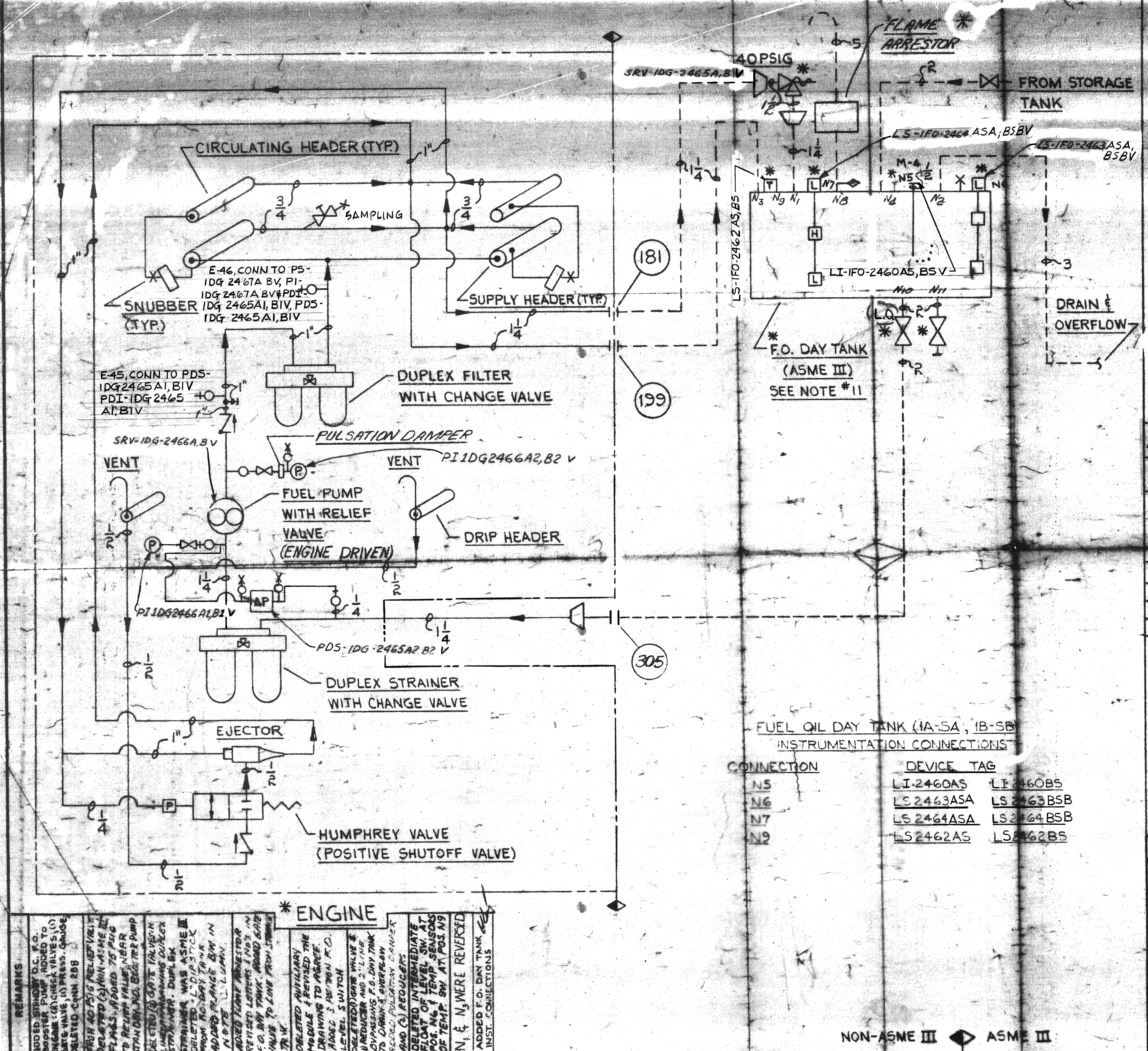


FUEL OIL DAY TANK (1A-SA, 1B-SB) INSTRUMENTATION CONNECTIONS

CONNECTION	DEVICE TAG	
N5	LI-2460AS	LI-2460BS
N6	LS 2463ASA	LS 2463BSB
N7	LS 2464ASA	LS 2464BSB
N9	LS 2462AS	LS 2462BS

CHG	DATE	REMARKS
	10-2-78	ADDED STANDBY D.C. F.O. BOOSTER PUMP ADDED TO ENGINE: (2) CHECK VALVES, (1) GATE VALVE, (1) PRESS. GAUGE; DELETED CONN 288
B	11-15-78	FROM 40 PSIG RELIEF VALVE DELETED (2) NON-ASME III FLAGS. ADDED 75 PSIG TO RELIEF VALVE NEAR STANDBY ND. BOOSTER PUMP
C	12-20-78	DELETED (2) GATE VALVES IN LINES FROM DUPLEX STRAINER. DUPLEX STRAINER WAS ASME III DELETED "L" DIPSTICK FROM F.O. DAY TANK ADDED FLANGE B/M IN NOTE COLUMN
D	11-15-79	ADDED FLAME ARRESTOR REVISED LETTERS & NO'S IN F.O. DAY TANK. ADDED GATE VALVE TO LINE FROM STORAGE TANK
E	5-6-80	DELETED AUXILIARY MODULE & REVISED THE DRAWING TO AGREE. ADDED 3 POSITION F.O. LEVEL SWITCH
F	10-17-80	DELETED (1) GATE VALVE & (1) REDUCER AND 2" LINE BYPASSING F.O. DAY TANK TO DRAIN & OVERFLOW ADDED PULSATION DAMPER AND (2) REDUCERS
G	3-2-81	DELETED INTERMEDIATE FLOAT OF LEVEL SW. AT POS. N6 & TEMP SENSORS OF TEMP. SW AT POS. N9
H	8-20-81	N_1 & N_3 WERE REVERSED
J	6-8-82	ADDED F.O. DAY TANK INST. CONNECTIONS

1. ALL ITEMS MARKED * ARE [illegible]
2. (100) – [illegible] PIPE [illegible]
3. SOLID LINES [illegible] CONNECTIONS [illegible] BY DELAVAL.
4. FOR [illegible]
5. FLEXIBLE [illegible] CUSTOMER [illegible] HAZARD [illegible]
6. ALL PIPING [illegible] PIPE VIBRATION [illegible]
7. CUSTOMER TO SUPPLY AND INSTALL [illegible] IN DOTTED LINE [illegible]
8. ALL PIPING TO BE MECHANICALLY CLEANED AFTER WELDING AND PRIOR TO ASSEMBLING.
9. PIPE SIZES SHOWN ARE [illegible] INSTALLATIONS, BUT MAY VARY IF LENGTH OF PIPING, NUMBER OF FITTINGS & VALVES RESULT IN EXCESSIVE PRESSURE DROP.
10. TANK TO BE AT ELEVATION TO PROVIDE FLOODED SUCTION AT BOTH FEED PUMPS, BUT NOT OVER [illegible] ABOVE CRANK ℄.
11. PROVIDE SUCH VENTS AND DRAINS AS DEEMED NECESSARY BY DELAVAL ENGINEERING.
12. ALL ○ REPRESENT INSTRUMENT CONNECTIONS, I.E. [illegible]
13. ALL (E-++) AND (M-++) NUMBERS CORRESPOND TO TUBING CONNECTIONS AS SHOWN ON INSTRUMENTATION DRAWINGS.
14. FOR DIESEL GENERATOR GENERAL TUBING INSTALLATION AND DESIGN CRITERIA, SEE DRAWING 1364-7812.

REV.	DATE	BY	APP.	DESCRIPTION EBASCO REVISION
E2	8/30/83	V.V. I&C	AS	ADDED EBASCO TAG NO'S TO PRESS INO'S / PREVIOUS REVIEW WAS A-5 B-1
E1				

ITEM	DESCRIPTION	REMARKS
181	FUEL OIL RETURN	1¼-150 STD. FLG.
199	FUEL OIL BYPASS OUTLET	1¼-150 STD. FLG.
305	FUEL OIL INLET	2"-150 STD. FLG.

NUCLEAR SAFETY RELATED

CERTIFIED FOR SCHEMATIC SYSTEM INTERCONNECTION ONLY -- NOT FOR CONSTRUCTION.

PROJECT ENGINEER John F. Gee

CUSTOMER CAROLINA POWER & LIGHT

CUSTOMER REF. CAR-SH-E-11

ENGINE NO. 74046-53

DELAVAL TURBINE INC.
ENGINE AND COMPRESSOR DIVISION
OAKLAND, CALIFORNIA 94621

DELAVAL

FUEL OIL PIPING SCHEMATIC

DRAWN	R.L. 9-25-78	09-825-74046	J
CHECKED	EP		
APPROVED	REB	DRAWING NUMBER	ALT.
SCALE: NONE			

DISCIPLINE COMMENTS DUE BY 8/6/82

DESIGN FOR INFO	DESIGN FOR COMM	DESIGN NC	DESIGN C	DISCIPLINE	ENGINEERING FOR INFO	ENGINEERING FOR COMM	ENGINEERING NC	ENGINEERING C
				MECHANICAL				
				CIVIL – A/S				
				CIVIL – C/H				
				CIVIL – ARCH.				
✓				ELECTRICAL	✓		✓	
	✓		✓	INSTR'N	✓			✓
				CONTROLS				
				PLUMBING				
				HVAC				
				APPLIED PHYSICS				
				WTR TREAT.				
				RADWASTE				
				SHIELDING				
				MATERIALS				
				STRESS SUPP & RESTRAINTS				
				CONSTR				
				QAE				
				PQAF				
				MODEL FACILITIES				
				SITE DOCUMENT CONTROL				
				CORROSION				

REPRODUCIBLE ILLEGIBLE
ADDRES
STANDARD DISTRIBUTION

1364-7818 R9

CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
3600 MW(e) – UNITS 1-2 1984-1990

P.O. NY435079 ITEM

DIESEL GEN FUEL OIL PIPING SCHEMATIC DIE BLDG

EBASCO SERVICES INCORPORATED
AGENT
2 WORLD TRADE CENTER, NEW YORK, NY 10048

17 X 26

REV.	DATE	DESCRIPTION	BY / SUP	CHK / APPR
14	2/16/00	INCORPORATED: ESR 95-00027		
13	6/23/93	INCORPORATED: PCR-5829	ESP / GOW	RPP / DWAS
12	2-26-90	INCORPORATED: PCR-1949	ESP / CWH	TRW
11	11-3-89	INCORPORATED: PCR-3502	CDH	TRW
10	11 14 85	INCORPORATED: DCA-M-439 FCR-I-1149 R4 FCR-I-1836	HJK / RPO	RAM / JBB

A	DRAWING REVIEW	REVIEWED WITHOUT COMMENTS	X
		REVIEWED WITH COMMENTS AS NOTED	
		NOT APPLICABLE	
		NO COMMENTS, NO PRINT RETURNED	
		FOR INFORMATION ONLY	
B	PROCEED WITH FAB./CONST.	NO FURTHER REPRODUCIBLE REQUIRED	X
		RESUBMIT REVISED REPRODUCIBLE	
		NOTES:	
	DO NOT PROCEED WITH FABRICATION RESUBMIT REVISED REPRODUCIBLE		

TRANSMITTAL LETTER

REVIEW OF THIS DOCUMENT WITH OR WITHOUT COMMENT IS ONLY FOR GENERAL CONFORMANCE WITH CP&L PREPARED SPECIFICATIONS AND FOR CONFIRMATION OF PHYSICAL INTERFACE OF ITEMS SHOWN WITH RELATED SYSTEMS. SUCH REVIEW SHALL IN NO WAY RELIEVE CONTRACTORS FROM ENTIRE RESPONSIBILITY FOR ENGINEERING, DESIGN, WORKMANSHIP, MATERIAL, PERFORMANCE OF EQUIPMENT AND MATERIAL, AND ALL OTHER LIABILITY UNDER THE CONTRACT. COMMENTS TO OR ACCEPTANCE OF REVISED DRAWINGS BY CP&L DOES NOT PROVIDE APPROVAL FOR REVISED CONTRACT PRICE. CP&L SHALL BE NOTIFIED WITHIN 30 DAYS OF ANY POTENTIAL PRICING IMPACT.

P.O.# NY435079 ITEM

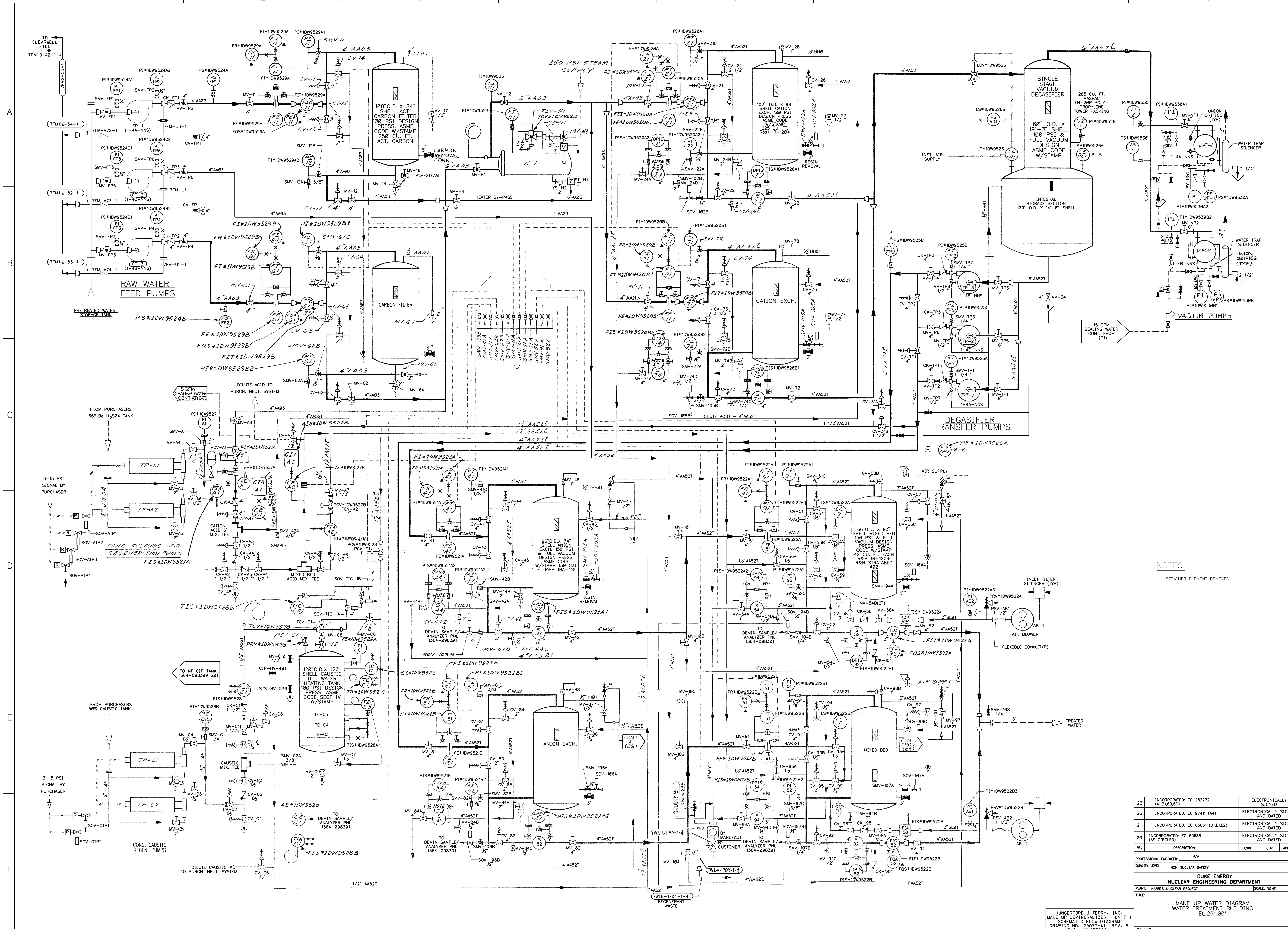
DISCIPLINARY REVIEW REQUIRED
- ☐ MECHANICAL (NSSS)
- ☒ MECHANICAL (SYSTEMS)
- ☐ ELECTRICAL
- ☐ I&C
- ☐ CIVIL
- ☐ HANGERS

CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT

DRAWING TITLE: DIESEL GENERATOR FUEL OIL PIPING SCHEMATIC

LEAD ENGINEER'S APPROVAL R. Palumbo

1364 - 7818 SHEET 1 OF 1



REV	DESCRIPTION	DWN	CHK	APPR'D
23	INCORPORATED: EC 282272 (A1,B1,6B,6C)	ELECTRONICALLY SIGNED		
22	INCORPORATED: EC 97411 (A4)	ELECTRONICALLY SIGNED AND DATED		
21	INCORPORATED: EC 65631 (D1,E1,E2)	ELECTRONICALLY SIGNED AND DATED		
20	INCORPORATED: EC 63688 (AS CIRCLED)	ELECTRONICALLY SIGNED AND DATED		

PROFESSIONAL ENGINEER: N/A

QUALITY LEVEL: NON NUCLEAR SAFETY

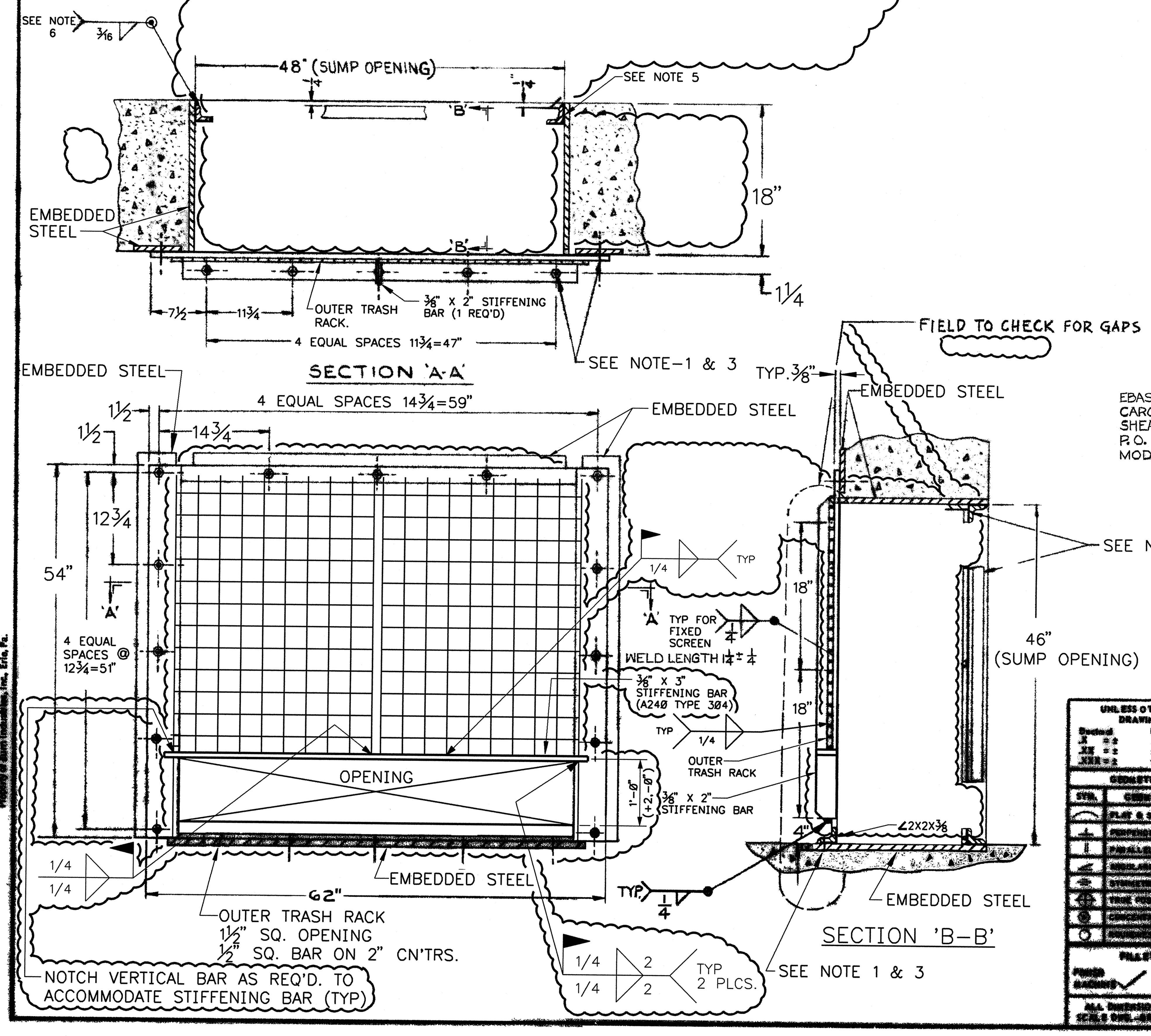
DUKE ENERGY
NUCLEAR ENGINEERING DEPARTMENT

PLANT: HARRIS NUCLEAR PROJECT — SCALE: NONE

TITLE:
MAKE UP WATER DIAGRAM
WATER TREATMENT BUILDING
EL.261.00'

HUNGERFORD & TERRY, INC.
MAKE UP DEMINERALIZER - UNIT 1
SCHEMATIC FLOW DIAGRAM
DRAWING NO. 29077-A1 REV. 5
P.O. NY435226

PLANT DWG NO.: 1364-020974



NOTES

1. ALL OUTER TRASH RACKS DRILLED FOR REMOVAL.
2.
3. 3/4" DIA. HOLES (18) REQ'D ON ALL 12 OUTER TRASH RACKS [5/8" x 1 1/4" LG. BOLTS, A193-B8 OR EQUAL MAT'L. PROVIDED BY CUSTOMER IN FIELD].
4.
5. 1" x 1 1/2 x 3/16" THK. ANGLE BACKSTOP ALL AROUND (ROUGH CUT - FIELD WELDED AND INSTALLED.)
6. FIELD WELD ALL AROUND TO ASSURE TOTAL SEAL. EXCEPT AT CORNERS-BREAK IN WELD NOT TO EXCEED 1" IN LENGTH.
7. WELDING PER ASME SECTION VIII.
8.
9.
10. 3/4"Ø HOLES IN TRASH RACKS MAY BE LENGTHENED 1/4" OR LESS AS NEEDED TO ALLOW FOR ALIGNMENT WITH HOLES IN EMBEDS. MIN. EDGE DISTANCES OF 1" ON SIDES, 7/8" ON TOP, AND 5/8" ON BOTTOM ARE TO BE MAINTAINED.

EBASCO SERVICES INC.
CAROLINA POWER & LIGHT
SHEARON HARRIS
P.O. NO NY 435163
MODEL 515

CONTAINMENT BUILDING RECIRCULATION SUMP SCREENS (QTY. OF 12 REQUIRED PER UNIT)
~~OUTER TRASH RACKS: 12 REMOVABLE~~
FLOW: 0.2 F.P.S.
SERVICE: BORATED WATER
SEISMIC CATEGORY I
SPEC. NO. CAR-SH-M-49 Z
MAT'L.: 316 SST.
WEIGHT:
OUTER TRASH RACK – 284lbs.
ZURN ORDER NO. 80-Q-1866

THE FOLLOWING DOCUMENTS HAVE BEEN REVIEWED BUT NOT INCORPORATED: FCR-AS-10327R1.

UNLESS OTHERWISE SPECIFIED DRAWING TOLERANCES

REV	DESCRIPTION		BY	CHK	APP	DATE
3	REVISED PER CUSTOMER COMMENTS		BD			3/24/80
2	ADDED 1/2 x 1 3/8 x 2 STIFF. BAR		BD			3/11/80
1	REVISED PER CUSTOMER COMMENTS					

CONTAINMENT BUILDING RECIRCULATION SUMP SCREENS

ZURN INDUSTRIES, INC. ERIE, PA

I-801501-A
REV. 3

DISCIPLINE COMMENTS
DUE BY 4/23

DESIGN FOR INFO	DESIGN FOR COMM	NC	C	DISCIPLINE	ENGINEERING FOR INFO	ENGINEERING FOR COMM	NC	C
	✓		✓	MECHANICAL			✓	✓
				CIVIL				
	✓		✓	ARCH - Struct			✓	✓
				ELECTRICAL				
				INSTR'N				
				CONTROLS				
				PLUMBING				
				HVAC				
				APPLIED PHYSICS				
				WTR TREAT				
				RADWASTE				
				SHIELDING				
				MATERIALS			✓	✓
				STRESS SUPP & RESTRAINTS				
				CONST				
				QAE				
				PQAF				
				MODEL FACILITIES				

REPRODUCIBLE ILLEGIBLE
ADDRES
STANDARD DISTRIBUTION

OFS 1364-36778 R2 DATE REC 5/7/80

CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
3600 MW(e) – UNITS 1-4 – 1984-1990

PO NY-435163 ITEM 4

				No.	
A	DRAWING REVIEW		NO COMMENTS, PRINT TO VENDOR	1	
			COMMENTS AS NOTED, PRINT TO VENDOR	2	X
			DRAWING NOT APPLICABLE, PRINT TO VENDOR	3	
			NO COMMENTS, NO PRINT TO VENDOR	4	
			FOR INFORMATION ONLY	5	
B	FABRICATION	PROCEED	NO FURTHER REPRODUCIBLE REQUIRED	1	X
			SUBMIT REVISED REPRODUCIBLE	2	
		DO NOT PROCEED	NO FURTHER REPRODUCIBLE REQUIRED	3	
			SUBMIT REVISED REPRODUCIBLE	4	

CONTAINMENT BLDG
RECIRC SUMP
SCREENS

REVIEWED BY	DATE	ORIG DIV	REPLY TO MFR BY:
S.R/GP.	4/25/80	M	5-22-80

REVIEW OF THIS DOCUMENT WITH OR WITHOUT COMMENTS IS ONLY FOR GENERAL CONFORMANCE WITH EBASCO PREPARED SPECIFICATIONS AND FOR CONFIRMATION OF PHYSICAL INTERFACE OF ITEMS SHOWN WITH RELATED SYSTEMS. SUCH REVIEW SHALL IN NO WAY RELIEVE CONTRACTOR FROM ENTIRE RESPONSIBILITY FOR ENGINEERING, DESIGN, WORKMANSHIP, MATERIAL, PERFORMANCE OF EQUIPMENT AND MATERIAL, AND ALL OTHER LIABILITY UNDER THE CONTRACT.

