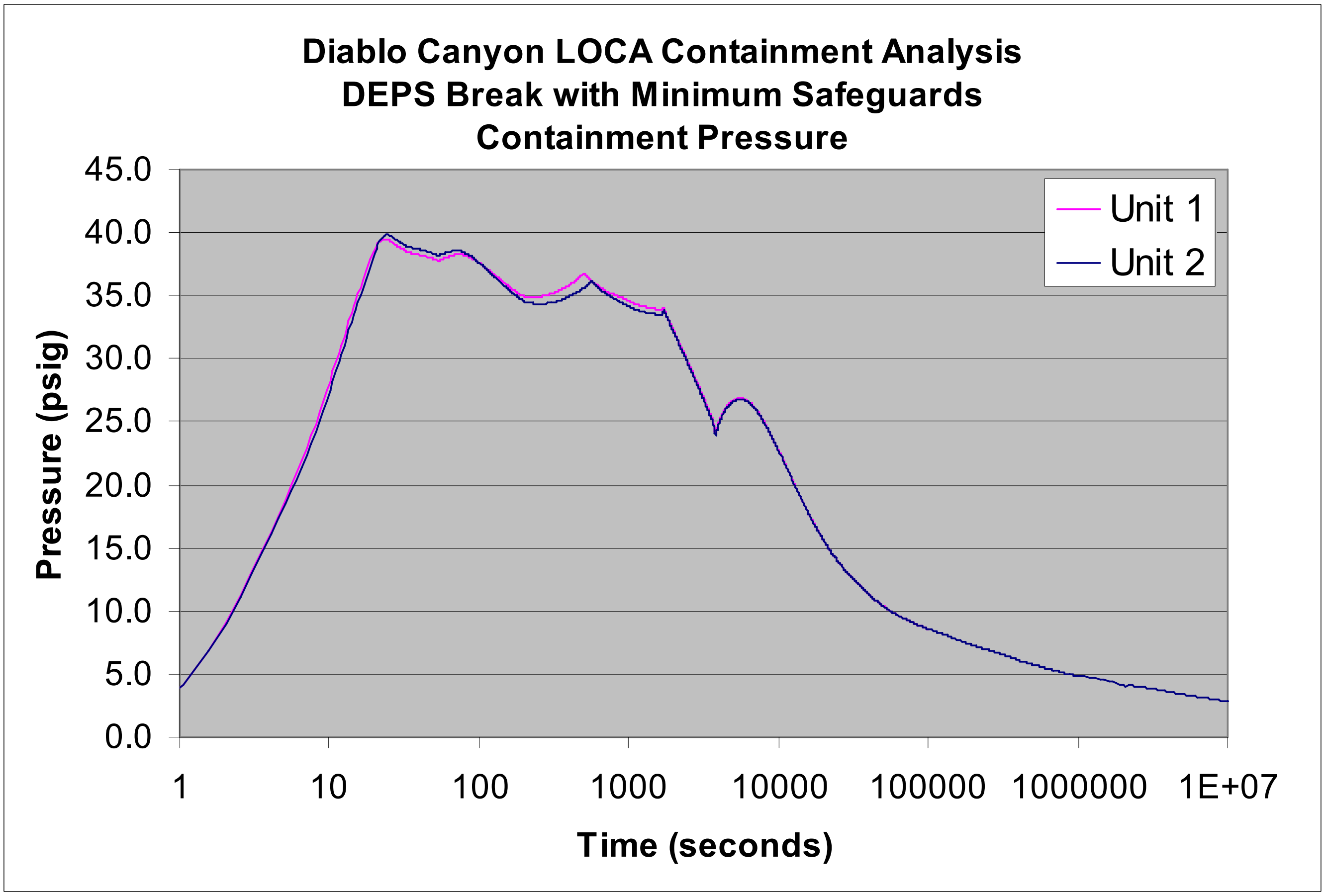
FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 6.2D-3 CONTAINMENT PRESSURE DOUBLE-ENDED HOT LEG BREAK



FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 6.2D-4 CONTAINMENT TEMPERATURE DOUBLE-ENDED HOT LEG BREAK



FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 6.2D-5 CONTAINMENT SUMP TEMPERATURE DOUBLE-ENDED HOT LEG BREAK

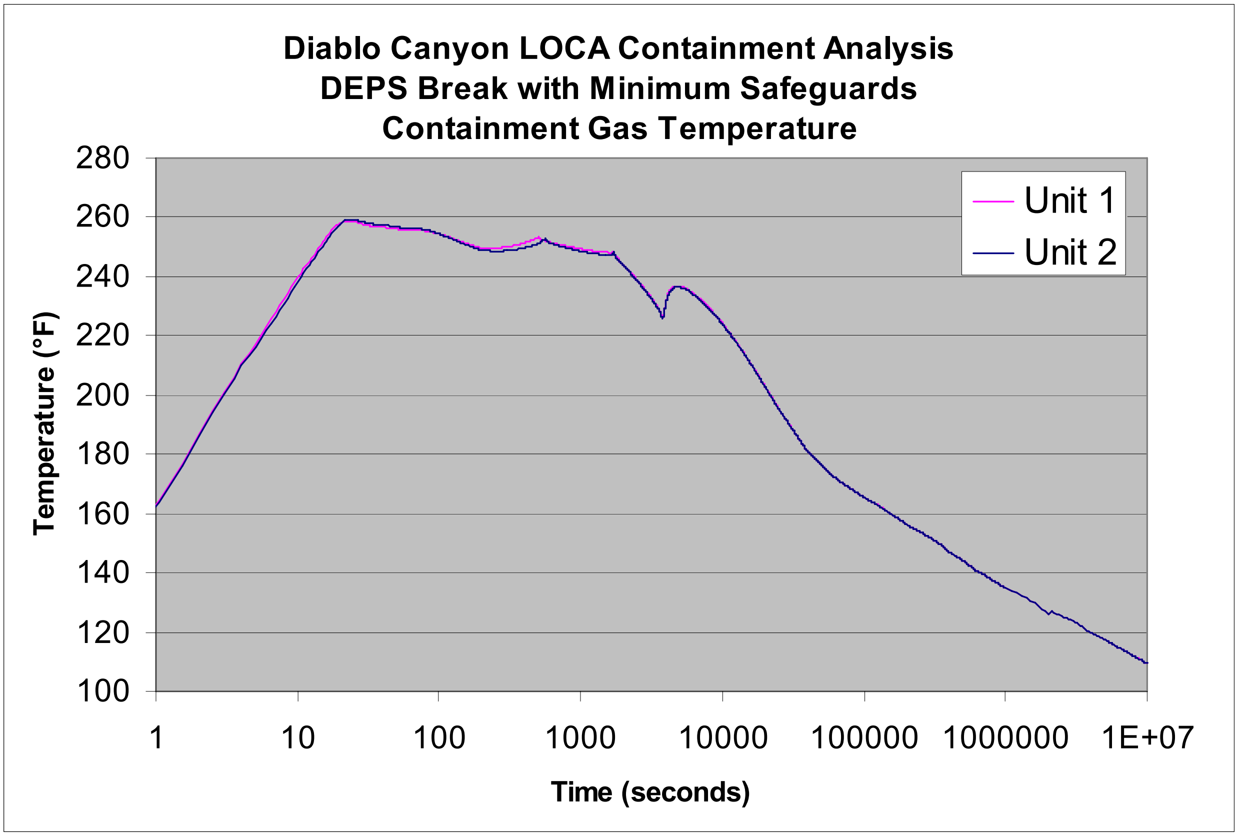


FSAR UPDATE

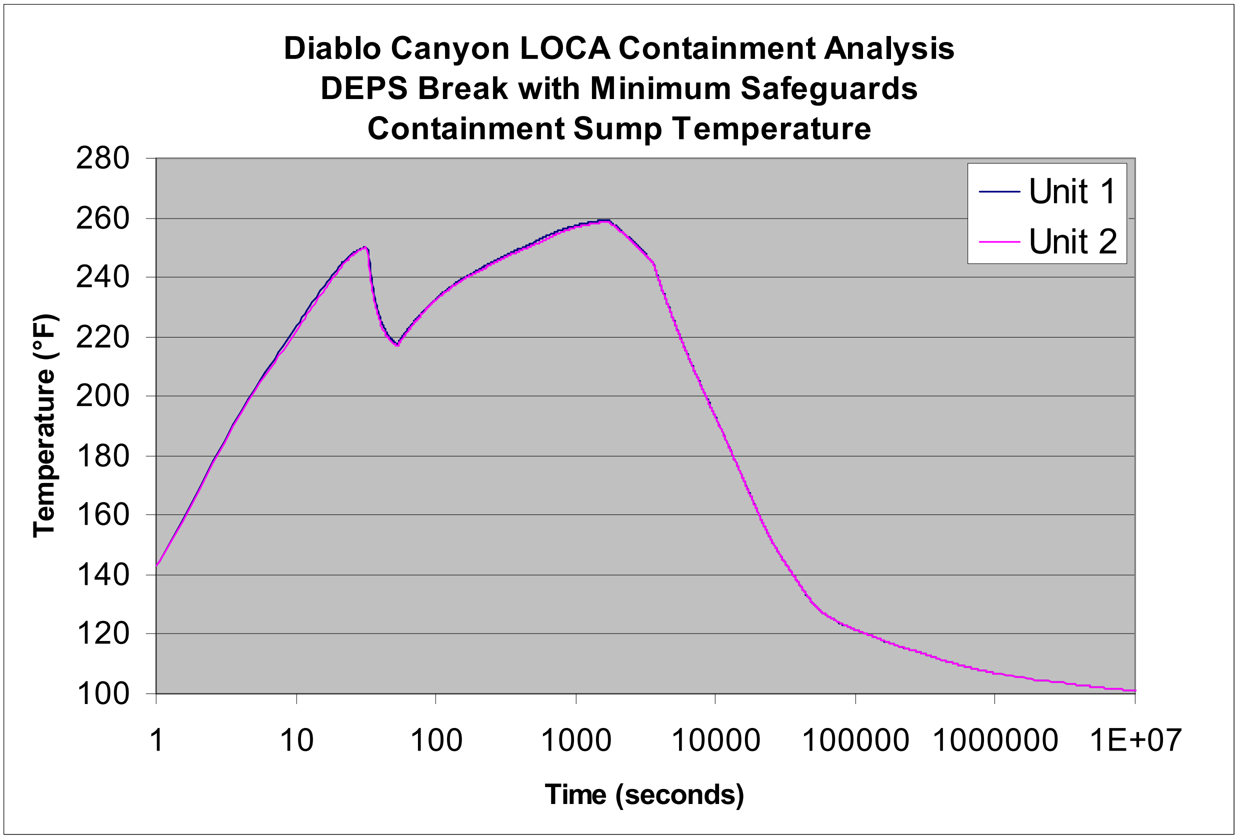
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2D-6

CONTAINMENT PRESSURE
DOUBLE-ENDED PUMP SUCTION BREAK



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2D-7 CONTAINMENT TEMPERATURE DOUBLE-ENDED PUMP SUCTION BREAK

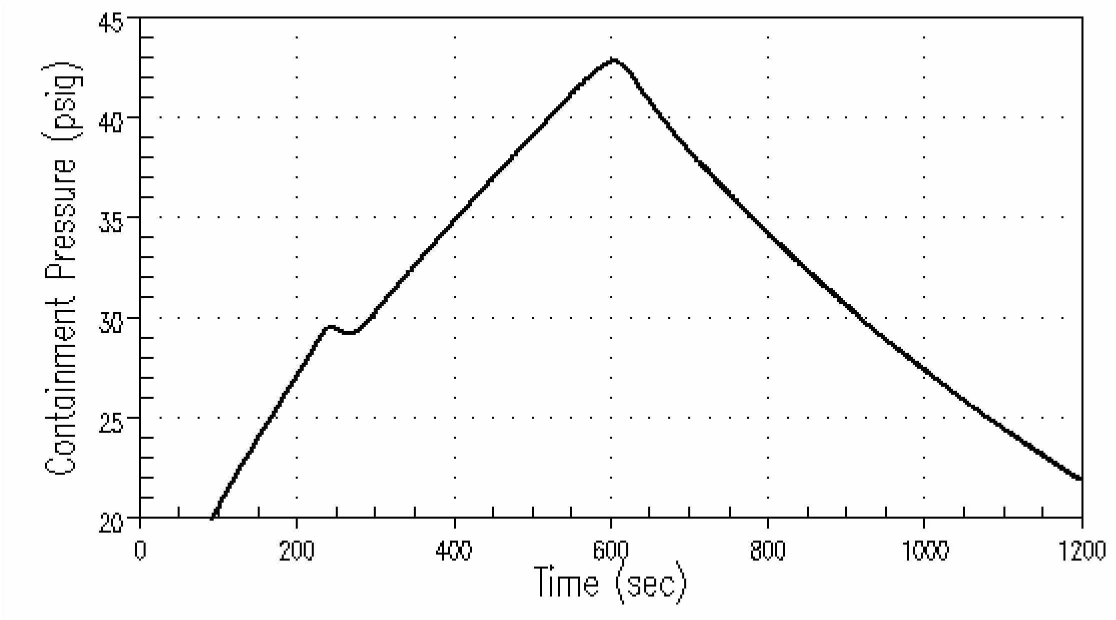


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2D-8

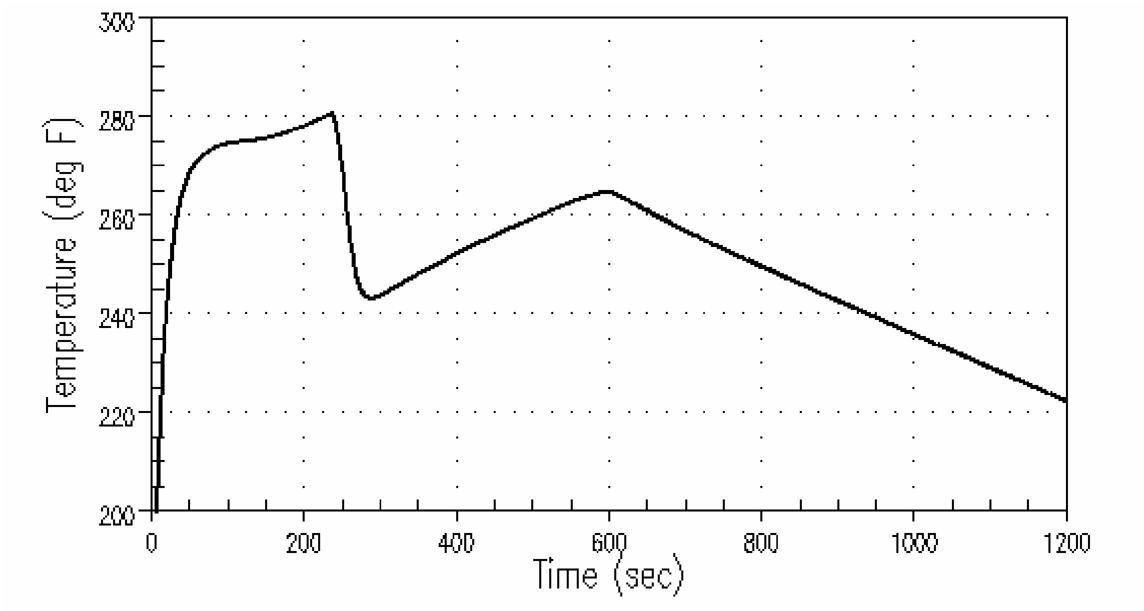
CONTAINMENT SUMP TEMPERATURE
DOUBLE-ENDED PUMP SUCTION BREAK



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2D-9
CONTAINMENT PRESSURE RESPONSE TO A STEAMLINE BREAK
1.4 ft^2 DER, 70% POWER, FRV FAILURE



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2D-10 CONTAINMENT TEMPERATURE RESPONSE TO A STEAMLINE BREAK 1.4 ft^2 DER, 70% POWER, FRV FAILURE

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FIGURES (Continued)

FIGURES (Continued)

FIGURES (Continued)

FIGURES (Continued)

FIGURES (Continued)

NOTE:

[a] This figure corresponds to a controlled engineering drawing that is incorporated by reference into the FSAR Update. See Table 1.6-1 for the correlation between the FSAR Update figure number and the corresponding controlled engineering drawing number.

Chapter 7

INSTRUMENTATION AND CONTROLS

7.1 INTRODUCTION

This chapter presents the various plant instrumentation and control systems by relating the functional performance requirements, design bases, system descriptions, design evaluations, and tests and inspections for each. The information provided in this chapter emphasizes those instruments and associated equipment that constitute the protection system as defined in IEEE 279-1971(Reference 1).

The primary purpose of the instrumentation and control systems is to provide automatic protection against unsafe and improper reactor operation during steady state and transient power operations (Conditions I, II, and III) and to provide initiating signals to mitigate the consequences of faulted conditions (Condition IV). For a discussion of the four conditions, refer to Chapter 15. The information presented in this chapter emphasizes those instrumentation and control systems necessary to ensure that the reactor can be operated to produce power in a manner that ensures no undue risk to the health and safety of the public.

It is shown that the applicable criteria and codes, such as the Atomic Energy Commission's General Design Criteria (GDC) and IEEE standards, concerned with the safe generation of nuclear power are met by these systems. Table 7.1-1 provides a summary of the applicable design basis criteria for each section within Chapter 7.

The classification of instrumentation is described in Section 3.2.2.5.

7.1.1 Definitions

The definitions below establish the meaning of certain terms in the context of their use in Chapter 7.

(1) *Actuation Accuracy* - Synonymous with trip accuracy, but used where the word "trip" may cause ambiguity.

(2) *Channel* - An arrangement of components, modules and software as required to generate a single protective action signal when required by a generating station condition. A channel loses its identity where single action signals are combined.

(3) *Channel Accuracy* (an element of trip accuracy) - Includes accuracy of the primary element, transmitter, and rack-mounted electronics, but does not include indication accuracy.

(4) *Cold Shutdown Condition* - When the reactor is subcritical by an amount greater than the margin specified in the applicable Technical Specification and Tavg is less than or equal to the temperature specified in the applicable Technical Specification. Section 15.1 defines this as MODE 5.

(5) *Components* - Items from which the system is assembled (such as resistors, capacitors, wires, connectors, transistors, tubes, switches, and springs).

(6) *Degree of Redundancy* - The difference between the number of channels monitoring a variable and the number of channels that, when tripped, will cause an automatic system trip.

(7) *Hot Shutdown Condition* - When the reactor is subcritical by an amount greater than the margin specified in the applicable Technical Specification and Tavg is within the temperature range specified in the applicable Technical Specification. Section 15.1 defines this as MODE 4.

(8) *Hot Shutdown Panel* – The hot shutdown panel, which is the alternate control location in the event that the main control room is rendered uninhabitable, is provided with a mode switch, control switch and status for each of the pumps required to bring the plant to a safe shutdown condition.

(9) *Hot Standby Condition* - When the reactor is subcritical by an amount greater than the margin specified in the Technical Specification and the Tavg is greater than or equal to the temperature specified in the applicable Technical Specification. Section 15.1 defines this as MODE 3.

(10) *Indication Accuracy* - The tolerance band containing the highest expected value of the difference between: (a) the value of a process variable read on an indicator or recorder, and (b) the actual value of that process variable. An indication must fall within this tolerance band. It includes channel accuracy, accuracy of readout devices, and rack environmental effects but not process effects such as fluid stratification.

(11) *Minimum Degree of Redundancy* - The degree of redundancy below which operation is prohibited or otherwise restricted by the Technical Specifications.

(12) *Module* - Any assembly of interconnected components that constitutes an identifiable device, instrument, or piece of equipment. A module can be disconnected, removed as a unit, and replaced with a spare. It has definable performance characteristics that permit it to be tested as a unit. A module can be a card or other subassembly of a larger device, provided it meets the requirements of this definition.

(13) *Phase A Containment Isolation* - Closure of all nonessential process lines that penetrate containment. Initiated by high containment pressure, pressurizer low pressure, low steamline pressure, or manual actuation.

(14) *Phase B Containment Isolation* - Closure of remaining process lines. Initiated by containment high-high pressure signal (process lines do not include engineered safety features lines) or manual actuation.

(15) *Protective Action* - A protective action can be at the channel or the system level. A protective action at the channel level is the initiation of a signal by a single channel when the variable sensed exceeds a limit. A protective action at the system level is the initiation of the operation of a sufficient number of actuators to effect a protective function.

(16) *Protective Function* - A protective function is the sensing of one or more variables associated with a particular generating station condition, signal processing, and the initiation and completion of the protective action at values of the variable established in the design bases.

(17) *Reproducibility* - This term may be substituted for "accuracy" in the above definitions for those cases where a trip value or indicated value need not be referenced to an actual process variable value, but rather to a previously established trip or indication value; this value is determined by test.

(18) *Safe Shutdown* - This term is defined as hot standby (MODE 3). Refer to Table 3.9-9, Note (a) for additional DCPP safe shutdown definitions.

(19) *Single Failure* - Any single event that results in a loss of function of a component or components of a system. Multiple failures resulting from a single event shall be treated as a single failure.

(20) *Trip Accuracy* - The tolerance band containing the highest expected value of the difference between (a) the desired trip point value of a process variable, and (b) the actual value at which a comparator trips (and thus actuates some desired result). This is the tolerance band within which a comparator must trip. It includes comparator accuracy, channel accuracy for each input, and environmental effects on the rack-mounted electronics. It comprises all instrumentation errors; however, it does not include any process effects such as fluid stratification.

(21) *Type Tests* - Tests made on one or more units to verify adequacy of design of that type of unit.

7.1.2 IDENTIFICATION OF SAFETY-RELATED SYSTEMS

The instrumentation and control systems and supporting systems discussed in Chapter 7 that are required to function to achieve the system responses assumed in the safety evaluations, and those needed to shut down the plant safely are:

(1) Reactor trip system (RTS)

(2) Engineered safety features actuation system (ESFAS)

(3) Instrumentation and control power supply system (refer to Section 8.3.1.1.5)

(4) Remote shutdown panel controls and instrumentation

The RTS and the ESFAS are functionally defined systems. The functional descriptions of these systems are provided in Sections 7.2 and 7.3. The trip functions identified in Section 7.2, Reactor Trip System, are provided by the following:

(1) Process instrumentation and control system (References 3 and 10)

(2) Nuclear instrumentation system (Reference 4)

(3) Solid-state logic protection system (Reference 5)

(4) Reactor trip switchgear (Reference 5)

(5) Manual actuation circuitry

The actuation functions identified in Section 7.3 are provided by the following:

(1) Process instrumentation and control system (References 3 and 10)

(2) Solid-state logic protection system (Reference 5)

(3) Engineered safety features (ESF) test cabinet (Reference 6)

(4) Manual actuation circuitry

WCAP-7671 (Reference 3) describes the instrumentation and instruments systems that are safety-related as defined in the scope of IEEE-279-1971 (Reference 1).

The original Hagan/Westinghouse PCS was replaced with a programmable logic controller (PLC) based system (DDP 1000000237 and 1000000501).

The PCS converts physical plant parameters such as temperature, pressure, level, and flow into electrical signals during normal operation. These signals are used for plant control, remote process indication, and computer monitoring. The PCS also provides signals to components located in the Hot Shutdown Panel. The PCS comprises Control Racks 17-32, panels PIA, PIB, PIC, and the Instrument Rack (RI Rack).

The sixteen Control Racks are divided into four Control Sets. Control Set I comprises Racks 17-20. Control Set II comprises Racks 21-24. Control Set III comprises Racks 25-27. Control Set IV comprises Racks 28-32. The Control Sets and the associated Class 1E 120-Vac power sources are physically separated. Each Control Set contains two sub-systems based on a PLC platform. One PLC sub-system contains PG&E Design Class I components and functions. The other PLC sub-system contains PG&E Design Class II components and functions. The two PLC sub-systems are separated within the Control Racks. The PG&E Design Class I sub-system in each Control Set receives Class 1E 120-Vac power from an independent Class 1E 120-Vac power source. The PG&E Design Class II sub-system in each Control Set receives non-Class 1E 120-Vac power from two separate sources; one of which is inverter backed. Circuit separation and isolation is maintained for Class 1E power sources to the Control Racks.