EBASCO SERVICES INCORPORATED
AGENT
2 RECTOR ST, NEW YORK, NY 10006

496A/3-78

17X26

REV.	DATE	DESCRIPTION	BY / SUP	CHK / APPR
4	6/22/92	INCORPORATED: PW-AS-10404 ADDED AS-BUILT BLOCK	MMP / LLS	RPP / JT
3	11/7/85	INCORPORATED: FCR-AS-9277, 9479, 9669	RJB	RAM / WKP

		DESCRIPTION	
A	DRAWING REVIEW	REVIEWED WITHOUT COMMENTS	X
		REVIEWED WITH COMMENTS AS NOTED	
		NOT APPLICABLE	
		NO COMMENTS, NO PRINT RETURNED	
		FOR INFORMATION ONLY	
B	PROCEED WITH FAB./CONST.	NO FURTHER REPRODUCIBLE REQUIRED	X
		RESUBMIT REVISED REPRODUCIBLE	
		NOTES:	
	DO NOT PROCEED WITH FABRICATION RESUBMIT REVISED REPRODUCIBLE		

TRANSMITTAL LETTER

REVIEW OF THIS DOCUMENT WITH OR WITHOUT COMMENT IS ONLY FOR GENERAL CONFORMANCE WITH CP&L PREPARED SPECIFICATIONS AND FOR CONFIRMATION OF PHYSICAL INTERFACE OF ITEMS SHOWN WITH RELATED SYSTEMS. SUCH REVIEW SHALL IN NO WAY RELIEVE CONTRACTORS FROM ENTIRE RESPONSIBILITY FOR ENGINEERING, DESIGN, WORKMANSHIP, MATERIAL, PERFORMANCE OF EQUIPMENT AND MATERIAL, AND ALL OTHER LIABILITY UNDER THE CONTRACT. COMMENTS TO OR ACCEPTANCE OF REVISED DRAWINGS BY CP&L DOES NOT PROVIDE APPROVAL FOR REVISED CONTRACT PRICE. CP&L SHALL BE NOTIFIED WITHIN 30 DAYS OF ANY POTENTIAL PRICING IMPACT.

P.O.# NY435163 ITEM

DISCIPLINARY REVIEW REQUIRED
☐ MECHANICAL (NSSS) ☐ I&C
■ MECHANICAL (SYSTEMS) ☐ CIVIL
☐ ELECTRICAL ☐ HANGERS

CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT

DRAWING TITLE:

LEAD ENGINEER'S APPROVAL R. Palumbo

1364-36778
SHEET 1 OF 1

REV	DESCRIPTION	APPROVED
5	INCORPORATED: EC# 64377	ELECTRONICALLY SIGNED

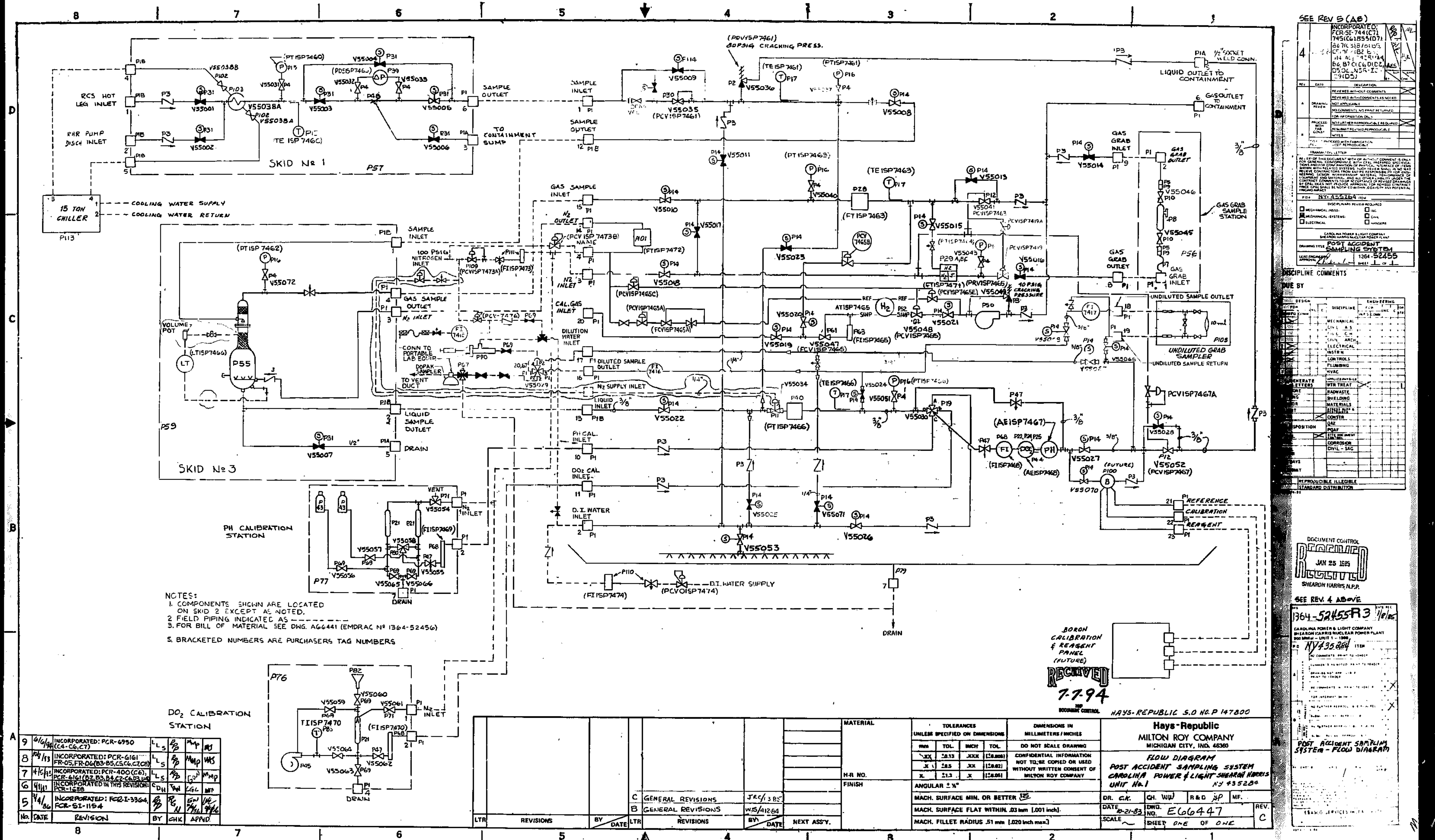
Progress Energy

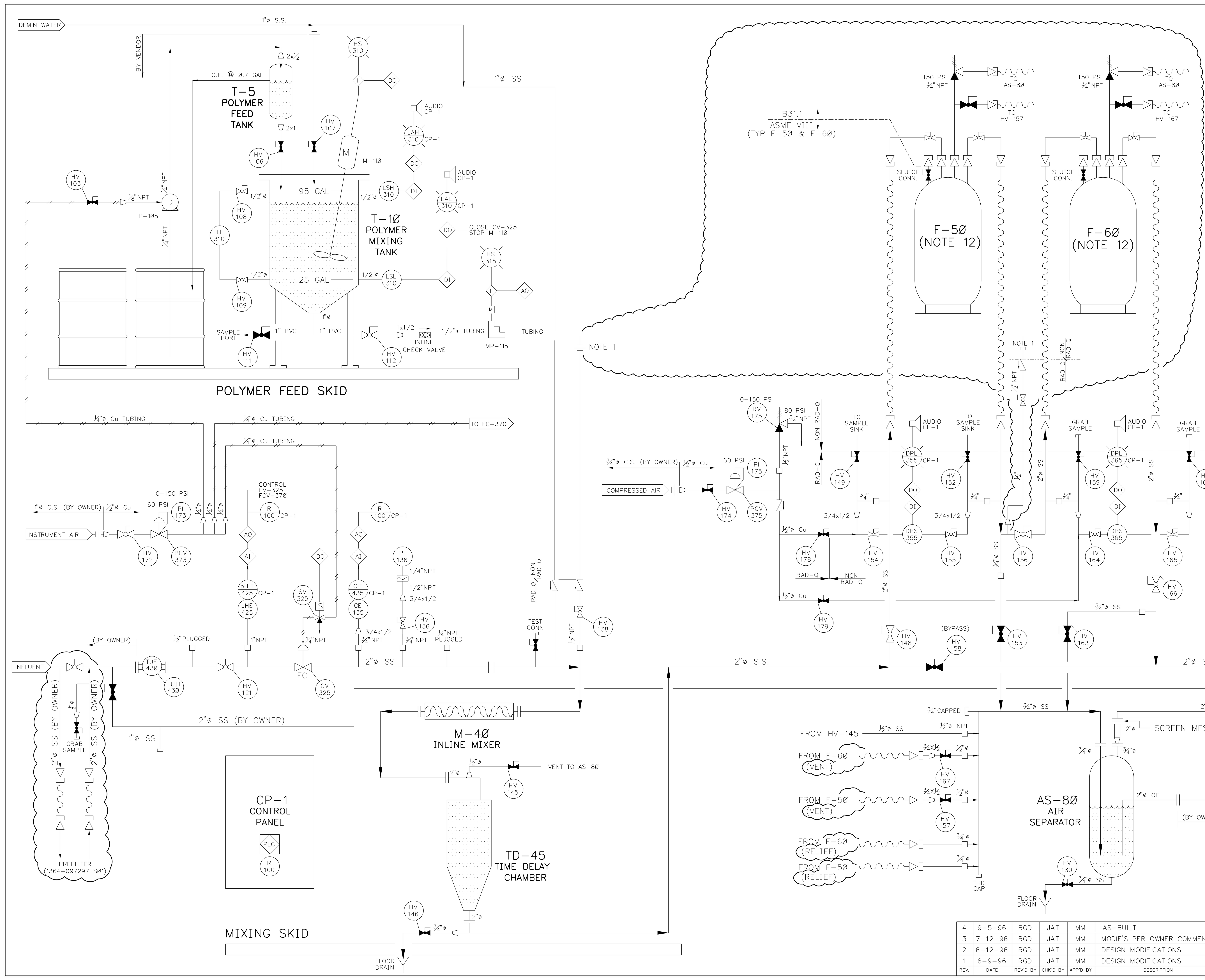
QUALITY LEVEL:

PLANT: HARRIS PROJECT – UNIT 1 SCALE: N/A

TITLE: CONTAINMENT BLDG RECIRC SUMP SCREENS

PLANT DWG NO.: 1364-036778


SKID Nº 1
SKID Nº 3
RCS HOT LEG INLET
RHR PUMP DISCH INLET
15 TON CHILLER
COOLING WATER SUPPLY
COOLING WATER RETURN
SAMPLE OUTLET
TO CONTAINMENT SUMP
SAMPLE INLET
SAMPLE OUTLET
GAS SAMPLE INLET
N2 OUTLET
N2 INLET
CAL. GAS INLET
DILUTION WATER INLET
DILUTED SAMPLE OUTLET
N2 SUPPLY INLET
LIQUID INLET
PH CAL. INLET
DO2 CAL INLET
D.I. WATER INLET
D.I. WATER SUPPLY
DRAIN
(PRV1SP7461) 80PSIG CRACKING PRESS.
LIQUID OUTLET TO CONTAINMENT
GAS OUTLET TO CONTAINMENT
GAS GRAB INLET
GAS GRAB OUTLET
GAS GRAB SAMPLE STATION
UNDILUTED SAMPLE OUTLET
UNDILUTED GRAB SAMPLER
UNDILUTED SAMPLE RETURN
100 PSIG NITROGEN INLET
CONN TO PORTABLE LAB EQUIP
DOPAK SAMPLER
TO VENT DUCT
VOLUME POT
LIQUID SAMPLE OUTLET
GAS SAMPLE OUTLET
PH CALIBRATION STATION
DO2 CALIBRATION STATION
REFERENCE
CALIBRATION
REAGENT
BORON CALIBRATION & REAGENT PANEL (FUTURE)
40 PSIG CRACKING PRESSURE
NOTES:
1. COMPONENTS SHOWN ARE LOCATED ON SKID 2 EXCEPT AS NOTED.
2. FIELD PIPING INDICATED AS
3. FOR BILL OF MATERIAL SEE DWG. A66441 (EMDRAC Nº 1364-52456)
5. BRACKETED NUMBERS ARE PURCHASERS TAG NUMBERS
RECEIVED 7-7-94
HAYS-REPUBLIC S.O NO. P 147800
Hays-Republic
MILTON ROY COMPANY
MICHIGAN CITY, IND. 46360
FLOW DIAGRAM
POST ACCIDENT SAMPLING SYSTEM
CAROLINA POWER & LIGHT SHEARON HARRIS UNIT No. 1
DWG. NO. E66447
REV. C
SHEET ONE OF ONE
DATE 10-21-83
9 6/6/94 INCORPORATED: PCR-6950 (C4-C6,C7)
8 INCORPORATED: PCR-6161 FR-05, FR-06(B3-B5,C5,C6,C7,C8)
7 INCORPORATED: PCR-400 (C6), PCR-6161 (B2,B3,B4,C2-C6,D3,D4)
6 INCORPORATED IN THIS REVISION: PCR-1588
5 INCORPORATED: FCR-I-3364, FCR-SI-1154
C GENERAL REVISIONS
B GENERAL REVISIONS
DOCUMENT CONTROL RECEIVED JAN 25 1995 SHEARON HARRIS N.P.P.
SEE REV. 4 ABOVE
1364-52455 R3
POST ACCIDENT SAMPLING SYSTEM
1364-52455
POST ACCIDENT SAMPLING SYSTEM - FLOW DIAGRAM



NOTES:

1. ALTERNATE INJECTION PATH – TO REMAIN CAPPED/PLUGGED WHEN NOT IN USE. PRIMARY INJECTION PATH TO BE CAPPED/PLUGGED WHEN NOT IN USE.
2. pHIT-425 TO MONITOR AND DISPLAY INFLUENT pH LEVEL ON CP-1. IF pH IS GREATER THAN 9, VISUAL AND AUDIO ALARMS OCCUR.
3. pH TO BE RECORDED ON RECORDER R-1ØØ.
4. TUIT-43Ø TO MONITOR AND DISPLAY INFLUENT TURBIDITY LEVEL ON CP-1.
5. HIGH TURBIDITY TO BE ALARMED ON CP-1.
6. CIT-435 TO MONITOR AND DISPLAY INFLUENT CONDUCTIVITY LEVEL ON CP-1, AND TO CONTROL POLYMER FEED PUMP MP-115.
7. TURBIDITY TO BE RECORDED ON RECORDER R-1ØØ.
8. FIT-47Ø TO MONITOR AND DISPLAY OUTPUT FLOW ON CP-1, AND TO REGULATE FLOW WITH MODULATING FLOW CONTROL VALVE FCV-37Ø WITHIN 15 GPM.
9. LOW FLOW (BELOW 13.5 GPM) TO BE ALARMED ON CP-1.
1Ø. BLOWDOWN AIR SUPPLY TO FILTERS F-5Ø AND F-6Ø TO BE REGULATED TO 60 PSI WITH PRESSURE REGULATOR PCV-375. (FILTERS DESIGNED FOR 15Ø PSI)
11. SEE 1364-Ø97536 FOR P&ID LEGEND.
12. VESSELS & PIPE SPOOLS WITH HOSE ATTACHMENTS SUPPLIED BY ENERGY-SOLUTIONS (1364-Ø99293).

REV.	DATE	REV'D BY	CHK'D BY	APP'D BY	DESCRIPTION
4	9-5-96	RGD	JAT	MM	AS-BUILT
3	7-12-96	RGD	JAT	MM	MODIF'S PER OWNER COMMENTS
2	6-12-96	RGD	JAT	MM	DESIGN MODIFICATIONS
1	6-9-96	RGD	JAT	MM	DESIGN MODIFICATIONS

MECH-CHEM
MECH-CHEM ASSOCIATES, Inc. NORFOLK, MA NORTH OLMSTED, OH

COMPANY: WMG, Inc. Peekskill, NY		DRAWN BY: RGD	DATE: 04-25-96
TITLE: FILTRATION SYSTEM P&ID		DESIGNED BY: RGD	DATE: 04-25-96
		CHECKED BY: MM	DATE: 04-25-96
		ENG. APPROVAL: MM	DATE: 04-25-96
SCALE - D SIZE: NONE	ORIG. ISSUE DATE: 04-25-96	DRAWING NO.: WMG-264-Ø2	SHEET NO.: 1 OF 1
			REVISION NO.: 4

REV	DATE	DESCRIPTION	DWN	CHK	APPR'D
4		INCORPORATED: EC 4ØØ448 (D4-F7, C1, B5)	ELECTRONICALLY SIGNED		
3	1/28/99	INCORPORATED: ESR-95ØØ565 (R/4) (C6-D6)	ARM	RPP	DLS

PROFESSIONAL ENGINEER:

QUALITY LEVEL: RADWASTE Q

DUKE ENERGY
NUCLEAR ENGINEERING DEPARTMENT

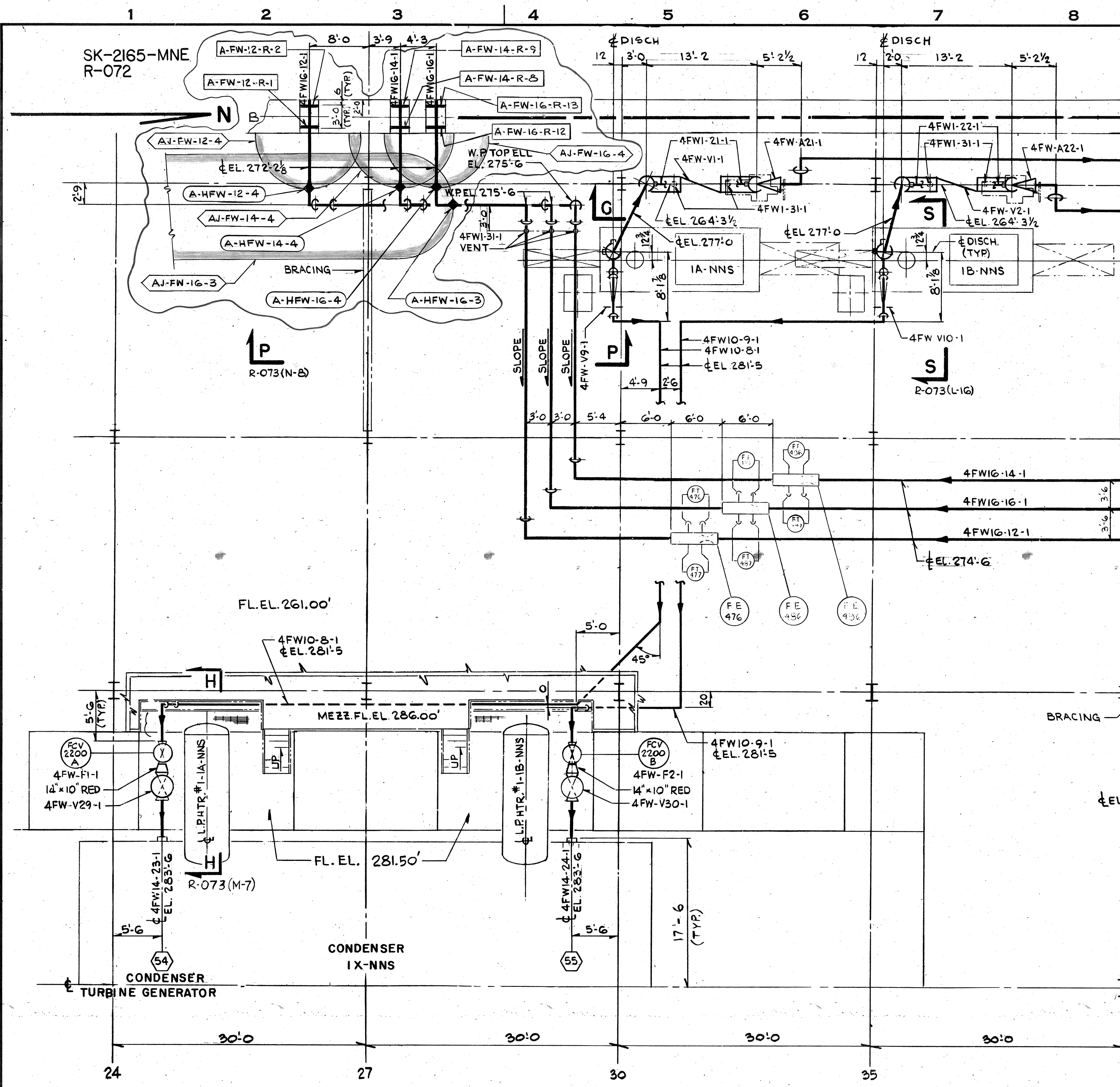
PLANT: HARRIS PROJECT – UNIT 1 SCALE: NONE

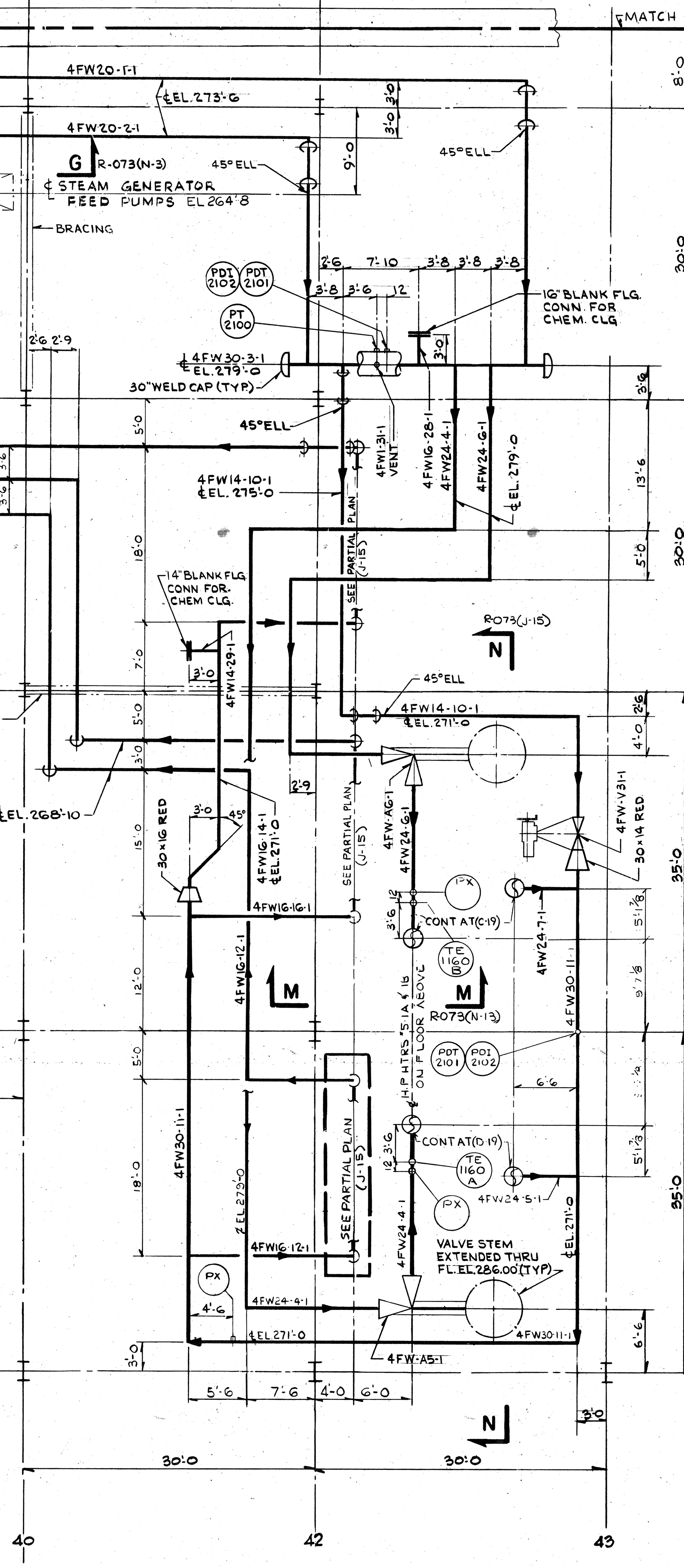
TITLE:

FILTRATION SYSTEM P&ID

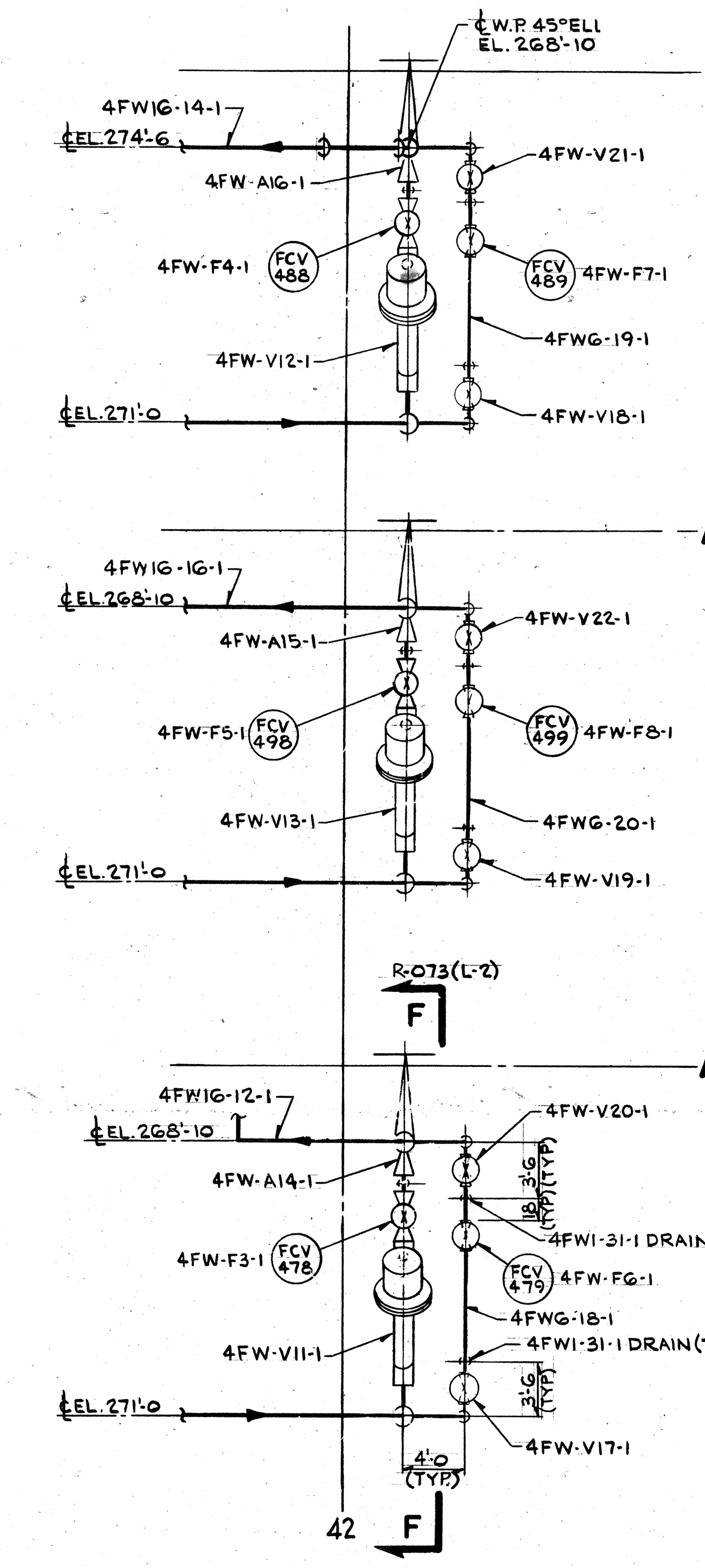
PLANT DWG NO.: 1364-Ø97532

SK-2165-MNE
R-072

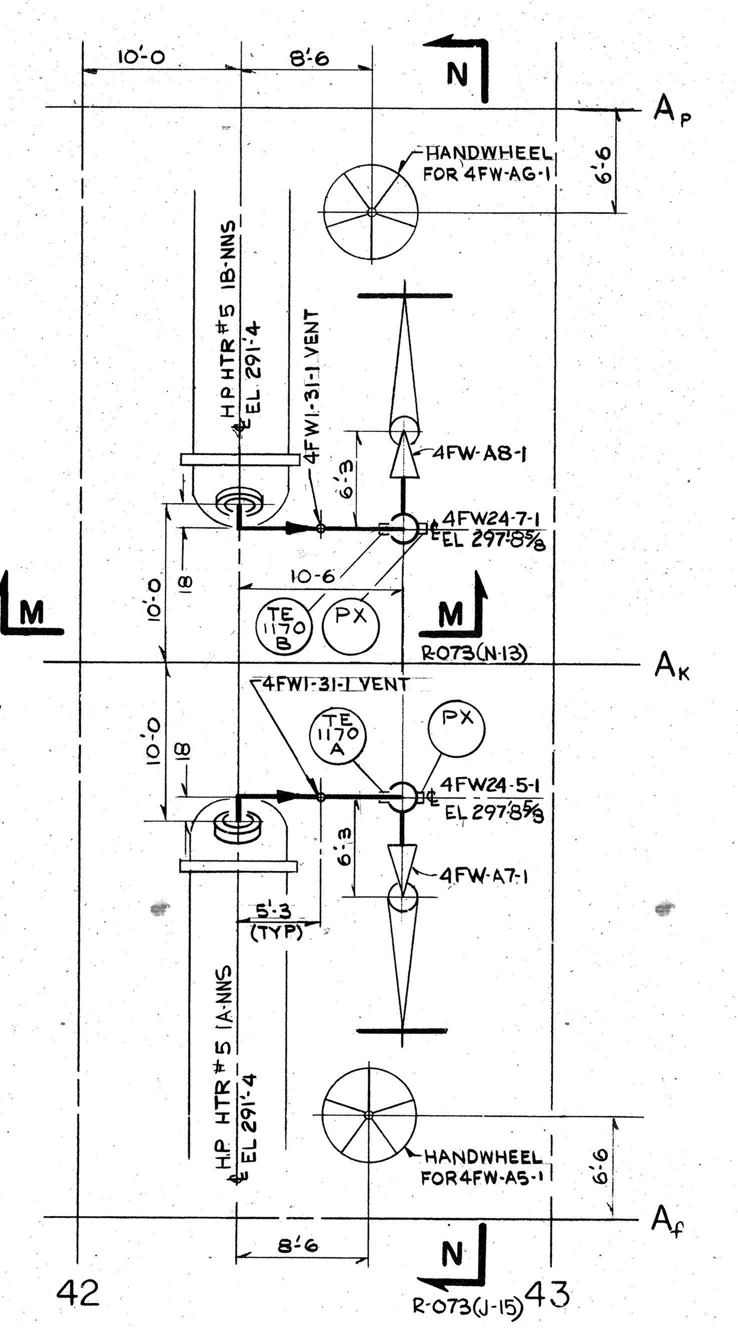




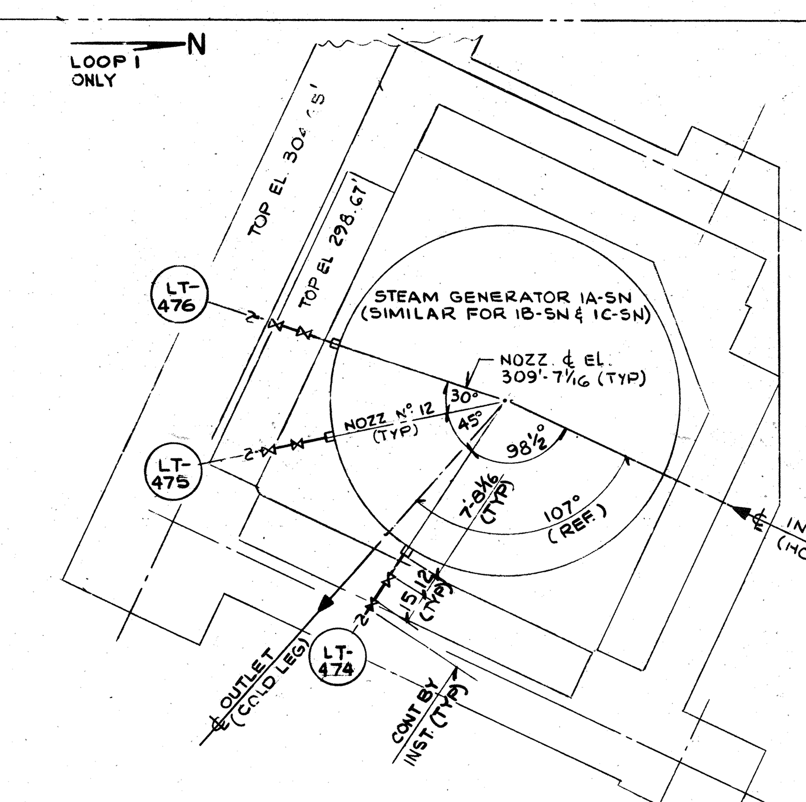
PLAN@ EL. 261.00'



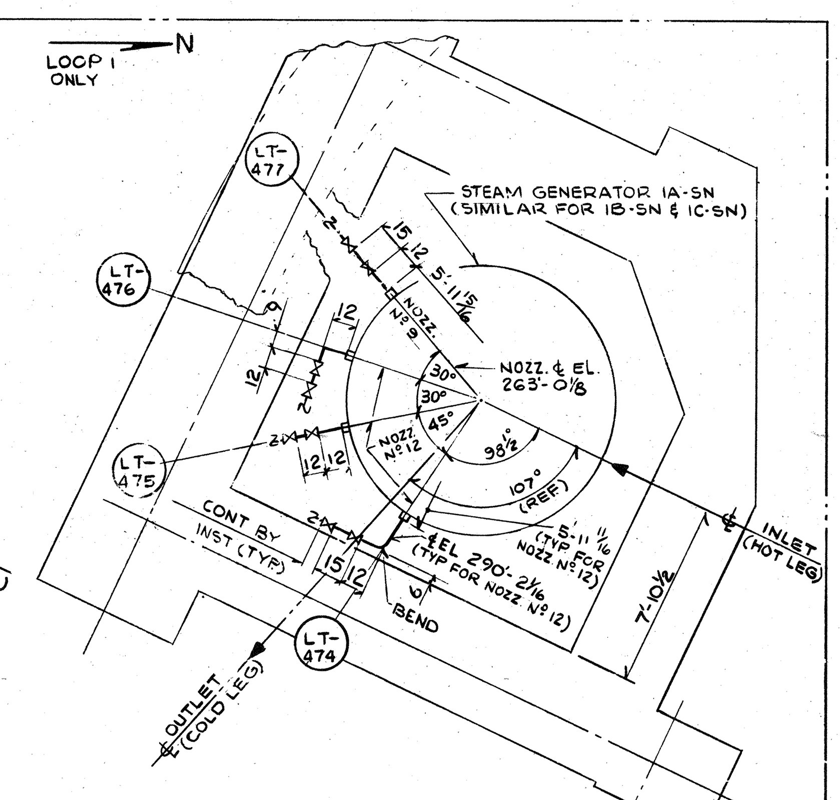
PARTIAL PLAN@ EL. 261.00'



PLAN@ EL. 286.00'

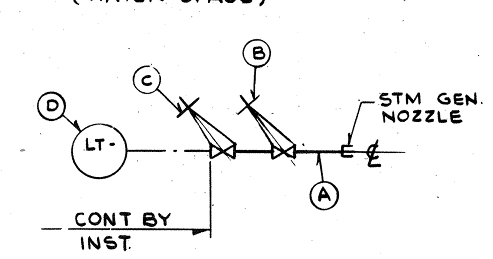


PART PLAN@ EL 309'-7 1/16
(STEAM SPACE)



PART PLAN@ EL 290'-2 1/16 & 263'-0 1/8
(WATER SPACE)

STM GEN		LINE Nº A	VALVE Nº B	VALVE Nº C	INST Nº D
1A-SN	STM SPACE	2FW3/4-37SN-1	2FW-V48SN-1	2FW-V47SN-1	LT-474
		2FW3/4-42SN-1	2FW-57SN-1	2FW-V58SN-1	LT-475
		2FW3/4-43SN-1	2FW V59SN-1	2FW-V60SN-1	LT-476
	WTR SPACE	2FW3/4-38SN-1	2FW-V50SN-1	2FW-V49SN-1	LT-474
		2FW3/4-41SN-1	2FW-V55SN-1	2FW-V56SN-1	LT-475
		2FW3/4-39SN-1	2FW-V51SN-1	2FW-V52SN-1	LT-476
		2FW3/4-40SN-1	2FW-V53SN-1	2FW-V54SN-1	LT-477
1B-SN	STM SPACE	2FW3/4-51SN-1	2FW-V75SN-1	2FW-V76SN-1	LT-484
		2FW3/4-52SN-1	2FW-V77SN-1	2FW-V78SN-1	LT-485
		2FW3/4-53SN-1	2FW-V79SN-1	2FW-V80SN-1	LT-486
	WTR SPACE	2FW3/4-57SN-1	2FW V87SN-1	2FW-V88SN-1	LT-484
		2FW3/4-56SN-1	2FW V86SN-1	2FW-V85SN-1	LT-485
		2FW3/4-54SN-1	2FW V82SN-1	2FW-V81SN-1	LT-486
		2FW3/4-55SN-1	2FW V83SN-1	2FW-V84SN-1	LT-487
1C-SN	STM SPACE	2FW3/4-44SN-1	2FW-V62SN-1	2FW-V61SN-1	LT-494
		2FW3/4-45SN-1	2FW-V64SN-1	2FW-V63SN-1	LT-495
		2FW3/4-46SN-1	2FW-V65SN-1	2FW-V66SN-1	LT-496
	WTR SPACE	2FW3/4-50SN-1	2FW-V73SN-1	2FW-V74SN-1	LT-494
		2FW3/4-49SN-1	2FW-V71SN-1	2FW V72SN-1	LT-495
		2FW3/4-47SN-1	2FW V67SN-1	2FW-V68SN-1	LT-496
		2FW3/4-48SN-1	2FW-V70SN-1	2FW-V69SN-1	LT-497



TYP ARRANGEMENT OF INST. PIPING AT STEAM GENERATORS
SEE DWG R-071 (B3,E5,B7)

FOR NOTES AND REFERENCE DRAWINGS SEE SK-2165-MNE-R-071

Effective as of 11-18-85, full responsibility for the maintenance of this document and for subsequent modifications made or required to be made to this document is assumed by Carolina Power & Light Company ("CP&L"). Ebasco Services Incorporated has no responsibility for maintenance and modifications after said date. All Field Change Requests, Design Change Notices, Nonconformance Reports and other change documents, which have been considered for the current or prior revisions of this document, are identified in the Document Close-out Log issue (current at the above date). Future revisions of this document will be issued by CP&L.

NOT FOR CONSTRUCTION
FOR REFERENCE ONLY

THIS DOCUMENT IS DELIVERED IN ACCORDANCE WITH AND IS SUBJECT TO THE PROVISIONS OF SECTION X OF THE CONTRACT BETWEEN CAROLINA POWER & LIGHT COMPANY AND EBASCO SERVICES INCORPORATED DATED SEPTEMBER 1, 1970, AS AMENDED.

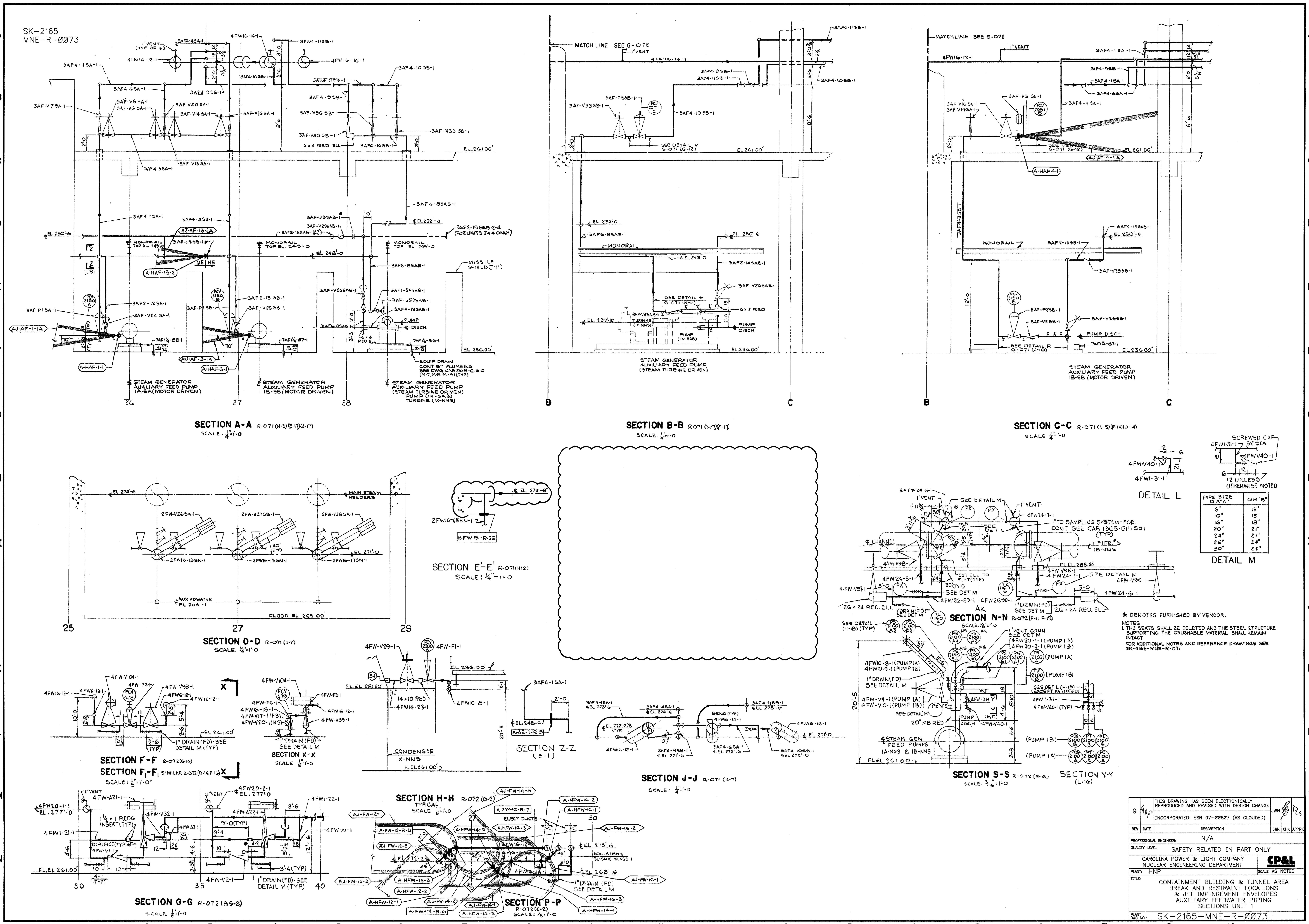
CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT

TURBINE BUILDING
BREAK & RESTRAINT LOCATIONS
FEEDWATER PIPING
PLANS - UNIT 1

EBASCO SERVICES INCORPORATED

NO.	DATE	REVISION	BY	CH.	APPROVED
1	10-30-80	ADDED: (B1 TO B4) BREAKS, JETS & RESTRAINTS.	C.G.	DS	

SCALE 1/8"=1'-0
DIV. MECH
DR. T.McCAFFREY
CH
APPROVED
DATE
SK-2165-MNE
R-072


SK-2165
MNE-R-Ø073
SECTION A-A R-071 (N-3)(E-17)(J-17)
SCALE: 1/4"=1'-0
SECTION B-B R-071 (N-7)(F-17)
SECTION C-C R-071 (N-5)(F-14)(J-14)
SCALE: 1/4"=1'-0
SECTION D-D R-071 (I-7)
SCALE: 1/4"=1'-0
SECTION E'-E' R-071(H12)
SCALE: 1/4"=1'-0
SECTION F-F R-072(G-16)
SECTION F1-F1 SIMILAR R-072(D-16,F16)
SCALE: 1/8"=1'-0"
SECTION X-X
SECTION Z-Z
(E-1)
SECTION G-G R-072 (B5-8)
SECTION H-H R-072 (G-2)
TYPICAL
SECTION P-P R-072 (C-2)
SECTION J-J R-071 (K-7)
SECTION N-N R-072 (F-11, F-19)
SECTION S-S R-072 (B-6)
SCALE: 3/16"=1'-0
SECTION Y-Y
(L-16)
DETAIL L
DETAIL M
STEAM GENERATOR AUXILIARY FEED PUMP 1A-SA (MOTOR DRIVEN)
STEAM GENERATOR AUXILIARY FEED PUMP 1B-SB (MOTOR DRIVEN)
STEAM GENERATOR AUXILIARY FEED PUMP (STEAM TURBINE DRIVEN) PUMP (1X-SAB) TURBINE (1X-NNS)
STEAM GENERATOR AUXILIARY FEED PUMP (STEAM TURBINE DRIVEN)
STEAM GENERATOR AUXILIARY FEED PUMP 1B-SB (MOTOR DRIVEN)
STEAM GEN FEED PUMPS 1A-NNS & 1B-NNS
CONDENSER 1X-NNS
PIPE SIZE DIA "A"	DIM "B"
6"	12"
10"	15"
16"	18"
20"	21"
24"	21"
26"	24"
30"	24"
* DENOTES FURNISHED BY VENDOR.
NOTES
1. THE SEATS SHALL BE DELETED AND THE STEEL STRUCTURE SUPPORTING THE CRUSHABLE MATERIAL SHALL REMAIN INTACT.
FOR ADDITIONAL NOTES AND REFERENCE DRAWINGS SEE SK-2165-MNE-R-071
REV	DATE	DESCRIPTION	DWN	CHK	APPR'D
9	5/16/02	THIS DRAWING HAS BEEN ELECTRONICALLY REPRODUCED AND REVISED WITH DESIGN CHANGE INCORPORATED: ESR 97-ØØ8Ø7 (AS CLOUDED)	JWB		
PROFESSIONAL ENGINEER: N/A
QUALITY LEVEL: SAFETY RELATED IN PART ONLY
CAROLINA POWER & LIGHT COMPANY
NUCLEAR ENGINEERING DEPARTMENT
CP&L
PLANT: HNP
SCALE: AS NOTED
TITLE: CONTAINMENT BUILDING & TUNNEL AREA BREAK AND RESTRAINT LOCATIONS & JET IMPINGEMENT ENVELOPES AUXILIARY FEEDWATER PIPING SECTIONS UNIT 1
PLANT DWG NO.: SK-2165-MNE-R-Ø073

SK-2165-MNE
R-139

LINE & VALVE NO. TABULATION (Detail R)

ITEM NO.	A	B	C
1	2CS3/4-102SN-1	2CS3/4-10SN-1	2CS-V19SN-1
2	1CS3/4-4SN-1	"	2CS-V16SN-1
3	2CS3/4-103SN-1	2CS3/4-11SN-1	2CS-V20SN-1
4	1CS3/4-5SN-1	"	2CS-V17SN-1
5	2CS3/4-104SN-1	2CS3/4-12SN-1	2CS-V21SN-1
6	1CS3/4-6SN-1	"	2CS-V18SN-1

LINE & VALVE NO. TABULATION (Detail X)

ITEM No.	A	B	C	D
1	1CS1½-16SN-1	2CS3/4-22SN-1	2CS-V37SN-1	2CS-V40SN-1
2	1CS1½-17SN-1	2CS3/4-23SN-1	2CS-V38SN-1	2CS-V41SN-1
3	1CS1½-18SN-1	2CS3/4-24SN-1	2CS-V39SN-1	2CS-V42SN-1
4	2CS3/4-125SN-1	2CS3/4-555SN-1	2CS-V257SN-1	2CS-V258SN-1

LINE & VALVE NO. TABULATION (Detail L)

ITEM	A	B	C	D	DET.
1	2CS3/4-102SN-1	2CS3/4-61SN-1	2CS-V159SN-1	2CS-V162SN-1	L2
2	7CS1-52-1	7CS3/4-141-1	7CS-D20-1	7CS-D23-1	L1
3	2CS3/4-103SN-1	2CS3/4-62SN-1	2CS-V160SN-1	2CS-V163SN-1	L2
4	7CS1-53-1	7CS3/4-142-1	7CS-D21-1	7CS-D24-1	L1
5	2CS3/4-104SN-1	2CS3/4-63SN-1	2CS-V161SN-1	2CS-V164SN-1	L3
6	7CS1-54-1	7CS3/4-143-1	7CS-D22-1	7CS-D25-1	L2

LINE & VALVE NO TABULATION (Detail V)

ITEM NO	A	B	C	D
1	2CS3/4-102SN-1	2CS3/4-25SN-1	2CS-V46SN-1	2CS-V43SN-1
2	1CS3/4-4SN-1	2CS3/4-7SN-1	2CS-V13SN-1	2CS-V10SN-1
3	2CS3/4-103SN-1	2CS3/4-26SN-1	2CS-V47SN-1	2CS-V44SN-1
4	1CS3/4-5SN-1	2CS3/4-8SN-1	2CS-V14SN-1	2CS-V11SN-1
5	2CS3/4-104SN-1	2CS3/4-27SN-1	2CS-V48SN-1	2CS-V45SN-1
6	1CS3/4-6SN-1	2CS3/4-9SN-1	2CS-V15SN-1	2CS-V12SN-1

LINE & VALVE NO. TABULATION (Detail Y)

A	B	C	D
2CS3-95SA-1	2CS3/4-111SA-1	2CS-V81SA-1	2CS-V80SA-1
2CS3-114SN-1	2CS3/4-110SN-1	2CS-V78SN-1	2CS-V79SN-1
2CS1½-19SB-1	2CS3/4-132SB-1	2CS-V100SB-1	2CS-V97SB-1
"	2CS3/4-129SB-1	2CS-V88SB-1	2CS-V85SB-1
2CS1½-20SB-1	2CS3/4-133SB-1	2CS-V190SB-1	2CS-V98SB-1
"	2CS3/4-130SB-1	2CS-V95SB-1	2CS-V86SB-1
2CS1½-21SB-1	2CS3/4-134SB-1	2CS-V191SB-1	2CS-V99SB-1
"	2CS3/4-131SB-1	2CS-V96SB-1	2CS-V87SB-1
2CS2-97SN-1	2CS3/4-113SN-1	2CS-V76SN-1	2CS-V77SN-1

TAG No. TABULATION

A	B	C	D	E	F	G
1-FE 156B	2CS3/4-28SN-1	2CS-V49SN-1	2CS-V52SN-1	2CS3/4-31SN-1	2CS-V55SN-1	2CS-V58SN-1
1-FE 155B	2CS3/4-29SN-1	2CS-V50SN-1	2CS-V53SN-1	2CS3/4-32SN-1	2CS-V56SN-1	2CS-V59SN-1
1-FE 154B	2CS3/4-30SN-1	2CS-V51SN-1	2CS-V54SN-1	2CS3/4-33SN-1	2CS-V57SN-1	2CS-V60SN-1

TYP PIPING AT No 1 SEAL LEAK-OFF ORIFICES
DWG G-137 (J-4)(L-13)(D-12)

TAG No TABULATION

A	B	C	D
1-FE 156	2CS3/4-1SN-1	2CS-V4SN-1	2CS-V1SN-1
1-FE 155	2CS3/4-2SN-1	2CS-V5SN-1	2CS-V2SN-1
1-FE 154	2CS3/4-3SN-1	2CS-V6SN-1	2CS-V3SN-1

TYP PIPING AT No.1 SEAL BY-PASS ORIFICES
DWG G-137 (J-4)(L-13)(D-12)

FOR NOTES & REFERENCE DRAWINGS SEE DWG SK-2165-MNE-R-137

NO.	DATE	REVISION	BY	CH.	APPROVED
6	10-15-86	REVISED PER CQL-9469 OF 9-15-86 REVISED: PIPING (A4, L6-L8, M6-M8, N6, N8), REF. DWG. REV. (L19); ADDED PIPE BREAK (E3-E5, F4, F5, L6, L7), JET ENVELOPE (D3-D5, E3-E5, F3-F5, L5-L7, M6, M7)	RC 10-13-86	10-13-86	10-15-86	

↑ CP&L - HPES FIELD REVISION ↑

NOT FOR CONSTRUCTION
FOR REFERENCE ONLY

REV. 6 OF THIS DWG. IS IN ACCORDANCE WITH PIPING DWG. G-139 REV. 15
FOR AFFECTED AREAS ONLY.