Instrument Panels PIA, PIB, and PIC are physically separated from each other and contain Class 1E power sources. These instrument panels receive 120-Vac power from Class 1E 120-Vac power supplies.

The RI Rack contains PG&E Design Class II related components and functions that are processed by a PLC. The RI Rack receives 120-Vac power from two non-Class 1E sources.

7.1.3 IDENTIFICATION OF SAFETY CRITERIA

7.1.3.1 Design Bases

The design bases and functional performance for the PG&E Design Class I systems described in this chapter are provided in Sections 7.2 (RTS), 7.3 (ESFAS), and 8.3.1.1.5 (Instrumentation and Control Power Supply System). Table 7.1-1 provides a summary of the applicable design basis criteria for each section within Chapter 7.

The design bases for the ESF are discussed in Chapter 6; specifically, Section 6.2 for containment systems and Section 6.3 for emergency core cooling system (ECCS).

7.1.3.2 Independence of Redundant Safety-Related Systems

Separation and independence for individual channels of the RTS and ESFAS are discussed in Sections 7.2 and 7.3, respectively. Separation of protection and control systems is discussed in Section 7.7. Refer to Section 8.3 for a discussion of separation and independence of Class 1E electrical systems.

For separation requirements for control board wiring, refer to Section 7.7.

Separation criteria for circuits entering the containment structure are met by providing separate electrical penetrations as follows:

(1) *Reactor Protection Instrumentation* - Each of the Eagle 21 protection sets (I, II, III, and IV) utilizes one or more penetrations dedicated to that protection set.

(2) *Isolation Valves (solenoid-operated)* - Each isolation valve inside the containment structure is connected to its respective ESF dc bus, and circuits are run through associated 480-V bus penetrations. All isolation valves inside the containment structure receive train A signals. Redundant isolation valves outside the containment receive train B signals.

(3) *Isolation Valves (motor-operated)* - Each isolation valve utilizes a penetration dedicated to the 480-V ESF bus that provides power to the valve.

(4) *Fan Coolers* - One penetration for each fan cooler motor.

(5) *Nuclear Instrumentation (out-of-core)* - Four separate penetrations are provided for out-of-core nuclear instrumentation.

The installation of other cable complies with the criteria presented in Chapter 8.

7.1.3.3 Physical Identification of Safety-Related Equipment

There are four separate process protection system rack sets. Separation of redundant process channels begins at the process sensors and is maintained in the field wiring, containment penetrations, and process protection racks to the redundant trains in the protection logic racks. Redundant process channels are separated by locating the electronics in different rack sets. A color-coded nameplate on each rack is used to differentiate between different protective sets. The color coding of the nameplates is:

Protection Set	Color Coding
I	Red with white lettering
II	White with black lettering
III	Blue with white lettering
IV	Yellow with black lettering

Each field wire termination point is tagged to assist identification. However, these tags are not color-coded.

All nonrack-mounted protective equipment and components are provided with an identification tag or nameplate. Small electrical components such as relays have nameplates on the enclosure that houses them.

Postaccident monitoring instruments and controls are identified "PAMS" as required by Regulatory Guide 1.97, Revision 3.

For further details of the process protection system, refer to Sections 7.2, 7.3, and 7.7.

There are identification nameplates on the input panels of the logic system. For details of the logic system, refer to Sections 7.2 and 7.3.

7.1.3.4 Conformance with IEEE Standards

The PG&E Design Class I control and instrumentation systems comply with the following IEEE standards, only as discussed in the appropriate sections. However, because the IEEE standards were issued after much of the design and testing had been completed, the equipment documentation may not meet the format requirements of the standards.

(1) IEEE 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations."

(2) IEEE 308-1971, "Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations."

(3) IEEE 317-1971, "IEEE Standard for Electrical Penetration Assemblies in Containment Structures for Nuclear Fueled Power Generating Stations."

(4) IEEE 323-1971, "IEEE Trial-Use Standard: General Guide for Qualifying Class I Electric Equipment for Nuclear Power Generating Stations."

(5) IEEE 323-1974, "IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations."

(6) IEEE 334-1971, "Trial-Use Guide for Type Tests of Continuous-Duty Class I Motors Installed Inside the Containment of Nuclear Power Generating Stations."

(7) IEEE 336-1971, "Installation, Inspection, and Testing Requirements for Instrumentation and Electrical Equipment During the Construction of Nuclear Power Generating Stations."

DCPP is in conformance with IEEE 336-1971, with the following exceptions:

Paragraph 2.4 - "Data sheets shall contain an evaluation of acceptability." The evaluation of acceptability is indicated on the results and data sheets by the approval signature.

Paragraph 3(4) - "Visual examination of contact corrosion." No visual examination for contact corrosion is made on breaker and starter contacts unless there is evidence of water damage or condensation. Contact resistance tests are made on breakers rated at 4 kV and above. No contact resistance test is made of lower voltage breakers or starters.

Paragraph 6.2.2 - "Demonstrate freedom from unwanted noise." No system test incorporates a noise measurement. If the system under test meets the test criteria, then noise is not a problem.

(8) IEEE 338-1971, "IEEE Trial-Use Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems."

(9) IEEE 344-1971, "Trial-Use Guide for Seismic Qualification of Class I Electric Equipment for Nuclear Power Generating Stations."

(10) IEEE 344-1975, "Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations."

(11) IEEE 384-1974, "Criteria for Independence of Class 1E Equipment and Circuits"

(12) IEEE 603-1980, “IEEE Standard Criteria for Safety Systems for Nuclear Power Generating Stations.”

(13) ANSI/IEEE-ANS-7-4.3.2-1982, “Application Criteria for Programmable Digital Computer Systems in Safety Systems of Nuclear Power Generating Stations,” 1982 (ANSI/IEEE-ANS-7-4.3.2-1982, expands and amplifies the requirements of IEEE 603-1980).

7.1.4 REFERENCES

1. IEEE Standard, 279-1971, Criteria for Protection Systems for Nuclear Power Generating Stations, The Institute of Electrical and Electronics Engineers, Inc.

2. Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.

3. J. A. Nay, Process Instrumentation for Westinghouse Nuclear Steam Supply Systems, WCAP-7671, April 1971.

4. J. B. Lipchak and R. A. Stokes, Nuclear Instrumentation System, WCAP-7669, April 1971.

5. D. N. Katz, Solid State Logic Protection System Description, WCAP-7672, June 1971.

6. J. T. Haller, Engineered Safeguards Final Device or Activator Testing, WCAP-7705, February 1973.

7. Deleted

8. Deleted

9. Deleted

10. Summary Report EAGLE 21 Process Protection System Upgrade for Diablo Canyon Power Plant Units 1 and 2, WCAP-12813, Revision 3, June 1993.

7.2 REACTOR TRIP SYSTEM

This section provides a system description and the design bases for the reactor trip system (RTS).

The RTS automatically keeps the reactor operating within a safe region by tripping the reactor whenever the limits of the region are approached. The safe operating region is defined by several considerations such as mechanical and hydraulic limitations on equipment, and heat transfer phenomena. Therefore, the RTS keeps surveillance on process variables that are directly related to equipment mechanical limitations such as pressure, pressurizer water level (to prevent water discharge through safety valves and uncovering heaters), and also on variables that directly affect the heat transfer capability of the reactor (e.g., flow and reactor coolant temperatures). Other parameters utilized in the RTS are calculated from various process variables. In any event, whenever a direct process or a calculated variable exceeds a setpoint, the reactor will be shut down to protect against either gross damage to fuel cladding or loss of system integrity that could lead to release of radioactive fission products into the containment.

7.2.1 Design Bases

7.2.1.1 General Design Criterion 2, 1967 – Performance Standards

The reactor trip system (RTS) is designed to withstand the effects of or is protected against natural phenomena, such as earthquakes, flooding, tornadoes, winds, and other local site effects.

7.2.1.2 General Design Criterion 11, 1967 – Control Room

The RTS includes the controls and instrumentation necessary to support the safe operational status of the plant and may be shutdown remotely if access to the control room is lost due to fire or other causes.

7.2.1.3 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain the RTS variables within prescribed operating ranges. The RTS is provided to receive plant instrumentation signals and automatically trip the reactor as prescribed limits are approached or reached.

7.2.1.4 General Design Criterion 14, 1967 – Core Protection Systems

The RTS is designed to act automatically to prevent or to suppress conditions that could result in exceeding acceptable fuel damage limits.

7.2.1.5 General Design Criterion 19, 1967 – Protection Systems Reliability

The RTS is designed for high functional reliability and in-service testability commensurate with the safety functions to be performed.

7.2.1.6 General Design Criterion 20, 1967 – Protection Systems Redundancy and Independence

Redundancy and independence are designed into the RTS sufficient to assure that no single failure or removal from service of any component or channel of a system will result in loss of the protection function. The redundancy provided shall include, as a minimum, two channels of protection for each protection function to be served. Different principles are used where necessary to achieve true independence of redundant instrumentation components.

7.2.1.7 General Design Criterion 21, 1967 – Single Failure Definition

The RTS is designed to remain operable after sustaining a single failure. Multiple failures resulting from a single event are treated as a single failure.

7.2.1.8 General Design Criterion 22, 1967 – Separation of Protection and Control Instrumentation Systems

The RTS is designed such that protection systems are separated from control instrumentation systems to the extent that failure or removal from service of any control instrumentation system component or channel, or of those common to control instrumentation and protection circuitry, leaves intact a system satisfying all requirements for the protection channels.

7.2.1.9 General Design Criterion 23, 1967 – Protection Against Multiple Disability for Protection Systems

The RTS is designed such that the effects of adverse conditions to which redundant channels or RTS might be exposed in common, either under normal conditions or those of an accident will not result in loss of the reactor trip function.

7.2.1.10 General Design Criterion 24, 1967 – Emergency Power for Protection Systems

The RTS is designed such that in the event of loss of all offsite power, sufficient alternate sources of power are provided to permit the required functioning of the RTS.

7.2.1.11 General Design Criterion 25, 1967 – Demonstration of Functional Operability of Protection Systems

The RTS includes the means for testing the RTS while the reactor is in operation to demonstrate that no failure or loss of redundancy has occurred.

7.2.1.12 General Design Criterion 26, 1967 – Protection Systems Fail-Safe Design

The RTS is designed, with noted exceptions, to fail into a safe state or into a state established as tolerable on a defined basis if conditions such as disconnection of the system, loss of energy (e.g., electric power, instrument air), or adverse environments (e.g., extreme heat or cold, fire, steam, or water) are experienced.

7.2.1.13 General Design Criterion 31, 1967 – Reactivity Control Systems Malfunction

The RTS is designed to prevent exceeding acceptable fuel damage limits by limiting reactivity transients resulting from any single malfunction in the reactivity control systems, such as, unplanned continuous withdrawal (not ejection) of a control rod.

7.2.1.14 General Design Criterion 49, 1967 – Containment Design Basis

RTS instrumentation circuits routed through containment electrical penetrations are designed to support the containment design basis so that the containment structure can accommodate a loss-of-coolant accident (LOCA) without exceeding the design leakage rate, the pressure and temperature.

7.2.1.15 10 CFR 50.49 – Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

The RTS electric components that require environmental qualification are qualified to the requirements of 10 CFR 50.49.

7.2.1.16 Safety Guide 22, February 1972 – Periodic Testing of Protection System Actuation Functions

The RTS is periodically tested to provide assurance that the system will operate as designed and will be available to function properly. The testing program conforms to Safety Guide 22, February 1972.

7.2.1.17 NUREG-0737 (Items II.K.3.10 and II.K.3.12), November 1980 – Clarification of TMI Action Plan Requirements

Item II.K.3.10 – Proposed Anticipatory Trip Modification: The setpoint for the anticipatory reactor trip on turbine trip bypass (P-9) cannot be raised above 10% reactor power until it has been shown that the probability of a small-break loss-of-coolant

accident (LOCA) resulting from a stuck-open power-operated relief valve (PORV) is substantially unaffected by the modification.

Item II.K.3.12 – Anticipatory Reactor Trip upon Turbine Trip: The RTS includes an anticipatory reactor trip upon turbine trip.

7.2.1.18 Generic Letter 83-28 (Actions 4.3 and 4.5), July 1983 – Required Actions Based on Generic Implications of Salem ATWS Events

Action 4.3 – RTS Reliability (Automatic Actuation of Shunt Trip Attachment for Westinghouse and B&W Plants): The RTS provides actuation of the breaker shunt trip attachments. The shunt trip attachment is considered safety related (Class 1E).

Action 4.5 – RTS Reliability (System Functional Testing): On-line functional testing of the RTS, including independent testing of the diverse trip features, is performed.

7.2.2 System Description

The RTS uses sensors that feed the process circuitry consisting of two to four redundant channels, which monitor various plant parameters. The RTS also contains the logic circuitry necessary to automatically open the reactor trip breakers. The logic circuitry consists of two redundant logic trains that receive input from the protection channels.

Each of the two logic trains, A and B, is capable of opening a separate and independent reactor trip breaker (52/RTA and 52/RTB). Logic train A opens reactor trip breaker 52/RTA and bypass breaker 52/BYB. Logic train B opens reactor trip breaker 52/RTB and bypass breaker 52/BYA. The two trip breakers in series connect three-phase ac power from the rod drive motor generator sets to the rod drive power bus, as shown in Figure 7.2-1, Sheets 3 and 4. For reactor trip, a loss of dc voltage to the undervoltage coil releases the trip plunger and trips open the breaker. Additionally, an undervoltage trip auxiliary relay provides a trip signal to the shunt trip coil that trips open the breaker in the unlikely event of an undervoltage coil malfunction. When either of the trip breakers opens, power is interrupted to the rod drive power supply, and the control rods fall by gravity into the core. The rods cannot be withdrawn until an operator resets the trip breakers. The trip breakers cannot be reset until the bistable, which initiated the trip, reenergizes. Bypass breakers BYA and BYB are provided to permit testing of the trip breakers, as discussed below.

The RTS design was evaluated in detail with respect to common mode failure and is presented in References 1 and 11. Preoperational testing was performed on RTS components and systems to determine equipment readiness for startup. This testing served as a further evaluation of the system design.

Analyses of the results of Conditions I, II, III, and IV events, including considerations of instrumentation installed to mitigate their consequences, are presented in Chapter 15.

The instrumentation installed to mitigate the consequences of load reduction and turbine trip is identified in Section 7.4.2 and Section 10.2.2.

7.2.2.1 Reactor Trips

The various reactor trip circuits automatically open the reactor trip breakers whenever a condition monitored by the RTS reaches a preset level. In addition to redundant channels and trains, the design approach provides an RTS that monitors numerous system variables, thereby providing RTS functional diversity. The extent of this diversity has been evaluated for a wide variety of postulated accidents and is detailed in Reference 1.

Table 7.2-1 provides a list of reactor trips that are described below.

7.2.2.1.1 Nuclear Overpower Trips

The specific trip functions generated are:

(1) *Power Range High Nuclear Power Trip* - The power range high nuclear power trip circuit trips the reactor when two of the four power range channels exceed the trip setpoint. There are two independent bistables each with its own trip setting (a high and a low setting). The high trip setting provides protection during normal power operation and is always active. The low trip setting, which provides protection during startup, can be manually blocked when two of the four power range channels read above approximately 10 percent power (P-10). This trip function is automatically reinstated when three of the four power range channels decrease below 10 percent power. Refer to Table 7.2-2 for a listing of all protection system interlocks.

(2) *Intermediate Range High Neutron Flux Trip* - The intermediate range high neutron flux trip circuit trips the reactor when one of the two intermediate range channels exceeds the trip setpoint. This trip, which provides protection during reactor startup, can be manually blocked if two of the four power range channels are above approximately 10 percent power (P-10). This trip function is automatically reinstated when three of the four power range channels decrease below 10 percent power. The intermediate range channels (including detectors) are separate from the power range channels. The intermediate range channels can be individually bypassed at the nuclear instrumentation racks to permit channel testing during plant shutdown or prior to startup. This bypass action is annunciated on the control board.

(3) *Source Range High Neutron Flux Trip* - The source range high neutron flux trip circuit trips the reactor when one of the two source range channels exceeds the trip setpoint. This trip, which provides protection during reactor startup and plant shutdown, can be manually blocked when one of the two intermediate range channels reads above the P-6 setpoint value

and is automatically reinstated when both intermediate range channels decrease below the P-6 value. This trip is also automatically bypassed by two-out-of-four logic from the power range interlock (P-10). This trip function can also be reinstated below P-10 by an administrative action requiring manual actuation of two control board-mounted switches. Each switch will reinstate the trip function in one of the two protection logic trains. The source range trip point is set between the P-6 setpoint (source range cutoff flux level) and the maximum source range flux level. The channels can be individually bypassed at the nuclear instrumentation racks to permit channel testing during plant shutdown or prior to startup. This bypass action is annunciated on the control board.

(4) *Power Range High Positive Nuclear Power Rate Trip* - This circuit trips the reactor when an abnormal rate of increase in nuclear power occurs in two of the four power range channels. This trip provides protection against rod ejection and rod withdrawal accidents of low worth from middle to low power conditions and is always active.

Figure 7.2-1, Sheets 5 and 6, shows the logic for all of the nuclear overpower and rate trips. A detailed functional description of the equipment associated with this function is provided in Reference 2.

7.2.2.1.2 Core Thermal Overpower Trips

The specific trip functions generated are:

(1) *Overtemperature ΔT Trip* - This trip protects the core against DNB and trips the reactor on coincidence, as listed in Table 7.2-1, with one set of temperature measurements per loop. The setpoint for this trip is continuously calculated by process protection circuitry for each loop by solving the following equation:

$$\Delta Ti\frac{(1+\tau_4 s)}{(1+\tau_5 s)} \le \Delta Ti^\circ\left\{K_1 - K_2\frac{(1+\tau_1 s)}{(1+\tau_2 s)}\left[Tavg_i - Tavg_i^\circ\right] + K_3(P - P^\circ) - f_1(\Delta I)\right\} \qquad (7.2\text{-}1)$$

where:

ΔTi° = indicated ΔT at rated thermal power from loop i, °F

$Tavg_i^\circ$ = Indicated Tavg at rated thermal power from loop i, °F

P° = 2235 psig (indicated RCS nominal operating pressure)

Th_{ij} = jth narrow range Thot input signal from loop i

$T^f h_{ij}$ = $Th_{ij}\ (1/(1+\tau_6 s))$

$\frac{1}{1+\tau_6 s}$ = Lag compensator on measured Thot

$Thave_i$ = $\sum (T^f h_{ij})/3$ for j = 1 - 3 for each loop, i = 1 - 4

Note: A 3-input redundant sensor algorithm (RSA) eliminates $T^f h_{ij}$ values that result from known bad inputs or that fail a consistency check. The RSA also determines a quality code for $Thave_i$, depending on the quality and consistency of the individual $T^f h_{ij}$ values. (Refer to Section 7.2.2.3)

Tc_{ij} = jth narrow-range Tcold input signal from loop i

$T^f c_{ij}$ = Tc_{ij} (1/(1+τ_7s))

$\frac{1}{1+\tau_7 s}$ = Lag compensator on measured Tcold

$\tau_6 ; \tau_7$ = Time constants utilized in the lag compensator for Thot and Tcold: τ_6 = 0 secs; τ_7 = 0 secs

$Tcave_i$ = $\sum (T^f c_{ij})/2$ for j = 1 - 2 for each loop, i = 1 - 4

Note: A 2-input RSA determines a quality code and a value for $Tcave_i$, depending on the quality and consistency of the individual $T^f c_{ij}$ values. (Refer to Section 7.2.2.3)

ΔTi = $(Thave_i - Tcave_i)$ for each loop, i = 1 - 4, °F

$\overline{Tavg}_i$ = ($Thave_i$ + $Tcave_i$)/2 for each loop, i = 1 - 4, °F

$\frac{1+\tau_4 s}{1+\tau_5 s}$ = The function generated by the lead-lag controller for ΔT dynamic compensation

$\tau_4 ; \tau_5$ = Time constants utilized in the lead-lag controller for ΔT: τ_4 = 0 sec; τ_5 = 0 sec

P = pressurizer pressure signal, psig

$\frac{1+\tau_1 s}{1+\tau_2 s}$ = the function generated by the lead-lag controller for $Tavg_i$ dynamic compensation

τ_1 ; τ_2 = time constants utilized in the lead-lag controller for Tavg:
τ_1 = 30 sec;
τ_2 = 4 sec

s = Laplace transform operator, sec^{-1}

K_1 = (*)

K_2 = (*)

K_3 = (*)

f_1 (ΔI) = a function of the indicated difference between top and bottom detectors of the power range nuclear ion chambers, with grains to be selected based on measured instrument response during plant startup tests such that:

(a) for $q_t - q_b$ between (*) and (*), f_1 (ΔI) = 0
(where q_t and q_b are percent rated thermal power in the top and bottom halves of the core respectively, and $q_t + q_b$ is total thermal power in percent of rated thermal power)

(b) for each percent that the magnitude of ($q_t - q_b$) exceeds (*), the ΔT trip setpoint shall be automatically reduced by (*) of its value at rated thermal power

(c) for each percent that the magnitude of ($q_t - q_b$) exceeds (*), the ΔT trip setpoint shall be automatically reduced by (*) of its value at rated thermal power

Note: The channel's maximum trip point shall not exceed its computed trip point by more than (*).

(*) Refer to Technical Specifications for current values to be used.

One power range channel separately feeds each overtemperature ΔT trip channel.

Changes in f_1 (ΔI) can only lead to a decrease in the trip setpoint; refer to Figure 7.2-2.

The single pressurizer pressure parameter required per loop is obtained from separate sensors that are connected to three pressure taps at the top of the pressurizer. The four pressurizer pressure signals are obtained from the three taps by connecting one of the taps to two pressure transmitters. Refer to Section 7.2.2.1.3 for analysis of this

arrangement. Figure 7.2-1, Sheets 9 and 10, shows the logic for the overtemperature ΔT trip function.

(2) *Overpower ΔT Trip* - This trip protects against excessive power (fuel rod rating protection) and trips the reactor on coincidence as listed in Table 7.2-1, with one set of temperature measurements per loop. The setpoint for each channel is continuously calculated using the following equation:

$$\Delta Ti \frac{(1+\tau_4 s)}{(1+\tau_5 s)} \le \Delta Ti^{\circ} \left\{ K_4 - K_5 \frac{\tau_3 s}{1+\tau_3 s} Tavg_i - K_6 \left[Tavg_i - Tavg_i^{\circ} \right] - f_2(\Delta I) \right\} \qquad (7.2\text{-}2)$$

where:

$Tavg_i$	=	As defined for overtemperature ΔT trip
ΔT_i	=	As defined for overtemperature ΔT trip
$Tavg_i^{o}$	=	As defined for overtemperature ΔT trip
ΔT_i^{o}	=	As defined for overtemperature ΔT trip
$\frac{1+\tau_4 s}{1+\tau_5 s}$	=	The function generated by the lead-lag controller for measured ΔT
τ_4; τ_5	=	Time constants used in the lead-lag controller for measured ΔT: τ_4 = 0 sec; τ_5 = 0 sec
K_4	=	(*)
K_5	=	(*)/°F for increasing average temperature; 0 for decreasing average temperature
K_6	=	(*) for $Tavg_i > Tavg_i^{o}$; K6 = 0 for $Tavg_i \le Tavg_i^{o}$
$\frac{\tau_3 s}{1+\tau_3 s}$	=	the function generated by the rate-lag controller for $Tavg_i$ dynamic compensation
τ_3	=	time constants utilized in the rate-lag controller for Tavg τ_3 = 10 sec
s	=	Laplace transform operator, sec^{-1}

$f_2 (\Delta I) = 0$ for all ΔI

Note: The channel's maximum trip point shall not exceed its computed trip point by more than (*).