Effective as of 11-18-85, full responsibility for the maintenance of this document and for subsequent modifications made or required to be made to this document is assumed by Carolina Power & Light Company ("CP&L"). Ebasco Services Incorporated has no responsibility for maintenance and modifications after said date. All Field Change Requests, Design Change Notices, Nonconformance Reports and other change documents, which have been considered for the current or prior revisions of this document, are identified in the Document Close-out Log issue (current at the above date). Future revisions of this document will be issued by CP&L.

NO.	DATE	REVISION	BY	CH.	APPROVED
5	9-25-85	DELETED: (A TO C-4, F-2 TO 6, D-7, I-3 TO 6) ARBITRARY INTERMEDIATE BREAKS PER NRC LETTER TO CP&L OF 8-15-85, DOCKET No. 50-400	J.H.		
4	8-4-83	DELETED BREAKS & JETS (G2, G5, H6)	GJS	SS	
3	5-24-83	REVISED: (B4) DIM'S.	JYH		
2	10/15/79	REVISED: (F4) REST. LOC.; (N18) TITLE. ADDED: JET ENVELOPES. DELETED: (F5, I5) RESTS.			
1	6/3/77	ADDED (I5) BREAK & RESTRAINT LOCATIONS FOR CLASS 1 BRANCH PIPING	GS	AF	
0	12/17/76	PRELIMINARY ISSUE OF BREAK & RESTRAINT LOCATIONS	AF	DK	

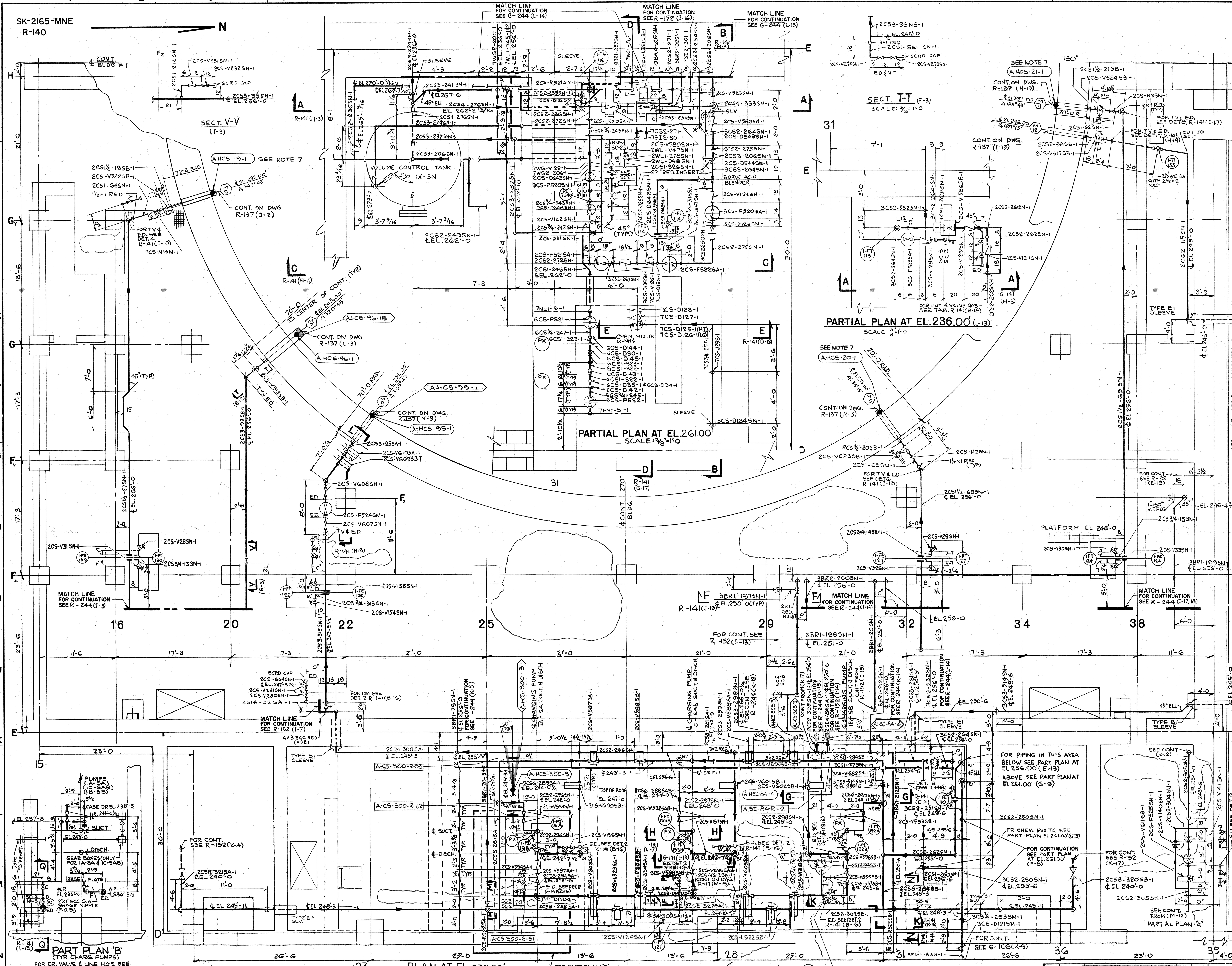
CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT

CONTAINMENT BUILDING
BREAK & RESTRAINT LOCATIONS
& JET IMPINGEMENT ENVELOPES
CHEMICAL & VOLUME CONTROL PIPING
SECTIONS & DETAILS - UNIT I

EBASCO SERVICES INCORPORATED

SCALE 3/8"=1'-0 & AS NOTED
DIV. MECH.
DR. T. McCAFFREY
CH.
APPROVED
DATE

SK-2165-MNE
R-139



LEGEND

- DOUBLE-ENDED GUILLOTINE BREAK
- PIPE WHIP RESTRAINT-
- SLOT BREAK
- BREAK DESIGNATION
- WHIP RESTRAINT DESIGNATION
- JET IMPINGEMENT ENVELOPE DESIGNATION

NOTES:

1. ALL PIPE BREAK LOCATIONS AND PIPE WHIP RESTRAINTS ARE ASSIGNED UNIQUE TAG NUMBERS.
2. UNLESS OTHERWISE DIMENSIONED, PIPE BREAK LOCATIONS ARE LOCATED AT THE PIPE TO FITTING WELD, OR AT THE VALVE TO PIPE WELD, AS APPLICABLE.
3. PIPE RUPTURE RESTRAINTS SHALL BE DESIGNED INDIVIDUALLY TO ACCOMMODATE THE FULL KPA VALUES TIMES THE APPROPRIATE. R/F FACTOR, IN THE DIRECTIONS INDICATED ON REFERENCED SKETCH ISOMETRIC BELOW.
4. PIPE RUPTURE RESTRAINTS ARE TO BE DESIGNED PERPENDICULAR TO ℄ AXIS. UNLESS OTHERWISE NOTED.
5. FOR INSULATION THICKNESS, DESIGN PIPE MOVEMENTS, KPA LOADS, ETC, SEE REFERENCED SKETCH ISOMETRIC BELOW.
6. THIS SKETCH INCLUDES JET IMPINGEMENT ENVELOPES. JET ENVELOPES ORIGINATE AT BREAK POINTS, ARE DRAWN TO SCALE UNLESS OTHERWISE NOTED, AND ARE ASSUMED TO EXTEND TO THE NEAREST MAJOR PHYSICAL BARRIER SUCH AS A WALL OR CEILING.
7. DUE TO FLOW RESTRICTIONS UPSTREAM OF THESE BREAKS, THE STEADY STATE JET FORCE IS PRACTICALLY ZERO.

PIPE LINES OTHER THAN CVCS (CS) INCLUDED ON THIS DRAWING:

2SI3-84SA-1 (K-11)	3WG1-56SN-1 (A-9)
3BR1-78SN-1 (K-6)	3BR4-205SN-1 (A-9)
3BR1-212SN-1 (K-12)	7SI2-301-1 (A-10)
3BR1-197SN-1 (I-11)	3BR2-200SN-1 (I-11)
3BR1-198SN-1 (J-11)	3BR3-102SN-1 (A-10)
3BR1-199SN-1 (H-17)	3WG2-206SN-1 (A-7)
3BR1-237SN-1 (A-9)	7WL1-745-1 (A-1)
3BR1-20SN-1 (I-12)	2WL1-336SN-1 (B-9)

REFERENCE DOCUMENTS

SK-2165-MNE-R-141
" " " R-142
" " " R-143
" " " R-144
" " " R-145
" " " R-146
SK-2165-MNE-BR-1A-236-CS-4
" " " " " " CS-5
" " " " " " CS-6
CS-7
" " " " " " CS-20
" " " " " " CS-22
CS-37
" " " " " " CS-24
" " " " " " CS-26
" " " " " " CS-27
" " " " " " CS-33
CAR-2168-G-246S01
" " -G-246S02
" " -G-247S01
" " -G-247S02

REV. 6 OF THIS DWG. IS IN ACCORDANCE WITH PIPING DWG. G-140 REV. OPEN 9 OF 4-17-80 FOR AFFECTED AREAS ONLY

NOT FOR CONSTRUCTION
FOR REFERENCE ONLY

NO	DATE	REVISION	BY	CH	APPROVED
6	10-1-85	DELETED: (D2, H5, H12, I8, L7, M-5 TO 7, M8, M10, L10 TO N-10 & 12, L17) ARBITRARY INTERMEDIATE BREAKS PER NRC LETTER TO CP&L OF 8-15-85 DOCKET No. 50-400	J.H.	GJS	[illegible]
5	5-23-83	ADDED: (D1) BREAK. DELETED: (K4, K5, K12, M11, N11, N12) BREAKS & JETS	JYH	GJS	[illegible]
4	11-5-80	DELETED: (A13, A14, B3, F4, H4, J4) BREAKS & JET ENVELOPES; (G18) NOTE	JYH	[illegible]	[illegible]
3	1-9-79	REVISED: (H4, K4, L4, M10) REST. LOC. ADDED: (G18) NOTES; JET ENVELOPE AS CIRCLED: (B3, B14, B15, C3, E4, G12, I3) BREAK LOCATIONS	AF	[illegible]	AF

NO.	DATE	REVISION	BY	CH.	APPROVED
2	9/8/78	ADDED: JET ENVELOPES BREAK PT DESIG; (H11, I8) SECT; (M7) BREAK PT; (L17) RESTS. DELETED: (M8, M10, M11) CRIF; (G2, I2, F3, G3, I3, K5, K7, M8, M10, M11, K11, J13) RESTS; (G14) SECT.	AF	[illegible]	[illegible]
1	5/10/77	ADDED RESTRAINTS FOR DWGS SK-2165-MNE-BR-1A-236-CS-24, 26, 27	KM	DK	[illegible]
0	4/13/77	PRELIMINARY ISSUE OF BREAK & RESTRAINT LOCATIONS	KM	DK	[illegible]

CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT

REACTOR AUXILIARY BUILDING
BREAK & RESTRAINT LOCATIONS
& JET IMPINGEMENT ENVELOPES
CHEMICAL & VOLUME CONTROL PIPING
PLANS-UNIT I

EBASCO SERVICES INCORPORATED

SCALE ~~AS NOTED~~ 3/16"=1'-0	APPROVED	DATE
DIV. MECH.		SK-2165-MNE R-140
DR. T. McCAFFREY		
CH.		

SK-2165-MNE
R-141

DRAIN, VALVE & LINE TABULATION

A	B	C	D	LOC.
2CS3-294SA-1	2CS1-338SA-1	2CS-V200SA-1	2CS-V202SA-1	G-140(M-7)
2CS3-292SAB-1	2CS1-339SAB-1	2CS-V203SAB-1	2CS-V204SAB-1	G-140(M-10)
2CS3-337SB-1	2CS1-340SB-1	2CS-V205SB-1	2CS-V206SB-1	G-140(M-12)
2CS2-296SN-1	2CS1-341SN-1	2CS-V207SN-1	2CS-V208SN-1	G-140(M-8)
2CS2-297SN-1	2CS1-342SN-1	2CS-V209SN-1	2CS-V210SN-1	G-140(M-10)
2CS2-298SN-1	2CS1-343SN-1	2CS-V211SN-1	2CS-V212SN-1	G-140(M-12)
2CS3-206SN-1	2CS1-344SN-1	2CS-D63SN-1	2CS-D64SN-1	G-141(J-5)
3BR1-78SN-1	3BR1-69SN-1	3BR-D175SN-1	3BR-D176SN-1	G-141(N-13)
3BR1-212SN-1	3BR1-217SN-1	3BR-D177SN-1	3BR-D178SN-1	G-141(N-15)
2CS2-261SN-1	2CS1-343SN-1	2CS-V213SN-1	2CS-V214SN-1	G-141(H-5)
3CS2-264SN-1	3CS1-346SN-1	3CS-V215SN-1	3CS-V216SN-1	G-141(H-4)
3CS2-264SN-1	3CS1-347SN-1	3CS-V217SN-1	3CS-V218SN-1	G-141(G-4)
2CS3-315SN-1	2CS1-150SN-1	2CS-V219SN-1	2CS-V220SN-1	G-141(M-9)
2CS1-239SN-1	2CS1-345SN-1	2CS-D95SN-1	2CS-D96SN-1	G-141 (F-16)
2CS3-315SN-1	2CS1-149SN-1	2CS-V253SN-1	2CS-V254SN-1	G-141(M-8)
2CS2-305SN-1	2CS1-620SN-1	2CS-V282SN-1	2CS-V283SN-1	G-140(L-17)
2CS2-305SN-1	2CS1-621SN-1	2CS-V284SN-1	2CS-V285SN-1	G-140(M-17)

DETAIL 4, R-140(D-2)
NO SCALE

CHARGING PUMPS LINE & INSTRUMENT TABULATION

	PUMP NUMBER		
	1A-SA	1C-SAB	1B-SB
A	2CS6-285SA-1	2CS6-288SAB-1	2CS6-290SB-1
B	2CS3/4-286SA-1	2CS3/4-287SAB-1	2CS3/4-289SB-1
C	2CS3-294SA-1	2CS3-292SAB-1	2CS3-337SB-1
D	2CS2-296SN-1	2CS2-297SN-1	2CS2-298SN-1
E	2CS3/4-295SA-1	2CS3/4-293SAB-1	2CS3/4-291SB-1
F	1-PI-151B	1-PI-153B	1-PI-152B
C	1-PI-151A	1-PI-153A	1-PI-152A
H	2CS-V130SA-1	2CS-V131SAB-1	2CS-V132SB-1
I	2CS-V135SA-1	2CS-V134SAB-1	2CS-V133SB-1
J	2CS-S1SA-1	2CS-S2SAB-1	2CS-S3SB-1
K	2CS3/4-643SA-1	2CS3/4-644SAB-1	2CS3/4-64SB-1
L	2CS-V287SA-1	2CS-V288SAB-1	2CS-V289SB-1
M	2CS-U521SN-1	2CS-U522SN-1	2CS-523SN-1

PUMP DRAIN PIPING TABULATION

CHARGING PUMPS	PUMP CASE DRAINS				BASE PLATE DR.	LOC
	B	C	D	E	F	
1A-SA	2CS1-475SN-1	2CS-V292SN-1	2CS-V293SN-1	7CS1-476-1	2CS1-477SN-1	(M-7)
1C-SAB	2CS1-478SN-1	2CS-V294SN-1	2CS-V295SN-1	7CS1-479-1	2CS1-480SN-1	(M-10)
1B-SB	2CS1-481SN-1	2CS-V296SN-1	2CS-V297SN-1	7CS1-482-1	2CS1-483SN-1	(M-12)

Effective as of 11-18-85, full responsibility for the maintenance of this document and for subsequent modifications made or required to be made to this document is assumed by Carolina Power & Light Company ("CP&L"). Ebasco Services Incorporated has no responsibility for maintenance and modifications after said date. All Field Change Requests, Design Change Notices, Nonconformance Reports and other change documents, which have been considered for the current or prior revisions of this document, are identified in the Document Close-out Log issue (current at the above date). Future revisions of this document will be issued by CP&L.

NOT RELEASED
(L12) F I.

INFO REQ'D
(F17, G4) SIGHT
GLASS 1-FT-1094
1-FT-113

NOTES

FOR NOTES AND REFERENCE DRAWING. SEE SK-2165-MNE-R-140

REV. 5 OF THIS DWG. IS IN ACCORDANCE WITH PIPING DWG. G-141 REV. 8 FOR AFFECTED AREAS ONLY.

NOT FOR CONSTRUCTION
FOR REFERENCE ONLY

THIS DOCUMENT IS DELIVERED IN ACCORDANCE WITH AND IS SUBJECT TO THE PROVISIONS OF SECTION X OF THE CONTRACT BETWEEN CAROLINA POWER & LIGHT COMPANY AND EBASCO SERVICES INCORPORATED DATED SEPTEMBER 1, 1970, AS AMENDED.

NO	DATE	REVISION	BY	CH	APPROVED
5	10-1-85	DELETED: (L&M-7 TO 10, J13,15) ARBITRARY INTERMEDIATE BREAKS PER NRC LETTER TO CP&L OF 8-15-85, DOCKET No. 50-400	J.H.		
4	5-23-83	DELETED: (I12, I15, J15, K12) BREAK & JET	JYH	GJS	
3	1-9-79	REVISED: (M9) DIM.	AF		
2	9-8-78	REVISED: (L8) RELOC. RESTS. ADDED: JET ENVELOPES BREAK PT. DESIG.; (I14, J15, M10, N8) BREAK PTS; (J15, M8) RESTS; (J14) ORIFICE. DELETED: (I14, J15, N8) RESTS; (J15) BREAK PTS.			
1	5/10/77	ADDED RESTRAINTS FOR DWGS SK 2165 MNE-BR-1A-236-CS-24, 26, 27	KM	DK	
0	4/13/77	PRELIMINARY ISSUE OF BREAK & RESTRAINT LOCATIONS	KM	DK	

CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT

REACTOR AUXILIARY BUILDING
BREAK & RESTRAINT LOCATIONS
& JET IMPINGEMENT ENVELOPES
CHEMICAL & VOLUME CONTROL PIPING
SECTIONS - UNIT 1

EBASCO SERVICES INCORPORATED

SCALE 3/8"=1'-0
APPROVED
DATE
DIV. MECH.
DR. T.McCAFFREY
CH.

SK-2165-MNE
R-141

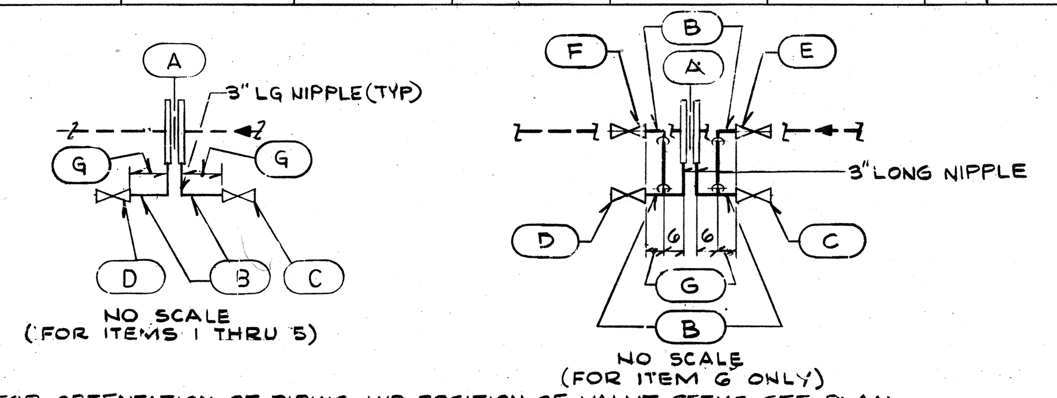
SK-2165-MNE
R-153

NOTE: FOR GENERAL NOTES AND REFERENCE DRAWINGS SEE SK-2165-MNE-R-151

REV. 4 OF THIS DWG. IS IN ACCORDANCE WITH PIPING DWG. G-153 REV. 9 FOR AFFECTED AREAS ONLY.

TAG NO. TABULATION

ITEM No	A	B	C	D	E	F	G	LOCATION
1	1-FE 605 A	2RH 3/4-22SA-1	2RH-V15SA-1	2RH-V16SA-1	—	—	10	G-152 (H12)
2	1-FE 605 B	2RH 3/4-35SB-1	2RH-V29SB-1	2RH-V30SB-1	—	—	10	G-152 (F19)
3	1-FE 934	3SI 3/4-97SN-1	3SI-V107SN-1	3SI-V108SN-1	—	—	8	(D2)
4	1-FE 940	2SI 3/4-48SA-1	2SI-V56SA-1	2SI-V57SA-1	—	—	9	G-152 (G6)
5	1-FE 943	2SI 3/4-46SA-1	2SI-V1SA-1	2SI-V2SA-1	—	—	9	G-152 (I15)
6	1-FE 944	4SI 3/4-200-1	4SI-V211-1	4SI-V210-1	4SI-V333-1	4SI-V332-1	6	G-152 (F15)



FOR ORIENTATION OF PIPING AND POSITION OF VALVE STEMS SEE PLAN
TYPICAL PIPING AT ORIFICES

Effective as of 11-18-85, full responsibility for the maintenance of this document and for subsequent modifications made or required to be made to this document is assumed by Carolina Power & Light Company ("CP&L"). Ebasco Services Incorporated has no responsibility for maintenance and modifications after said date. All Field Change Requests, Design Change Notices, Nonconformance Reports and other change documents, which have been considered for the current or prior revisions of this document, are identified in the Document Close-out Log issue (current at the above date). Future revisions of this document will be issued by CP&L.

NOT FOR CONSTRUCTION
FOR REFERENCE ONLY

THIS DOCUMENT IS DELIVERED IN ACCORDANCE WITH AND IS SUBJECT TO THE PROVISIONS OF SECTION X OF THE CONTRACT BETWEEN CAROLINA POWER & LIGHT COMPANY AND EBASCO SERVICES INCORPORATED DATED SEPTEMBER 1, 1970, AS AMENDED.

NO.	DATE	REVISION	BY	CH.	APPROVED
5	9/21/01	INCORPORATED: ESR 97-00351 (C4,C5,D5,D6,J7,K5,K6)	[illegible]	[illegible]	DLS
4	10-9-85	DELETED: (B-1 TO 5, A TO D-5 & 6, H TO J-5) ARBITRARY INTERMEDIATE BREAKS PER LTR. FROM CP&L TO NRC DTD. 2-13-85, SERIAL: NLS-85-022 & NRC APPROVAL VIA LTR FROM T.M. NOVAK OF NRC TO F.E. UTLEY OF CP&L DATED 8-15-85	J.H.	[illegible]	[illegible]
3	5/27/83	DELETED: (G5, I5, I6) WHIP RESTRAINT & DESIGNATION.	JYH	A.D.	[illegible]
2	12/11/78	REVISED: (B2 TO B5) PIPING & BRK & REST.; (D5) VLV. & BRK. ADDED: (H5) REST. DELETED: (B5) REST.	AF	FAH	AF
1	4/5/78	ADDED: (C5) DIM.; (A7, B1, E5, E6, I6) JET ENVELOPE. DELETED: (B2, B4, C5, D5, G5, I5) WHIP REST.	AF	GS	[illegible]
0	3/28/77	PRELIMINARY ISSUE	AF	DK	[illegible]

CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT

REACTOR AUXILIARY BUILDING
BREAK & RESTRAINT LOCATIONS
& JET IMPINGEMENT ENVELOPES
RHR & SAFETY INJECTION PIPING
PARTIAL PLANS & SECTIONS - UNIT 1