(*) Refer to Technical Specifications for current values.

The source of temperature and flux information is identical to that of the overtemperature ΔT trip and the resultant ΔT setpoint is compared to the same ΔT. Figure 7.2-1, Sheets 9 and 10, shows the logic for this trip function.

7.2.2.1.3 Reactor Coolant System Pressurizer Pressure and Water Level Trips

The specific trip functions generated are:

(1) *Pressurizer Low-Pressure Trip* - The purpose of this trip is to protect against low pressure that could lead to departure from nucleate boiling (DNB), and to limit the necessary range of protection afforded by the overtemperature ΔT trip. The parameter being sensed is reactor coolant pressure as measured in the pressurizer. Above P-7, the reactor is tripped when the dynamically compensated pressurizer pressure measurements fall below preset limits. This trip is blocked below P-7 to permit startup. The trip logic and interlocks are provided in Table 7.2-1.

The trip logic is shown in Figure 7.2-1, Sheets 11 and 12.

(2) *Pressurizer High-Pressure Trip* - The purpose of this trip is to protect the reactor coolant system (RCS) against system overpressure.

The same sensors and transmitters used for the pressurizer low-pressure trip are used for the high-pressure trip except that separate comparators are used for the trip. These comparators trip when nondynamically compensated pressurizer pressure signals exceed preset limits on coincidence, as listed in Table 7.2-1. There are no interlocks or permissives associated with this trip function.

The logic for this trip is shown in Figure 7.2-1, Sheets 11 and 12.

(3) *Pressurizer High Water Level Trip* - This trip is provided as a backup to the pressurizer high-pressure trip and prevents the pressurizer from becoming water solid during low worth and low power rod withdrawal accidents. This trip is blocked below P-7 to permit startup. The coincidence logic and interlocks of the pressurizer high water level signals are provided in Table 7.2-1.

The trip logic for this function is shown in Figure 7.2-1, Sheets 11 and 12.

7.2.2.1.4 Reactor Coolant System Low-Flow Trips

These trips protect the core from DNB in the event of a loss of coolant flow situation. The means of sensing the loss of coolant are:

(1) *Reactor Coolant Low-Flow Trip* - The parameter sensed is reactor coolant flow. Three elbow taps in each coolant loop are used as flow devices that indicate the status of reactor coolant flow. The basic function of these devices is to provide information as to whether or not a reduction in flow has occurred. An output signal from two out of the three comparators in a loop would indicate a low flow in that loop. The trip logic for this function is shown in Figure 7.2-1, Sheets 9 and 10. The coincidence logic and interlocks are shown in Table 7.2-1.

(2) *Reactor Coolant Pump Breakers Open Trip* - Opening of two reactor coolant pump breakers or redundant overcurrent protection breakers above the P-7 interlock setpoint, which is indicative of an imminent loss of coolant flow, also causes a reactor trip.

One set of auxiliary contacts on each pump breaker serves as the input signal to the trip logic. The trip logic for this function is shown in Figure 7.2-1, Sheets 9 and 10. The coincident logic and interlocks are shown in Table 7.2-1.

(3) *Reactor Coolant Pump Bus Undervoltage Trip* - This trip is required to protect against low flow that can result from loss of voltage to the reactor coolant pumps. Time delays are incorporated in the undervoltage trip relays to prevent spurious reactor trip from momentary electrical power transients. The maximum external time delay is determined to be 0.6 seconds. This allows the total time delay for reactor UV trip to stay within the limits specified in Equipment Control Guidelines and also within the limit established in the accident analysis, Section 15.1.5. (The nominal time delay will be 0.5 seconds, with a tolerance of +/- 0.05 seconds.) There are two undervoltage sensors on each of the two buses. A one-out-of-two undervoltage signal on both buses trips the reactor if above the P-7 setpoint and starts the turbine-driven auxiliary feedwater pump at any reactor power level. The trip logic for this function is shown in Figure 7.2-1, Sheets 9 and 10.

(4) *Reactor Coolant Pump Bus Underfrequency Trip* - This trip is required to protect against low flow resulting from bus underfrequency, which might result from a major power grid frequency disturbance.

There are three underfrequency sensors on each of two buses. A two-out-of-three underfrequency signal on either bus trips the reactor if above

the P-7 setpoint. The logic scheme is arranged so that a two-out-of-three underfrequency signal on bus 1 trips the breakers to reactor coolant pumps 1 and 2 only, and a two-out-of-three underfrequency signal on bus 2 will trip the breakers to reactor coolant pumps 3 and 4 only. The trip logic for this function is shown in Figure 7.2-1, Sheets 9 and 10.

7.2.2.1.5 Low-Low Steam Generator Water Level Trip (Including Trip Time Delay)

This trip protects the reactor from loss of heat sink in the event of a loss of feedwater to one or more steam generators or a major feedwater line rupture. This trip is actuated on two out of three low-low water level signals occurring in any steam generator. If a low-low water level condition is detected in one steam generator, signals shall be generated to trip the reactor and start the motor-driven auxiliary feedwater pumps. If a low-low water level condition is detected in two or more steam generators, a signal is generated to start the turbine-driven auxiliary feedwater pump as well.

The signals to actuate reactor trip and start auxiliary feedwater pumps are delayed through the use of a Trip Time Delay (TTD) system for reactor power levels below 50 percent of RTP. Low-low water level in any protection set in any steam generator will generate a signal that starts an elapsed time trip delay timer. The allowable trip time delay is based upon the prevailing power level at the time the low-low level trip setpoint is reached. If power level rises after the trip time delay setpoints have been determined, the trip time delay is redetermined (i.e., decreased) according to the increase in power level. However, the trip time delay is not changed if the power level decreases after the delay has been determined. The use of this delay allows added time for natural steam generator level stabilization or operator intervention to avoid an inadvertent protection system actuation.

The logic is shown in Figure 7.2-1, Sheets 13 and 14.

Steam generator water level low-low trip time delay:

$$TD = B1(P)^3 + B2(P)^2 + B3(P) + B4 \qquad (7.2\text{-}3)$$

where:

P = RCS loop ΔT equivalent to power (% rated thermal power (RTP)); $P \leq 50\%$ RTP

TD = time delay for steam generator water level low-low reactor trip (in seconds)

B1, B2, B3, and B4 are constants:

B1 = -0.007128
B2 = +0.8099

B3 = -31.40
B4 = +464.1

7.2.2.1.6 Turbine Trip-Reactor Trip

The turbine trip-reactor trip is actuated by two-out-of-three logic from low autostop oil pressure signals or by all closed signals from the turbine steam stop valves. A turbine trip causes a direct reactor trip above P-9.

Other turbine trips are discussed in Chapter 10.

The logic for this trip is shown in Figure 7.2-1, Sheets 3, 7, 19, 31 and Sheets 4, 8, 20, 32.

The analog portion of the trip shown in Figure 7.2-1, Sheets 31 and 32, is represented by dashed lines. When the turbine is tripped, turbine autostop oil pressure drops, and the pressure is sensed by three pressure sensors. A logic output is provided from each sensor when the oil pressure drops below a preset value. These three outputs are transmitted to two redundant two-out-of-three logic matrices, either of which trips the reactor if above P-9.

The autostop oil pressure signal also dumps the emergency trip fluid, closing all of the turbine steam stop valves. When all stop valves are closed, a reactor trip signal is initiated if the reactor is above P-9. This trip signal is generated by redundant (two each) limit switches on the stop valves.

7.2.2.1.7 Safety Injection Signal Actuation Trip

A reactor trip occurs when the safety injection system (SIS) is actuated. The means of actuating the SIS are described in Section 7.3.2. Figure 7.2-1, Sheets 15 and16, shows the logic for this trip.

7.2.2.1.8 Manual Trip

The manual trip consists of two switches with four outputs on each switch. Each switch provides a trip signal for both trip breakers and both bypass breakers. (Operating a manual trip switch also removes the voltage from the undervoltage trip coil.)
There are no interlocks that can block this trip. Figure 7.2-1, Sheets 5 and 6, shows the manual trip logic.

7.2.2.1.9 Seismic Trip

The seismic trip system operates to shut down reactor operations should ground accelerations exceed a preset level in any two of the three orthogonal directions monitored (one vertical, two horizontal). The preset level is indicated in the Technical Specifications (Reference 4). No credit was taken for operation of the seismic trip in the

safety analysis; however, its functional capability at the specified trip settings is required to enhance the overall reliability of the reactor protection system.

Three triaxial sensors (accelerometers) are anchored to the containment base in three separate locations 120 degrees apart (Figure 7.2-6). Each senses acceleration in three mutually orthogonal directions. Output signals are generated when ground accelerations exceed the preset level. These signals, lasting from 6 to 20 seconds (adjustable), are wired directly to the Trains A and B solid state protection system (SSPS). Refer to Figure 7.2-1, Sheets 35 and 36. If two of the three sensors in any direction produce simultaneous outputs, the logic produces trains A and B reactor trip signals.

The seismic reactor trip system was designed in compliance with IEEE 279-1971 (Reference 7) and IEEE 344-1975 (Reference 21), but will not be required to function during or following a LOCA or fire. Cables and raceways are separated in accordance with Section 8.3.1.4.1

7.2.2.1.10 Automatic Trip Logic

The general alarm system, described in Reference 5, maintains a check on each train of the solid-state logic protection system for the existence of certain undesirable conditions. Both trains are tripped if an abnormal condition occurs simultaneously in both trains. Reference 5 states that SSPS printed circuit boards (PCBs) use Motorola High Threshold Logic (MHTL). MHTL based PCBs are obsolete and have been replaced with PCBs which are not based on MHTL (Reference 33). The replacement universal logic, safeguards driver, or under voltage driver PCBs have diagnostic features that can activate a general warning alarm when there is a critical board problem.

7.2.2.2 Reactor Trip System Interlocks

7.2.2.2.1 Power Escalation Permissives

The overpower protection provided by the out-of-core nuclear instrumentation consists of three discrete, but overlapping, levels. Continuation of startup operation or power increase requires a permissive signal from the higher range instrumentation channels before the lower range level trips can be manually blocked by the operator.

A one-out-of-two intermediate range permissive signal (P-6) is required prior to source range level trip blocking and detector high voltage cutoff. Source range level trips are automatically reactivated and high voltage restored when both intermediate range channels are below the permissive (P-6) levels. There is a manual reset switch for administratively reactivating the source range level trip and detector high voltage when between the permissive P-6 and P-10 level, if required. Source range level trip block and high voltage cutoff are always maintained when above the permissive P-10 level.

The intermediate range level trip and power range (low setpoint) trip can be blocked only after satisfactory operation and permissive information are obtained from two-out-of-four power range channels. Individual blocking switches are provided so that the low range power range trip and intermediate range trip can be independently blocked. These trips are automatically reactivated when any three of the four power range channels are below the permissive (P-10) level, thus ensuring automatic activation to more restrictive trip protection.

The development of permissives P-6 and P-10 is shown in Figure 7.2-1, Sheets 7 and 8. All of the permissives are digital; they are derived from analog signals in the nuclear power range and intermediate range channels.

Refer to Table 7.2-2 for the list of protection system interlocks.

7.2.2.2.2 Blocks of Reactor Trips at Low Power

Interlock P-7 blocks a reactor trip at low power (below approximately 10 percent of full power) on a low reactor coolant flow or reactor coolant pump open breaker signal in more than one loop, reactor coolant pump undervoltage, reactor coolant pump underfrequency, pressurizer low pressure, and pressurizer high water level on both units. Refer to Figure 7.2-1, Sheets 9, 10 and Sheets 11, 12 for permissive applications. The low power signal is derived from three-out-of-four power range neutron flux signals below the setpoint in coincidence with one-out-of-two turbine impulse chamber pressure signals below the setpoint (low plant load).

The P-8 interlock blocks a reactor trip when the plant is below a preset level specified in the Technical Specifications on a low reactor coolant flow in any one loop. The block action (absence of the P-8 interlock signal) occurs when three-out-of-four neutron flux power range signals are below the setpoint. Thus, below the P-8 setpoint, the reactor is allowed to operate with one inactive loop, and trip will not occur until two loops are indicating low flow. Refer to Figure 7.2-1, Sheets 7 and 8, for derivation of P-8, and Sheet 5 for the applicable logic.

The P-9 interlock blocks a reactor trip below the maximum value of 50 percent of full power on a turbine trip signal. Refer to Figure 7.2-1, Sheets 2, 7, 31 and Sheets 4, 8, 32 for the application logic. The reactor trip on turbine trip is actuated by two-out-of-three logic from emergency trip fluid pressure signals or by all closed signals from the turbine steam stop valves.

Refer to Table 7.2-2 for the list of protection system blocks.

7.2.2.3 Coolant Temperature Sensor Arrangement and Calculational Methodology

The individual narrow range cold and hot leg temperature signals required for input to the reactor trip circuits and interlocks are obtained using resistance temperature detectors (RTDs) installed in each reactor coolant loop.

The cold leg temperature measurement on each loop is accomplished with a dual element narrow-range RTD mounted in a thermowell. The cold leg sensors are inherently redundant in that either sensor can adequately represent the cold leg temperature measurement. Temperature streaming in the cold leg is not a concern due to the mixing action of the reactor coolant pump.

The hot leg temperature measurement on each loop is accomplished with three dual element narrow-range RTDs mounted in thermowells spaced 120 degrees apart around the circumference of the reactor coolant pipe for spatial variations. One of the elements in each thermowell is an installed spare.

These cold and hot leg narrow-range RTD signals are input to the protection system digital electronics and processed as follows:

The two filtered cold leg temperature input signals $T^f c_j$ for each loop i are processed to determine a group average value $T^f cave_i$. The 2-input redundant sensor algorithm (RSA) calculates the group average value based on the number of good input signals.

If both input signals are BAD, the group value is set equal to the average of the two bad sensor values. If one signal is BAD and the other is DISABLED, the group value is set equal to the value of the bad sensor. The group quality is set to BAD in either case.

If one of the input signals is BAD and the other is GOOD, the group value is set equal to the GOOD value. A consistency check is not performed. The group quality is set to POOR.

If neither of the input signals is BAD, a consistency check is performed. If the deviation of these two signals is within an acceptance tolerance (±DELTAC), the group quality is set to GOOD and the group value is set equal to the average of the two inputs. If the difference exceeds ±DELTAC, the group quality is set to BAD, and the individual signal qualities are set to POOR. The group value is set equal to the average of the two inputs.

DELTAC is a fixed input parameter based on operating experience. One DELTAC value is required for each protection set.

Estimates of hot leg temperature are derived from each T_{hot} input signal as follows:

$$\overline{T}_{hestij} = T^f_{hij} - P_{B_i S^o_{ij}} \qquad (7.2\text{-}4)$$

where:

T^{f}_{hij} is the filtered T_{hot} signal for the jth RTD (j = 1 to 3) in the ith loop (i = 1 to 4)

P_{B_i} = power fraction being used to correct the bias value being used for any power level

$$P_{B_i} = \left(T^{f}_{have_i} - T^{f}_{cave_i}\right) / \Delta T^{\circ}_{i} \qquad (7.2\text{-}5)$$

where:

ΔT^{o}_{i} is the full power ΔT in the ith loop

S^{o}_{ij} = manually input bias that corrects the individual T_{hot} RTD value to the loop average.

The three hot leg temperature estimates T_{hestj} for each loop i are processed to determine a group average value T^{f}_{havei}. The 3-input RSA calculates the group value T^{f}_{havei} based on the available number of good input values.

If all three inputs are BAD, the group value is set to the average of the three input sensor values. The group value quality is set to BAD. If only one input is GOOD, the group value is set equal to the value of the good sensor. The group quality is set to BAD.

If two inputs are good, the difference between the two sensors is compared to DELTAH. If the inputs do not agree within ±DELTAH, the group quality is set to BAD and the quality of both inputs is set to POOR. If the inputs agree, the group quality is set to GOOD. The group value is set equal to the average of the two inputs in either case.

If all three inputs are good, an average of the three estimated hot leg temperatures is computed and the individual signals are checked to determine if they agree within ± DELTAH of the average value. If all of the signals agree within ± DELTAH of the average value, the group quality is set to GOOD. The group value (T^{f}_{havei}) is set to the average of the three estimated average hot leg temperatures.

If the signal values do not all agree within ± DELTAH of the average, the RSA will delete the signal value that is furthest from the average. The quality of this signal will be set to POOR and a consistency check will then be performed on the remaining GOOD signals. If these signals pass the consistency check, the group value will be taken as the average of these GOOD signals and the group quality will be set to POOR. However, if these signals again fail the consistency check (within ± DELTAH), then the group value

will be set to the average of these two signals; but the group quality will be set to BAD. All of the individual signals will have their quality set to POOR.

DELTAH is a fixed input parameter based upon temperature fluctuation within the hot leg. One DELTAH value is required for each protection set.

Delta T and T Average are calculated as follows:

$$\Delta T_i = T^f_{have_i} - T^f_{cave_i} \tag{7.2-6}$$

$$T_{avg_i} = (T^f_{have_i} + T^f_{cave_i})/2.0 \tag{7.2-7}$$

The calculated values for Delta T and T_{avg} are then utilized for both the remainder of the Overtemperature and Overpower Delta T protection channel and channel outputs for control purposes.

A similar calculation of Delta T is performed for and used by the steam generator low-low level trip time delay (TTD) function.

Alarms are generated from a group status that is based on the quality of $T^f_{have_i}$ and $T^f_{cave_i}$ out of the RSA. If the quality of either group is BAD and all of the inputs for that group are not off scale low, then the group status is set to TROUBLE and RTD FAILURE. If either quality is POOR and all of its inputs are not off scale low, then the group status is set to TROUBLE. Otherwise, the group status is set to GOOD.

7.2.2.4 Pressurizer Water Level Reference Leg Arrangement

The design of the pressurizer water level instrumentation includes a slight modification of the usual tank level arrangement using differential pressure between an upper and a lower tap. The modification shown in Figure 7.2-4 consists of the use of a sealed reference leg instead of the conventional open column of water. Refer to Section 7.2.2.11.4 for an analysis of this arrangement.

7.2.2.5 Process Protection System

The process protection system is described in Reference 3.

With the installation of the RTD bypass elimination functional upgrade as part of the Eagle 21 process protection system upgrade, the following plant operating concerns are addressed:

(1) The possibility of loss of flow or reduced flow through the common return line of the hot and cold RTD bypass manifold, as a result of transport time of the temperature measurements for the RTD loop, affecting the design basis for the overtemperature, overpower and control channels monitoring associated with the affected RTD bypass loop is eliminated.

(2) Operator indication of the loop Tavg, Tavg, and Delta-T deviation alarms is maintained, providing the operator the same detecting signals as with the bypass loops.

(3) The potential for a failed Thot RTD affecting the loop Tavg, Tavg, and ΔT measurements is reduced due to the algorithms provided in the Eagle 21 process protection system software that automatically detect a failed RTD and eliminate the failed RTDs measurement from affecting these plant parameters

7.2.2.6 Solid State (Digital) Logic Protection

The solid-state logic protection system takes binary inputs, (voltage/no voltage) from the process and nuclear instrument channels and direct inputs corresponding to conditions (normal/abnormal) of plant parameters. The system combines these signals in the required logic combination and generates a trip signal (no voltage) to the undervoltage coils of the reactor trip circuit breakers and an undervoltage auxiliary relay when the necessary combination of signals occurs. The undervoltage auxiliary relay sends a trip signal (125-Vdc) to the shunt trip coils of the reactor trip breakers. The system also sends actuation signals to engineered safety features (ESF) components (as discussed in Section 7.3), provides annunciator, status light, and computer input signals that indicate the condition of bistable input signals, partial- and full-trip functions, and the status of the various blocking, permissive, and actuation functions. In addition, the system includes means for semiautomatic testing of the logic circuits. A detailed description of this system is provided in Reference 6. Reference 6 is based on SSPS printed circuit boards (PCBs) that use Motorola High Threshold Logic (MHTL). MHTL based PCBs are obsolete and have been replaced with PCBs which are not based on MHTL (Reference 33).

7.2.2.7 Reactor Trip Breakers

The reactor trip breakers are equipped for automatic actuation of both the undervoltage trip device and the shunt trip device. The reactor trip breakers are also equipped to permit manual trip of the breakers at the switchgear cabinet.

7.2.2.8 Isolation Devices

In certain applications, it is advantageous to employ control signals derived from individual protection channels through isolation devices contained in the protection channel, as permitted by IEEE-279-1971 (Reference 7).

In all of these cases, signals derived from protection channels for nonprotective functions are obtained through isolation devices located in the process protection racks. By definition, nonprotective functions include those signals used for control, remote process indication, and computer monitoring.

Isolation devices qualification type tests are described in References 8, 9, and 32.

7.2.2.9 Energy Supply and Environmental Qualification Requirements

The energy supply for the RTS, including the voltage and frequency variations, is described in Section 8.3.1.1.5.2.1, Class 1E 120-Vac Instrument Power Supply System.

Refer to Section 8.3.1.1.5.2.1 and Section 8.3.1.1.5.3.8 for a discussion on the power supply for the RTS and compliance with IEEE 308-1971 (Reference 13).

There are no Class I motors in the RTS; therefore, IEEE 334-1971 (Reference 15) does not apply.

The environmental qualification requirements are identified in Section 3.11.

7.2.2.10 Reactor Trip System Instrumentation Trip Setpoints

While most setpoints used in the RTS are fixed, there are variable setpoints, most notably the overtemperature ΔT and overpower ΔT setpoints. All setpoints in the RTS have been selected either on the basis of applicable engineering code requirements or engineering design studies. Methodologies for determining RTS setpoint and allowable values are presented in WCAP-11082, Technical Specification 3.3.1, or in plant procedures. The capability of the RTS to prevent loss of integrity of the fuel cladding and/or RCS pressure boundary during Condition II transients is demonstrated in Section 15.2. A reactor trip is also credited for certain Condition III and IV events as described in Sections 15.3 and 15.4. These accident analyses are carried out using those setpoints determined from results of the engineering design studies. Functions that require a reactor trip and associated setpoint limits are presented in the Technical Specifications. A discussion of the intent for each of the various reactor trips and the accident analysis (where appropriate) that utilize the trip is presented in Section 7.2.2.1. It should be noted that the selected trip setpoints all provide for margin before protection action is actually required to allow for uncertainties and instrument errors.

The setpoints for the various functions in the RTS have been analytically determined such that the operational limits so prescribed prevent fuel rod cladding damage and loss of integrity of the RCS as a result of any Condition II incident (anticipated malfunction). As such, the RTS limits the following parameters to:

(1) Minimum DNBR = The applicable limit value (Refer to Section 4.4.1.1 and Section 4.4.2.3)

(2) Maximum system pressure = 2,750 psia

(3) Total core power less than or equal to 118 percent of nominal (limits the fuel rod maximum linear power to a kW/ft., less than the value that could cause fuel centerline melt)

The accident analyses described in Section 15.2 demonstrate that the functional requirements as specified for the RTS are adequate to meet the above considerations, even assuming, for conservatism, adverse combinations of instrument errors (Refer to Table 15.1-2). A discussion of the safety limits associated with the reactor core and RCS, plus the limiting safety system setpoints, is presented in the Technical Specifications.

7.2.2.11 Specific Control and Protection Interactions

7.2.2.11.1 Nuclear Power

Four power range nuclear power channels are provided for overpower protection. An additional control input signal is derived by auctioneering of the four channels for automatic rod control. If any channel fails producing a low output, that channel is incapable of proper overpower protection but does not cause control rod movement because of the auctioneer. Two-out-of-four overpower trip logic ensures an overpower trip, if needed, even with an independent failure in another channel.

In addition, a deviation signal gives an alarm if any nuclear power channel deviates significantly from any of the other channels. Also, the control system responds only to rapid changes in nuclear power; slow changes or drifts are compensated by the temperature control signals. Finally, an overpower signal from any nuclear power range channel will block manual and automatic rod withdrawal. The setpoint for this rod stop is below the reactor trip setpoint.

7.2.2.11.2 Coolant Temperature

The accuracy of the RTD temperature measurements is demonstrated during plant startup tests by comparing temperature measurements from all RTDs with one another. The comparisons are done with the RCS in an isothermal condition. The linearity of the ΔT measurements obtained from the hot leg and cold leg RTDs as a function of plant power is also checked during plant startup tests.

The absolute value of ΔT versus plant power is not important as far as reactor protection is concerned. RTS setpoints are based on percentages of the indicated ΔT at nominal full power, rather than on absolute values of ΔT. For this reason, the linearity of the ΔT signals as a function of power is of importance rather than the absolute values of the ΔT. As part of the plant startup tests, the loop RTDs signals are compared with the core exit thermocouple signals. Note also that reactor control is based on signals derived from protection system channels after isolation by isolation devices so that no feedback effect can perturb the protection channels.

Because control is based on the average temperature of the loop having the highest average temperature, the control rods are always moved based on the most conservative temperature measurement with respect to margins to DNB. A spurious low

average temperature measurement from any loop temperature control channel causes no control action. A spurious high average temperature measurement causes rod insertion (safe direction).

In addition, channel deviation signals in the control system give an alarm if any temperature channel deviates significantly from the auctioneered (highest) value. Automatic rod withdrawal blocks also occur if any two of the temperature channels indicate an overtemperature or overpower condition.

7.2.2.11.3 Pressurizer Pressure

The pressurizer pressure protection channel signals are used for high- and low-pressure protection and as inputs to the overtemperature ΔT trip protection function. Isolated output signals from these channels are used for pressure control. These are used to control pressurizer spray and heaters, and power-operated relief valves. Pressurizer pressure is sensed by fast-response pressure transmitters.

A spurious high-pressure signal from one channel can cause decreasing pressure by actuation of either spray or relief valves. Additional redundancy is provided in the low pressurizer pressure reactor trip logic and in the logic for safety injection to ensure low-pressure protection.

The pressurizer heaters are incapable of over pressurizing the RCS. Overpressure protection is based on the positive volume surge of the reactor coolant produced as a result of turbine trip under full load, assuming the core continues to produce full power. The self-actuated safety valves are sized on the basis of steam flow from the pressurizer to accommodate this surge at a setpoint of 2500 psia and an accumulation of 3 percent. Note that no credit is taken for the relief capability provided by the power-operated relief valves during this surge.

In addition, operation of any one of the power-operated relief valves can maintain pressure below the high-pressure trip point for most transients. The rate of pressure rise achievable with heaters is slow, and ample time and pressure alarms are available to alert the operator to the need for appropriate action.

Two of the pressure sensors share a common tap. The other two sensors use separate taps. Redundancy is not impaired by having a shared tap because the logic for this trip is two-out-of-four. If the shared tap is plugged, the reading of the affected channels will remain static. If the impulse line bursts, the indicated pressure will drop to zero. In either case, the fault is easily detectable, and the protective function remains operable.

7.2.2.11.4 Pressurizer Water Level

Three pressurizer water level channels are used for reactor trip (two-out-of-three high level). Isolated signals from these channels are used for pressurizer water level control. A failure in the water level control system could fill or empty the pressurizer at a slow rate (on the order of 1/2 hour or more).

Experience has shown that hydrogen gas can accumulate in the upper part of the condensate pot on conventional open reference leg systems in pressurizer water level service. At RCS operating pressures, high concentrations of dissolved hydrogen in the reference leg water are possible. On sudden depressurization accidents, it has been hypothesized that rapid effervescence of the dissolved hydrogen could blow water out of the reference leg and cause a large level error, measuring higher than actual level. Accurate calculations of this effect have been difficult to obtain. To eliminate the possibility of such effects in this application, a bellows is used in a pot at the top of the reference leg to provide an interface seal and prevent dissolving the hydrogen gas into the reference leg water. Supplier tests confirmed a time response of less than 1 second for the channel.

The reference leg is uninsulated and remains at local ambient temperature. This temperature varies somewhat over the length of the reference leg piping under normal operating conditions, but does not exceed 140°F. During the extreme temperature conditions caused by a blowdown accident, any reference leg water flashing to steam is confined to the condensate steam interface in the weir at the top of the temperature barrier leg and has only a small (about 12 inches between the top of weir and bellows) effect on the measured level. Some additional error may be expected due to effervescence of hydrogen in the temperature barrier water. However, even if complete loss of this water is assumed, the error will be less than 1 foot and will not violate a safety limit.

The sealed reference leg design has been installed in various plants since early 1970, and operational accuracy was verified by use of the sealed reference leg system in parallel with an open reference leg channel. No effects of operating pressure variations on either the accuracy or integrity of the channel have been observed.

Calibration of the sealed reference leg system is done in place, after installation, by application of known pressure to the high pressure side of the transmitter with the pressure of the height of the reference column, corrected for density, applied to the transmitter low side. The effects of static pressure variations are predictable. The largest effect is due to the density change in the saturated fluid in the pressurizer itself. The effect is typical of level measurements in all tanks with two-phase fluid and is not peculiar to the sealed reference leg technique.

In the sealed reference leg, there is a slight compression of the fill water with increasing pressure, but this is taken up by the flexible bellows. A leak of the fill water in the sealed reference leg is detectable by comparison of redundant channel readings while the plant is on-line, and by physical inspection of the reference leg while the plant is off-line. Leaks of the reference leg to atmosphere are immediately detectable by off-scale indications and alarms on the control board. A closed pressurizer level instrument shutoff valve would be detected by comparing the level indications from the redundant level channels (three channels). In addition, there are alarms on one of the three channels to indicate an error between the measured pressurizer water level and the programmed pressurizer water level. The instrument sensing lines for these level

sensing instruments are designed so that no single instrument valve can affect more than one of the three level channels.

The high water level trip setpoint provides sufficient margin so that the undesirable condition of discharging liquid coolant through the safety valves is avoided. Even at full power conditions, which would produce the worst thermal expansion rates, a failure of the water level control would not lead to any liquid discharge through the safety valves. This is due to the automatic high pressurizer pressure reactor trip actuating at a pressure sufficiently below the safety valve setpoint.

For control failures that tend to empty the pressurizer, two-out-of-four logic for safety injection action low pressurizer pressure ensures that the protection system can withstand an independent failure in another channel. In addition, ample time and alarms exist to alert the operator of the need for appropriate action.

7.2.2.11.5 Signal Validation Functions

The basic function of the reactor protection circuits associated with low steam generator water level is to preserve the steam generator heat sink for removal of long-term residual heat.

Should a complete loss of feedwater occur, the reactor would be tripped on low-low steam generator water level. In addition, redundant auxiliary feedwater pumps are provided to supply feedwater in order to maintain residual heat removal after trip, preventing eventual thermal expansion and discharge of the reactor coolant through the pressurizer relief valves into the relief tank even when main feedwater pumps are incapacitated. This reactor trip acts before the steam generators are dry to reduce the required capacity and starting time requirements of these auxiliary feedwater pumps, and to minimize the thermal transient on the RCS and steam generators. Therefore, a low-low steam generator water level reactor trip is provided for each steam generator to ensure that sufficient initial thermal capacity is available in the steam generator at the start of the transient. It is desirable to minimize thermal transients on a steam generator for a credible loss of feedwater accident. Hence, it should be noted that a protection system failure causing control system reaction is eliminated by implementation of control system signal validation; that is, steam generator water level (SGWL) median signal selector (MSS) and steam flow arbitrator (SFA) functions in the PG&E Design Class II digital feedwater control system.

The prime objective of the signal validation functions is to prevent a single failed protection system instrument channel from causing a disturbance in the feedwater control system requiring subsequent protective action, as required by IEEE 279-1971. All three isolated narrow range water level channels for each steam generator are input to the SGWL MSS. The device selects the median value of its inputs for use by the feedwater control system, and control system action is then based on this validated signal. By rejecting the high and low signals, the control system is prevented from acting on any single, failed protection system instrument channel.

The SFA function is provided to validate the steam flow inputs. The SFA uses logic to determine an appropriate control signal output based on the two steam flow channels for each steam generator. If the two input signals agree within a specified limit, the arbitrator output is the average of the inputs. If the deviation between the input signals exceeds the specified limit, the input signal closest to the arbitration signal is selected as the output. If neither of the inputs is within a specified limit, the arbitration signal itself is selected as the output of the arbitrator. The arbitration signal is based on turbine first stage pressure.

These algorithms prevent a single input channel failure from causing a control system transient requiring protective action. This includes failure of the instrument tap that is shared between one narrow-range level channel and one steam flow channel on each steam generator. The MSS function for steam generator narrow range level and the SFA function for steam flow satisfy the control and protection interaction requirement of IEEE 279-1971.

Since no adverse control system action may result from a single, failed protection instrument channel, a second random protection system failure (as would otherwise be required by IEEE 279-1971) need not be considered. A more detailed discussion of the SFA and MSS and their compliance with control and protection system interaction criteria is provided in Reference 27.

7.2.2.12 TESTS AND INSPECTIONS

The periodic testing of the RTS conforms to the requirements of IEEE 338-1971 (Reference 16), with the following comment:

(1) The periodic test frequency specified in the Technical Specifications was conservatively selected, using the considerations discussed in paragraph 4.3 of Reference 16, to ensure that equipment associated with protection functions has not drifted beyond its minimum performance requirements.

The testability of the system is discussed in Section 7.2.4.1.10.

The minimum frequencies for checks, calibration, and testing at each of the plant's operating modes are defined in the Technical Specifications. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

7.2.2.12.1 In-Service Tests and Inspections

Periodic surveillance of the RTS is performed to ensure proper protective action. This surveillance consists of checks, calibrations, and functional testing that are summarized in the following sections.

7.2.2.12.1.1 Channel Checks

A channel check consists of a qualitative assessment of channel behavior during operation by observation. This determination shall include, where possible, comparison of the channel indication and/or status with other indications and/or status derived from independent instrument channels measuring the same parameters.

7.2.2.12.1.2 Channel Calibration

A channel calibration shall be the adjustment, as necessary, of the channel such that it responds within the required range and accuracy to known values of input. The channel calibration shall encompass the entire channel including the sensors and alarm, interlock and/or trip functions, and may be performed by any series of sequential, overlapping, or total channel steps such that the entire channel is calibrated.

7.2.2.12.1.3 Actuation Logic Test

An actuation logic test shall be the application of various simulated input combinations in conjunction with each possible interlock logic state and verification of the required logic output. The actuation logic test shall include a continuity check, as a minimum, of output devices.

7.2.2.12.1.4 Process Protection Channel Operational Test

A channel operational test shall be the injection of a simulated signal into the channel as close to the sensor as practicable to verify operability of alarm, interlock, and/or trip functions. The channel operational test shall include adjustments, as necessary, of the alarm, interlock, and/or trip setpoints such that the setpoints are within the required range and accuracy.

7.2.2.12.1.5 Trip Actuating Device Operational Test

A trip actuating device operational test shall consist of operating the trip actuating device and verifying operability of alarm, interlock, and/or trip functions. The trip actuating device operational test shall include adjustment, as necessary, of the trip actuating device such that it actuates at the required setpoint within the required accuracy.

7.2.2.12.1.6 Reactor Trip System Response Time

The RTS response time shall be the time interval from when the monitored parameter exceeds its trip setpoint at the channel sensor until loss of stationary gripper coil voltage.

7.2.2.13 Current System Drawings

The current system drawings for the RTS and supporting systems are presented in Figures 7.2-1 through 7.2-6, and 7.3-1 through 7.3-52.

7.2.3 SAFETY EVALUATION

7.2.3.1 General Design Criterion 2, 1967 – Performance Standards

The RTS is located in the auxiliary building, which is a PG&E Design Class I structure. The auxiliary building is designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), and earthquakes (refer to Section 3.7) to protect the RTS and ensure its design function will be performed. Externally exposed equipment is evaluated in Section 3.3.2.3.2.6.

The seismic design considerations for the RTS are discussed in Section 3.10.
A discussion of the seismic testing of the RTS equipment is presented in Section 3.10.2.

The monitoring circuitry, sensors and signal electronics, for several variables that provide inputs to the RTS are not seismically qualified, and in some cases, are not seismically mounted or classified as PG&E Design Class I. Those circuits are:

(1) Source range (SR) nuclear instrumentation - sensors and electronics (PG&E Design Class I)

(2) Intermediate range (IR) nuclear instrumentation - sensors and electronics (PG&E Design Class I)

(3) Main turbine stop valve closed limit switches (PG&E Design Class II)

(4) Main turbine auto-stop oil pressure switches (PG&E Design Class II)

(5) 12-kV bus underfrequency relays, potential transformers and test switches (PG&E Design Class II)

(6) 12-kV bus undervoltage relays, potential transformers and test switches (PG&E Design Class II)

(7) 12-kV reactor coolant pump circuit breaker open position switches (PG&E Design Class II)

Analyses have been performed to assure that the lack of seismic qualification and seismic installation of these inputs will not degrade the function of the RTS. The electrical circuits that provide the inputs to the RTS from these monitoring channels all are classified as PG&E Design Class I, Class 1E circuits. These analyses are based upon the following:

(1) *SR and IR Nuclear Instrumentation* - The DCPP safety analysis does not take credit for the SR or IR nuclear instrumentation as a primary reactor trip function. The safety analysis is bounded by credit taken for the

seismically qualified power range nuclear instrumentation. Although the SR and IR nuclear instrumentation sensors and electronics are not seismically qualified, the SR and IR electronics drawers that provide the inputs to the RTS are seismically mounted in a seismically qualified cabinet. Therefore, no seismically induced common mode failures of the SR or IR nuclear instrumentation drawers exist that could degrade the RTS safety function.

(2) *Main Turbine Stop Valve Closed Limit Switches* - The main turbine stop valve closed limit switches provide inputs to the RTS to signal a turbine tripped (loss of heat sink) condition. These inputs are secondary (backup) reactor trip signals. The stop valve limit switches and field termination cabinets have been seismically analyzed to confirm that the structural integrity of the limit switches and field termination cabinets are such that no seismically induced common mode failures of the main turbine stop valve closed limit switches or field termination cabinets exist that could degrade a primary RTS safety function.

(3) *Main Turbine Auto-Stop Oil Pressure Switches* - The main turbine auto-stop oil pressure switches provide inputs to the RTS to signal a turbine tripped (loss of heat sink) condition. These inputs are secondary (backup) reactor trip signals. The auto-stop oil pressure switches and the cabinet have been seismically analyzed to confirm that the structural integrity of the pressure switches and cabinet to which they are mounted is such that no seismically induced common mode failures of the pressure switches or cabinet exist that could degrade a primary RTS safety function.

(4) *12-kV System RTS Input Signals* - The 12-kV undervoltage (UV) circuits, underfrequency (UF) circuits and breaker open position switches provide inputs from the 12-kV system to the RTS to signal a loss of reactor coolant flow condition. The UV and UF inputs are primary reactor trip signals. The breaker open position inputs are secondary (backup) reactor trip signals. These circuits individually do not meet the RTS seismic qualification or mounting requirements. The UF circuits do not meet the fail-safe criterion. However, when analyzed as a "system," the 12-kV inputs to the RTS fail in such a manner as to assure a reactor trip should the equipment be subjected to an RTS design basis seismic event. In addition, the UV, UF and breaker position switch monitoring circuits and the equipment in which they are mounted have been seismically analyzed to confirm that their structural integrity is such that no seismically induced common mode failures of the monitoring circuits or the equipment in which they are mounted exist that could degrade a primary RTS safety function.

7.2.3.2 General Design Criterion 11, 1967 – Control Room

Controls and instrumentation related to RTS include control room status lights, annunciator displays and RTB switches on the control board with indicating lights to display breakers' position. Additionally, the reactor trip and bypass breakers can be operated locally.

7.2.3.3 General Design Criterion 12, 1967 – Instrumentation and Control Systems

The RTS keeps surveillance on process variables that are directly related to equipment mechanical limitations such as pressure, pressurizer water level (to prevent water discharge through safety valves and uncovering heaters), and also on variables that directly affect the heat transfer capability of the reactor (e.g., flow and reactor coolant temperatures). Other parameters utilized in the RTS are calculated from various process variables. In any event, whenever a direct process or a calculated variable exceeds a setpoint, the reactor will be shut down to protect against either gross damage to fuel cladding or loss of system integrity that could lead to release of radioactive fission products into the containment.

While most setpoints used in the RTS are fixed, there are variable setpoints, most notably the overtemperature ΔT and overpower ΔT setpoints. All setpoints in the RTS have been selected either on the basis of applicable engineering code requirements or engineering design studies. Methodologies for determining RTS setpoint and allowable values are presented in WCAP-11082, Technical Specification 3.3.1, or in plant procedures. It should be noted that the selected trip setpoints all provide for margin before protection action is actually required to allow for uncertainties and instrument errors.

7.2.3.4 General Design Criterion 14, 1967 – Core Protection Systems

The RTS, together with associated equipment, is designed to act automatically to prevent or to suppress conditions that could result in exceeding acceptable fuel damage limits.

Operation below the applicable DNBR limit could result in excessive cladding temperature because of the onset of DNB and the resultant sharp reduction in heat transfer coefficient. Fuel centerline melting occurs when the local LHR, or power peaking, in a region of the fuel is high enough to cause the fuel centerline temperature to reach the melting point of the fuel. The core safety limits are established to prevent overheating of the fuel and cladding as well as possible cladding perforation. Figure 15.1-1 presents the allowable reactor coolant loop average temperature and ΔT for the design flow and the NSSS Design Thermal Power distribution as a function of primary coolant pressure. Refer to Section 15.1 for additional information.

DNBR is not a directly measurable quantity; however, the process variables that are statistically related to DNBR are sensed and evaluated. Small isolated changes in

various process variables may not individually result in violation of a core safety limit, whereas the combined variation over sufficient time may cause the overpower or overtemperature safety limit to be exceeded. The design concept of the RTS takes cognizance of this situation by providing reactor trips associated with individual process variables in addition to the overpower and overtemperature safety limit trips. The process variable trips prevent reactor operation whenever a change in the monitored value is such that a core or system safety limit is in danger of being exceeded should operation continue. Basically, the high-pressure, low-pressure, and overpower and overtemperature ΔT trips provide sufficient protection for slow transients, as opposed to such trips as low flow or high flux, which trip the reactor for rapid changes in flow or flux, respectively, that could result in fuel damage before actuation of the slower responding ΔT channels.

Therefore, the RTS has been designed to provide protection for fuel cladding and RCS pressure boundary integrity where: (a) a rapid change in a single variable or factor that will quickly result in exceeding a core or a system safety limit, and (b) a slow change in one or more variables has an integrated effect that causes safety limits to be exceeded. Overall, the RTS offers diverse and comprehensive protection against fuel cladding failure and/or loss of RCS integrity. Technical Specification Table 3.3.1-1 lists information related to the reactor trip system instrumentation safety limits and safety system settings. The limiting safety system settings are defined in Technical Specification Table 3.3.1-1 as the Allowable Values. The capability of the RTS to prevent loss of integrity of the fuel cladding and/or RCS pressure boundary during Condition II transients is demonstrated in Section 15.2. A reactor trip is credited for certain Condition III and IV events as described in Sections 15.3. and 15.4.

7.2.3.5 General Design Criterion 19, 1967 – Protection Systems Reliability

The protection systems are designed for high functional reliability and inservice testability. Each design employs redundant logic trains and measurement and equipment diversity. Sufficient redundancy is provided to enable individual end-to-end channel tests with each reactor at power without compromise of the protective function. Built-in semiautomatic testers provide means to test the majority of system components very rapidly.

The RTS uses sensors that feed the process circuitry consisting of two to four redundant channels, which monitor various plant parameters. The RTS also contains the logic circuitry necessary to automatically open the reactor trip breakers. The logic circuitry consists of two redundant logic trains that receive input from the protection channels.

Each of the two logic trains, A and B, is capable of opening a separate and independent reactor trip breaker (52/RTA and 52/RTB).

7.2.3.6 General Design Criterion 20, 1967 – Protection Systems Redundancy and Independence

Sufficient redundancy and independence is designed into the protection systems to ensure that neither single failure nor removal from service of any component or channel of a system will result in loss of the protection function.

Each individual channel is assigned to one of four channel designations, e.g., Channel I, II, III, or IV, refer to Figure 7.2-5. Channel independence is carried throughout the system, extending from the sensor through to the devices actuating the protective function. Physical separation is used to achieve separation of redundant transmitters. Separation of wiring is achieved using separate wireways, cable trays, conduit runs, and containment penetrations for each redundant channel. Redundant process equipment is separated by locating electronics in different protection rack sets. Each redundant channel is energized from a separate ac power feed.

Position Regarding Separation of Isolated Signal Outputs within Process Protection Racks

It is PG&E's position that specific physical separation is not required within the process protection racks between the protection circuits and isolated nonprotection circuits, and that the degree of electrical separation plus the physical separation associated with the insulation on the wires is sufficient to meet the requirements of IEEE 279-1971.

The justification for this position is that IEEE 279-1971 covers this situation in three paragraphs quoted below:

4.2 Single Failure Criterion. Any single failure within the protection system shall not prevent proper protective action at the system level when required.

4.6 Channel Independence. Channels that provide signals for the same protective function shall be independent and physically separated to accomplish decoupling of the effects of unsafe environmental factors, electric transients, and physical accident consequences documented in the design basis, and to reduce the likelihood of interactions between channels during maintenance operations or in the event of channel malfunction.

4.7.2 Isolated Devices. The transmission of signals from protection system equipment for control system use shall be through isolation devices, which shall be classified as part of the protection system and shall meet all the requirements of this document. No credible failure at the output of an isolation device shall prevent the associated protection system channel from meeting the minimum performance requirements specified in the design base.

Examples of credible failures include short circuits, open circuits, grounds, and the application of the maximum credible ac and dc potential. A failure in an isolation device is evaluated in the same manner as a failure of other equipment in the protection system.

The intent of 4.2 and 4.6 with regard to protection signals is handled through a combination of electrical and physical separation. The electrical separation is handled by supplying each protection rack set with separate independent sources of power. Physical separation is provided by locating redundant channels in separate racks sets. Thus separation, both electrical and physical, outside the rack is ensured. The intent of 4.7.2 is met within the process protection racks by the provision of qualified isolators that have been tested and verified to perform properly under the credible failures listed in 4.7.2. The isolator is designed to be an electrical barrier between protection and nonprotection and, as such, the degree of physical separation provided within the modules is that which is consistent with the voltages involved.

The question of whether or not specific physical separation is required is best addressed by reviewing the potential hazards involved. There are three general categories of hazards that must be protected against. These are missiles, electrical faults, and fire. Missiles external to the rack can be ruled out on the basis that the racks are located in general plant areas where it is not credible to assume missiles capable of penetrating the steel rack. (Refer to Section 3.5) Missiles within the rack can be ruled out on the basis that there is no mechanism within the racks for the generation of missiles with sufficient energy to cause damage to the hardware or wiring.