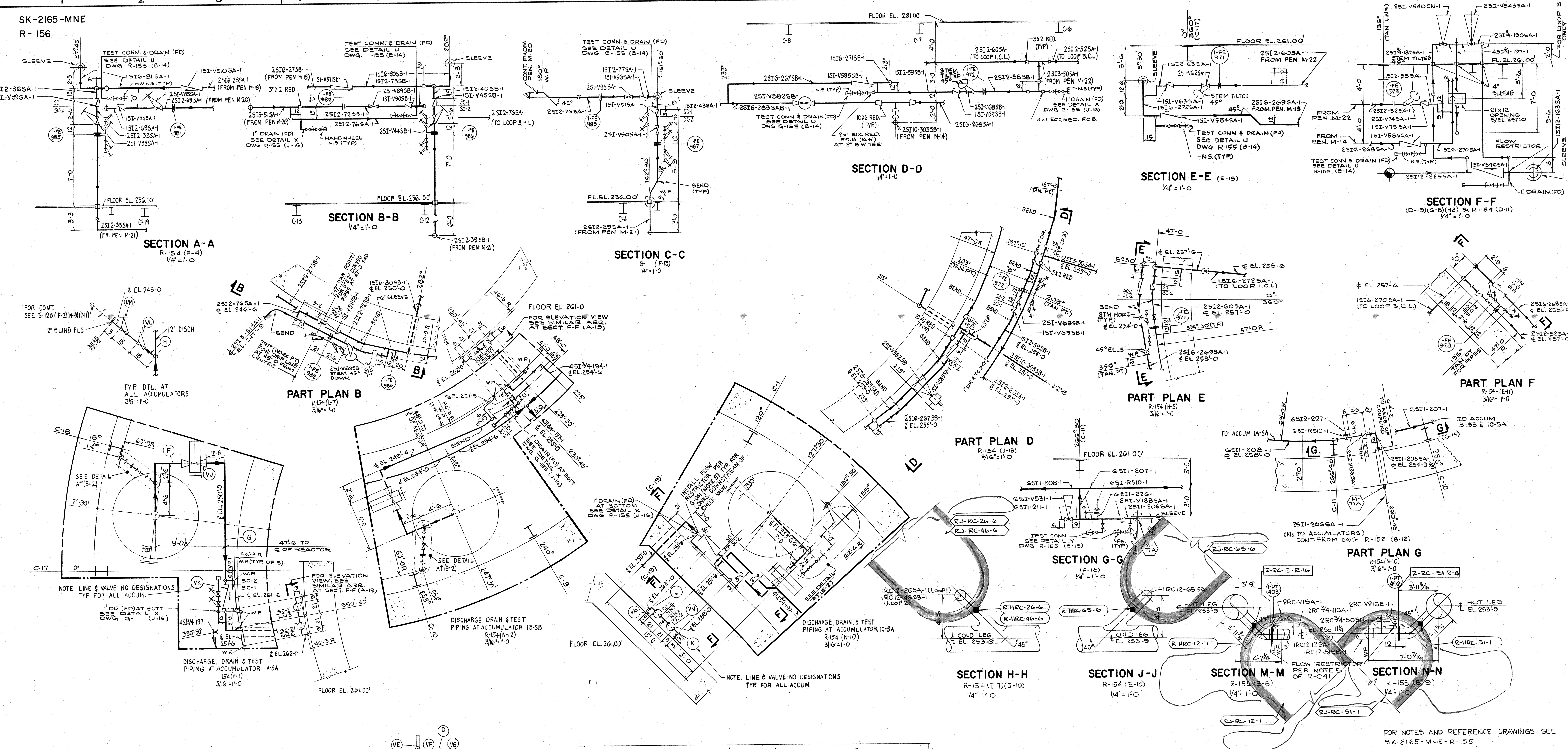
EBASCO SERVICES INCORPORATED

SCALE AS NOTED | APPROVED | DATE

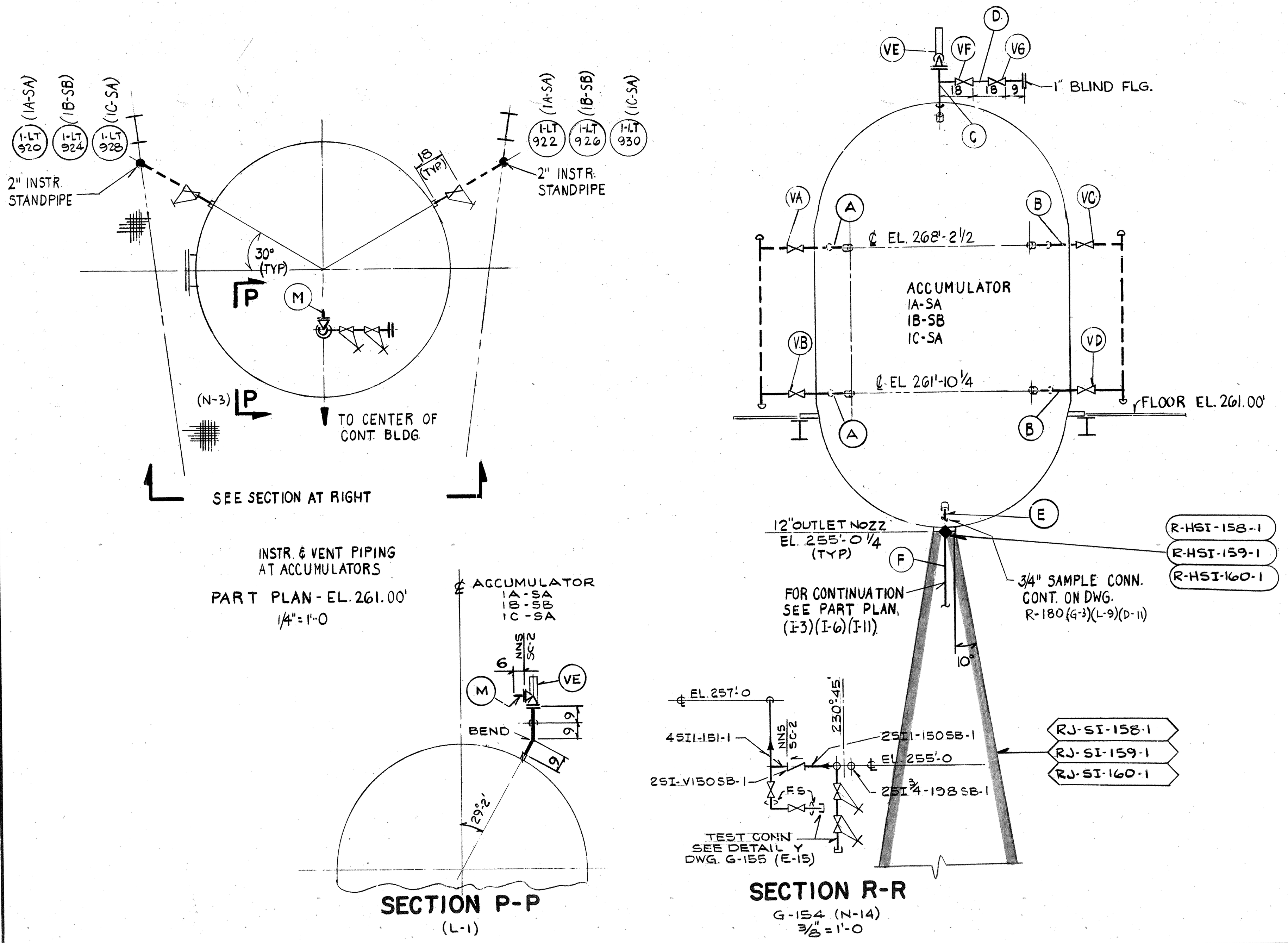
DIV. MECH.
DR. T. McCAFFREY
CH.

SK-2165-MNE
R-153

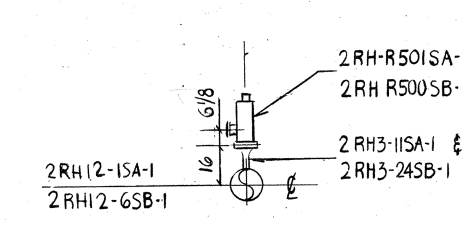
SK-2165-MNE
R-156



FOR NOTES AND REFERENCE DRAWINGS SEE SK-2165-MNE-R-155



ACCUMULATOR LINE & VALVE NUMBER TABULATION							
LINE				VALVE			
ITEM	1A-SA	1B-SB	1C-SA	ITEM	1A-SA	1B-SB	1C-SA
A	2SI2-165SA-1	2SI2-167SB-1	2SI2-169SA-1	VA	2SI-V157SA-1	2SI-V159SB-1	2SI-V161SA-1
B	2SI2-164SA-1	2SI2-166SB-1	2SI2-168SA-1	VB	2SI-V158SA-1	2SI-V160SB-1	2SI-V162SA-1
C	2SI1-170SA-1	2SI1-171SB-1	2SI1-172SA-1	VC	2SI-V151SA-1	2SI-V153SB-1	2SI-V155SA-1
D	2SI1-173SA-1	2SI1-174SB-1	2SI1-175SA-1	VD	2SI-V152SA-1	2SI-V154SB-1	2SI-V156SA-1
E	2SI3/4-182SA-1	2SI3/4-183SB-1	2SI3/4-184SA-1	VE	2SI-R511SA-1	2SI-R512SB-1	2SI-R513SA-1
F	2SI12-158SA-1	2SI12-159SB-1	2SI12-160SA-1	VF	2SI-V164SA-1	2SI-V166SB-1	2SI-V168SA-1
G	2SI12-223SA-1	2SI12-224SB-1	2SI12-225SA-1	VG	2SI-V163SA-1	2SI-V165SB-1	2SI-V167SA-1
H	2SI2-179SA-1	2SI2-180SB-1	2SI2-181SA-1				
				VJ	2SI-V537SA-1	2SI-V536SB-1	2SI-V535SA-1
K	2SI3/4-185SA-1	2SI3/4-186SB-1	2SI3/4-187SA-1	VK	1SI-V544SA-1	1SI-V545SB-1	1SI-V546SA-1
L	2SI3/4-188SA-1	2SI3/4-189SB-1	2SI3/4-190SA-1	VL	2SI-V172SA-1	2SI-V173SB-1	2SI-V174SA-1
M	6SI2-228-1	6SI2-229-1	6SI2-230-1	VM	2SI-V189SA-1	2SI-V191SB-1	2SI-V171SA-1
				VN	2SI-V538SN-1	2SI-V539SN-1	2SI-V540SN-1
				VP	2SI-V541SN-1	2SI-V542SN-1	2SI-V543SN-1



REV. 3 OF THIS DWG. IS IN ACCORDANCE WITH PIPING DWG. G-156 REV. 9 FOR AFFECTED AREAS ONLY.

NOT FOR CONSTRUCTION
FOR REFERENCE ONLY

Effective as of 11-18-85, full responsibility for the maintenance of this document and for subsequent modifications made or required to be made to this document is assumed by Carolina Power & Light Company ("CP&L"). Ebasco Services Incorporated has no responsibility for maintenance and modifications after said date. All Field Change Requests, Design Change Notices, Nonconformance Reports and other change documents, which have been considered for the current or prior revisions of this document, are identified in the Document Close-out Log issue (current at the above date). Future revisions of this document will be issued by CP&L.

THIS DOCUMENT IS DELIVERED IN ACCORDANCE WITH AND IS SUBJECT TO THE PROVISIONS OF SECTION X OF THE CONTRACT BETWEEN CAROLINA POWER & LIGHT COMPANY AND EBASCO SERVICES INCORPORATED DATED SEPTEMBER 1, 1970, AS AMENDED.

NO.	DATE	REVISION	BY	CH.	APPROVED
3	10-7-85	DELETED: (H12, H15, I16, I18) ARBITRARY INTERMEDIATE BREAKS PER NRC LETTER TO CP&L OF 8-15-85, DOCKET No. 50-400	J.H.		
2	12-29-78	GENERAL REVISION: ADDED: JET ENVELOPES	AF	FAH	
1	6-10-77	ADDED: (A1, A6, B11, B12, B15, B18, C16, D15, D19, E5, E12, I16, I18, M8 THRU M13) PRELIMINARY BREAK & RESTRAINT LOCATIONS SIS-CLASS 1 BRANCH PIPING: (D12, J12 THRU J17, L15, L17) SECTIONS	ARL	AF	
0	4-25-77	PRELIMINARY BREAK & RESTRAINT LOCATIONS SIS-CLASS 2 PIPING & PARTIAL CLASS 1 PIPING	AF	ARL	

CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT

CONTAINMENT BUILDING
BREAK & RESTRAINT LOCATIONS
& JET IMPINGEMENT ENVELOPES
RHR & SAFETY INJECTION PIPING
PARTIAL PLANS & SECTIONS-UNIT 1

EBASCO SERVICES INCORPORATED

SCALE: AS NOTED
DIV. MECH
DRT. M^CCAFFREY
CH.
APPROVED
DATE

SK-2165-MNE
R-156

SK-2165-MNE
R-244

NOTES:

1. ALL PIPE BREAK LOCATIONS AND PIPE WHIP RESTRAINTS ARE ASSIGNED UNIQUE TAG NUMBERS.
2. UNLESS OTHERWISE DIMENSIONED, PIPE BREAK LOCATIONS ARE LOCATED AT THE PIPE TO FITTING WELD, OR AT THE VALVE TO PIPE WELD, AS APPLICABLE.
3. PIPE RUPTURE RESTRAINTS SHALL BE DESIGNED INDIVIDUALLY TO ACCOMMODATE THE FULL KPA VALUES TIMES THE APPROPRIATE. R/F FACTOR, IN THE DIRECTIONS INDICATED ON REFERENCED SKETCH ISOMETRIC BELOW.
4. PIPE RUPTURE RESTRAINTS ARE TO BE DESIGNED PERPENDICULAR TO ℄ AXIS. UNLESS OTHERWISE NOTED.
5. FOR INSULATION THICKNESS, DESIGN PIPE MOVEMENTS, KPA LOADS, ETC, SEE REFERENCED SKETCH ISOMETRIC BELOW.
6. THIS SKETCH INCLUDES JET IMPINGEMENT ENVELOPES. JET ENVELOPES ORIGINATE AT BREAK POINTS, ARE DRAWN TO SCALE UNLESS OTHERWISE NOTED, AND ARE ASSUMED TO EXTEND TO THE NEAREST MAJOR PHYSICAL BARRIER SUCH AS A WALL OR CEILING.

LEGEND

- DOUBLE-ENDED GUILLIOTINE BREAK
- PIPE WHIP RESTRAINT-ARROW SHOWS DIRECTION OF FORCE
- SLOT BREAK
- BREAK DESIGNATION
- WHIP RESTRAINT DESIGNATION
- JET IMPINGEMENT ENVELOPE DESIG.

REFERENCE DRAWINGS

1A-236-CS-4
" -5
" -26
" -27
" -31
" -33

Effective as of 11-18-85, full responsibility for the maintenance of this document and for subsequent modifications made or required to be made to this document is assumed by Carolina Power & Light Company ("CP&L"). Ebasco Services Incorporated has no responsibility for maintenance and modifications after said date. All Field Change Requests, Design Change Notices, Nonconformance Reports and other change documents, which have been considered for the current or prior revisions of this document, are identified in the Document Close-out Log issue (current at the above date). Future revisions of this document will be issued by CP&L.

NOT FOR CONSTRUCTION
FOR REFERENCE ONLY

THIS DOCUMENT IS DELIVERED IN ACCORDANCE WITH AND IS SUBJECT TO THE PROVISIONS OF SECTION X OF THE CONTRACT BETWEEN CAROLINA POWER & LIGHT COMPANY AND EBASCO SERVICES INCORPORATED DATED SEPTEMBER 1, 1970, AS AMENDED.

CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT

COMPOSITE PIPING-SHIELDED PIPE TUNNEL
REACTOR AUXILIARY BUILDING
BREAK & RESTRAINT LOCATIONS
& JET IMPINGEMENT ENVELOPES
SHEET 1 – UNITS 1 & 2

EBASCO SERVICES INCORPORATED

NO.	DATE	REVISION	BY	CH.	APPROVED
2	10-1-85	DELETED: (G5, H8, H12, J3, I&J-14, K5) ARBITRARY INTERMEDIATE BREAKS PER NRC LETTER TO CP&L OF 8-15-85 DOCKET No. 50-400	J.H.		
1	11-6-80	ADDED: (G8, K5) BREAKS AND JET ENVELOPES.	C.G.		
0	10-9-79	ORIGINAL ISSUE			

SCALE 3/16" = 1'-0
DIV. MECH.
DR. T.J. KITZ
CH.
APPROVED
DATE

SK-2165-MNE
R-244

NOT FOR CONSTRUCTION
FOR REFERENCE ONLY

THIS DOCUMENT IS DELIVERED IN ACCORDANCE WITH AND IS SUBJECT TO THE PROVISIONS OF SECTION X OF THE CONTRACT BETWEEN CAROLINA POWER & LIGHT COMPANY AND EBASCO SERVICES INCORPORATED DATED SEPTEMBER 1, 1970, AS AMENDED.

Effective as of 11-18-85, full responsibility for the maintenance of this document and for subsequent modifications made or required to be made to this document is assumed by Carolina Power & Light Company ("CP&L"). Ebasco Services Incorporated has no responsibility for maintenance and modifications after said date. All Field Change Requests, Design Change Notices, Nonconformance Reports and other change documents, which have been considered for the current or prior revisions of this document, are identified in the Document Close-out Log issue (current at the above date). Future revisions of this document will be issued by CP&L.

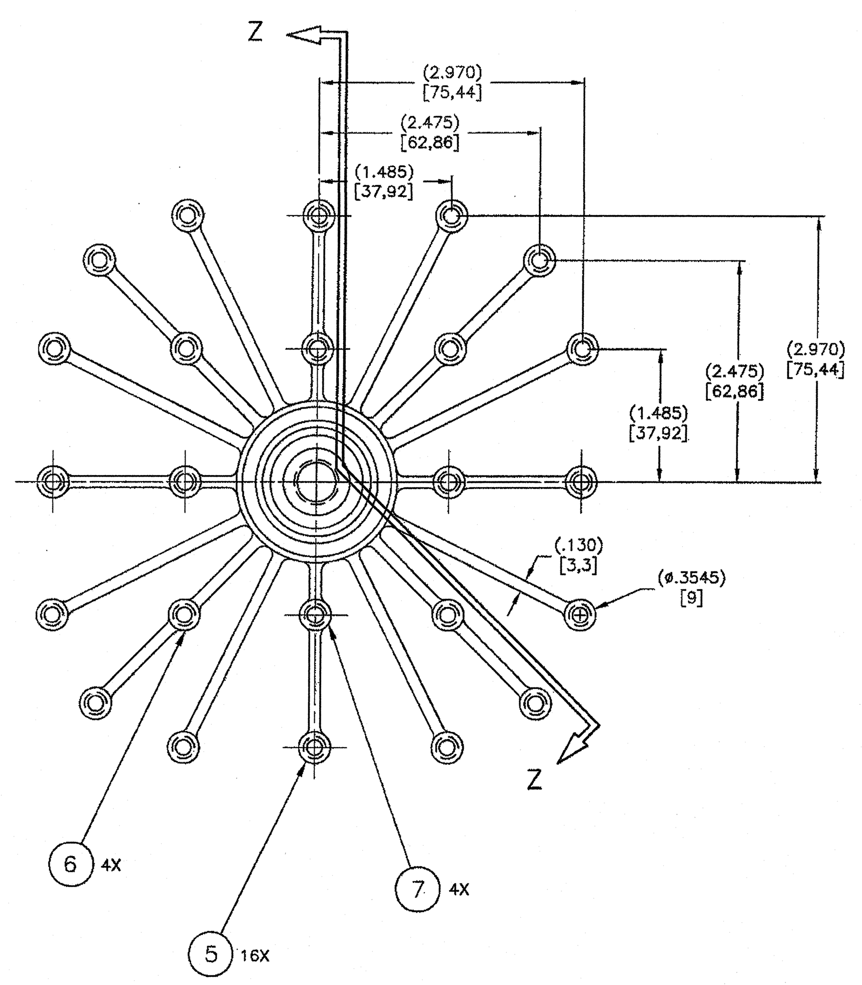
CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT

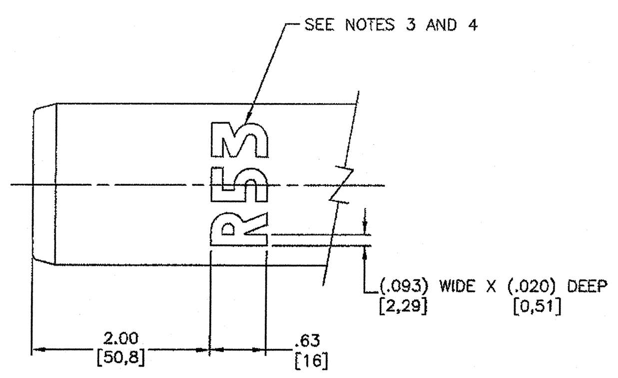
COMPOSITE PIPING-SHIELDED PIPE TUNNEL
REACTOR AUXILIARY BUILDING
BREAK & RESTRAINT LOCATIONS
& JET IMPINGEMENT ENVELOPES
SHEET 2 - UNITS 1 & 2

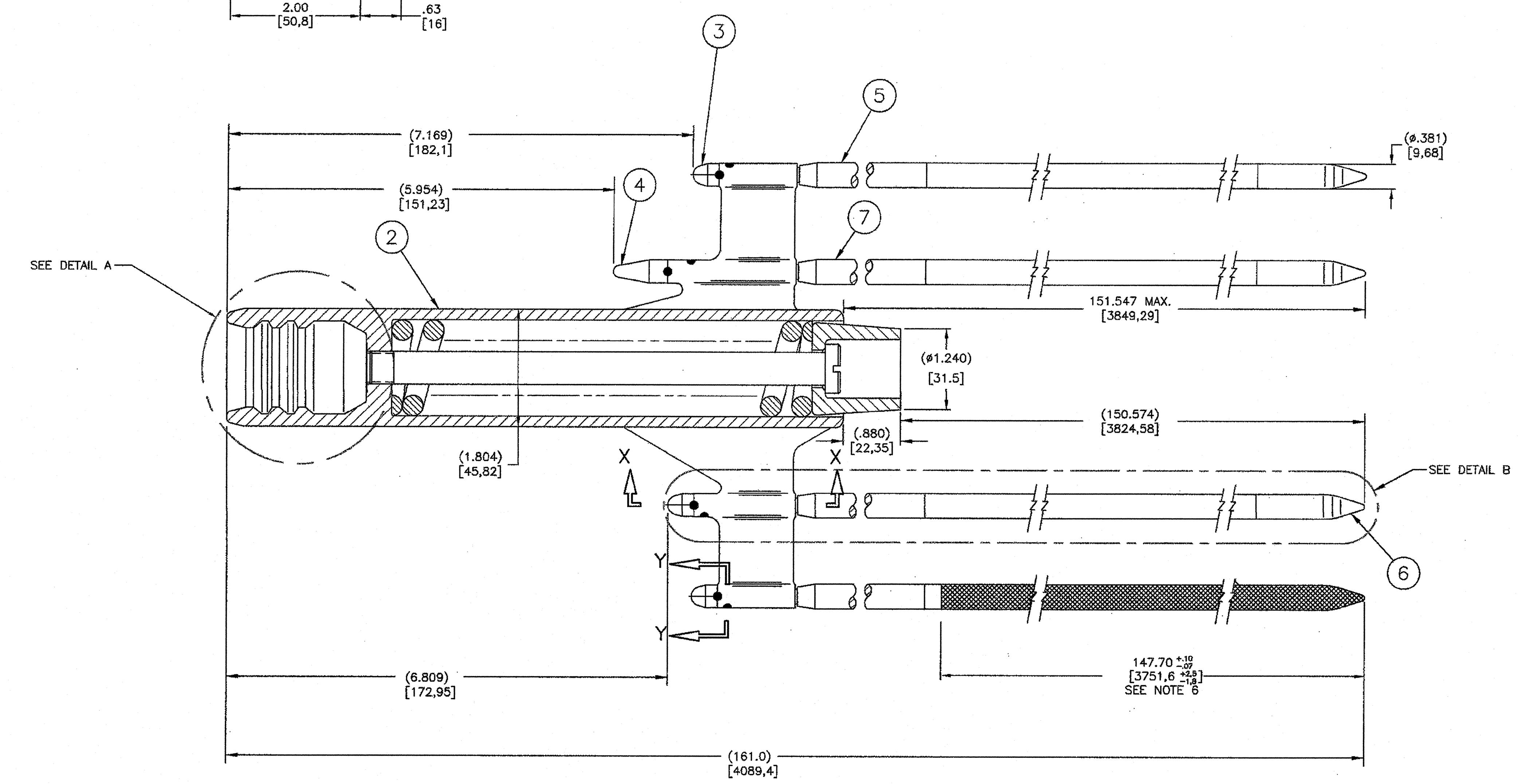
EBASCO SERVICES INCORPORATED

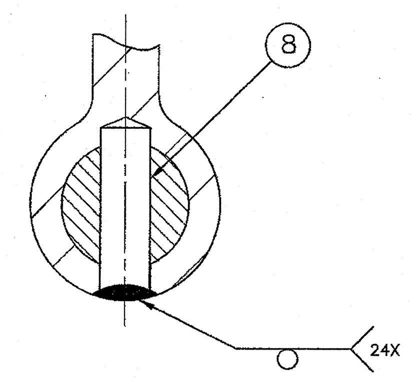
NO.	DATE	REVISION	BY	CH.	APPROVED
1	10-1-85	DELETED: (C9, B,C&D-10, F-14, H,I&J-15, N-13&14) ARBITRARY INTERMEDIATE BREAKS PER NRC LETTER TO CP&L OF 8-15-85 DOCKET No. 50-400	J.H.	GJS	MG
0	10-9-79	ORIGINAL ISSUE	D.S.		