Electrical faults within a rack constitute a single failure. Since there is no internal mechanism capable of simultaneously causing such a failure in more than one protection set, the result is acceptable. The plant remains safe with three out of the four protection sets remaining in operation. A few very specific electrical faults, external to the protection racks, on the signals derived from protection channels may have access to the outputs of all protection sets simultaneously. However, the isolators have been shown to prevent these disturbances from entering the protection circuits; thus the results are acceptable.

Fire external to the racks is a potential hazard; however, fire retardant paint and wiring, fire barriers at the rack entrances, and adequate separation external to the racks provide a satisfactory defense against the hazard. For further discussions on fire protection, refer to Sections 8.3.1.2 and 9.5.1. A potential cause of fire within more than one protection set is an electrical fault involving the nonprotection outputs from these sets; however, it has been verified during the isolator tests that the fault current is terminated by the failure of certain components with no damage occurring in the wiring leading to the module. Thus, a fire within a rack set due to high current igniting or otherwise damaging the wiring is not possible.

The remaining source of fire within the racks - a short circuit within the protection wiring-effects only one protection set and thus is acceptable since three of the four protection sets remain.

It is thus established that no credible failure associated with the isolator output wiring violates the single failure criterion; therefore, the present method of rack wiring is entirely adequate.

7.2.3.7 General Design Criterion 21, 1967 – Single Failure Definition

The protection system is designed to provide two, three, or four instrumentation channels for each protective function and redundant (two) logic trains. These redundant channels and trains are electrically isolated and physically separated. Thus, any single failure within a channel or train will not prevent protective action at the system level when required.

To prevent the occurrence of common mode failures, such additional measures as functional diversity, testing, as well as administrative control during design, production, installation, and operation are employed, as discussed in Reference 11, for protection logic. Standard reliability engineering techniques were used to assess the likelihood of trip failure due to random component failures. Common mode failures were also qualitatively investigated. It was concluded from the evaluation that the likelihood of no trip following initiation of Condition II events is extremely small (2×10^{-7} derived for random component failures). The solid-state protection system design has been evaluated by the same methods as used for the relay system and the same order of magnitude of reliability is provided.

7.2.3.8 General Design Criterion 22, 1967 – Separation of Protection and Control Instrumentation Systems

The protection system is designed to be independent of the control system. In certain applications, the control signals and other nonprotective functions are derived from individual protective channels through isolation devices. The isolation devices are classified as part of the protection system and are located in the process protection racks. Nonprotective functions include those signals used for control, remote process indication, and computer monitoring. The isolation devices are designed so that a short circuit, open circuit, or the application of 118-Vac or 140-Vdc on the isolated output portion of the circuit (i.e., the nonprotective side of the circuit) will not affect the input (protective) side of the circuit. The signals obtained through the isolation devices are never returned to the protective racks.

A detailed discussion of the design and testing of the isolation devices is provided in References 8, 9, and 32. These reports include the results of applying various malfunction conditions on the output portion of the isolation devices. The results show that no significant disturbance to the isolation devices input signal occurred.

To provide additional assurance that the electrical wiring to and from the isolators, as installed, would not permit control-side faults to enter the protection system through input-output electrical coupling, tests were conducted at DCPP using voltages of 118-Vac, 250-Vdc, 460-Vac, 580-Vac and electrical noise. A description of these tests is provided in References 8, 12, and 32.

Where failure of a protection system component can cause a process excursion that requires protective action, the protection system can withstand another independent failure without loss of protective action. The steam generator low-low water level protective function relies upon two-out-of-three (2/3) trip logic. The digital feedwater control system (DFWCS) uses the same steam generator level sensors as the steam generator low-low water level protective function. The DFWCS includes the median signal selector (MSS) and the Steam Flow Arbitrator (SFA). The installation of the MSS and SFA eliminates the possibility that failure of the instrument tap shared between one narrow-range level channel and one steam flow channel on each steam generator will cause a transient that would require protective action by any of the level channels. The MSS prevents the resulting failed high narrow range level signal from causing a level transient via the level portion of the DFWCS. The SFA prevents the resulting failed low steam flow signal from causing a level transient via the feed forward mass balance portion of the DFWCS. (Refer to Section 7.2.2.11.5) For details refer to Reference 27.

7.2.3.9 General Design Criterion 23, 1967 – Protection Against Multiple Disability for Protection Systems

Physical separation and electrical isolation of redundant channels and subsystems are employed in the RTS as defenses against functional failure through exposure to common causative factors.

Information from both logic trains is transmitted to the plant control boards and computer using a multiplex system. To ensure separation of the signals from each train, each signal is passed through an optically-coupled isolator. Verification tests on these isolators using voltages of 118-Vac and 250-Vdc are described in Reference 12.

To provide physical separation between input and output circuits in the solid-state protection system racks, physical barriers have been provided to separate input and output wire bundles.

Independence of the logic trains is discussed in Reference 6. Two reactor trip breakers are actuated by two separate logic matrices that interrupt power to the control rod drive mechanisms. The breaker main contacts are connected in series with the power supply so that opening either breaker interrupts power to all control rod drive mechanisms, permitting the rods to free-fall into the core. The design philosophy is to make maximum use of a wide variety of measurements. The protection system continuously monitors numerous diverse system variables. The extent of this diversity has been evaluated for a wide variety of postulated accidents and is discussed in Reference 1. Generally, two

or more diverse protection functions would terminate the accident conditions before intolerable consequences could occur.

For a discussion of the tests made to verify the performance requirements, refer to Section 3.11.

7.2.3.10 General Design Criterion 24, 1967 – Emergency Power for Protection Systems

The instrumentation and controls portions of the protection systems are supplied initially from the station batteries and subsequently from the emergency diesel generators. A single failure of any one component will not prevent the required functioning of the RTS.

7.2.3.11 General Design Criterion 25, 1967 – Demonstration of Functional Operability of Protection Systems

The RTS is capable of being tested during power operation. Where only parts of the system are tested at any one time, the testing sequence provides the necessary overlap between the parts to ensure complete system operation. The process protection equipment is designed to permit any channel to be maintained in a bypassed condition and, when required, tested during power operation without initiating a protective action at the system level. This is accomplished without lifting electrical leads or installing temporary jumpers.

If a protection channel has been bypassed for any purpose, a signal is provided to allow this condition to be continuously indicated in the control room.

The operability of the process sensors is ascertained by comparison with redundant channels monitoring the same process variables or those with a fixed known relationship to the parameter being checked. The in-containment process sensors can be calibrated during plant shutdown, if required.

Surveillance testing of the process protection system is performed with the use of a Man Machine Interface (MMI) test system. The MMI is used to enter instructions to the installed test processor in the process protection rack being tested which then generates the appropriate test signals to verify proper channel operation. The capability is provided to test in either partial trip mode or bypass mode where the channel comparators are maintained in the not-tripped state during the testing. Testing in bypass is allowed by the plant Technical Specifications. The bypass condition is continuously indicated in the control room via an annunciator.

The power range channels of the nuclear instrumentation system are tested by superimposing a test signal on the actual detector signal being received by the channel at the time of testing. The output of the bistable is not placed in a tripped condition prior to testing. Also, because the power range channel logic is two-out-of-four, bypass of this

reactor trip function is not required. Note, however, that the source and intermediate-range high neutron flux trips must be bypassed during testing.

To test a power range channel, a TEST-OPERATE switch is provided to require deliberate operator action. Operation of the switch initiates the CHANNEL TEST annunciator in the control room. Bistable operation is tested by increasing the test signal level up to its trip setpoint and verifying bistable relay operation by control board annunciator and trip status lights.

It should be noted that a valid trip signal would cause the channel under test to trip at a lower actual reactor power level. A reactor trip would occur when a second bistable trips. No provision has been made in the channel test circuit for reducing the channel signal level below that signal being received from the nuclear instrumentation system detector. A nuclear instrumentation system channel that causes a reactor trip through one-out-of-two protection logic (source or intermediate range) is provided with a bypass function, which prevents the initiation of a reactor trip from that particular channel during the short period that it is undergoing testing. These bypasses initiate an alarm in the control room.

For a detailed description of the nuclear instrumentation system, refer to Reference 2.

The logic trains of the RTS are designed to be capable of complete testing at power, except for those trips listed in Section 7.2.3.17. Annunciation is provided in the control room to indicate when a train is in test, when a reactor trip is bypassed, and when a reactor trip breaker is bypassed. Details of the logic system testing are provided in Reference 6.

The reactor coolant pump breakers cannot be tripped at power without causing a plant upset by loss of power to a coolant pump. However, the reactor coolant pump breaker trip logic and continuity through the shunt trip coil can be tested at power. Manual trip cannot be tested at power without causing a reactor trip, because operation of either manual trip switch actuates both trains A and B. Note, however, that manual trip could also be initiated from outside the control room by manually tripping one of the reactor trip breakers. Initiating safety injection cannot be done at power without upsetting normal plant operation. However, the logic for these trips is testable at power.

7.2.3.12 General Design Criterion 26, 1967 – Protection Systems Fail-Safe Design

The PPS channels are designed so that upon loss of electrical power to any channel, the output of that channel is a trip signal. The following exceptions to GDC 26, 1967 are applicable to DCPP:

1. The RCP bus underfrequency trip channels are an exception to the fail-safe design requirement. The RCP bus underfrequency trip function, in conjunction with the RCP bus undervoltage function, provides a fail-safe protective function.

2. The seismic trip channels are an exception to the fail-safe design. Since no credit is taken in accident analyses for the seismic trip, the seismic trip channels are designed energize-to-actuate to eliminate the possibility of spurious trips.

7.2.3.13 General Design Criterion 31, 1967 – Reactivity Control Systems Malfunction

The RTS and its function, reactor shutdown by RCCA insertion, is completely independent of the normal control function, since the trip breakers interrupt power to the drive mechanisms regardless of existing control signals. The protection system is designed to limit reactivity transients so that DNBR will exceed the applicable limit value (refer to Sections 4.4.1.1 and 4.4.2.3) for any single malfunction in either reactor control system.

The analysis presented in Chapter 15 shows that for postulated dilution during refueling, startup, or manual or automatic operation at power, the operator has ample time to determine the cause of dilution, terminate the source of dilution, and initiate reboration before the shutdown margin is lost. The facility reactivity control systems are discussed further in Chapter 7, and analyses of the effects of the other possible malfunctions are discussed in Chapter 15. The analyses show that acceptable fuel damage limits are not exceeded in the event of a single malfunction of either system.

7.2.3.14 General Design Criterion 49, 1967 – Containment Design Basis

The RTS instrumentation circuits routed through containment electrical penetrations are designed to support the containment design basis as described in Section 7.2.4.2.

7.2.3.15 10 CFR 50.49 – Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

The Class 1E RTS instrument cables required to function in harsh environments under accident conditions are qualified to the applicable environmental conditions to ensure that they will continue to perform their safety functions. Section 3.11 describes the DCPP EQ program and the requirements for the environmental design of the electrical and related mechanical equipment. The affected components are listed on the EQ Master List.

7.2.3.16 Safety Guide 22, February 1972 – Periodic Testing of Protection System Actuation Functions

Periodic testing of the RTS actuation functions, as described, complies with AEC Safety Guide 22, February 1972 (Reference 22). Under the present design, there are protection functions that are not tested at power. These are:

(1) Generation of a reactor trip by tripping the reactor coolant pump breakers

(2) Generation of a reactor trip by tripping the turbine

(3) Generation of a reactor trip by use of the manual trip switch

(4) Generation of a reactor trip by actuating the safety injection system

(5) Generation of a reactor trip by general warning circuitry (both redundant trains)

(6) Generation of a reactor trip by closing both reactor trip bypass breakers

The actuation logic for the functions listed is tested as described in Section 7.2.2.12. As required by Safety Guide 22, February 1972, where equipment is not tested during reactor operation, it has been determined that:

(1) There is no practicable system design that would permit operation of the equipment without adversely affecting the safety or operability of the plant.

(2) The probability that the protection system will fail to initiate the operation of the equipment is, and can be maintained, acceptably low without testing the equipment during reactor operation.

(3) The equipment can be routinely tested when the reactor is shut down.

Where the ability of a system to respond to a bona fide accident signal is intentionally bypassed for the purpose of performing a test during reactor operation, each bypass condition is automatically indicated to the reactor operator in the main control room by a separate annunciator for the train in test. Test circuitry does not allow two trains to be tested at the same time so that extension of the bypass condition to redundant systems is prevented.

7.2.3.17 NUREG-0737 (Items II.K.3.10 and II.K.3.12), November 1980 – Clarification of TMI Action Plan Requirements

Item II.K.3.10 – Proposed Anticipatory Trip Modification: The setpoint for the anticipatory reactor trip on turbine trip bypass (P-9) cannot be raised above 10% reactor power until it has been shown that the probability of a small-break loss-of-coolant accident (LOCA) resulting from a stuck-open power-operated relief valve (PORV) is substantially unaffected by the modification. DCPP raised P-9 to 50% with prior approval of the NRC after meeting this requirement. Refer also to Section 7.2.2.2.2.

Item II.K.3.12 – Anticipatory Reactor Trip upon Turbine Trip: The RTS includes an anticipatory reactor trip upon turbine trip for DCPP Unit 1 and Unit 2.

7.2.3.18 Generic Letter 83-28 (Actions 4.3 and 4.5), July 1983 – Required Actions Based on Generic Implications of Salem ATWS Events

Action 4.3 -- RTS Reliability (Automatic Actuation of Shunt Trip Attachment for Westinghouse and B&W Plants). The shunt trip was added to the reactor trip and bypass breakers.

Action 4.5 – RTS Reliability (System Functional Testing). The RTS is designed to allow on-line functional testing of the reactor trip system and this on-line testing includes independent testing of the undervoltage and shunt trip attachments of the reactor trip breakers. The intervals for on-line testing of the RTS are consistent with achieving high RTS availability.

7.2.4 COMPLIANCE WITH IEEE STANDARDS

7.2.4.1 Compliance with IEEE 279-1971

The RTS meets the requirements of IEEE 279-1971 as indicated below. SSPS was designed prior to IEEE 279-1971; however, its design has been approved by the NRC.

7.2.4.1.1 General Functional Requirement

The following are the generating station conditions requiring reactor trip:

(1) DNBR approaching the applicable limit value (Refer to Section 4.4.1.1 and Section 4.4.2.3)

(2) Power density (kilowatts per foot) approaching rated value for Condition II faults (Refer to Sections 4.2.1, 4.3.1, and 4.4.1 for fuel design limits)

(3) RCS overpressure creating stressing approaching the limits specified in Sections 5.2 and 5.5

For a discussion of energy supply and environmental variations, refer to Sections 8.3.1.1.5 and 3.11.

The following is a list of the malfunctions, accidents, or other unusual events that could physically damage RTS components or cause environmental changes. The UFSAR sections noted with each item present discussions on the provisions made to retain the necessary protective action.

(1) Loss-of-coolant accident (Refer to Sections 15.3.1, 15.3.4, and 15.4.1)

(2) Steam breaks (Refer to Sections 15.3.2 and 15.4.2)

(3) Earthquake (Refer to Sections 2.5, 3.2, 3.7, and 3.8)

(4) Fire (Refer to Section 9.5)

(5) Explosion (hydrogen buildup inside containment; refer to Sections 6.2 and 15.4)

(6) Missiles (Refer to Section 3.5)

(7) Flood (Refer to Sections 2.4 and 3.4)

(8) Wind (Refer to Section 3.3)

The performance requirements are:

(1) System Response Times

The RTS response time shall be the time interval from when the monitored parameter exceeds its trip setpoint at the channel sensor until loss of stationary gripper coil voltage. The RTS response times shall be demonstrated as required by the Technical Specifications.

Maximum allowable time delays in generating the reactor trip signal are identified in the Equipment Control Guidelines.

(2) Reactor trip setpoint allowable values are provided in the Technical Specifications.

(3) RTS ranges:

RTS range is the output range for a device that provides input to the RTS. It is defined as the range for which the device is calibrated and verified to be operable. As described in Sections 7.2.2.10 and 7.2.3.3, methodologies for determining RTS setpoint and allowable values are presented in WCAP-11082, Technical Specification 3.3.1 or in plant procedures. Specific device ranges are presented in plant procedures.

RTS	Range
(a) Power range nuclear power	1 to 120% rated thermal power (RTP)
(b) Neutron flux rates	+5 to +30% of full power
(c) Overtemperature ΔT	
$T_{hot\ leg}$	530 to 650°F

RTS	Range
$T_{cold\ leg}$	510 to 630°F
T_{avg}	530 to 630°F
Pressurizer pressure	1250 to 2500 psig
ΔI	-60 to +60%
f_1 (ΔI)	1 to 3%/%ΔI
ΔT setpoint	0 to 150% power
(d) Overpower ΔT	
$T_{hot\ leg}$	530 to 650°F
$T_{cold\ leg}$	510 to 630°F
T_{avg}	510 to 630°F
ΔI	-60 to +60%
f_2 (ΔI)	1 to 3%/%ΔI
ΔT setpoint	0 to 150 % power
(e) Pressurizer pressure	1250 to 2500 psig
(f) Pressurizer water level	Entire cylindrical portion of pressurizer (0 - 100 %)
(g) Reactor coolant flow	0 to 120% of rated flow
(h) Reactor coolant pump bus	50 to 70 Hz underfrequency
(i) Reactor coolant pump	0 to 150 Vac bus voltage
(j) Low-low steam generator water level	0 to 45% of narrow-range span

7.2.4.1.2 Single Failure Criterion

Refer to Section 7.2.3.7 for a discussion regarding the single failure criterion for RTS.

7.2.4.1.3 Quality of Components and Modules

For a discussion on the quality assurance program for the components and modules used in the RTS, refer to Chapter 17 and Section 3.1.2.1.

7.2.4.1.4 Equipment Qualification

Portions of the RTS are designated PG&E Design Class I. Refer to Sections 7.2.3.15 and 3.11 for a discussion on Class 1E electrical equipment environmental qualification and compliance to IEEE 323-1971 (Reference 14). Documentation of the Environmental and Seismic qualification of the process protection system is provided in References 23, 24, 25, 26 and 34.

7.2.4.1.5 Channel Integrity

The RTS channels are designed to maintain necessary functional capability under extremes of conditions related to environment, (refer to Section 7.2.3.1), energy supply (refer to Section 7.2.3.10), malfunctions (refer to Section 7.2.3.7), and accidents (refer to Section 7.2.4.1.1).

7.2.4.1.6 Channel Independence

Refer to Section 7.2.3.6 for a discussion regarding RTS channel independence.

7.2.4.1.7 Control and Protection System Interaction

Refer to Section 7.2.2.11 for a discussion regarding RTS control and protection interaction.

7.2.4.1.8 Derivation of System Inputs

The following are the variables required to be monitored in order to provide reactor trips (refer to Figure 7.2-1 and Table 7.2-1):

(1) Neutron flux

(2) Reactor coolant temperature

(3) RCS pressure (pressurizer pressure)

(4) Pressurizer water level

(5) Reactor coolant flow

(6) Reactor coolant pump operational status (bus voltage and frequency, and breaker position)

(7) Steam generator water level

(8) Turbine operational status (autostop oil pressure and stop valve position)

Reactor coolant temperature is a spatially dependent variable. The effect on the measurement is negated by taking multiple samples from the reactor coolant hot leg and electronically averaging these samples in the process protection system.

7.2.4.1.9 Capability for Sensor Checks

The RTS provides a means for checking, with a high degree of confidence, the operational availability of each system input sensor during reactor operation. This is accomplished by channel checks as described in Section 7.2.2.12.1.1, Channel Checks.

7.2.4.1.10 Capability for Test and Calibration

The reactor protection system is capable of testing and calibrating channels and the devices used to derive the final system output signal from the various channel signals. Testing of the logic trains of the reactor protection system includes a check of the input relays and a logic matrix check. The following sequence is used to test the system:

(1) Check of Input Relays - During testing of the process instrumentation system and nuclear instrumentation system comparators, each channel comparator is placed in a trip mode causing one input relay in train A and one in train B to de-energize. A contact of each relay is connected to a universal logic printed circuit card. This card performs both the reactor trip and monitoring functions. The contact that creates the reactor trip also causes a status lamp and an annunciator on the control board to operate. Either train A or B input relay operation lights the status lamp and sounds the annunciator.

    Each train contains a multiplexing test switch. This switch is normally configured such that train A is in the A+B position, while train B is in the Normal position. Administrative controls are used to control this configuration and may be changed to other configurations as necessary to meet plant conditions. The A+B position alternately allows information to be transmitted from the two trains to the control board. A steady-status lamp and annunciator indicates that input relays in both trains have been deenergized. A flashing lamp means that both input relays in the two trains did not deenergize. Contact inputs to the logic protection system, such as reactor coolant pump bus underfrequency relays, operate input relays that are tested by operating the remote contacts as previously described and using the same indications as those provided for bistable input relays.

    Actuation of the input relays provides the overlap between the testing of the logic protection system and the testing of those systems supplying the inputs to the logic protection system. Test indications are status lamps and annunciators on the control board. Inputs to the logic protection system are checked one channel at a time, leaving the other channels in service.

For example, a function that trips the reactor when two-out-of-four channels trip becomes a one-out-of-three trip when one channel is placed in the trip mode. Both trains of the logic protection system remain in service during this portion of the test.

(2) Check of Logic Matrices - Logic matrices are checked one train at a time. Input relays are not operated during this portion of the test. Reactor trips from the train being tested are inhibited with the use of the input error inhibit switch on the semiautomatic test panel in the train. Details of semiautomatic tester operation are provided in Reference 6. At the completion of the logic matrix tests, one bistable in each channel of process instrumentation or nuclear instrumentation is tripped or is verified in the tripped state to check closure of the input error inhibit switch contacts.

With the exception of the P-8 blocking function, the logic test scheme uses pulse techniques to check the coincidence logic. All possible trip and nontrip combinations are checked. Pulses from the tester are applied to the inputs of the universal logic card at the same points electrically that connect to the input relay contacts. Thus, there is an overlap between the input relay check and the logic matrix check. Pulses are fed back from the reactor trip breaker undervoltage coil to the tester. The pulses are of such short duration that the reactor trip breaker undervoltage coil armature should not respond mechanically.

Because the P-8 block of the one of four RCS low flow trip is not connected to the semiautomatic tester, it is tested using the manual input function pushbuttons. The P-8 block function is verified in accordance with the Surveillance Frequency Control Program.

Test indications that are provided are an annunciator in the control room indicating that reactor trips from the train have been blocked and that the train is being tested, and green and red lamps on the semiautomatic tester to indicate a good or bad logic matrix test. Protection capability provided during this portion of the test is from the train not being tested.

The general design features and details of the testability of the logic system are described in Reference 6.

(3) Testing of Reactor Trip Breakers - Normally, reactor trip breakers 52/RTA and 52/RTB are in service, and bypass breakers 52/BYA and 52/BYB are withdrawn (out of service). In testing the protection logic, pulse techniques are used to avoid tripping the reactor trip breakers, thereby eliminating the need to bypass them during the testing, although the associated bypass breaker is closed to preclude an inadvertent reactor trip and to allow

reactor trip breaker testing. The following procedure describes the method used for testing the trip breakers:

(a) Bypass breaker 52/BYB is racked to test position and closed

(b) With bypass breaker 52/BYA racked out (test position), manually close and trip it to verify its operation

(c) Rack in and close 52/BYA (bypasses 52/RTA)

(d) While blocking 52/RTA shunt trip, manually trip 52/RTA and 52/BYB through a protection system logic matrix

(e) Reset 52/RTA

(f) Manually trip 52/RTA using the shunt trip coil only with the shunt trip test push button

(g) Reset 52/RTA

(h) Rack out 52/BYB

(i) Trip and rack out 52/BYA

(j) Repeat above steps to test trip breaker 52/RTB and bypass breaker 52/BYA using bypass breaker 52/BYB to bypass 52/RTB

Auxiliary contacts of the bypass breakers are connected so that if either train is placed in test while the bypass breaker of the other train is fully racked in and closed, both reactor trip breakers and the bypass breaker automatically trip.

Auxiliary contacts of the bypass breakers are also connected in such a way that if an attempt is made to fully rack in and close the bypass breaker in one train while the bypass breaker of the other train is already fully racked in and closed, both bypass breakers automatically trip. Additionally, trip signals will be sent to both reactor trip and bypass breakers through the protection system logic.

The train A and train B alarm systems operate an annunciator in the control room. The two bypass breakers also operate an annunciator in the control room. Bypassing of a protection train with either the bypass or the test switches results in audible and visual indications.

The complete RTS is normally required to be in service. However, to permit on-line testing of the various protection channels or to permit

continued operation in the event of a subsystem instrumentation channel failure, a Technical Specification defining the minimum number of operable channels and the minimum degree of channel redundancy has been formulated. This Technical Specification also defines the required restriction to operation in the event that the channel operability and degree of redundancy requirements cannot be met.

The RTS is designed in such a way that some components' response time tests can only be performed during shutdown. However, the safety analyses utilize conservative numbers for trip channel response times. The measured channel response times are compared with those used in the safety evaluations.

Refer to Sections 7.2.2.12, 7.2.2.12.1.2, and 7.3.4.1.5 for additional discussion.

7.2.4.1.11 Channel Bypass or Removal from Operation

The Eagle 21 process protection system is designed to permit an inoperable channel to be placed in a bypass condition for the purpose of troubleshooting or periodic test of a redundant channel. Use of the bypass mode disables the individual channel comparator trip circuitry that forces the associated logic input relays to remain in the non-tripped state until the "bypass" is removed. If the process protection channel has been bypassed for any purpose, a signal is provided to allow this condition to be continuously indicated in the control room. During such operation, the process protection system continues to satisfy the single failure criterion. This is acceptable since there are 4 channels and the two-out-of-four trip logic reduces to two-out-of-three during the test. For functions that use two-out-of-three logic, it is implicitly accepted that the single failure criterion is met because of the results of the system reliability study. From the results of this it was concluded that the Eagle 21 digital system availability is equivalent to the respective analog process protection system availability even without the incorporation of the redundancy, automatic surveillance testing, self-calibration and self diagnostic features of the Eagle 21 process protection system.

The following exception to IEEE 279-1971 is applicable to DCPP:

> Technical Specifications allow a temporary relaxation, up to 4 hours, of the single failure criterion for the “one-out-of-two” function, reactor trip on SI signal, during channel bypass for surveillance testing provided the other train is operable.

7.2.4.1.12 Operating Bypasses

A listing of the operating bypasses is included in Table 7.2-2. These bypasses meet the requirement of Paragraph 4.12 of IEEE 279-1971 that the bypass will be removed automatically whenever permissive conditions are not met. The SSPS is used to achieve automatic removal of the bypass of a protective function.

Note: The term "bypass" is defined as the meeting of the coincident permissive (interlock) logic to permit the protective logic to become enabled/disabled as required. The term "bypass," in this section is not intended to be defined as the disabling of the individual channel comparator trip circuitry during routine test or surveillance that forces the associated logic input relays to remain in the non-tripped state until the "bypass" is removed.

7.2.4.1.13 Indication of Bypasses

Indication is provided in the control room if some part of the system has been administratively bypassed or taken out of service.

7.2.4.1.14 Access to Means for Bypassing

The design provides for administrative control of access to the means for manually bypassing channels or protective functions. For details refer to References 23 and 24.

7.2.4.1.15 Multiple Set Points

For monitoring neutron flux, multiple setpoints are used. When a more restrictive trip setting becomes necessary to provide adequate protection for a particular mode of operation or set of operating conditions, the protective system circuits are designed to provide positive means or administrative control to ensure that the more restrictive trip setpoint is used. The SSPS logic is used to prevent improper use of less restrictive trip settings.

7.2.4.1.16 Completion of Protective Action Once It Is Initiated

The RTS is so designed that, once initiated, a protective action goes to completion. Return to normal operation requires action by the operator.

7.2.4.1.17 Manual Initiation

Switches are provided on the control board for manual initiation of protective action. Failure in the automatic system does not prevent the manual actuation of the protective functions. Manual actuation relies on the operation of a minimum of equipment. Additionally, the reactor trip and bypass breakers can be operated locally.

7.2.4.1.18 Access to Set Point Adjustments, Calibration, and Test Points

The design provides for administrative control of access to all setpoint adjustments, module calibration adjustments, and test points. For details refer to References 23 and 34.

7.2.4.1.19 Identification of Protective Actions

The system provides annunciator, status light, and computer input signals that indicate the condition of bistable input signals, partial- and full-trip functions, and the status of the various blocking, permissive, and actuation functions.

7.2.4.1.20 Information Read-out

The RTS provides the operator with complete information pertinent to system status and safety. All transmitted signals (flow, pressure, temperature, etc.) that cause a reactor trip are either indicated or recorded for every channel including all neutron flux power range currents (top detector, bottom detector, algebraic difference, and average of bottom and top detector currents).

Any reactor trip actuates an annunciator.

Annunciators are also used to alert the operator of deviations from normal operating conditions so that he may take appropriate corrective action to avoid a reactor trip. Actuation of any rod stop or trip of any reactor trip channel actuates an annunciator.

7.2.4.1.21 System Repair

The RTS design features allow for recognition, location, replacement, and repair or adjustment of malfunctioning components or modules as discussed in References 3, 23 and 34.

7.2.4.1.22 Identification

The identification described in Section 7.1.3.3 provides immediate and unambiguous identification of the protection equipment.

7.2.4.2 Compliance with IEEE 317-1971

RTS instrumentation cables which are routed through containment penetrations are designed to meet IEEE 317-1971. Circuits without direct in-line redundant protection have been analyzed, which determined the available fault current is not of sufficient magnitude to damage the penetration conductor or penetration. These circuits will not adversely heat the penetrations as presently designed. (Refer to Section 8.3.1.4.8).

7.2.4.3 Evaluation of Compliance with IEEE 344-1971

The seismic testing, as discussed in Section 3.10.1, conforms to IEEE 344-1971 (Reference 17) except the format of the documentation may not meet the requirements because testing was completed prior to issuance of the standard. Documentation of the Environmental and Seismic qualification of the process protection system is provided in References 23, 24, 25, 26 and 34.

7.2.4.4 Evaluation of Compliance with IEEE 603-1980

IEEE 603-1980 (Reference 28), which is endorsed by Regulatory Guide 1.153, December 1985 (Reference 30), is applicable to the Eagle 21 Design, Verification, and Validation Plan.

7.2.4.5 Evaluation of Compliance with ANSI/IEEE-ANS-7-4.3.2-1982

ANSI/IEEE-ANS-7-4.3.2-1982 (Reference 31), which is endorsed by Regulatory Guide 1.152, November 1985 (Reference 29), is applicable to the Eagle 21 Design, Verification, and Validation Plan.

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7.2.6 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

7.3 ENGINEERED SAFETY FEATURES ACTUATION SYSTEM

The engineered safety features actuation system (ESFAS) senses selected plant parameters and initiates necessary safety systems to protect against violating core design limits and the Reactor Coolant System (RCS) pressure boundary and to mitigate accidents. If the measured value of a sensed parameter exceeds a predetermined setpoint, a signal is sent into logic matrices sensitive to combinations indicative of faults described in Chapter 15. Once the required logic combination is completed, the system sends actuation signals to those engineered safety features (ESF) components whose aggregate function best serves the requirements of the accident. Included in this Section are the electrical schematic diagrams for all ESF systems circuits and supporting systems. Figure 7.3-52 shows containment electrical penetrations, cable trays, and supports.

7.3.1 DESIGN BASES

7.3.1.1 General Design Criterion 2, 1967 – Performance Standards

ESFAS is designed to withstand the effects of or is protected against natural phenomena, such as earthquakes, flooding, tornadoes, winds, and other local site effects.

7.3.1.2 General Design Criterion 11, 1967 – Control Room

ESFAS includes the controls and instrumentation in the control room necessary to support the safe operational status of the plant.

7.3.1.3 General Design Criterion 15, 1967 – Engineered Safety Features Protection Systems

ESFAS provides for sensing accident situations and initiating the operation of necessary engineered safety features.

7.3.1.4 General Design Criterion 19, 1967 – Protection Systems Reliability

ESFAS is designed for high functional reliability and in-service testability commensurate with the safety functions to be performed.

7.3.1.5 General Design Criterion 20, 1967 – Protection Systems Redundancy and Independence

Redundancy and independence are designed into the ESFAS sufficient to assure that no single failure or removal from service of any component or channel of a system will result in loss of the protection function. The redundancy provided includes, as a minimum, two channels of protection for each protection function served.

7.3.1.6 General Design Criterion 21, 1967 – Single Failure Definition

ESFAS is designed to perform its function after sustaining a single failure. Multiple failures resulting from a single event shall be treated as a single failure.

7.3.1.7 General Design Criterion 22, 1967 – Separation of Protection and Control Instrumentation Systems

ESFAS is designed such that protection functions are separated from control instrumentation functions to the extent that failure or removal from service of any control instrumentation system component or channel, or of those common to control instrumentation and protection circuitry, leaves intact a system satisfying all requirements for the protection channels.

7.3.1.8 General Design Criterion 23, 1967 – Protection Against Multiple Disability for Protection Systems

ESFAS is designed such that the effects of adverse conditions to which redundant channels or protection systems might be exposed in common, either under normal conditions or those of an accident, does not result in loss of the protection function.

7.3.1.9 General Design Criterion 24, 1967 – Emergency Power for Protection Systems

ESFAS is designed such that in the event of loss of all offsite power, sufficient alternate sources of power are provided to permit the required functioning of the protection systems.

7.3.1.10 General Design Criterion 25, 1967 – Demonstration of Functional Operability of Protection Systems

ESFAS includes means for testing protection systems while the reactor is in operation to demonstrate that no failure or loss of redundancy has occurred.

7.3.1.11 General Design Criterion 26, 1967 – Protection Systems Fail-Safe Design

The ESFAS is designed to fail into a safe state or into a state defined as tolerable on a defined basis if conditions such as disconnection of the system, loss of electric power, or adverse environments are experienced.

7.3.1.12 General Design Criterion 37, 1967 – Engineered Safety Features Basis for Design

ESFAS is designed to actuate the ESFs provided to back up the safety provided by the core design, the reactor coolant pressure boundary, and their protection systems.

7.3.1.13 General Design Criterion 38, 1967 – Reliability and Testability of Engineered Safety Features

ESFAS is designed to provide high functional reliability and ready testability.

7.3.1.14 General Design Criterion 40, 1967 – Missile Protection

ESFAS is protected against dynamic effects and missiles that might result from plant equipment failures.

7.3.1.15 General Design Criterion 48, 1967 – Testing of Operational Sequence of Emergency Core Cooling Systems

ESFAS is designed with the capability to test under conditions as close to design as practical the full operational sequence that brings the emergency core cooling system into action, including the transfer to alternate power sources.

7.3.1.16 General Design Criterion 49, 1967 – Containment Design Basis

ESFAS circuits routed through containment electrical penetrations are designed to support the containment design basis so that the containment structure can accommodate without exceeding the design leakage rate, the pressures and temperatures following a loss-of-coolant accident (LOCA).

7.3.1.17 10 CFR 50.49 – Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

The ESFAS electric components that require environmental qualification are qualified to the requirements of 10 CFR 50.49.

7.3.1.18 Safety Guide 22, February 1972 – Periodic Testing of Protection System Actuation Functions

The ESFAS are periodically tested to provide assurance that the systems will operate as designed and will be available to function properly in the unlikely event of an accident. The testing program conforms to Safety Guide 22, February 1972.

7.3.2 System Description

7.3.2.1 Functional Design

The following summarizes those generating station conditions requiring protective action:

(1) Primary system

(a) Rupture in small pipes or crack in large pipes (refer to Section 15.3.1)

(b) Rupture of a reactor coolant pipe - loss-of-coolant accident (LOCA) (refer to Section 15.4.1)

(c) Steam generator tube rupture (refer to Section 15.4.3)

(2) Secondary system

(a) Minor secondary system pipe break resulting in steam release rates equivalent to the actuation of a single dump, relief, or safety valve (refer to Section 15.2.14)

(b) Rupture of a major secondary system pipe (refer to Section 15.4.2)

The following summarizes the generating station variables required to be monitored for the initiation of the ESF for each accident in the preceding list:

(1) Rupture in small pipes or crack in large primary system pipes

(a) Pressurizer pressure

(b) Containment pressure

(2) Rupture of a reactor coolant pipe LOCA

(a) Pressurizer pressure

(b) Containment pressure

(3) Steam generator tube rupture

(a) Pressurizer pressure

(4) Minor or major secondary system pipe rupture

(a) Pressurizer pressure

(b) Steam line pressures

(c) Steam line pressure rate

(d) Containment pressure

7.3.2.2 Signal Computation

The ESFAS consists of two discrete portions of circuitry: (a) a process protection portion consisting of three to four redundant channels that monitor various plant parameters and containment pressures, and (b) a logic portion consisting of two redundant logic trains that receive inputs from the process protection channels and perform the needed logic to actuate the ESF. Each logic train is capable of actuating the ESF equipment required. The intent is that any single failure within the ESFAS shall not prevent system action when required.

The redundancy concept is applied to the process protection and logic portions of the system. Separation of redundant process protection channels begins at the process sensors and is maintained in the field wiring, containment penetrations, and process protection racks, terminating at the redundant groups of ESF logic racks as shown in Figure 7.3-50. This conforms to GDC 20, 1967 (refer to Section 7.3.3.5).

Section 7.2 provides further details on protection instrumentation. The same design philosophy applies to both systems and conforms to GDC 19, 1967, GDC 20, 1967, GDC 22, 1967 and GDC 23, 1967 (refer to Sections 7.3.3.4, 7.3.3.5, 7.3.3.7, and 7.3.3.8).

The variables are sensed by the process protection circuitry, as discussed in Reference 2 and in Section 7.2. The outputs from the process protection channels are combined into actuation logic as shown on Sheets 9 and 10, 11 and 12, 13 and 14, 15 and 16 of Figure 7.2-1. Tables 7.3-1 and 7.3-2 provide additional information pertaining to logic and function.

The interlocks associated with the ESFAS are outlined in Table 7.3-3. These interlocks satisfy the functional requirements discussed in Section 7.3.2.1

7.3.2.3 Devices Requiring Actuation

The following are the actions that the ESFAS initiates when performing its function:

(1) Safety injection (safety injection pumps, residual heat removal pumps, charging pumps)

(2) Reactor trip

(3) Feedwater line isolation by closing all main control valves, feedwater bypass valves, main feedwater isolation valves and tripping the feedwater pumps.

(4) Auxiliary feedwater system actuation

(5) Auxiliary saltwater pump start

(6) Automatic containment spray (spray pumps, sodium hydroxide tank)
(7) Containment isolation

(8) Containment fan coolers start

(9) Emergency diesel generator startup

(10) Main steam line isolation

(11) Turbine and generator trips

(12) Control room isolation

(13) Component cooling water pump start

(14) Trip RHR pumps on low refueling water storage tank (RWST) level

Refer to Figure 7.3-50 for a complete list of actuated components.

7.3.2.4 Implementation of Functional Design

7.3.2.4.1 Process Protection Circuitry

The process protection sensors and racks for the ESFAS are covered in References 2, 17, 72 and 73. Discussed in these reports are the parameters to be measured including pressures, tank and vessel water levels, as well as the measurement and signal transmission considerations. These latter considerations include the basic current signal transmission system, transmitters, resistance temperature detectors (RTDs), and pneumatics. Other considerations covered are automatic calculations, signal conditioning, and location and mounting of the devices.

The sensors monitoring the primary system are located as shown on the piping schematic diagram, Figure 3.2-7, Reactor Coolant System. The secondary system sensor locations are shown on the piping schematic diagram, Figure 3.2-4, Turbine Steam Supply System.

Containment pressure is sensed by four physically separated differential pressure transmitters mounted outside of the containment structure. The transmitters are connected to containment atmosphere by filled and sealed hydraulic transmission systems similar to the sealed pressurizer water level reference leg described in Section 7.2.2.11.4. Refer to Section 6.2.4.4.2.2 for additional information on instrument lines penetrating containment.

Three water level instrumentation channels are provided for the RWST. Each channel provides independent indication on the main control board, thus meeting the requirements of Paragraph 4.20 of IEEE-279 1971 (Reference 4). Two-out-of-three

logic is provided for residual heat removal (RHR) pump trip and low-level alarm initiation. One channel provides low-low-level alarm initiation; another channel provides a high-level alarm to alert the operator of overfill and potential spillage of radioactive material. Refer to Sections 3.10.2.5 and 6.3.3.4.4.1 for additional information on the RWST level circuits and logic relays.

7.3.2.4.2 Logic Circuitry

The ESF logic racks are discussed in detail in Reference 5. The description includes the considerations and provisions for physical and electrical separation as well as details of the circuitry. Reference 5 also covers certain aspects of on-line test provisions, provisions for test points, considerations for the instrument power source, considerations for accomplishing physical separation, and provisions for ensuring instrument qualification. The outputs from the process protection channels are combined into ESF actuation logic, as shown on Sheets 9 and 10 (RCP bus undervoltage), 11 and 12 (pressurizer pressure), 13 and 14 (steam pressure rate, steamline pressure, and steam generator level), and 15 and 16 (ESF actuation and containment pressure) of Figure 7.2-1.

To facilitate ESF actuation testing, two cabinets (one per train) are provided that enable operation, to the maximum practical extent, of safety features loads on a group-by-group basis until actuation of all devices has been checked. Final actuation testing is discussed in detail in Section 7.3.4.1.5.8.

7.3.2.4.3 Final Actuation Circuitry

The outputs of the solid-state logic protection system (the slave relays) are energized to actuate, as are most final actuators and actuated devices. These devices are:

(1) *Safety Injection (SI) System Pumps and Valve Actuators* - Refer to Section 6.3 for flow diagrams and additional information.

(2) *Containment Isolation* - Phase A - T signal isolates all nonessential (to reactor operation) process lines on receipt of SI signal; Phase B - P signal isolates remaining process lines (which do not include SI lines) on receipt of a two-out-of-four high-high containment pressure signal. For further information, refer to Section 6.2.4.

(3) *Containment Fan Coolers* - Refer to Section 6.2.2.3.

(4) *Component Cooling Pumps and Valves* - Refer to Section 9.2.2.

(5) *Auxiliary Saltwater Pumps* - Refer to Section 9.2.7.

(6) *Auxiliary Feedwater Pumps Start* - Refer to Section 6.5.5.

(7) *Diesel Generators Start* - Refer to Section 8.3.1.1.3.3.5.2.

(8) *Feedwater Isolation* - Refer to Section 10.4.7.

(9) *Ventilation Isolation Valve and Damper Actuators* - Refer to Section 6.2.4.

(10) *Steam Line Isolation Valve Actuators* - Refer to Section 10.3.2.

(11) *Containment Spray Pumps and Valve Actuators* - Refer to Section 6.2.2.3.

When the ESF loads are to be powered by diesel generators, they must be sequenced to prevent overloading. This sequencing is discussed in Section 8.3.1.1.3.3.5.2.

The following systems are required for support of the engineered safety features:

(1) *Auxiliary Saltwater System* - Heat removal, refer to Section 9.2.7.

(2) *Component Cooling Water System* - Heat removal, refer to Section 9.2.2.

(3) *Electrical Power Distribution Systems* - Refer to Chapter 8.

7.3.2.4.4 Safety System Status Display

The following provisions have been made to automatically display the status of safety systems.

(1) Monitor light display panels are provided to verify correct system alignment for:

  (a) Safety feature valves

  (b) Phase A isolation system equipment

  (c) SI, charging (CCP1 and CCP2), component cooling water, auxiliary feedwater, auxiliary saltwater, and RHR pumps

  (d) Phase B isolation system equipment and containment spray pumps

  (e) Containment fan coolers

(2) A partial list of annunciator displays is included in Section 7.7.2.10.1.1.1:

In addition to the status lights and annunciator displays described, system control switches on the control board are provided with indicating lights to display valve position

and motor status with power potential indicating lights provided where equipment power is 480 V or higher.

The features described above, supplemented with administrative procedures, provide the operator with safety system status information, by means of which the status of bypassed or inoperable systems is available to the operator, in accordance with the intent of RG 1.47 (Reference 6).

7.3.2.5 Additional Design Information

The generating station conditions that require protective action are discussed in Section 7.3.2.1. The generating station variables that are required to be monitored in order to provide protective actions are also summarized in Section 7.3.2.1.

The ESFAS functional units and trip setpoints are provided in the Technical Specifications (Reference 7). The methodology for determining ESFAS setpoints and allowable values is presented in WCAP 11082 or in plant procedures.

The following is a list of the malfunctions, accidents, or other unusual events that could physically damage protection system components or could cause environmental changes. The sections noted with each item present discussions on the provisions made to retain the necessary protective action.

(1) LOCA (refer to Sections 15.3.1 and 15.4.1)

(2) Secondary System breaks (refer to Sections 15.3.2 and 15.4.2)

(3) Earthquakes (refer to Sections 2.5, 3.2, 3.7, and 3.8)

(4) Fire (refer to Section 9.5.1)

(5) Explosion (hydrogen buildup inside containment; refer to Sections 6.2 and 15.4)

(6) Missiles (refer to Section 3.5)

(7) Flood (refer to Sections 2.4 and 3.4)

(8) Wind (refer to Section 3.3)

Minimum performance requirements are:

(1) *System response times*

The actuation system response time is included in the overall ESF response time.

The Technical Specifications define ESF response time. Acceptance criteria for ESF response time testing is located in ECG 38.2, "Engineered Safety Features (ESF) Response Times."

(2) *System accuracies*

The system actuation setpoints together with their allowable values are provided in the Technical Specifications.

(3) *Ranges of sensed variables to be accommodated until conclusion of protective action is ensured*

Information readouts and the ranges required in generating the required actuation signals for loss-of-coolant and secondary system pipe break protection are discussed in Section 7.5.1 and presented in Tables 7.5-1 and 7.5-2.

7.3.2.6 Current System Drawings

The schematic diagrams and logic diagrams for ESF circuits and supporting systems are presented at the end of Section 7 (refer to Figures 7.3-1 through 7.3-49).

7.3.3 SAFETY EVALUATION

7.3.3.1 General Design Criterion 2, 1967 – Performance Standards

The ESFAS structures, systems and components (SSCs) are contained in the auxiliary buildings that are PG&E Design Class I (refer to Section 3.8). These buildings are designed to withstand the effects of winds and tornadoes (Refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), earthquakes (refer to Section 3.7), and other natural phenomena to protect ESFAS SSCs to ensure their safety-related functions and designs will perform.

Refer to Section 7.3.2.5 for additional information.

7.3.3.2 General Design Criterion 11, 1967 – Control Room

Controls and instrumentation related to ESFAS include control room status lights, annunciator displays and system control switches on the control board with indicating lights to display valve position and motor status with power potential indicating lights provided where equipment power is 480-V or higher.

Refer to Section 7.3.2.4.4 for additional information.

7.3.3.3 General Design Criterion 15, 1967 – Engineered Safety Features Protection Systems

The ESFAS is designed to monitor plant variables and respond to the accident conditions identified in Section 7.3.2.1. If necessary, ESFAS will initiate the operation of the engineered safety features as described in Section 7.3.2.3.

The effectiveness of the ESFAS is evaluated in Chapter 15 based on the ability of the system to contain the effects of Conditions III and IV faults including loss of coolant and secondary system pipe rupture accidents. The ESFAS parameters are based on the component performance specifications that are provided by the manufacturer, or verified by test for each component. Appropriate factors to account for uncertainties in the data are factored into the constants characterizing the system.