SCALE 3/8"=1'-0
APPROVED
DATE
DIV. MECH.
DR. T.J. KITZ
CH.
SK-2165-MNE
R-245





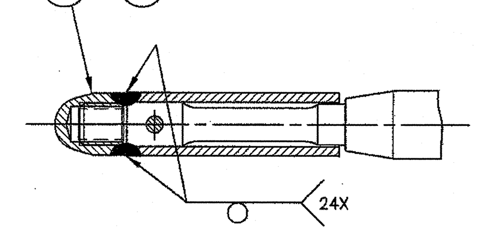




SECTION Y–Y
SCALE: 6:1

SECTION Z–Z

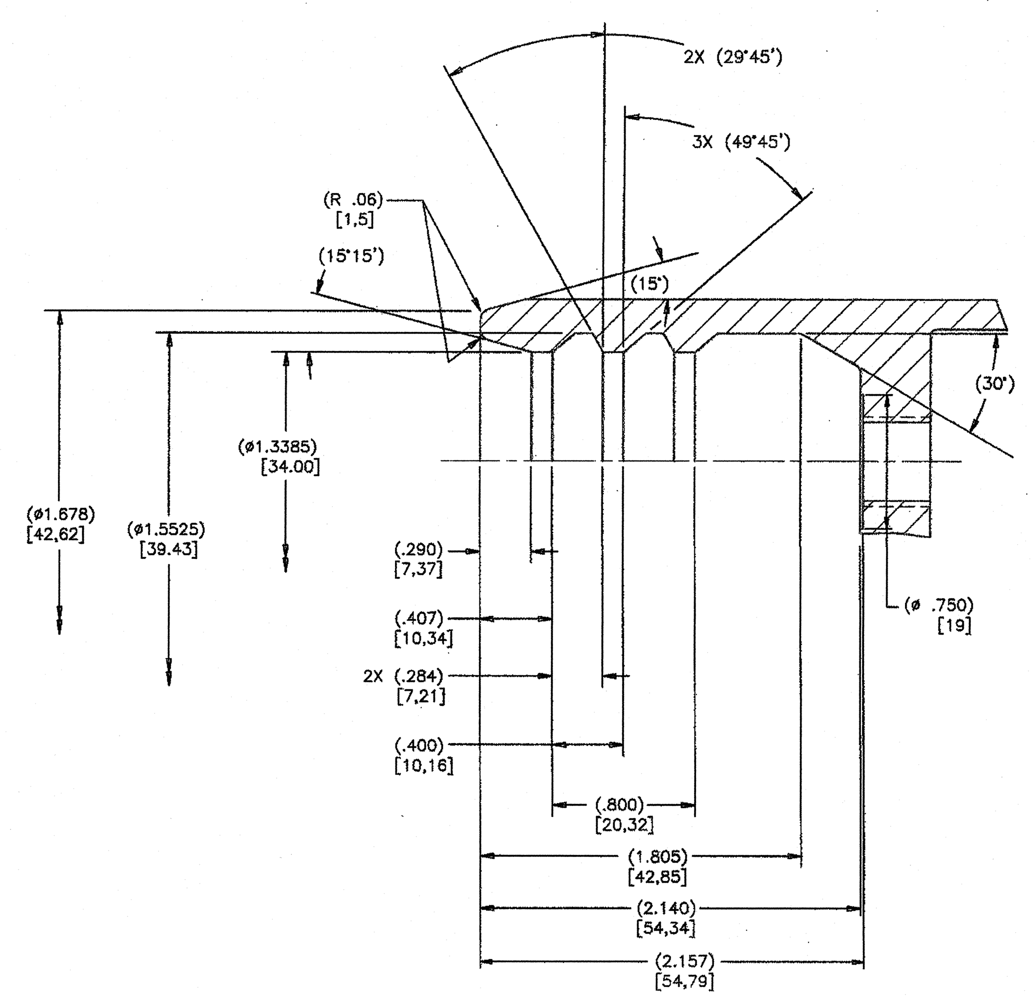
1 RCCA



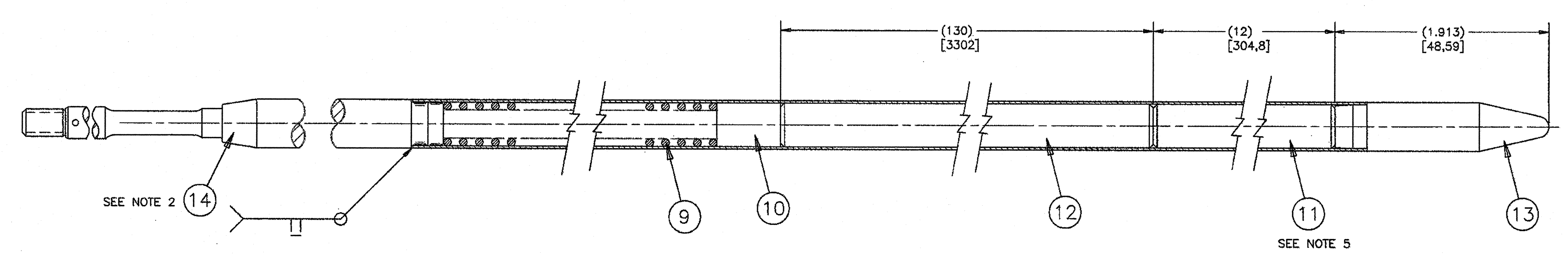
SECTION X–X
SCALE: 2:1

General Notes: UNLESS OTHERWISE SPECIFIED

1. THE WEIGHT OF THE ASSEMBLED RCCA IS 149 LBS.
2. THIS ITEM CAN BE ONE OF THREE DIFFERENT LENGTHS DEPENDING ON THE ROD TYPE.
3. THE IDENTIFICATION NUMBERS SHOWN ARE FOR ILLLUSTRATION ONLY. THE SPECIFIED NUMBER SEQUENCE SHALL BE IN ACCORDANCE WITH THE COMMERCIAL PURCHASE AUTHORIZATION.
4. THE SPACING OF THE CHARACTERS IS TO BE APPROXIMATELY EQUAL. ORIENTATION OF THE ENGRAVING ON THE HUB SIDE SHOULD BE APPROXIMATELY CENTERED ALONG ONE OF THE FOUR FACES OF THE SPIDER ASSEMBLY.
5. ITEM 11 HAS A REDUCED DIAMETER TO COMPENSATE FOR THE EFFECTS OF ABSORBER SWELLING.
6. THIS DIMENSION SHOWS ION NITRIDE REGION OF CONTROL ROD. THE ION NITRIDE REGION IS TYPICAL OF ALL 24 CONTROL RODS



DETAIL–A
SCALE 2:1



DETAIL B
5 6 7
SCALE: 2:1

ITEM	DESCRIPTION
14	UPPER END PLUG
13	BOTTOM END PLUG
12	ABSORBER ROD (UPPER)
11	ABSORBER ROD (LOWER)
10	SOLID SPACER
9	SPRING SPACER
8	LOCK PIN
7	CONTROL ROD C (LONG)
6	CONTROL ROD B (MEDIUM)
5	CONTROL ROD A (SHORT)
4	NUT TYPE–B
3	NUT TYPE–A
2	SPIDER ASSEMBLY
1	RCCA

REVISIONS

REV	DESCRIPTION	APPROVAL/DATE
001	SEE NATURE OF CHANGE PAGE.	FOR SIGNATURES AND DATE SEE SIGNATURE PAGE

FOR SIGNATURES, DATE OR PREVIOUS REVISIONS SEE SCANNED IMAGE IN RECORDS CENTER

VIEW ORIENTATION
3RD ANGLE PROJECTION

TOLERANCES

UNLESS OTHERWISE SPECIFIED
ALL DIM. PRACTICES PER ISO 1101
TOP DIM. IN INCHES AT ROOM TEMPERATURE
BOTTOM DIM. IN MM (FOR REFERENCE ONLY)
DECIMAL: 1–PLACE – .X ± 0.1
2–PLACE – .XX ± 0.02
3–PLACE – .XXX ± 0.005
4–PLACE – .XXXX ± 0.0005
ANGLE ± 5°
FILLET RADII .03 R MAX.
BREAK CORNERS .02 MAX. R OR CHAM.
ALL MACHINED SURFACES 3.18 Ra(125/AA)
FINISH PER ISO 1302

DWN.BY	DW ROBERTS
OWNER	SEE SIGNATURE PAGE
REVIEWER	SEE SIGNATURE PAGE
USER	SEE SIGNATURE PAGE
DATE	SEE SIGNATURE PAGE

RCCA DESIGN INTERFACE DRAWING (DID) – MODIFIED COUPLING

THIS DRAWING IS THE PROPERTY OF
AREVA NP INC.
AN AREVA AND SIEMENS COMPANY
AND IS LOANED UPON CONDITION THAT IT IS NOT TO BE REPRODUCED OR COPIED IN WHOLE OR IN PART, OR USED FOR FURNISHING INFORMATION TO OTHERS, OR FOR ANY OTHER PURPOSE DETRIMENTAL TO THE INTEREST OF AREVA NP AND WILL BE RETURNED UPON REQUEST.

SCALE 1:1 | SHEET 1 OF 1

DO NOT SCALE USE DIMENSIONS ONLY | SIZE A0 | DOC ID. 02 | DWG NO. 9088563 | REV 001

Ø	NEW DRAWING PER EC# 69253	ELECTRONICALLY SIGNED
REV	DESCRIPTION	APPROVED

Progress Energy

QUALITY LEVEL: SAFETY RELATED

PLANT: HARRIS PROJECT – UNIT 1 | SCALE: N/A

TITLE: RCCA DESIGN INTERFACE DRAWING (DID)–MODIFIED COUPLING

PLANT DWG NO.: 1364–Ø42493

1. LONGITUDINAL SECTION – 1Ø34.6 MW NSSS TURBINE
TANDEM – COMPOUND QUADRUPLE–FLOW 18ØØ RPM
967.3 Psig., 542.4°F, 517.9°F, 2.99 TO 4.13 IN. Hg. Abs.
DWG/SUB N 771J185/1 AND DSPPG–0162233/B
CAROLINA POWER & LIGHT CO
SHEARRON HARRIS NUCLEAR POWER PLANT
UNIT #1 – 13A4681, 23A4688, 23A4689

SEE SHEET 6 OF 6
FOR NEW HP TURBINE

P.O. # NY435ØØ1

TRANSMITTAL LETTER HV#853Ø14(E)

Westinghouse Electric Corporation			23A4694
LARGE TURBINE DIVISION, LESTER, PA, U.S.A.			741J372
00	ASSEMBLY LONGITUDINAL SECTION THRU TURBINE	771J185	
BP-296-281-281			30:000:700

REV	DATE	DESCRIPTION	DWN	CHK	APPR'D
3		INCORPORATED: EC#749Ø7	ELECTRONICALLY SIGNED		
Ø2		THIS DRAWING HAS BEEN ELECTRONICALLY REPRODUCED WITH DESIGN CHANGE INCORPORATED: ESR 94–ØØØØ1	ACK	EJE	DCS

PROFESSIONAL ENGINEER: N/A

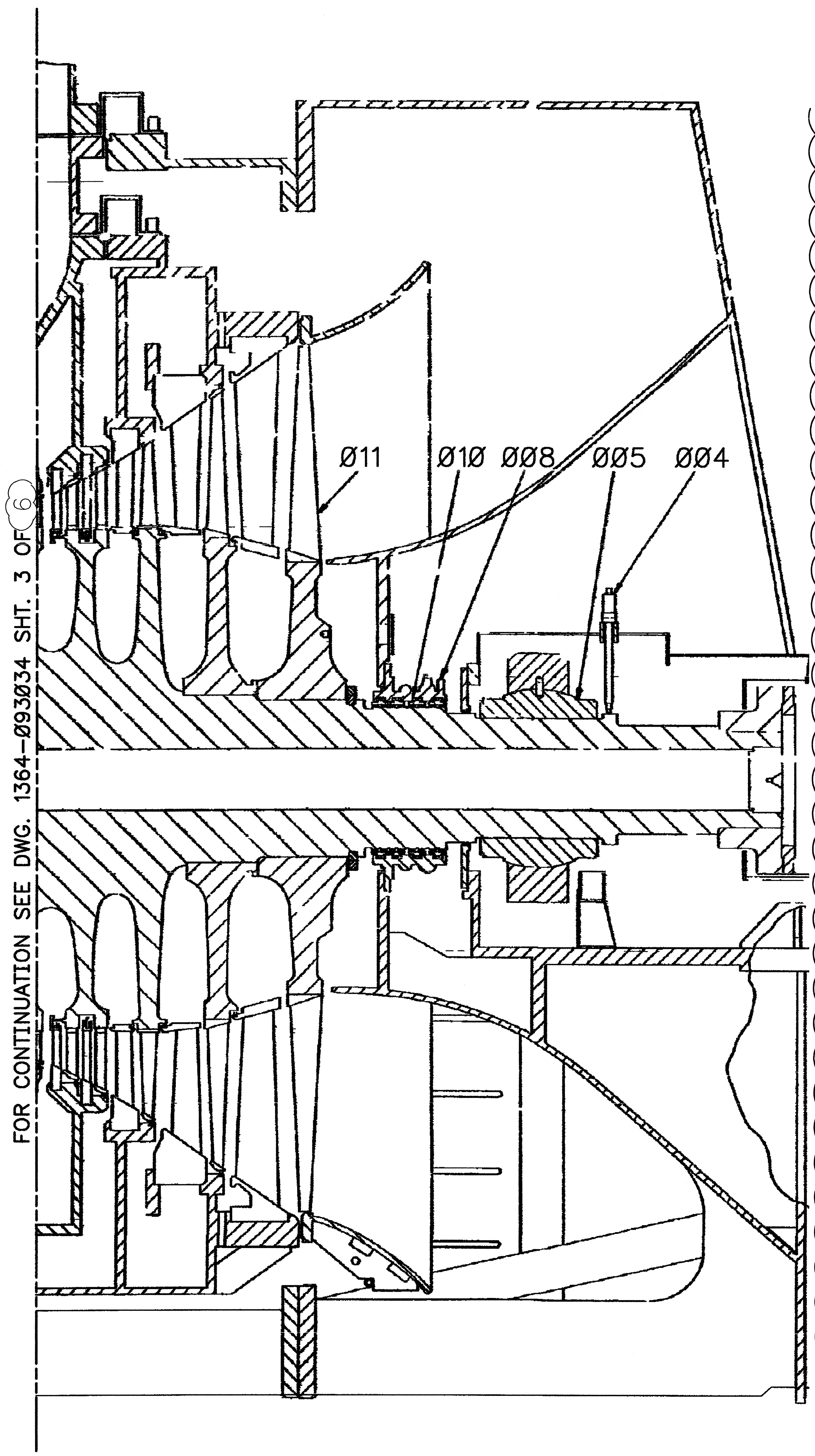
QUALITY LEVEL: NON–SAFETY RELATED

CAROLINA POWER & LIGHT COMPANY
NUCLEAR ENGINEERING DEPARTMENT
CP&L

PLANT: HNP SCALE: NTS

TITLE: ASSEMBLY
LONGITUDINAL SECTION THRU TURBINE
NSSS TURBINE
SHT. 1 OF 6

PLANT DWG NO.: 1364–Ø93Ø34



FOR CONTINUATION SEE DWG. 1364-Ø93Ø34 SHT. 3 OF 6

SEE SHEET 6 OF 6
FOR NEW HP TURBINE

3	INCORPORATED: EC#749Ø7	ELECTRONICALLY SIGNED

PROFESSIONAL ENGINEER: N/A

QUALITY LEVEL: NON-SAFETY RELATED

CAROLINA POWER & LIGHT COMPANY
NUCLEAR ENGINEERING DEPARTMENT

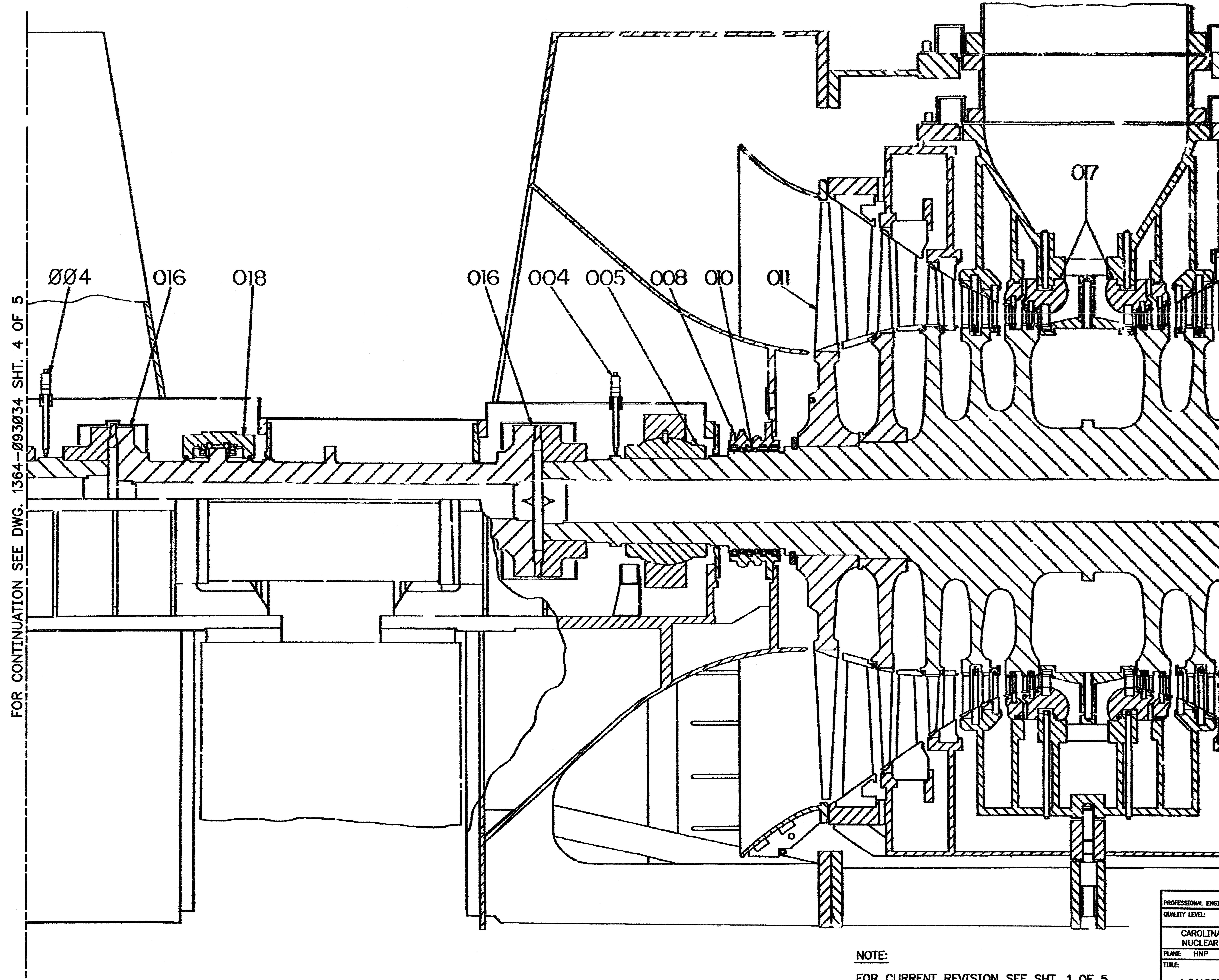
CP&L

PLANT: HNP

SCALE: NTS

TITLE:
ASSEMBLY
LONGITUDINAL SECTION THRU TURBINE
NSSS TURBINE
SHT. 2 OF 6

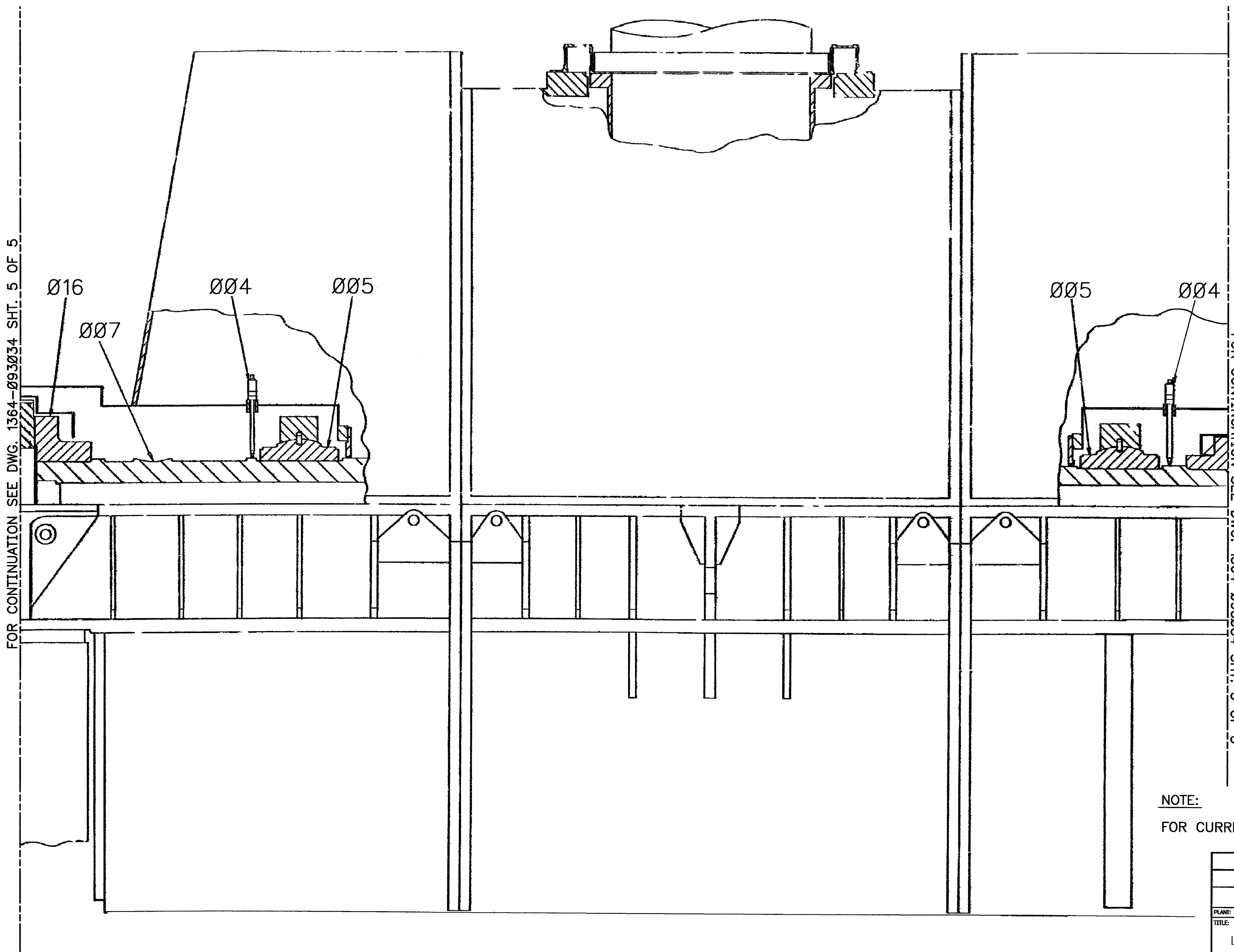
PLANT DWG NO.: 1364-Ø93Ø34



NOTE:

FOR CURRENT REVISION SEE SHT. 1 OF 5

PROFESSIONAL ENGINEER:	N/A
QUALITY LEVEL:	NON-SAFETY RELATED
CAROLINA POWER & LIGHT COMPANY NUCLEAR ENGINEERING DEPARTMENT	CP&L
PLANT: HNP	SCALE: NTS
TITLE:	ASSEMBLY LONGITUDINAL SECTION THRU TURBINE NSSS TURBINE SHT. 3 OF 6
PLANT DWG NO.:	1364-Ø93Ø34



NOTE:

FOR CURRENT REVISION SEE SHT. 1 OF 5

N/A

SAFETY RELATED

GHT COMPANY DEPARTMENT

CP&L

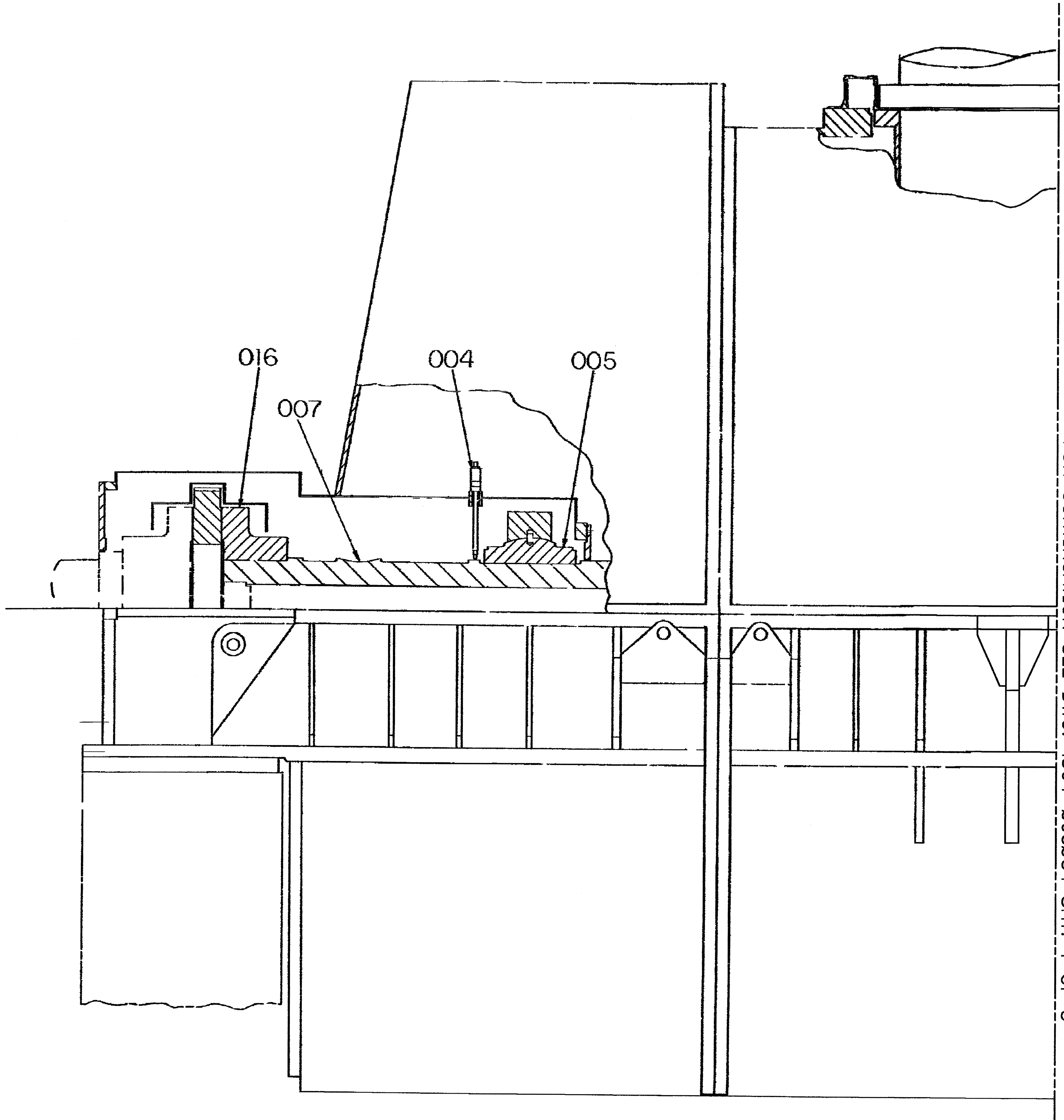
PLANT: HNP

SCALE: NTS

TITLE:

ASSEMBLY
LONGITUDINAL SECTION THRU TURBINE
NSSS TURBINE
SHT. 4 OF 6

PLANT DWG NO.: 1364-Ø93Ø34



NOTE:

FOR CURRENT REVISION SEE SHT. 1 OF 5

PROFESSIONAL ENGINEER:	N/A
QUALITY LEVEL:	NON-SAFETY RELATED
CAROLINA POWER & LIGHT COMPANY NUCLEAR ENGINEERING DEPARTMENT	CP&L
PLANT: HNP	SCALE: NTS
TITLE:	ASSEMBLY LONGITUDINAL SECTION THRU TURBINE NSSS TURBINE SHT. 5 OF 6
PLANT DWG NO.:	1364-Ø93Ø34

PART NO.	DESCRIPTION
019	INNER CASING
020	GUIDE BLADE CARRIER I GE
021	GUIDE BLADE CARRIER I TE
022	ROTOR

FOR ALL OTHER PART NUMBERS SEE ORIGINAL DRAWING 771J185.

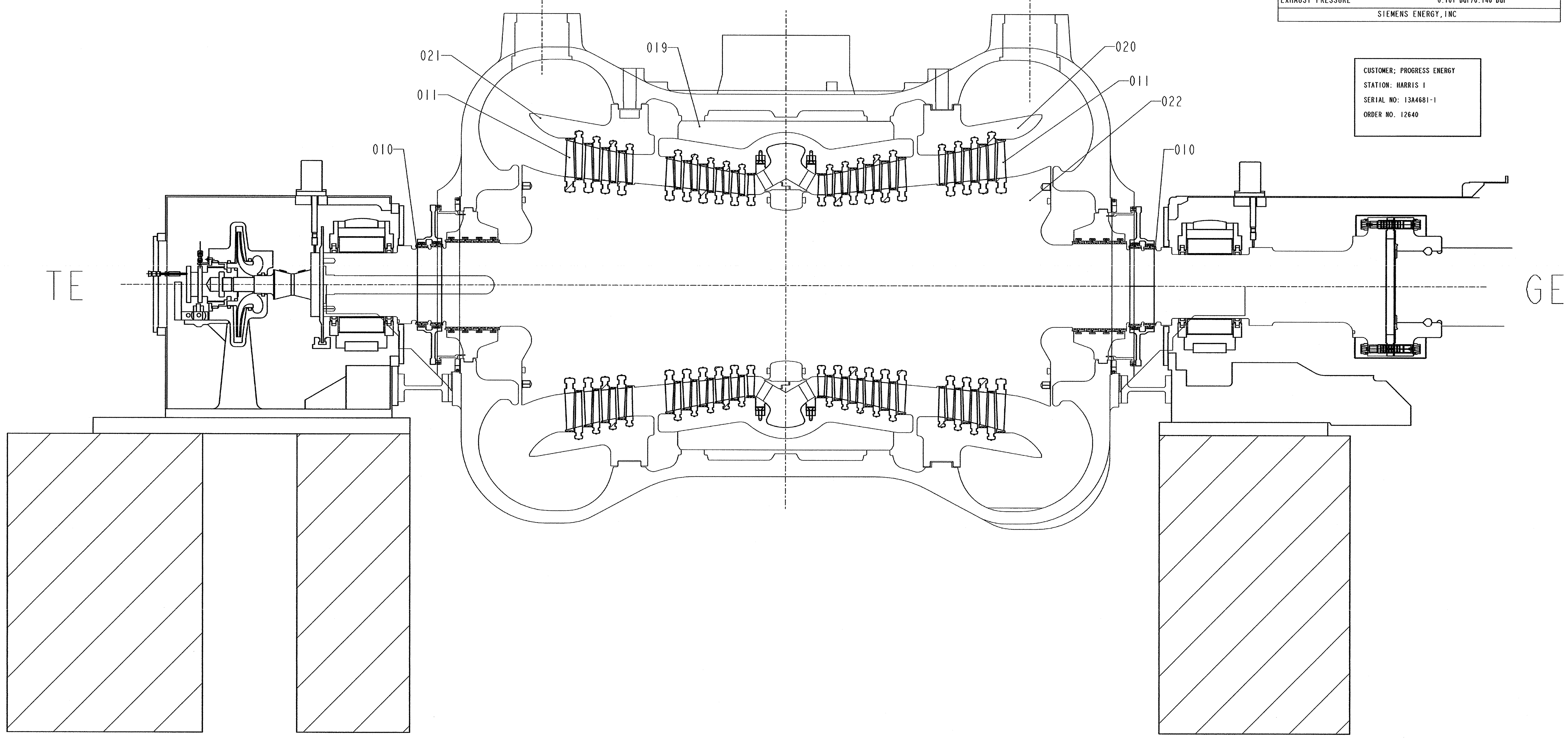
SIEMENS			
Dampfturbine STEAM TURBINE	HARRIS I		
Dampfdruck STEAM PRESURE	982 psia 67.71 bar	Dampftemperatur STEAM TEMPERATURE	542.4°F 283.5°C
Drehzahl SPEED	1800 RPM	Leistung RATED CAPACITY	1034.6 MW
Abdampfdruck EXHAUST PRESSURE	2.99 inHgA / 4.13 inHgA 0.101 bar/0.140 bar		
SIEMENS ENERGY, INC			

CUSTOMER; PROGRESS ENERGY

STATION: HARRIS I

SERIAL NO: 13A4681-1

ORDER NO. 12640



THIS DRAWING SUPPLEMENTS THE ORIGINAL DRAWING 771J185

EXPORT CONTROLLED: TECHNOLOGY SPECIFIED IN THE CCL, AL OR ECL

TECHNICAL CLASSIFICATION:
ECCN: AL: ECL: U.S.-CONTENT: X

THIS DOCUMENT CONTAINS CONTROLLED TECHNOLOGY AND IS SUBJECT TO U.S. AND/OR NATIONAL EXPORT REGULATIONS. UNAUTHORIZED DIVERSION IS PROHIBITED. IN CASES OF DOUBT CONTACT YOUR EXPORT COMPLIANCE DEPARTMENT.

REVISION: SEE SEPARATE CID DOCUMENT

SIEMENS ENERGY, INC

WEIGHT:	SCALE: 1:1	SPEC.:KUN351.00	DCC:
ORIGINATED: 2011-05-06 R. KUBACKI	TITLE: LONGITUDINAL SECTION		
CHECKED: 2011-05-06 K. AKUMALLA			
RELEASED: 2011-05-06 K. AKUMALLA	LAENGSSCHNITT		
CONFIDENTIAL COPYRIGHT (c) SIEMENS ENERGY, INC 2011 ALL RIGHTS RESERVED	LANG. - DRAWING NO. / VALUE: DSPPG-0162233 12640-002000	REV.: B	SHEET: 1/1

Pro/ENGINEER A0

DO NOT SCALE, WORK TO DIMENSIONS SHOWN

Ø	NEW DRAWING PER EC# 74907	ELECTRONICALLY SIGNED
REV	DESCRIPTION	APPROVED

Progress Energy

QUALITY LEVEL: NON-SAFETY RELATED

PLANT: HARRIS PROJECT - UNIT 1 SCALE: N/A

TITLE: ASSEMBLY LONGITUDINAL SECTION THRU TURBINE NSSS TURBINE SHT. 6 OF 6

PLANT DWG NO.: 1364-093034

Reference Use

HARRIS UNIT 1

ADMINISTRATIVE PROCEDURE

NON-SAFETY RELATED

PLP-106

TECHNICAL SPECIFICATION EQUIPMENT LIST PROGRAM AND CORE OPERATING LIMITS REPORT

REVISION 063

REVISION SUMMARY
PRR 2109488 **DESCRIPTION**
Corrected Attachment 1 through 11 header such that it is tied to the procedure body header. This corrected an error that made the procedure revision number to be different on the attachments. Attachment 9 added missing "Δ" symbol from $F_{\Delta H}$ (for Section 1.0, 3/4.2.3 title) Attachment 10 added missing footnote numbers.

TABLE OF CONTENTS

SECTION PAGE

ATTACHMENTS

TABLE OF CONTENTS
(continued)

SECTION PAGE

ATTACHMENTS

1.0 PURPOSE

1. This procedure identifies and controls the various equipment lists required by Shearon Harris Technical Specifications. These lists are comprised of plant equipment used to fulfill the respective LCO/Surveillance Requirements, as follows:

   - Reactor Trip System Instrumentation Response Times
   - Engineered Safety Features Actuation System Instrumentation Response Times
   - Reactor Vessel Material Surveillance Program
   - Snubber Surveillance Program
   - Containment Isolation Valves
   - Containment Penetration Conductor Overcurrent Protection Devices
   - Motor-Operated Valve Thermal Overload Protection Bypass
   - Instrument Uncertainties associated with Reactor Vessel Pressure - Temperature Limits and Low Temperature Overpressure Protection System
   - Reactor Trip System Instrumentation Setpoint As-Found/As-Left Tolerances

2. Additionally, the following equipment list is used to provide actions for components not covered by Technical Specifications, yet these components provide backup (not redundant) protective actions:

   - Safeguards Systems Isolation Valves in Closed Systems

3. This procedure also implements the limits of the Core Operating Limits Report.

4. This procedure is required to implement License Renewal (LR) commitments and requirements and supports the following LR Aging Management programs (AMPs) [7.3.3]:

   - Reactor Vessel Surveillance Program {7.1.2}

2.0 SCOPE

1. The equipment lists, figures, and surveillance programs attached to this procedure were generated to fulfill the requirements of various Technical Specifications for the Shearon Harris Nuclear Power Plant and to ensure prudent actions are taken for other equipment for which no Technical Specification provides explicit actions.

   Historically, those items comprising the Technical Specification Equipment List Program were maintained directly in the Technical Specifications. By maintaining these items independent of the Technical Specifications but still fulfilling the regulatory requirements, they are maintained more current and accurate with respect to the actual plant configuration without the delay typically encountered with Operating License/Technical Specification amendments.

2. The Core Operating Limits Report also contains information previously maintained in the Technical Specifications. The limits may change from cycle to cycle although the methodologies used to calculate these limits are unchanged. By locating these limits independent of the Technical Specifications, the limits are kept more accurate without delay.

3. The controls maintained on this procedure will exceed those normally required by AD-DC-ALL-0201, Development and Maintenance of Controlled Procedure Manual Procedures.

   a. In addition to the reviews required by AD-DC-ALL-0201, this procedure will require PNSC concurrence prior to approval.

   b. Changes to this procedure will also require concurrent changes to the FSAR per AD-LS-ALL-0005, UFSAR Updates, when changes are made to the Technical Specification Equipment Lists.

   c. Changes to the Core Operating Limits Report are submitted to NRC per Technical Specification 6.9.1.6.4.

   d. This procedure is incorporated by reference into the FSAR and is therefore made a part of the FSAR, which is part of the Harris Current Licensing Basis (CLB). This procedure is subject to the update and reporting requirements of 10 CFR 50.71(e) and change controls of 10 CFR 50.59 and as such cannot be exempted from 50.59 screening.

   By maintaining these additional controls on this procedure, its contents may be modified with assurance that they are accurate and that the full implications of the changes have been considered even more carefully than using routine methodology.

2.0 SCOPE (continued)

4. Operability of Structures, Systems, or Components (SSC) described in Technical Specifications

   The scope of the SSCs considered in the operability determination process includes the following:

   a. SSCs required to be OPERABLE by Tech Specs. These SSCs may perform required support functions for other SSCs required to be OPERABLE by Tech Specs (example - Emergency Diesel and Service Water)

   b. SSCs that are not explicitly required to be OPERABLE by Tech Specs, but that perform required support functions (as specified by the TS definition of operability) for SSCs required to be OPERABLE by Tech Specs.

3.0 DEFINITIONS

1. **COLR**: Core Operating Limits Report
2. **FSAR**: Final Safety Analysis Report
3. **LCO**: Limiting Condition for Operation
4. **LR**: License Renewal
5. **PNSC**: Plant Nuclear Safety Committee
6. **SSC**: Structures, Systems, or Components
7. **TS**: Technical Specification

4.0 RESPONSIBILITIES

1. HESS Reactor Systems and Nuclear Fuel Engineering (NFE) are responsible for revising this procedure as changes to the COLR are required. At a minimum, revisions are required once per cycle, at Beginning of Cycle, to make the COLR cycle-specific.

2. The Plant Nuclear Safety Committee (PNSC) is responsible for reviewing revisions to the COLR and providing concurrence prior to implementation of COLR revisions (UFSAR Section 17.3, HNP Quality Assurance Program Description).

3. HESS Reactor Systems and Operations are responsible for monitoring plant conditions to ensure the Core Operating Limits specified in this procedure are met.

4. Licensing/Regulatory Programs is responsible for providing prompt notification of COLR revisions to the NRC in accordance with TS 6.9.1.6.4 upon procedure approval.

5. Licensing/Regulatory Programs is responsible for administering the Technical Specifications List Program.

6. Operations is responsible for monitoring plant conditions to ensure the Technical Specifications List Program specified in this procedure is met.

5.0 INSTRUCTIONS

5.1 Criteria for Establishing the Equipment Lists/Surveillance Programs/Limits

5.1.1 Reactor Trip System Instrumentation Response Times (TS Table 3.3-2)

The response time of each Reactor Trip function shown in Technical Specification Table 3.3-1 shall be as shown in Attachment 1.

5.1.2 Engineered Safety Feature Actuation System Instrumentation Response Times (TS Table 3.3-5)

The response time of each Engineered Safety Feature Actuation System Function shown in Technical Specification Table 3.3-3 shall be as shown in Attachment 2.

5.1.3 Reactor Vessel Material Surveillance Program (TS Table 4.4-5)

The reactor vessel material irradiation surveillance specimens shall be withdrawn and examined to determine changes in material properties, as required by 10CFR50, Appendix H, in accordance with the schedule in Attachment 3.

The results of these examinations shall be used to update Technical Specification Figures 3.4-2 and 3.4-3.

NOTE

Based on HNP fluence projections, the HNP reactor vessel fracture toughness properties have been evaluated using established methods and techniques in accordance with the requirements of Regulatory Guide 1.99, Revision 2, and the Code of Federal Regulations, Title 10, Part 50.61. {7.1.1}

If future plant operations exceed the limitations in Section 1.3 of Regulatory Guide 1.99, Revision 2, {7.1.2}, or the applicable bounds, e.g., cold leg operating temperature and neutron fluence, as applied to the surveillance capsules, the impact of these plant operation changes on the extent of reactor vessel embrittlement will be evaluated and the NRC will be notified.

5.1.4 Snubbers (TS 4.7.8 and TS Figure 4.7-1)

The surveillance requirements for snubbers, as defined by Technical Specification 4.7.8, shall be performed in accordance with the augmented in-service inspection program as described in Attachment 4.

5.1.5 Containment Isolation Valves (TS Table 3.6-1)

The containment isolation valves required to be OPERABLE by Technical Specification 3.6.3 shall be demonstrated OPERABLE with isolation times shown in Attachment 5.

5.1.6 Containment Penetration Conductor Overcurrent Protective Devices (TS Table 3.8-1)

The containment penetration conductor overcurrent protective devices required by Technical Specification shall be as shown in Attachment 6.

5.1.7 Motor-Operated Valves Thermal Overload Protection Bypass (TS Table 3.8-2)

The thermal overload protection for motor-operated valves required to be bypassed by Technical Specification 3.8.4.2 shall be as shown in Attachment 7.

5.1.8 Safeguards Systems Isolation Valves in Closed Systems

The isolation ability of nonessential lines in closed systems is designed to meet single failure criteria, although only the outside containment isolation valve is covered by Technical Specification. The functionality requirement for non-containment isolation valves shall be as shown in Attachment 8. This functionality requirement is a desired backup (not a redundancy) feature. Unavailability of these valves to perform isolation functions is an off-normal condition but does not warrant required Technical Specifications actions.

5.1.9 Core Operating Limits Report

The following cycle-specific data shall be as shown in Attachment 9:

- Shutdown Margin limits for Specification 3/4.1.1.2,
- Moderator Temperature Coefficient Positive and Negative Limits and 300 ppm surveillance limit for Specification 3/4.1.1.3,
- Shutdown Bank Insertion Limits for Specification 3/4.1.3.5,
- Control Bank Insertion Limits for Specification 3/4.1.3.6,
- Axial Flux Difference Limits for Specification 3/4.2.1,
- Heat Flux Hot Channel Factor, FQRTP, K(Z), and V(z)for Specification 3/4.2.2,
- Enthalpy Rise Hot Channel Factor, PF∆H RTP, and Power Factor Multiplier, for Specification 3/4.2.3,
- Boron Concentration During Refueling Operations for Specification 3/4.9.1.

5.1.10 Instrument Uncertainties Associated with Reactor Vessel Pressure & Temperature Limits & Low Temperature Overpressure Protection

The values that will provide a conservative margin to compensate for instrument uncertainties related to reactor vessel pressure and temperature limits and low temperature overpressure protection are provided in Attachment 10.

5.1.11 Reactor Trip System Instrumentation Setpoint As-Found/As-Left Tolerances

The As-Found/As-Left tolerances of Reactor Trip Nuclear Instrumentation Setpoints shall be as shown in Attachment 11.

5.2 <u>Additions, Changes, and Deletions to the Attachments Required By Technical Specifications</u>

1. If modifications are required to the respective lists, the following process shall be performed. This process exceeds the normal procedure review process as indicated in AD-DC-ALL-0201, Development and Maintenance of Controlled Procedure Manual Procedures.

    a. Prepare a revision to the procedure in accordance with AD-DC-ALL-0201 for review by plant personnel.

    b. Upon completion of the final revision draft, the proposed revision shall be submitted to the PNSC for their concurrence in accordance with AP-013.

    c. Prior to approval by the Plant Manager - Harris, Licensing/Regulatory Programs shall ensure procedure revisions or new procedures are prepared to incorporate changes made to the attachments or shall establish action items per AD-PI-ALL-0100 for changes not requiring immediate implementation.

    d. Upon PNSC concurrence of the proposed revision, the procedure revision shall be submitted to the General Manager - Harris Plant for final approval along with an FSAR revision (if required for changes to the Technical Specification Equipment List Program) which incorporates the changes made to the attachments in accordance with AD-LS-ALL-0005.

    e. Changes to the Core Operating Limits Report shall be submitted to NRC per Technical Specification 6.9.1.6.4.

6.0 RECORDS

1. None

7.0 REFERENCES

7.1 Commitments

1. BAW-2355, Supplement 3, June 2006, "Supplement to the Analysis of Capsule X Carolina Power & Light Company Shearon Harris Nuclear Power Plant - Reactor Vessel Material Surveillance Program," AREVA NP Inc.

2. U.S. Nuclear Regulatory Commission, Regulatory Guide 1.99, "Radiation Embrittlement of Reactor Vessel Materials," Revision 2, May 1988.

7.2 Procedures

1. AD-DC-ALL-0202, Procedure Numbering System

2. AP-013, Plant Nuclear Safety Committee

3. AD-DC-ALL-0201, Development and Maintenance of Controlled Procedure Manual Procedures

4. AD-EG-ALL-1132, Preparation and Control of Design Change Engineering Changes

5. AD-EG-ALL-1137, Engineering Change Product Selection

6. AD-EG-ALL-1202, Preventive Maintenance and Surveillance Testing Administration

7. AD-EG-HNP-1618, Snubber Program Plan

8. AD-LS-ALL-0005, UFSAR Updates

9. AD-LS-ALL-0008, 10 CFR 50.59 Review Process

10. AD-PI-ALL-0100, Corrective Action Program

7.3 Miscellaneous Documents

1. SHNPP FSAR

2. SHNPP Technical Specifications

3. CR 188047, HNP LR Commitments 'Enhancement to Existing Program'

4. BAW-2355, Supplement 1, November 1999, "Supplement to the Analysis of Capsule X Carolina Power & Light Company Shearon Harris Nuclear Power Plant - Reactor Vessel Material Surveillance Program," Framatome Technologies, Inc.

7.3 Miscellaneous Documents (continued)

5. BAW-2355, Supplement 2, June 2006, "Supplement to the Analysis of Capsule X Carolina Power & Light Company Shearon Harris Nuclear Power Plant - Reactor Vessel Material Surveillance Program," AREVA NP Inc.

6. EC 252649, Reduced Minimum Thimble Requirements for Full Core Flux Mapping

7. EC 254021, Disablement of Remote Actuation Capability of Unused Ammonia/Hydrazine Injection Valves, AR 95397

8. EC 260001, H1C14 Reload Core Design and Safety Analysis

9. EC 260241, Resolution of Unanalyzed Single Failure for E-6

10. EC 264030, H1C15 Reload Core Design and Safety Analysis

11. EC 267297, Change HNP COLR to Modify Rod Insertion Limit for Shutdown Rods

12. EC 272465, Harris Cycle 15 Burnup Extension

13. EC 269003, HNP Cycle 16 Core Design and Safety Analysis

14. EC 276187, H1C16 Reduced Minimum Thimble Requirements for Flux Mapping

15. EC 273394, HNP Cycle 17 Core Design and Safety Analysis

16. EC 283899, HNP Cycle 17 COLR Update - EOL MTC Surveillance Limit

17. EC 274914, Implement License Change for the MUR Uprate

18. EC 275840, HNP Cycle 18 Core Design and Safety Analysis

19. EC 288072, HNP Cycle 19 Core Design and Safety Analyses

20. EC 294210, Resolve AR 613482 (Fuse 1A-16/2746 Label Issues)

21. EC 403338, PHPP-1C Heater Restoration (EC300229, Temporarily Restored Heaters to Group C)

22. ESR 9400001, Steam Generator Replacement and Power Uprate

23. ESR 9400004, Instantaneous Trip Setting Tolerances for MCCBs

24. ESR 9400072, 1SW 39 & 40 Stroke Versus Flow Questions

25. ESR 9400546, 1SW-39 & 40 Stroke Versus Flow Questions

7.3 Miscellaneous Documents (continued)

26. ESR 9500941, Feedwater Isolation Time Acceptance Criteria

27. ESR 9600093, Cycle 8 Core Design and Analysis

28. ESR 9600098, 42/0 Seal-In Contact Modification for Control Room Isolation (EC 206196)

29. ESR 9700351, Change Status of SI-1&2 "BIT Inlet Isol Valves" to Normally (EC 245386)

30. ESR 9700807, SGR Large Bore Piping Modifications (EC 244109)

31. ESR 9700808, SGR Small Bore Piping Modifications (EC 206403)

32. ESR 9800537, Tempering Lines Modification (EC 248470)

33. ESR 9900093, Reactor Vessel Surveillance Capsule 'X' Analysis

34. ESR 0000221, Cycle 11 Core Design and Analysis (EC 245816)

35. ESR 0000325, RCS Head Vent Path Redesign (EC 244336)

36. ESR 0000262, PUR/SGR Instrumentation Changes Converted to EC 0000048392 Rev 009, Including ADL (EC 244641)

37. FCQL-465, 4/13/87, Parker to Loflin, VCT to RWST Alignment for Steam Line Break

38. HNP Calculation HNP-P/LR-0613, License Renewal Aging Management Program Description of the Reactor Vessel Surveillance Program

39. NRC Inspection Manual Part 9900: Technical Guidance

40. NRC Letter to Mr. W. R. Robinson, "Issuance of Amendment No. 65 of Facility Operating License No. NPF-63 Regarding Relocation of Incore Instrument Requirements - Shearon Harris Nuclear Power Plant, Unit 1 (TAC No. M95064", July 24, 1996)

41. NRC letter to W.R. Jefferson, "Safety Evaluation for Revision to Reactor Vessel Surveillance Capsule Withdrawal Schedule", dated October 21, 2011.

42. HNP Letter HNP-06-136, Letter from HNP to US Nuclear Regulatory Commission, Application for Renewal of Operating License, dated November 14, 2006

7.3 Miscellaneous Documents (continued)

43. HNP Letter HNP-07-112, Letter from HNP to US Nuclear Regulatory Commission, "License Renewal Application, Amendment 1: Changes resulting from Request for Additional information, Site Audit Questions, and Applicant Identified Changes", dated August 20, 2007.

44. US NRC Letter, December 17, 2008, "Issuance of Renewed Facility Operating license No. NFP-63 for the Shearon Harris Nuclear Power Plant, Unit 1", License Condition 2.K.

45. Evaluation of RTS/ESFAS Tech Spec Related Setpoints, Allowable Values and Uncertainties

46. PCR 4839, Component Cooling Water Mechanical Snubber Failure

47. Shearon Harris Nuclear Plant – Safety Evaluation for Revision to Reactor Vessel Surveillance Capsule Withdrawal Schedule (TAC No, ME6998), dated October 21, 2011, ADAMS Accession No. ML11293A076

ATTACHMENT 1
Page 1 of 2

<< Reactor Trip System Instrumentation Response Times >>

FUNCTIONAL UNIT		**RESPONSE TIME**
1.	Manual Reactor Trip	NA
2.	Power Range, Neutron Flux	≤ 0.5 second*
3.	Power Range, Neutron Flux, High Positive Rate	NA
4.	Power Range, Neutron Flux, High Negative Rate	≤ 0.5 second*
5.	Intermediate Range, Neutron Flux	NA
6.	Source Range, Neutron Flux	NA
7.	Overtemperature ΔT	≤ 9.50 seconds * (through ΔT)[(1)]; ≤ 5.50 seconds * (through other inputs)[(1)]
8.	Overpower ΔT	≤ 9.50 seconds * (through ΔT)[(1)]; ≤ 5.50 seconds * (through other inputs)[(1)]
9.	Pressurizer Pressure--Low	≤ 2 seconds
10.	Pressurizer Pressure--High	≤ 2 seconds
11.	Pressurizer Water Level--High	NA
12.	Reactor Coolant Flow--Low	
	a. Single Loop (Above P-8) b. Two Loops (Above P-7 and below P-8)	≤ 1 second ≤ 1 second
13.	Steam Generator Water Level--Low-Low	≤ 3.5 seconds

ATTACHMENT 1
Page 2 of 2

<< Reactor Trip System Instrumentation Response Times >>

FUNCTIONAL UNIT		**RESPONSE TIME**
14.	Steam Generator Water Level--Low Coincident with Steam/Feedwater Flow Mismatch	NA
15.	Undervoltage - Reactor Coolant Pumps (Above P-7)	≤ 1.5 seconds
16.	Underfrequency - Reactor Coolant Pumps (Above P-7)	≤ 0.6 second
17.	Turbine Trip	
	a. Low Fluid Oil Pressure	NA
	b. Turbine Throttle Valve Closure	NA
18.	Safety Injection Input from ESF	NA
19.	Reactor Trip System Interlocks	NA
20.	Reactor Trip Breakers	NA
21.	Automatic Trip and Interlock Logic	NA
22.	Reactor Trip Bypass Breakers	NA

TABLE NOTATIONS

*	Neutron detectors are exempt from response time testing. Response time of the neutron flux signal portion of the channel shall be measured from detector output or input of first electronic component in channel.
(1)	The 9.50 seconds includes a 4.25-second limit for each RTD/thermowell thermal time constant (measured by a loop current step response [LCSR] test), a 1.25-second limit on the trip circuit electronics delay, and an additional 4.0-second electronics delay in only the measured ΔT circuitry (due to a lag filter time constant). Note that the safety analysis uses a 4.75-second thermal time constant due to allowances for the accuracy of the LCSR test, and a 4.40-second lag filter time constant (on measured ΔT) due to allowance for a 10% calibration tolerance.