The ESFAS must detect Conditions III and IV faults and generate signals that actuate the ESF. The system must sense the accident condition and generate the signal actuating the protection function reliably, and within a time determined by, and consistent with, the accident analyses in Sections 15.3 and 15.4. The ESFAS will mitigate other faults as discussed in Section 15.2.

The time required for the generation of the actuation signal of ESFAS is relatively short. The remainder of the time is associated with the actuation of the mechanical and fluid system equipment associated with ESF. This includes the time required for switching, bringing pumps and other equipment to speed, and the time required for them to take load.

7.3.3.3.1 Loss-of-Coolant Protection

By analysis of LOCA and in-system tests, it has been verified that except for very small coolant system breaks, which can be protected against by the charging pumps (CCP1 and CCP2) followed by an orderly shutdown, the effects of various LOCAs are reliably detected by the low pressurizer pressure. The emergency core cooling system (ECCS) is actuated in time to prevent or limit core damage.

For large coolant system breaks, the passive accumulators inject first because of the rapid pressure drop. This protects the reactor during the unavoidable delay associated with actuating the active ECCS phase.

High containment pressure also actuates the ECCS, providing additional protection as a backup to actuation on low pressurizer pressure. Emergency core cooling actuation can be brought about upon sensing this other direct consequence of a primary system break; that is, the protection system detects the leakage of the coolant into the containment.

Containment spray provides containment pressure reduction and also limits fission product release, upon sensing elevated containment pressure (high-high), to mitigate the effects of a LOCA.

The delay time between detection of the accident condition and the generation of the actuation signal for these systems is well within the capability of the protection system equipment. However, this time is short compared to that required for startup of the fluid systems.

The analyses in Chapter 15 show that the diverse methods of detecting the accident condition and the time for generation of the signals by the protection systems are adequate to provide reliable and timely protection against the effects of loss of coolant.

7.3.3.3.2 Secondary System Pipe Rupture Protection

The ECCS is also actuated to protect against a secondary system line break. Analysis of secondary system pipe rupture accidents shows that the ECCS is actuated for a secondary system pipe rupture in time to limit or prevent further damage.

There is a reactor trip, but the core reactivity is further reduced by the highly borated water injected by the ECCS.

Additional protection against the effects of secondary system pipe rupture is provided by feedwater isolation that occurs upon actuation of the ECCS. Feedwater line isolation is initiated to prevent excessive cooldown of the reactor.

Additional protection against a secondary system pipe rupture accident is provided by closure of all steam line isolation valves to prevent uncontrolled blowdown of all steam generators. Generation of the protection system signal is again short compared to the time to trip the fast acting steam line isolation valves that are designed to close in less than 5 seconds.

The analyses in Chapter 15 of the secondary system pipe rupture accidents and an evaluation of the protection system instrumentation and channel design show that the EFSAS are effective in preventing or mitigating the effects of a secondary system pipe rupture accident.

7.3.3.4 General Design Criterion 19, 1967 – Protection Systems Reliability

The ESFAS is designed for high functional reliability and in-service testability. The design employs redundant logic trains and measurement and equipment diversity. Sufficient redundancy is provided to enable individual end-to-end channel tests with each reactor at power without compromise of the protective function. Built-in semiautomatic testers provide means to test the majority of system components very rapidly.

Refer to Section 7.3.4.1.5.1 and Section 7.2.3.11 for additional information.

7.3.3.5 General Design Criterion 20, 1967 – Protection Systems Redundancy and Independence

Sufficient redundancy and independence is designed into the protection systems to ensure that no single failure, or removal from service of any component or channel of a system will result in loss of the protection function. The minimum redundancy is exceeded in each protection function that is active with the reactor at power. Functional diversity and consequential location diversity are designed into the systems.

The ESF outputs from the solid-state logic protection cabinets are redundant, and the actuations associated with each train are energized to actuate, up to and including the final actuators, by the separate ac power supplies that power the respective logic trains. Mutually redundant ESF circuits utilize separate relays in separate racks.

The protection system is designed to provide two, three, or four instrumentation channels for each protective function and redundant (two) logic trains. These redundant channels and trains are electrically isolated and physically separated. Thus, any single failure within a channel or train will not prevent protective action at the system level when required.

Each individual channel is assigned to one of four channel designations, e.g., Channel I, II, III, or IV. Channel independence is carried throughout the system, extending from the sensor through to the devices actuating the protective function. Physical separation is used to achieve separation of redundant transmitters. Separation of wiring is achieved using separate wireways, cable trays, conduit runs, and containment penetrations for each redundant channel. Redundant process equipment is separated by locating electronics in different protection rack sets. Each redundant channel is energized from a separate ac power feed.

Refer to Sections 7.3.4.1.1 and 7.3.4.1.3 for additional information.

7.3.3.6 General Design Criterion 21, 1967 – Single Failure Definition

The protection system is designed to provide two, three, or four instrumentation channels for each protective function and redundant (two) logic trains. These redundant channels and trains are electrically isolated and physically separated. Thus, any single failure within a channel or train will not prevent protective action at the system level when required.

Refer to Section 7.3.4.1.1 for additional information.

7.3.3.7 General Design Criterion 22, 1967 – Separation of Protection and Control Instrumentation Systems

The protection systems comply with the requirements of IEEE-279, 1971, Criteria for Protection Systems for Nuclear Power Generating Stations (Reference 4), although construction permits for the DCPP units were issued prior to issuance of the 1971 version of the standard (refer to Section 7.3.4.1). Each protection system is separate and distinct from the respective control systems. The control system is dependent on the protection system in that control signals are derived from protection system measurements, where applicable. These signals are transferred to the control system by isolation amplifiers that are classified as protection system components. The adequacy of system isolation has been verified by testing or analysis under conditions of all postulated credible faults. Isolation devices that serve to protect Instrument Class IA instrument loops have all been tested. For certain applications where the isolator is protecting an Instrument Class IB instrument loop, and the isolation device is a simple linear device with no complex failure modes, the analysis was used to verify the adequacy of the isolation device. The failure or removal of any single control instrumentation system component or channel, or of those common to the control instrumentation system component or channel and protection circuitry, leaves intact a system that satisfies the requirements of the protection system.

To provide physical separation between input and output circuits in the solid-state protection system racks, physical barriers have been provided to separate input and output wire bundles.

The protection system is designed to be independent of the control system. In certain applications, the control signals and other non-protective functions are derived from individual protective channels through isolation devices. The isolation devices are classified as part of the protection system and are located in the process protection racks. Non-protective functions include those signals used for control, remote process indication, and computer monitoring. The isolation devices are designed so that a short circuit, open circuit, or the application of 118-Vac or 140-Vdc on the isolated output portion of the circuit (i.e., the non-protective side of the circuit) will not affect the input (protective) side of the circuit. The signals obtained through the isolation devices are never returned to the protective racks.

7.3.3.8 General Design Criterion 23, 1967 – Protection Against Multiple Disability for Protection Systems

Physical separation and electrical isolation of redundant channels and subsystems, functional diversity of subsystems, and safe failure modes are employed in the design of the reactor’s defenses against functional failure through exposure to common causative factors. The redundant logic trains, reactor trip breakers, and ESF actuation devices are physically separated and electrically isolated. Physically separate channel trays, conduits, and penetrations are maintained upstream from the logic elements of each train.

The protection system components have been qualified by testing under extremes of the normal environment. In addition, components are tested and qualified according to individual requirements for the adverse environment specific to their location that might result from postulated accident conditions.

Refer to Sections 7.3.4.1.2 and 7.3.4.3 for additional information.

7.3.3.9 General Design Criterion 24, 1967 – Emergency Power for Protection Systems

Emergency power for the instrumentation and control portions of the protection systems is provided initially from the station batteries, supplying dedicated 120-Vac inverters for each protection channel, and subsequently from the emergency diesel generators. A single failure of any one component will not prevent the required functioning of protection systems.

Refer to Section 8.3 for additional information.

7.3.3.10 General Design Criterion 25, 1967 – Demonstration of Functional Operability of Protection Systems

The ESFAS includes means for testing protection systems while the reactor is in operation to demonstrate that no failure or loss of redundancy has occurred.

Operating procedures normally require that the complete ESF actuation system be operable. However, redundancy of system components is such that the system operability assumed for the safety analyses can still be met with certain instrumentation channels out of service. Channels that are out of service are to be placed in the bypass/tripped mode.

Refer to Section 7.3.4.1.5.1 for additional information.

7.3.3.11 General Design Criterion 26, 1967 – Protection Systems Fail-Safe Design

In the ESF, a loss of instrument power to a specific channel/rack/or protection set will call for actuation of ESF equipment controlled by the specific channel that lost power (exceptions to the fail-safe design requirement are the containment spray and the radiation monitoring channels that initiate containment ventilation isolation). The actuated equipment in some cases must have power to comply. The power supply for the protection systems is discussed in Chapter 8. The containment spray function is energized to trip in order to avoid spurious actuation. In addition, manual containment spray requires simultaneous actuation of both manual controls. This is considered acceptable because spray actuation on high-high containment pressure signal provides automatic initiation of the system via protection channels, meeting the criteria in Reference 4. When the construction permits for the Diablo Canyon units were issued in April 1968 and December 1970, manual initiation at the system level was in compliance

with paragraph 4.17 of IEEE-279, 1968 (Reference 8). No single random failure in the manual initiation circuits can prevent automatic initiation. Failure of manual initiation at the system level is not considered a significant safety problem because the operator can initiate operation manually at the component level.

Refer to section 7.3.4.1.1 for additional information.

7.3.3.12 General Design Criterion 37, 1967 – Engineered Safety Features Basis for Design

ESFAS actuates the engineered safety features required to cope with any size reactor coolant pipe break up to and including the circumferential rupture of any pipe in that boundary assuming unobstructed discharge from both ends, and to cope with any steam or feedwater line break up to and including the main steam or feedwater headers. Limiting the release of fission products from the reactor fuel is accomplished by the ECCS, which, by cooling the core, keeps the fuel in place and substantially intact and limits the metal-water reaction to an acceptable amount.

7.3.3.13 General Design Criterion 38, 1967 – Reliability and Testability of Engineered Safety Features

A comprehensive program of testing has been formulated for all equipment and instrumentation vital to the functioning of the ESF. The program consists of startup tests of system components and integrated tests of the system. Periodic tests of the activation circuitry and system components, throughout the station lifetime, with maintenance performed as necessary, ensure that high reliability will be maintained and that the system will perform on demand. Details of the test program are provided in the Technical Specifications.

Refer to section 7.3.4.1.5.1 for additional information.

7.3.3.14 General Design Criterion 40, 1967 – Missile Protection

The various sources of missiles that might affect the ESF have been identified, and protective measures have been implemented to minimize these effects (refer to Sections 3.5 and 8.3). Electrical raceways containing circuits for the ESF have not been installed in zones where provision against dynamic effects must be made, with a few exceptions. When routing through such zones was necessary, metallic conduits only were used, and conduits containing redundant circuits were separated physically as far as practical.

7.3.3.15 General Design Criterion 48, 1967 – Testing of Operational Sequence of Emergency Core Cooling Systems

The design provides for capability to test, to the extent practical, the full operational sequence up to design conditions, including transfer to alternative power sources for the ECCS, to demonstrate the state of readiness and capability of the system. This functional test is performed with the RCS initially cold and at low pressure. The ECCS valve alignment is set to initially simulate the system alignment for plant power operation. Details of the ECCS are found in Section 6.3. Refer to Section 7.3.4.1.5.5 for a description of the initiation circuitry.

Refer to section 7.3.4.1.5.1 for additional information.

7.3.3.16 General Design Criterion 49, 1967 – Containment Design Basis

ESFAS circuits routed through containment are analyzed for redundant overcurrent protection and available fault energy. ESFAS circuits routed through containment penetrations are installed without direct in-line protection. The available fault current is not of sufficient magnitude to damage the penetration conductor. These circuits will not adversely heat the penetrations as presently designed.

Refer to Section 8.3 for additional information.

7.3.3.17 10 CFR 50.49 – Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

The Class 1E ESFAS SSCs required to function in harsh environments under accidents conditions are qualified to the applicable environmental conditions to ensure that they will continue to perform their safety functions. Section 3.11 describes the DCPP EQ program and the requirements for the environmental design of the electrical and related mechanical equipment. The affected components are listed on the EQ Master List.

7.3.3.18 Safety Guide 22, February 1972 – Periodic Testing of Protection System Actuation Functions

Periodic testing of the ESF actuation functions, as described, complies with Safety Guide 22, February 1972 (Reference 9). Under the present design, those protection functions that are not tested at power are discussed in Section 7.3.4.1.5.9.

As described by Safety Guide 22, February 1972, where actuated equipment is not tested during reactor operation, it has been determined that:

(1) There is no practicable system design that would permit operation of the actuated equipment without adversely affecting the safety or operability of the plant.

(2) The probability that the protection system will fail to initiate the operation of the actuated equipment is, and can be maintained, acceptably low without testing the actuated equipment during reactor operation.

(3) The actuated equipment can be routinely tested when the reactor is shut down.

Where the ability of a system to respond to a bona fide accident signal is intentionally bypassed, for the purpose of performing a test during reactor operation, each bypass condition is automatically indicated to the reactor operator in the control room by a common "ESF testing" annunciator for the train in test. Test circuitry does not allow two ESF trains to be tested at the same time so that extension of the bypass condition to redundant systems is prevented.

The discussion on "bypass" in Section 7.2.4.1.11 is applicable.

Refer to Section 7.3.4.1.5.1 for additional information.

7.3.4 COMPLIANCE WITH IEEE STANDARDS

7.3.4.1 Evaluation of Compliance with IEEE-279, 1971 – Criteria for Protection Systems for Nuclear Power Generating Stations

The ESFAS meets the criteria as set forth in IEEE-279, 1971 (Reference 4), as follows:

7.3.4.1.1 Single Failure Criterion

The discussion presented in Section 7.2.3.7 is applicable to the ESFAS, with the following exception:

In the ESF, a loss of instrument power to a specific channel/rack/or protection set will call for actuation of ESF equipment controlled by the specific channel that lost power (exceptions to the fail-safe design requirement are the containment spray and the radiation monitoring channels that initiate containment ventilation isolation). The actuated equipment in some cases must have power to comply. The power supply for the protection systems is discussed in Section 8. The containment spray function is energized to trip in order to avoid spurious actuation. In addition, manual containment spray requires simultaneous actuation of both manual controls. This is considered acceptable because spray actuation on high-high containment pressure signal provides automatic initiation of the system via protection channels, meeting the criteria in Reference 4. When the construction permits for the Diablo Canyon units were issued in April 1968 and December 1970, manual initiation at the system level was in compliance with paragraph 4.17 of IEEE-279, 1968 (Reference 8). No single random failure in the manual initiation circuits can prevent automatic initiation. Failure of manual initiation at the system level is not considered a significant safety problem because the operator can initiate operation manually at the component level.

The design conforms to GDC 21, 1967 and GDC 26, 1967.

7.3.4.1.2 Equipment Qualification

The ability of the equipment inside the containment required to function for post-LOCA operation in the adverse environment associated with the LOCA or in-containment steam break, has been evaluated in Section 3.11.

Sensors for measurement of pressurizer pressure, are located inside the containment and will be exposed to the post-LOCA environment.

7.3.4.1.3 Channel Independence

The discussion presented in Section 7.2.3.6 is applicable. The ESFAS outputs from the solid-state logic protection cabinets are redundant, and the actuations associated with each train are energized to actuate, up to and including the final actuators, by the separate ac power supplies that power the respective logic trains. Mutually redundant ESFAS circuits utilize separate relays in separate racks.

7.3.4.1.4 Control and Protection System Interaction

The discussions presented in Section 7.3.3.7 are applicable.

7.3.4.1.5 Capability for Sensor Checks and Equipment Test and Calibration

The discussions of system testability in Section 7.2.4.1.10 are applicable to the sensors, analog circuitry and logic trains of the ESFAS.

The following sections cover those areas in which the testing provisions differ from those for the RTS.

7.3.4.1.5.1 Testing of Engineered Safety Features Actuation System

The ESFAS is tested to ensure that the systems operate as designed and function properly in the unlikely event of an accident. The testing program, which conforms with GDC 19, 1967; Criteria GDC 25 1967, GDC 38 1967, GDC 48 1967, and GDC 57 1967, and to Safety Guide 22, February 1972 (Reference 9), is as follows:

(1) Prior to initial plant operations, ESFAS tests will be conducted.

(2) Subsequent to initial startup, ESFAS tests will be conducted as required in the Technical Specifications.

(3) During on-line operation of the reactor, the ESFAS process and logic circuitry are fully tested. In addition, essentially all of the ESF final

actuators can be fully tested. The few final actuators whose operation is not compatible with continued on-line plant operation are checked during refueling outages. Slave relays are tested on an interval defined in the Technical Specifications.

(4) During normal operation, the operability of testable final actuation devices of the ESFAS are tested by manual initiation from the test control panel.

The discussions on capability for testing, as presented in Section 7.2.2.12, are applicable.

7.3.4.1.5.2 Performance Test Acceptability Standard for the "S" (Safety Injection Signal) and the "P" (Automatic Demand Signal for Containment Spray Actuation) Actuation Signals Generation

During reactor operation, the acceptability of the ESFAS is based on the successful completion of the overlapping tests performed on the initiating system and the ESFAS. Checks of process indications verify operability of the sensors. Process checks and tests verify the operability of the process circuitry from the input of these circuits through the logic input relays and the inputs to the logic matrices. Solid-state logic testing checks the signal path through the logic matrices and master relays and performs continuity tests on the coils of the output slave relays. Final actuator testing can be performed by operating the output slave relays and verifying the required ESF actuation. Actuators whose testing is not compatible with on-line operation are tested during refueling outages, except those actuators normally in their required positions, which will not be tested. Operation of the final devices is confirmed by control board indication and visual observation that the appropriate pump breakers close and automatic valves have completed their travel.

The basis for acceptability for the ESFAS interlocks is receipt of proper indication upon introducing a trip.

Maintenance checks (performed during regularly scheduled refueling outages), such as resistance to ground of signal cables in radiation environments, are based on qualification test data that identify what constitutes acceptable degradation, e.g., radiation and thermal.

7.3.4.1.5.3 Frequency of Performance of Engineered Safety Features Actuation Tests

During reactor operation, complete system testing (excluding sensors or those devices whose operation would cause plant upset) is performed as required by the Technical Specifications. Testing, including the sensors, is also performed during scheduled plant shutdown for refueling.

7.3.4.1.5.4 Engineered Safety Features Actuation Test Description

The following sections describe the testing circuitry and procedures for the on-line portion of the testing program. The guidelines used in developing the circuitry and procedures are:

(1) The test procedures must not involve the potential for damage to any plant equipment.

(2) The test procedures must minimize the potential for accidental tripping.

(3) The provisions for on-line testing must minimize complication of ESF actuation circuits so that their reliability is not degraded.

7.3.4.1.5.5 Description of Initiation Circuitry

Several systems comprise the total ESFAS, the majority of which may be initiated by different process conditions and reset independently of each other.

The remaining functions (listed in Section 7.3.2) are initiated by a common signal (safety injection), which in turn may be generated by different process conditions.

In addition, operation of all other vital auxiliary support systems, such as auxiliary feedwater, component cooling water, and auxiliary saltwater, is initiated via the ESF starting sequence actuated by the safety injection signal.

Each function is actuated by a logic circuit that is duplicated for each of the two redundant trains of ESF initiation circuits.

The output of each of the initiation circuits consists of a master relay, which drives slave relays for contact multiplication as required. The logic, master, and slave relays are mounted in the solid-state logic protection cabinets designated trains A and B, respectively, for the redundant counterparts. The master and slave relay circuits operate various pump and fan circuit breakers or starters, motor-operated valve contactors, solenoid-operated valves, start the emergency diesel generator, etc.

7.3.4.1.5.6 Process Protection Testing

Process protection testing is identical to that used for reactor trip circuitry and is described in Section 7.2.4.1.10. Briefly, in the process protection racks, a man machine interface (MMI) unit is used together with a rack mounted test panel to facilitate testing.

Section 7.2.3.11 discusses testing in bypass which is the normal method. Alternatively, administrative controls allow, during channel testing, that the channel output be put in a trip condition that de-energizes (operates) the input relays in train A and train B cabinets. Of necessity this is done on one channel at a time. Status lights and single channel trip alarms in the main control room verify that the logic input relays have been deenergized and the channel outputs are in the trip mode. An exception to this is

containment spray, which is energized to actuate two-out-of-four logic and reverts to two-out-of-three logic when one channel is in test.

7.3.4.1.5.7 Solid-State Logic Testing

After the individual process channel testing is complete, the logic matrices are tested from the trains A and B logic rack test panels. This step provides overlap between the process protection and logic portions of the test program. During this test, each of the logic inputs is actuated automatically in all combinations of trip and nontrip logic. Trip logic is not maintained long enough to permit master relay actuation - master relays are "pulsed" to check continuity. Following the logic testing, the individual master relays are actuated electrically to test their mechanical operation. Actuation of the master relays during this test applies low voltage to the slave relay coil circuits to allow continuity checking, but not slave relay actuation. During logic testing of one train, the other train can initiate the required ESF function. For additional details, refer to Reference 5.

7.3.4.1.5.8 Actuator Testing

At this point, testing of the initiation circuits through operation of the master relay and its contacts to the coils of the slave relays has been accomplished. Slave relays do not operate because of reduced voltage.

In the next step, operation of the slave relays and the devices controlled by their contacts are checked. For this procedure, control switches mounted in the safeguards test cabinet (STC) near the logic rack area are provided for most slave relays. These controls require two deliberate actions on the part of the operator to actuate a slave relay. By operation of these relays one at a time through the control switches, all devices that can be operated on-line without risk to the plant are tested.

Devices are assigned to the slave relays to minimize undesired effects on plant operation. This procedure minimizes the possibility of upset to the plant and again ensures that overlap in the testing is continuous, since the normal power supply for the slave relays is utilized.

During this last procedure, close communication between the main control room operator and the person at the test panel is required. Before energizing a slave relay, the operator in the control room ensures that plant conditions will permit operation of the equipment that will be actuated by the relay. After the tester has energized the slave relay, the control room operator observes that all equipment has operated as indicated by appropriate indicating lamps, monitor lamps, and annunciators on the control board. The test director, using a prepared check list, records all operations. The operator then resets all devices and prepares for operation of the next slave relay-actuated equipment.

By means of the procedure outlined above, all devices actuated by ESFAS initiation circuits can be operated by the test circuitry during on-line operation, with the following exceptions:

(1) Main steam isolation - During cold shutdowns, these valves are full stroke tested.

(2) Feedwater isolation - Air-operated, spring-closed regulating control valves and feedwater bypass valves are provided for each main feedwater line. Operation of these valves is continually monitored by normal operation. During cold shutdown, these valves are tested for closure times. Motor-operated feedwater isolation valves are also provided for each feedwater isolation line.

(3) Reactor coolant pump essential service isolation

  (a) Component cooling water supply and return. These valves cannot be fully tested during normal operation.

  (b) Seal water return header. These valves cannot be fully testing during normal operation.

(4) Normal charging and normal letdown isolation. These valves cannot be fully tested during normal operation due to thermal and hydraulic transients induced on the lines.

(5) Sequential transfer of centrifugal charging pump (CCP1 and CCP2) suction from the volume control tank (VCT) to the RWST for charging injection. These valves cannot be fully tested during normal operation due to reactivity transients associated with the swap. Additionally, restoration of normal charging and letdown following testing causes thermal and hydraulic transients.

(6) Autotransfer vital buses to startup power or emergency diesel generator.

(7) Containment spray additive tank outlet valves. These valves cannot be tested during normal operation without isolating the spray additive tank.

(8) Accumulator outlet valves. These valves are required by Technical Specifications to be open with power removed from their operators during normal operation to prevent their inadvertent closure by a spurious signal, and therefore are not tested (see Section 7.3.4.1.5.2).

(9) Main turbine trip.

(10) Main feedwater pump trip.

(11) Blocking of the non-ESF starts of ESF pumps during an SI signal to assure bus loading will be controlled by the ESF load sequencing timers.

This circuitry cannot be fully tested during normal operation since slave relay contact position cannot be verified.

(12) Containment spray initiation circuit interlock from an SI signal. This circuit cannot be fully tested during normal operation since slave relay contact position cannot be verified.

(13) Other circuitry not associated with the ESF; for example, main generator trip, reactor coolant pump trip, and source range block.

7.3.4.1.5.9 Actuator Blocking and Continuity Test Circuits

The limited number of components that cannot be operated on-line are assigned to slave relays separate from those assigned to components that can be operated on-line. For some of these components, additional blocking relays are provided that allow operation of the slave relays without actuation of the associated ESF devices. Interlocking prevents blocking the output of more than one slave relay at a time. The circuits provide for monitoring of the slave relay contacts, the devices control circuit cabling, control voltage, and the devices actuating solenoids. These slave relays and actuators may be tested using the blocking and continuity test circuits while the unit is on line; however, use of these circuits can increase the risk associated with testing, since failure of the blocking circuits may result in a reactor trip.

7.3.4.1.5.10 Time Required for Testing

The system design includes provisions for timely testing of both the process protection and logic sections of the system. Testing of actuated components (including those that can only be partially tested) is a function of control room operator availability. It is expected to require several shifts to accomplish these tests. During this procedure, automatic actuation circuitry will override testing, except for those few devices associated with a single slave relay whose outputs must be blocked and then only while blocked. It is anticipated that continuity testing associated with a blocked slave relay could take several minutes. During this time, the redundant devices in the other trains would be functional.

7.3.4.1.5.11 Summary

The testing program and procedures described provide capability for checking completely from the process signal to the logic cabinets and from these to the individual pump and fan circuit breakers or starters, valve contactors, pilot solenoid valves, etc., including all field cabling actually used in the circuitry called upon to operate for an accident condition. For those devices whose operation could affect plant or equipment operation, the same procedure provides for checking from the process signal to the logic rack. To check the final actuation device, the device itself is tested during shutdown conditions. All testing is performed as required by the Technical Specifications.

The procedures require testing at various locations:

(1) Process channel testing and verification of setpoints are accomplished at the process protection racks. Verification of logic input relay operation is done at the control room status lights.

(2) Logic testing through operation of the master relays and low voltage application to slave relays is done at the logic rack test panel.

(3) Testing of pumps, fans, and valves is done at a test panel located in the vicinity of the logic racks, in combination with the control room operator.

(4) Continuity testing for the circuits that cannot be operated is done at the same test panel mentioned in (3) above.

7.3.4.1.6 Testing During Shutdown

ECCS components and the system, including emergency power supplies, will be tested in accordance with the Technical Specifications.

Containment spray system tests are performed at each major fuel reloading. The tests are performed with the isolation valves in the spray supply lines at the containment and spray additive tank blocked closed, and are initiated manually or by using an actual or simulated actuation signal.

All final actuators can be tested during a refueling outage. The final actuators that cannot be tested during on-line operation are tested during each major fuel reloading. All testing is performed as required by the Technical Specifications.

7.3.4.1.7 Periodic Maintenance Inspections

Periodic maintenance on the system equipment is accomplished and documented according to the maintenance procedures contained in the Plant Manual. Refer to Section 13.5.1.

The balance of the requirements listed in Reference 4 (Paragraphs 4.11 through 4.22) is discussed in Section 7.2.4.1. Paragraph 4.20 receives special attention in Section 7.5.

7.3.4.2 Evaluation of Compliance with IEEE-308-1971, Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations

The power supplies for the ESF equipment conform to IEEE 308-1971 (Reference 10).

Refer to Section 7.6 and 8, which discuss the power supply for the protection systems, for additional discussions on compliance with this criteria.

7.3.4.3 Evaluation of Compliance with IEEE-323-1971, Trial-Use Standard: General Guide for Qualifying Class I Electric Equipment for Nuclear Power Generating Stations

Refer to Section 3.11 for a discussion on ESF electrical equipment environmental qualification and compliance to IEEE-323-1971 (Reference 11). Documentation of the environmental and seismic qualification of the process protection system is provided in References 18, 19, 20, and 21.

7.3.4.4 Evaluation of Compliance with IEEE-338-1971, Trial-Use Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

The periodic testing of the ESF actuation system conforms to the requirements of IEEE-338-1971 (Reference 13), with the following comments:

(1) The periodic test frequency specified in the Technical Specifications was conservatively selected, using considerations in paragraph 4.3 of Reference 13, to ensure that equipment associated with protection functions has not drifted beyond its minimum performance requirements.

(2) The test interval discussed in Paragraph 5.2 of Reference 13 is primarily developed on past operating experience, and modified, as necessary, to ensure that system and subsystem protection is reliably provided. Analytic methods for determining reliability are not used to determine test interval.

7.3.4.5 Evaluation of Compliance with IEEE-344-1971, Trial-Use Guide for Seismic Qualifications of Class I Electric Equipment for Nuclear Power Generating Stations

The seismic testing, as set forth in Section 3.10, conforms to the testing requirements of IEEE-344-1971 (Reference 14); however, because the IEEE standards were issued after much of the design and testing had been completed the equipment documentation may not meet the format requirements of the standards. Documentation of the environmental and seismic qualification of the process protection system is provided in References 18, 19, 20, and 21.

7.3.4.6 Evaluation of Compliance with IEEE-317-1971, Electric Penetration Assemblies in Containment Structures for Nuclear Fueled Power Generating Stations

Refer to Section 7.2.4.2 for a discussion of conformance with IEEE-317-1971 (Reference 15). The same applies to penetrations for systems described in Section 7.3.

7.3.4.7 Evaluation of Compliance with IEEE-336-1971, Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

Refer to Section 7.1.2.4 for a discussion of conformance with IEEE-336-1971 (Reference 16).

7.3.4.8 Eagle 21 and Process Control System Design, Verification, and Validation

The standards that are applicable to the Eagle 21 Design, Verification and Validation Plan (refer to reference 17) are IEEE-Standard 603-1980 (Reference 21), which was endorsed by Regulatory Guide 1.153-December 1985 (Reference 23), and ANSI/IEEE-ANS-7-4.3.2-1982 (Reference 24) which was endorsed by Regulatory Guide 1.152-November 1985 (Reference 22).

The following ESFAS related instrument signals are processed by the PCS:

(1) RHR Pump Trip on Low RWST Level (see Sections 6.3.3.4.4.1 and 7.3.2.4.1).

References 4, 10, 13, 16, and 27 through 71 were used for design, verification, validation, and qualification of all or portions of the safety related PCS hardware and software (encompassing Triconex components, manual/auto hand stations, signal converters/isolators and loop power supplies).

7.3.5 REFERENCES

1. Deleted in Revision 21.

2. J. A. Nay, Process Instrumentation for Westinghouse Nuclear Steam Supply Systems, WCAP-7671, April 1971.

3. Safety Guide 11, Instrument Lines Penetrating Primary Reactor Containment, USAEC, March 1971.

4. IEEE Standard 279-1971, Criteria for Protection Systems for Nuclear Power Generating Stations, Institute of Electrical and Electronics Engineers, Inc.

5. D. N. Katz, Solid State Logic Protection System Description, WCAP-7672, June 1971.

6. Regulatory Guide 1.47, Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems, USAEC, May 1973.

7. Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.

8. IEEE Standard 279-1968, Criteria for Protection Systems for Nuclear Power Generating Stations, Institute of Electrical and Electronics Engineers, Inc.

9. Safety Guide 22, Periodic Testing of Protection System Actuation Functions, USAEC, February 1972.

10. IEEE 308-1971, Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations, Institute of Electrical and Electronics Engineers, Inc.

11. IEEE Standard 323-1971, Trial-Use Standard: General Guide for Qualifying Class I Electric Equipment for Nuclear Power Generating Stations, Institute of Electrical and Electronics Engineers, Inc.

12. Deleted in Revision 21.

13. IEEE Standard 338-1971, Trial-Use Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems, Institute of Electrical and Electronics Engineers, Inc.

14. IEEE Standard 344-1971, Trial-Use Guide for Seismic Qualifications of Class I Electric Equipment for Nuclear Power Generating Stations, Institute of Electrical and Electronics Engineers, Inc.

15. IEEE Standard 317-1971, Electric Penetration Assemblies in Containment Structures for Nuclear Fueled Power Generating Stations, Institute of Electrical and Electronics Engineers, Inc.

16. IEEE Standard, 336-1971, Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations, Institute of Electrical and Electronics Engineers, Inc.

17. L. E. Erin, Topical Report Eagle 21 Microprocessor Based Process Protection System, WCAP-12374, September 1989.

18. R. B. Miller, Methodology for Qualifying Westinghouse WRD Supplied NSSS Safety Related Electrical Equipment, WCAP-8587, Westinghouse Proprietary Class 3.

19. Equipment Qualification Data Package, WCAP-8587, Supplement 1, EQDP-ESE-69A and 69B, Westinghouse Proprietary Class 3.

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7.3.6 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

7.4 SYSTEMS REQUIRED FOR SAFE SHUTDOWN

The functions necessary safe shutdown, defined as hot standby (MODE 3), are available from instrumentation channels that are associated with the major systems in both the primary and secondary sides of the plant. These channels are normally aligned to serve a variety of operational functions, including startup and shutdown, as well as protective functions. Prescribed procedures for securing and maintaining the plant in a safe shutdown condition can be instituted by appropriate alignment of selected systems. The discussion of these systems, together with the applicable codes, criteria, and guidelines, is included in other sections. In addition, the alignment of shutdown functions associated with the engineered safety features that are invoked under postulated limiting fault situations is discussed in Chapter 6 and Section 7.3.

The instrumentation and control functions that are required to be aligned for maintaining safe shutdown (MODE 3) of the reactor, which are discussed in this section, are the minimum number under nonaccident conditions. These functions permit the necessary operations to:

(1) Prevent the reactor from achieving criticality in violation of the Technical Specifications (Reference 2)

(2) Provide an adequate heat sink so that design and safety limits are not exceeded

Refer to Appendix 9.5G for an identification of the instrumentation and controls required for safe shutdown in the event of fire.

7.4.1 DESIGN BASES

7.4.1.1 General Design Criterion 3, 1971 – Fire Protection

The instrumentation and control systems required for safe shutdown are designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

7.4.1.2 General Design Criterion 11, 1967 – Control Room

The instrumentation and control systems required for safe shutdown are designed to support actions to maintain and control the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

7.4.1.3 General Design Criterion 12, 1967 – Instrumentation and Control Systems

The instrumentation and control systems required for safe shutdown are designed to monitor and maintain variables within prescribed operating ranges.

7.4.2 DESCRIPTION

The designation of systems used for safe shutdown depends on identifying those systems that provide the following capabilities for maintaining a safe shutdown (MODE 3):

(1) Boration

(2) Adequate supply of auxiliary feedwater

(3) Decay heat removal

These systems are identified in the following sections, together with the associated instrumentation and controls provisions. The design basis information for these systems, as required by IEEE-279-1971 (Reference 3), is provided in other sections herein. For convenience, cross-referencing to these other sections is provided.

In the event that safe shutdown from outside of the control room is required, remote instrumentation, controls, and transfer switches are required for the following functions to maintain safe shutdown (MODE 3):

(1) Reactor trip indication

(2) Reactor coolant system (RCS) pressure control

(3) Decay heat removal via the auxiliary feedwater system and the steam generator safety valves

(4) RCS inventory control via charging flow

(5) Safety support systems for the above functions, including auxiliary saltwater (ASW), component cooling water (CCW), and emergency diesel generators (EDGs)

Instrumentation and controls required to fulfill these functions are described in the following sections. Other instrumentation and controls provided for cold shutdown (MODE 5) and operator convenience are also identified but are not required for safe shutdown (MODE 3).

7.4.2.1 Safe Shutdown Equipment

7.4.2.1.1 Monitoring Indicators

The characteristics of the monitoring indicators that are provided inside and outside, the control room are described in Section 7.5. The necessary safe shutdown (MODE 3) indications are:

(1) Water level indications for each steam generator

(2) Pressure indication for each steam generator

(3) Pressurizer water level indication

(4) Pressurizer pressure indication

(5) Condensate storage tank level indication

(6) RCS temperature indication for loop 1 hot leg and cold leg

(7) AFW flow indication

(8) Charging flow indication

(9) Reactor trip breaker indication

All indications external to the control room are provided at the hot shutdown panel except for the RCS temperature indication (which is provided at the dedicated shutdown panel) and the reactor trip breaker indication (which is provided at the trip breaker switchgear). The dedicated shutdown panel is described in Section 7.5.2.7.

In addition, other remote shutdown indications are provided for operator convenience at the hot shutdown panel (see Figure 7.7-30) but not required for safe shutdown (MODE 3).

7.4.2.1.2 Controls

Controls utilized for obtaining and maintaining safe shutdown (MODE 3) are addressed below.

7.4.2.1.2.1 General Considerations

(1) The turbine is tripped from the control room (note that this can also be accomplished at the turbine).

(2) The reactor is tripped from the control room (note that this can also be accomplished at the reactor trip switchgear).

(3) All automatic systems continue functioning (discussed in Sections 7.2 and 7.7).

    Safe shutdown (MODE 3) is a stable plant condition automatically reached following a plant shutdown. The safe shutdown condition can be safely maintained for an extended time.

In addition, the safety injection signal trip circuit must be defeated and the accumulator isolation valves closed.

(4) For motor-driven equipment that must be operated from outside the control room due to control room evacuation, controls are provided at the hot shutdown panel. A control transfer switch is provided at the 4.16-kV switchgear to directly transfer control to the hot shutdown panel for some equipment. For other equipment, a control transfer switch is provided at the hot shutdown panel to transfer control to that panel. Transfer of control is interlocked with a permissive switch that is located at the motor control center. This interlock is provided to permit isolation of the hot shutdown panel to prevent spurious actions in the event of a fire in or at the hot shutdown panel.

Three methods of transfer control are employed:

(a) For one set of redundant equipment, the permissive switch is normally closed, permitting transfer of control to the hot shutdown panel when the control transfer switch is operated. Abnormal permissive switch alignment or transfer of control is annunciated in the control room.

(b) For the second set of redundant equipment, the permissive switch is normally open, permitting transfer of control by operating the transfer switch only after closing the permissive switch. Abnormal permissive switch alignment is annunciated in the control room.

(c) For the third set of redundant equipment, the transfer switch on the 4.16-kV switchgear permits the transfer of control to the hot shutdown panel. Transfer of control is annunciated in the control room.

7.4.2.1.2.2 Pumps, Fan Coolers, and Ventilation Systems

To maintain safe shutdown (MODE 3) conditions from inside or outside of the control room, controls and transfer switches are required for the AFW pumps, centrifugal charging pumps (CCP1 and CCP2), ASW pumps and the CCW pumps. Other controls are available for "operational convenience" but are not required for safe shutdown. The controls for the required pumps and other equipment are described below.

(1) *AFW Pumps* - In the event of a main feedwater pump stoppage due to a loss of electric power, the motor-driven and turbine-driven AFW pumps start automatically (these pumps can also be started manually). Motor-driven AFW pump start and stop motor controls are located on the hot shutdown panel, in the 4.16-kV switchgear rooms, and in the control room (refer to Figures 7.3-8 and 7.3-17). Controls for the steam supply valve to

the turbine-driven AFW pump are located on the hot shutdown panel and in the control room (refer to Figure 7.3-18).

(2) *Centrifugal Charging and Boric Acid Transfer Pumps* - Start and stop motor controls are provided for these pumps. The controls for the centrifugal charging pumps (CCP1 and CCP2) and the boric acid transfer pumps are located on the hot shutdown panel, as well as in the control room. Additionally, the charging pumps can be started and stopped in the 4.16-kV switchgear rooms. (For charging pumps, refer to Figures 7.3-3, 7.3-4, and 7.3-29. For boric acid transfer pumps, refer to Figures 7.3-13 and 7.3-30, Sheet 2.)

(3) *ASW Pumps* - These pumps restart automatically following a loss of normal electric power. Start and stop motor controls are located on the hot shutdown panel, in the 4.16-kV switchgear rooms, as well as in the control room (refer to Figures 7.3-5 and 7.3-28).

(4) *CCW Pumps* - These pumps restart automatically following a loss of normal electric power. Start and stop motor controls are located on the hot shutdown panel, in the 4.16-kV switchgear rooms, as well as in the control room (refer to Figures 7.3-7 and 7.3-27).

(5) *Reactor Containment Fan Cooler Units* - These units restart automatically following a loss of normal electric power. Start and stop motor controls with a selector switch are provided for the fan motors. The controls are located on the hot shutdown panel, as well as in the control room (refer to Figures 7.3-6 and 7.3-31).

(6) *Control Room HVAC System (includes fans and dampers)* - A start and stop switch is located in the control room for the fan(s). Also, a control to open or close the inlet air damper(s) is located near the dampers. When placed in automatic control, the inlet air dampers are designed to position automatically to meet the requirements of the mode of operation of the system.

(7) *Auxiliary Building Ventilation System* - Operation of the system can be initiated from the ventilation control board in the control room. The system is designed to automatically shift to meet the requirements of the mode of operation of the system.

(8) *Fuel Handling Building Ventilation System (Provides ventilation for the auxiliary feedwater pumps)* - Operation of the system can be initiated from the control room. Normally, the system operates with one set of supply and exhaust fans. In the event of failure of an operating fan, the redundant fan is designed to start automatically.

(9) *4.16-kV Switchgear Room Ventilation System* - Operation of the system can be initiated from the locally mounted control switches. The system is automatically started by a thermostat located in the associated safety-related room.

(10) *125-Vdc and 480-V Switchgear Room Ventilation System* - Operation of the system can be initiated from the locally mounted control switches.

7.4.2.1.2.3 Valves

To maintain safe shutdown (MODE 3) conditions from inside or outside of the control room, control of AFW system level control valves is required. Other controls are available for "operational convenience" but are not required for safe shutdown. The controls for the AFW valves and other remotely operated valves with controls external to the control room are described below.

(1) *Letdown Orifice Isolation Valves* - Open and close controls for these valves are located on the hot shutdown panel . These controls duplicate functions that are inside the control room (refer to Figure 7.3-45, Sheet 1).

(2) *AFW Control Valves* - Manual control is provided on the hot shutdown panel that duplicates functions inside the control room (refer to Figure 7.3-14).

(3) *Condenser Steam Dump and Atmospheric Steam Relief Valves* - The condenser steam dump and atmospheric relief valves are automatically controlled. In addition to local and control room control, the 10 percent steam dump valves can be manually controlled at the hot shutdown panel. Manual control is provided locally as well as inside the control room for the atmospheric relief valves. Steam dump to the condenser is blocked on high condenser pressure.

(4) *Charging Flow Control Valves* - Controls for the emergency borate valve (refer to Figure 7.3-34) and charging pump discharge header flow control valves are located on the hot shutdown panel in addition to the control room. Controls for a pressurizer auxiliary spray valve are located at the dedicated shutdown panel in addition to the control room (refer to Figure 7.3-45, Sheet 1).

(5) *Pressurizer Power Operated Relief Valves* - Emergency close controls for these valves are provided on the hot shutdown panel in addition to control from the control room (refer to Figure 7.3-21).

7.4.2.1.2.4 Pressurizer Heater Control

The pressurizer heaters are normally controlled from the control room. On-off control is provided on the hot shutdown panel for two backup heater groups. The control is grouped with the charging flow controls and duplicates functions available in the control room. These controls are for "operational convenience" but are not required for safe shutdown (MODE 3).

7.4.2.1.2.5 Diesel Generators

These units are started automatically on a safety injection, loss of voltage on either the offsite source or the vital buses, or on degraded bus voltage on the vital buses. Manual controls for diesel starting and control are provided at the main control room and also locally at the diesel generators. Additional description is provided in Section 8.3.

7.4.2.1.3 Maintenance of Safe Shutdown (MODE 3) Conditions Using Remote Shutdown Instrumentation and Controls

The normal and preferred location to operate the plant from is the control room. However, in the event that the control room becomes inaccessible, the operators can establish remote control and place the unit in safe shutdown (MODE 3). Remote Shutdown System Technical Specifications (Reference 2) have been established to ensure the operability of the remote shutdown instrumentation and controls.

To establish and maintain safe shutdown (MODE 3) conditions from outside of the control room, the reactor must be tripped, decay heat must be removed, and the RCS temperature, pressure, and inventory must be controlled. Additionally, systems required to support equipment performing these functions must be operable. The following provides a discussion of the minimum functions required to establish and maintain safe shutdown (MODE 3) conditions from outside of the control room until a cooldown is initiated or control is transferred back to the control room.

(1) *Reactor Trip* - Core subcriticality is achieved by tripping the reactor. The reactor can be tripped from outside the control room by opening the reactor trip breakers at the reactor trip switchgear. Reactor trip indication is provided from outside the control room by the reactor trip breaker position. The insertion of the control rods during a reactor trip provides the negative reactivity needed to establish and maintain safe shutdown (MODE 3) conditions until such time that either control is returned to the control room or a cooldown is initiated.

(2) *Decay Heat Removal via the AFW System and the Steam Generator Safety Valves* - Heat removal from the reactor coolant system is accomplished by transferring heat to the secondary plant through the steam generators. The decay heat is then removed from the steam

generators via boiling and steam release through the steam generator code safety valves.

Indication of secondary heat sink is provided by steam generator pressure indication, steam generator wide range level indication, and AFW flow indication at the hot shutdown panel. The hot shutdown panel also provides indication of condensate storage tank level to allow monitoring of water available to supply the suction of the AFW pumps for extended operation at safe shutdown (MODE 3).

To ensure that steam generator level remains within its expected range, the AFW pump and level control valves are controllable from the hot shutdown panel. Upon initiation of a reactor trip, steam generator level will decrease due to shrink and the trip of the main feedwater pumps. The AFW pumps supply feedwater to the steam generators to compensate for the loss of main feedwater. After the level in the steam generators recovers, the feedwater supply to the steam generators must be controlled to prevent the steam generators from overfilling and overcooling the reactor coolant system, which could result in a safety injection. The feedwater flow can be controlled from the hot shutdown panel by using the AFW level control valves or by starting and stopping the AFW pumps. AFW flow indication is provided to aid in flow control.

To monitor the rate of heat removal from the core during all plant conditions, including a loss of offsite power, indications of RCS hot and cold leg temperature indication are required. Loop 1 RCS hot and cold leg temperature indication is available at the dedicated shutdown panel.

(3) *RCS Pressure Control* - Indication of RCS pressure is provided by the pressurizer pressure indication located at the hot shutdown panel. RCS overpressure protection is provided by the pressurizer code safety valves. Although pressurizer heaters would assist in controlling RCS pressure, they are not required to maintain RCS pressure control.

(4) *Reactor Coolant System Inventory Control via Charging Flow* - Indication of RCS inventory is provided by the pressurizer level indication located at the hot shutdown panel. Level control is necessary to prevent the loss of level in the pressurizer and the subsequent loss of RCS pressure control, to prevent the RCS from achieving a solid water condition where pressure would no longer be readily controllable, and to prevent the core from being uncovered due to low level.

The hot shutdown panel contains controls to start and stop each centrifugal charging pump (CCP1 and CCP2). The charging pumps not only supply water to the RCS for pressurizer level control, but also provide water to the reactor coolant pump (RCP) seals. By starting and stopping