<< Engineered Safety Features Response Times >>

INITIATION SIGNAL AND FUNCTION		RESPONSE TIME IN SECONDS
1.	Manual Initiation	
	a. Safety Injection (ECCS) (12)	NA
	b. Containment Spray	NA
	c. Containment Phase "A" Isolation	NA
	d. Containment Ventilation Isolation	NA
	e. Steam Line Isolation	NA
	f. Reactor Trip	NA
2.	Containment Pressure - High-1	
	a. Safety Injection (ECCS) (10)(12)	≤ 27 (1) / 12 (5) [High Press. Injec.] ≤ 29 (14) / 27 (15) [Low Press. Injec.]
	1) Reactor Trip	≤ 2
	2) Feedwater Isolation	≤ 10 (3)
	3) Containment Phase "A" Isolation	≤ 62 (2) / 72 (1)
	4) Containment Ventilation Isolation	≤ 4.75 (6)
	5) Motor-Driven Auxiliary Feedwater Pumps	≤ 60
	6) Emergency Service Water Pumps	≤ 32 (1) / 22 (8)
	7) Containment Fan Coolers	≤ 80 (1)(13) / 70 (8)(13)
	8) Control Room Isolation	NA

<< Engineered Safety Features Response Times >>

INITIATION SIGNAL AND FUNCTION		**RESPONSE TIME IN SECONDS**
3.	Pressurizer Pressure - Low	
	a. Safety Injection (ECCS) (10)(12)	≤ 27 (1) / 12 (5) [High Press. Injec.] ≤ 29 (14) / 27 (15) [Low Press. Injec.]
	1) Reactor Trip	≤ 2
	2) Feedwater Isolation	≤ 10 (3)
	3) Containment Phase "A" Isolation	≤ 62 (2) / 72 (1)
	4) Containment Ventilation Isolation	≤ 4.75 (6)
	5) Motor-Driven Auxiliary Feedwater Pumps	≤ 60
	6) Emergency Service Water Pumps	≤ 32 (1) / 22 (8)
	7) Containment Fan Coolers	≤ 80 (1)(13) / 70 (8)(13)
	8) Control Room Isolation	NA
4.	Main Steam Line Pressure - Low	
	a. Safety Injection (ECCS) (10)(12)	≤ 12 (5) / 22 (4)
	1) Reactor Trip	≤ 2
	2) Feedwater Isolation	≤ 10 (3)
	3) Containment Phase "A" Isolation	≤ 62 (2) / 72 (1)
	4) Containment Ventilation Isolation	≤ 4.75 (6)
	5) Motor-Driven Auxiliary Feedwater Pumps	≤ 60
	6) Emergency Service Water Pumps	≤ 32 (1) / 22 (8)
	7) Containment Fan Coolers	≤ 80 (1)(13) / 70 (8)(13)
	8) Control Room Isolation	NA
	b. Steam Line Isolation	≤ 7 (9)

<< Engineered Safety Features Response Times >>

INITIATION SIGNAL AND FUNCTION		**RESPONSE TIME IN SECONDS**
5.	Containment Pressure - High-3	
	a. Containment Spray	≤ 12.3 (8) / 24.3 (11)
	b. Containment Phase "B" Isolation	≤ 22.5 (1) / 12 (2)
6.	Containment Pressure - High-2	
	Steam Line Isolation	≤ 7 (9)
7.	Negative Steam Line Pressure Rate - High	
	Steam Line Isolation	≤ 7 (9)
8.	Steam Generator Water Level - High-High	
	a. Turbine Trip	≤ 2.5
	b. Feedwater Isolation	≤ 10 (3)
9.	Steam Generator Water Level - Low-Low	
	a. Motor-Driven Auxiliary Feedwater Pumps	≤ 61.5
	b. Turbine-Driven Auxiliary Feedwater Pumps	≤ 61.5
10.	Loss-of-Off-Site Power	
	Motor- and Turbine-Driven Auxiliary Feedwater Pumps	≤ 60
11.	Trip of All Main Feedwater Pumps	
	Motor-Driven Auxiliary Feedwater Pumps	NA
NOTE: AFW Isolation response time is only applicable when there is AFW flow.		
12	Steam Line Differential Pressure--High Coincident with Main Steam Line Isolation Signal	
	Isolate Auxiliary Feedwater to the Affected Steam Generator	≤ 41

<< Engineered Safety Features Response Times >>

INITIATION SIGNAL AND FUNCTION		**RESPONSE TIME IN SECONDS**
13.	RWST Level--Low-Low	
	a. Safety Injection Switchover to Containment Sump Coincident with Safety Injection	≤ 20
	b. Safety Injection Switchover to Containment Sump Coincident with Containment Spray	≤ 103
14.	Containment Radioactivity-High	
	a. Normal Containment Purge Isolation	≤ 3.5 (7)
	b. Pre-Entry Containment Purge Isolation	≤ 15 (7)

TABLE NOTATIONS	
(1)	Diesel generator starting and sequence loading delays included. RHR pump not included.
(2)	Diesel generator starting and sequence loading delay not included. Off site power available.
(3)	Applicable to Main Feedwater Isolation Valves only. Other valves that get a Feedwater Isolation signal are excluded.
(4)	Diesel generator starting and sequence loading delay included. RHR pumps not included.
(5)	Diesel generator starting and sequence loading delays not included. RHR pumps not included.
(6)	Isolation of Normal Containment Purge. This value is not applicable to Pre-entry Containment Purge which is permitted to be operating only in MODES 5 or 6 as per Technical Specification 3.6.1.7.
(7)	Response time testing of radiation monitors is not required.
(8)	Diesel generator starting delay not included, but sequencer loading delays are included.

<< Engineered Safety Features Response Times >>

TABLE NOTATIONS	
(9)	Applicable to main steam isolation valves only. Other valves that get a Main Steam Isolation signal (for example, bypass isolation, main steam drains to the condenser) are excluded.
(10)	RWST to CSIP opening times and VCT to CSIP closing times not included. Response time for these valves shall be ≤ 17$^{(2)}$ / 27$^{(1)}$ seconds for the RWST to CSIP valves and ≤ 27$^{(2)}$ / 37$^{(1)}$ seconds for the VCT to CSIP valves. [7.3.23]
	a) The Table Notation NOTEs (1) and (2) are related to on-site and off-site power considerations.
	b) The 27 second value is the collective stroke times for both valves to stroke,
	c) The 17 second value is specific to the RWST to CSIP stroke open time,
	d) The VCT to CSIP stroke close time is 10 seconds,
	e) The RWST to CSIP valve must complete its stroke open function before the system logic will allow the permissive for the VCT to CSIP valve to begin closure - hence 27 seconds minus 17 seconds equals 10 seconds maximum for this valve.
(11)	Containment spray response times includes diesel generator starting and sequencer loading delays and HI-1 signal. The containment spray HI-3 signal is excluded since HI-3 is actuated prior to the closure of the diesel generator output breaker.
(12)	Alternate Miniflow Valve (1CS-746 and 1CS-752) open/close times on Safety Injection signal coincident with RCS high pressure and low pressure are not included. These valves shall open in less than 15 seconds and close in less than 15 seconds.
(13)	These values are based on stroke times of valves 1SW-39 and 1SW-40. Since the Containment Fan Coolers are direct driven, their ESF response time is the time from the ESF actuation setpoint until the fan cooler circuit breaker closure actuation. This time shall not exceed the valve stroke time. (Reference letter number MS-864348(E) and ESR 94-00546.) The Containment Analysis assumes 110 seconds due to two-phase flow with LOCA/LOOP.
(14)	Diesel generator starting and sequence loading delays included. This entry is specific to RHR response.
(15)	Diesel generator starting and sequence loading not included. This entry is specific to RHR response.

<< Reactor Vessel Material Surveillance Program - Withdrawal Schedule* >>**

CAPSULE NUMBER	VESSEL LOCATION	LEAD* FACTOR	WITHDRAWAL TIME (EFPY)**
U	343°	2.9	1st Refueling
V	107°	3.3	3 EFPY
X	287°	2.68	9 EFPY
W	110°	2.38[(a)] 2.68[(b)]	18 EFPY ****
Y	290°	2.38[(a)] 2.68[(b)]	Either Y or Z but not both shall be withdrawn during Refueling Outage 21, at 27.2 EFPY. *****
Z	340°	2.38[(a)] 2.68[(b)]	

TABLE NOTATIONS	
(a)	Factor by which the capsule leads the vessel's maximum inner wall fluence for cycles 1 through 10.
(b)	Factor by which the capsule leads the vessel's maximum inner wall fluence for cycles 11 through 55 EFPY. Lead factor updated based on operation at an uprated core power level of 2948 MWt and due to the equilibrium loading pattern near the periphery for uprated power conditions.
*	The factor by which the capsule fluence leads the vessel maximum inner wall fluence. (Values are estimates based on calculations)
**	Withdrawal time may be modified to coincide with those refueling outages or plant shutdowns most closely approaching the withdrawal schedules.
***	Changes to the reactor materials surveillance schedule must receive NRC approval prior to implementation. (Reference: Section III.B.3 of 10 CFR 50 Appendix H)

<< Reactor Vessel Material Surveillance Program - Withdrawal Schedule* >>**

TABLE NOTATIONS	
****	A withdrawal time range of 13.66 to 21.32 EFPY is permitted. Withdrawal of Capsule "W" occurred during Refueling Outage 16 (RFO-16), which is the outage immediately following the operating cycle in which the capsule fluence is equivalent to the 60-year maximum vessel fluence. {7.1.1}, {7.1.2}
*****	The licensee proposes to remove either Capsule Y or Z during their 21st refueling outage, circa 2018, when the capsule will have been exposed to a total neutron fluence of 9.39 x 1019 n/cm2 (E > 1.0 MeV). Removing the capsule at this target fluence will provide valuable information in the higher fluence ranges, for which there is currently little experience or data. The staff reiterates the recommendation found in the GALL Report that either Capsule Y or Z be withdrawn and tested while the other is left in place and maintained in readiness should it become necessary at a future date. [7.3.47]

<< Snubbers >>

1.0 PURPOSE

To demonstrate that each snubber is OPERABLE by the performance of the following augmented inspection program.

Each snubber shall be demonstrated OPERABLE by performance of the following augmented Inservice Inspection Program.

2.0 REFERENCES

1. Technical Specification 3/4.7.8
2. ASME OM Code 2001 edition with 2003 addenda
3. ASME OM Code Case OMN-13
4. AD-EG-HNP-1618

3.0 DEFINITIONS

Definitions applicable to the snubber program and snubbers are in AD-EG-HNP-1618.

4.0 INSTRUCTIONS

4.1 <u>Snubber Removal or Out of Service</u>

Technical Specification 3.7.8 and the surveillance requirements apply to all snubbers. The only snubbers excluded from the requirements are those installed on non-safety related systems and then only if their failure or failure of the system on which they are installed would have no adverse effect on any safety-related system. A listing of individual snubbers is maintained by Inservice Inspection (ISI) Group.

<< Snubbers >>

NOTE

Hangers are not subject to T.S. 3.7.8; the supported system is immediately declared INOPERABLE when hangers are removed or found damaged, unless an engineering evaluation has been completed. An exception to this requirement is if the hanger's only function is to secure a snubber. In this case, the snubber is INOPERABLE and only T.S. 3.7.8 applies.

4.1.1 System Operability

Technical Specification 3.7.8 allows 72 hours for one or more snubbers to be out of service. The attached system must be declared INOPERABLE by the end of this 72 hour period unless the snubber(s) are repaired or replaced, and a satisfactory engineering evaluation on the system is completed, except as specified in Section 4.1.2. Snubber removal on redundant trains of a system is not allowed on systems required to be OPERABLE in the existing mode. For example, a snubber cannot be removed from "A" RHR concurrently with an INOPERABLE snubber on "B" RHR.

For those systems covered by a specific technical specification, the action required shall be as specified. If the attached piping is common to both safety trains of a system, the snubber shall be isolated from at least one train, or both shall be declared INOPERABLE. However, if the piping attached to the INOPERABLE snubber is a non-essential portion of the system, it may be isolated from the rest of the system, removed from service and depressurized, and the system may be declared OPERABLE, and operation may continue. Such actions must be accomplished within the times specified by the system technical specification.

Snubbers located on piping with a containment isolation valve where the snubber is adjacent to the valve require application of Specification 3.6.3 for that valve, after expiration of the 72 hour limit per Technical Specification 3.7.8.

During power operations, the required number of hydraulic snubbers per steam generator is three (RAF-3106).

For those systems not covered by a specific Technical Specification, the piping attached to the INOPERABLE snubber shall be isolated, removed from service and depressurized within the next 72 hours; that is, an additional 72 hours after expiration of the 72 hours in Technical Specification 3.7.8.

Operation of Technical Specification systems in modes where their LCOs are not applicable is not restricted due to snubber removal (for example, use of AFW in MODE 5). However, if water hammer does occur, it should be recorded and referred to Harris Nuclear Plant Engineering for inspection and evaluation.

<< Snubbers >>

4.1.2 Determination of Inoperability & Engineering Evaluations

The responsibility for determination of operability or inoperability rests with the Operating Shift. The ISI Group will be responsible for providing the necessary technical input to assist with making or validating any operability determinations.

The 72 hour clock in Technical Specification 3.7.8 can be started by three events: removal for access or testing, visual inspection, or bench testing. These events are discussed by the following:

a. Removal of a snubber for testing, or access to do work, requires starting of the 72 hour clock but does not require an engineering evaluation under the action statement of the specification. The clock is stopped when the snubber is reinstalled and satisfactorily examined.

b. If a snubber is declared INOPERABLE based on visual inspection, the 72 hour clock may be stopped with either:

   (1) a successful functional test and reinstallation of the snubber, or

   (2) installation of a repaired or replacement snubber and verification that the "as left" condition of the pipe is acceptable and meets the design criteria of the system (PCR 4839); this is documented on the Work Order (WO). If the snubber fails the functional test, the clock continues to run, unless option (2) is completed.

c. If a snubber is declared INOPERABLE based on a functional test, or is verified INOPERABLE by a functional test following visual determination of inoperability, the 72 hour clock is started or continues to run, and continues until a repaired or replacement snubber is installed and satisfactorily examined, and an engineering evaluation is complete either per option (2) above or by separate Engineering Change Request (ECR). The evaluation must also address the root cause of the failure. Determination of reportability is required when a generic program deficiency or specific design deficiency is identified as the root cause.

4.2 <u>Visual Examinations, Functional Testing and Service Life Monitoring</u>

Visual examinations, functional testing and service life monitoring shall be performed in accordance with the ASME OM Code Subsection ISTD 2001 edition and 2003 addenda and Code Case OMN-13 as described in AD-EG-HNP-1618.

<< Containment Isolation Valves >>

PENETRATION NO.	VALVE NO.CP&L (EBASCO)	FUNCTION	MAXIMUM ISOLATION TIME (SEC)	APPLICABLE NOTES	REDUNDANT VALVE(S)
1.	PHASE A ISOLATION				
1	1MS-29 (MS-V126)	MS LINE C TO SAMPLING SYSTEM	60	1, 6, 13	NONE
2	1MS-27 (MS-V124)	MS LINE B TO SAMPLING SYSTEM	60	1, 6, 13	NONE
3	1MS-25 (MS-V122)	MS LINE A TO SAMPLING SYSTEM	60	1, 6, 13	NONE
7	1CS-7 (CS-V511)	CVCS NORMAL LTDN ISOL	10	7, 13	1CS-11
7	1CS-8 (CS-V512)	CVCS NORMAL LTDN ISOL	10	7, 13	1CS-11
7	1CS-9 (CS-V513)	CVCS NORMAL LTDN ISOL	10	7, 13	1CS-11
7	1CS-11 (CS-V518)	CVCS NORMAL LTDN ISOL	10	7, 13	1CS-7,8, 9 and 10
12	1CS-470 (CS-V516)	RCP SEAL WTR RETURN & EXCESS LTDN	10	7, 13	1CS-472
12	1CS-472 (CS-V517)	RCP SEAL WTR RETURN & EXCESS LTDN	10	7, 13	1CS-470 and 471
33	1SP-209 (SP-V408)	GAS RETURN FROM PASS SKID #2	5	7, 13	1SP-208
33	1SP-208 (SP-V409)	GAS RETURN FROM PASS SKID #2	5	7, 13	1SP-209
37	1CC-176 (CC-V172)	CCW TO RCDT & EXCESS LTDN HEAT EXCHS	10	1, 6, 13	NONE
38	1CC-202 (CC-V182)	CCW FROM RCDT & EXCESS LTDN HEAT EXCHS	10	1, 6, 13	NONE
40	1RC-161 (RC-D525)	REACTOR MAKEUP WTR TO PRT	60	7, 13	1RC-164
42	1ED-121 (WL-L600)	RCDT PUMPS DISCH	10	7, 13	1ED-125
42	1ED-125 (WL-D650)	RCDT PUMPS DISCH	10	7, 13	1ED-121 and 119
73A	1SP-12 (SP-V300)	HYDROGEN ANALYZER A	60	7, 13	1SP-915
73A	1SP-915 (SP-V348)	HYDROGEN ANALYZER A	60	7, 13	1SP-12

<< Containment Isolation Valves >>

PENETRATION NO.	VALVE NO.CP&L (EBASCO)	FUNCTION	MAXIMUM ISOLATION TIME (SEC)	APPLICABLE NOTES	REDUNDANT VALVE(S)
1. PHASE A ISOLATION (continued)					
73B	1SP-941 (SP-V301)	HYDROGEN ANALYZER A	60	7, 13	1SP-917
73B	1SP-917 (SP-V349)	HYDROGEN ANALYZER A	60	7, 13	1SP-941
74	1ED-94 (MD-V36)	CNMT SUMP PUMP DISCH	60	7, 13	1ED-95
74	1ED-95 (MD-V77)	CNMT SUMP PUMP DISCH	60	7, 13	1ED-94
76A	1SI-179 (SI-V554)	ACCUMULATOR FILL FROM RWST	10	7, 13	1SI-182
76B	1SI-263 (SI-V555)	ACCUMULATOR DRAIN TO RWST	10	7, 13	1SI-264
76B	1SI-264 (SI-V550)	ACCUMULATOR DRAIN TO RWST	10	7, 13	1SI-263
77A	1SI-287 (SI-V530)	NITROGEN SUPPLY	10	7, 13	1SI-290
77B	1RC-141 (RC-D528)	PRT NITROGEN CONNECTION	10	7, 13	1RC-144
77B	1RC-144 (RC-D529)	PRT NITROGEN CONNECTION	10	7, 13	1RC-141
77C	1ED-164 (WG-D590)	RCDT HYDROGEN CONNECTION	10	7, 13	1ED-161
77C	1ED-161 (WG-D291)	RCDT HYDROGEN CONNECTION	10	7, 13	1ED-164
78A	1SP-948 (SP-V111)	RCS SAMPLE	60	7, 13	1SP-949
78A	1SP-949 (SP-V23)	RCS SAMPLE	60	7, 13	1SP-948
78B	1SP-40 (SP-V11)	PRESSURIZER LIQ SAMPLE	60	7, 13	1SP-41
78B	1SP-41 (SP-V12)	PRESSURIZER LIQ SAMPLE	60	7, 13	1SP-40
78C	1SP-59 (SP-V1)	PRESSURIZER STEAM SAMPLE	60	7, 13	1SP-60
78C	1SP-60 (SP-V2)	PRESSURIZER STEAM SAMPLE	60	7, 13	1SP-59
78D	1SP-78 (SP-V113)	ACCUMULATOR A SAMPLE	60	7, 13	1SP-85

<< Containment Isolation Valves >>

PENETRATION NO.	VALVE NO.CP&L (EBASCO)	FUNCTION	MAXIMUM ISOLATION TIME (SEC)	APPLICABLE NOTES	REDUNDANT VALVE(S)
1.	PHASE A ISOLATION (continued)				
78D	1SP-81 (SP-V114)	ACCUMULATOR B SAMPLE	60	7, 13	1SP-85
78D	1SP-84 (SP-V115)	ACCUMULATOR C SAMPLE	60	7, 13	1SP-85
78D	1SP-85 (SP-V116)	ACCUMULATORS SAMPLE	60	7, 13	1SP-78, 81, and 84
80	1IA-819 (IA-V192)	INSTRUMENT AIR SUPPLY	60	7, 13	1IA-220
83A	1SP-916 (SP-V448)	RADIATION MONITOR REM-3502A	60	7, 13	1SP-16
83A	1SP-16 (SP-V449)	RADIATION MONITOR REM-3502A	60	7, 13	1SP-916
83B	1SP-918 (SP-V450)	RADIATION MONITOR REM-3502A	60	7, 13	1SP-939
83B	1SP-939 (SP-V451)	RADIATION MONITOR REM-3502A	60	7, 13	1SP-918
86A	1SP-42 (SP-V308)	HYDROGEN ANALYZER B	60	7, 13	1SP-919
86A	1SP-919 (SP-V314)	HYDROGEN ANALYZER B	60	7, 13	1SP-42
86B	1SP-62 (SP-V309)	HYDROGEN ANALYZER B	60	7, 13	1SP-943
86B	1SP-943 (SP-V315)	HYDROGEN ANALYZER B	60	7, 13	1SP-62
88	1SP-201 (SP-V406)	LIQUID RETURN FROM PASS SKID #1	5	7, 13	1SP-200
88	1SP-200 (SP-V407)	LIQUID RETURN FROM PASS SKID #1	5	7, 13	1SP-201
91	1SW-240 (SW-B89)	SERVICE WTR FROM NNS FAN COILS	60	7, 13	1SW-242
91	1SW-242 (SW-B90)	SERVICE WTR FROM NNS FAN COILS	60	7, 13	1SW-240
92	1SW-231 (SW-B88)	SERVICE WTR TO NNS FAN COILS	60	7, 13	1SW-233
105	1FP-347 (FP-B1)	FIRE WATER SPRINKLER SUPPLY	60	7, 13	1FP-349

<< Containment Isolation Valves >>

PENETRATION NO.	VALVE NO.CP&L (EBASCO)	FUNCTION	MAXIMUM ISOLATION TIME (SEC)	APPLICABLE NOTES	REDUNDANT VALVE(S)

2. PHASE B ISOLATION

NOTE: Valve 1CC-207 in penetration 35 is not classified as a containment isolation valve.

PENETRATION NO.	VALVE NO.CP&L (EBASCO)	FUNCTION	MAXIMUM ISOLATION TIME (SEC)	APPLICABLE NOTES	REDUNDANT VALVE(S)
35	1CC-208 (CC-V170)	CCW TO RCPS	10	7, 13	1CC-211
36	1CC-297 (CC-V184)	CCW FROM RCP BEARING OIL HXS	10	7, 13	1CC-299
36	1CC-299 (CC-V183)	CCW FROM RCP BEARING OIL HXS	10	7, 13	1CC-297 and 298
39	1CC-249 (CC-V191)	CCW FROM RCP THERMAL BARRIER HXS	10	7, 13	1CC-251
39	1CC-251 (CC-V190)	CCW FROM RCP THERMAL BARRIER HXS	10	7, 13	1CC-249 and 250

3. SAFETY INJECTION ACTUATION

NOTE: Valve 1CS-235 in penetration 8 is not classified as a containment isolation valve; refer to Specifications 3.1.2.1, 3.1.2.2, 3.3.3.5.b, 3.5.2, and 3.5.3.

PENETRATION NO.	VALVE NO.CP&L (EBASCO)	FUNCTION	MAXIMUM ISOLATION TIME (SEC)	APPLICABLE NOTES	REDUNDANT VALVE(S)
8	1CS-238 (CS-V610)	CVCS NORMAL CHARGING	10	7, 13	1CS-477

NOTE: Refer to Attachment 8 for additional requirements for SG Blowdown and Sample valves.

PENETRATION NO.	VALVE NO.CP&L (EBASCO)	FUNCTION	MAXIMUM ISOLATION TIME (SEC)	APPLICABLE NOTES	REDUNDANT VALVE(S)
51	1BD-11 (BD-V11)	SG A BLOWDOWN	60	1, 6, 13	NONE
52	1BD-30 (BD-V15)	SG B BLOWDOWN	60	1, 6, 13	NONE
53	1BD-49 (BD-V19)	SB C BLOWDOWN	60	1, 6, 13	NONE
54	1SP-217 (SP-V120)	SG A SAMPLE	60	1, 6, 13	NONE
55	1SP-222 (SP-V121)	SG B SAMPLE	60	1, 6, 13	NONE
56	1SP-227 (SP-V122)	SG C SAMPLE	60	1, 6, 13	NONE

<< Containment Isolation Valves >>

PENETRATION NO.	VALVE NO. CP&L (EBASCO)	FUNCTION	MAXIMUM ISOLATION TIME (SEC)	APPLICABLE NOTES	REDUNDANT VALVE(S)
4. CONTAINMENT VENTILATION ISOLATION					
57	1CP-9 (CP-B1)	CONTAINMENT ATMOSPHERE PURGE MAKEUP (8")	3.5	5, 7, 13	1CP-6 and 7
57	1CP-10 (CP-B3)	CONTAINMENT ATMOSPHERE PURGE MAKEUP (42")	15	5, 7, 13	1CP-6 and 7
57	1CP-7 (CP-B4)	CONTAINMENT ATMOSPHERE PURGE MAKEUP (42")	15	5, 7, 13	1CP-9 and 10
57	1CP-6 (CP-B2)	CONTAINMENT ATMOSPHERE PURGE MAKEUP (8")	3.5	5, 7, 13	1CP-9 and 10
58	1CP-4 (CP-B7)	CONTAINMENT ATMOSPHERE PURGE EXHAUST (42")	15	5, 7, 13	1CP-1 and 3
58	1CP-5 (CP-B5)	CONTAINMENT ATMOSPHERE PURGE EXHAUST (8")	3.5	5, 7, 13	1CP-1 and 3
58	1CP-1 (CP-B8)	CONTAINMENT ATMOSPHERE PURGE EXHAUST (42")	15	5, 7, 13	1CP-4 and 5
58	1CP-3 (CP-B6)	CONTAINMENT ATMOSPHERE PURGE EXHAUST (8")	3.5	5, 7, 13	1CP-4 and 5
59	1CB-2 (CB-B1)	CONTAINMENT VACUUM RELIEF	5	7, 13	1CB-3
98	1CB-6 (CB-B2)	CONTAINMENT VACUUM RELIEF	5	7, 13	1CB-7

<< Containment Isolation Valves >>

PENETRATION NO.	VALVE NO. CP&L (EBASCO)	FUNCTION	MAXIMUM ISOLATION TIME (SEC)	APPLICABLE NOTES	REDUNDANT VALVE(S)
5.	MAIN STEAM LINE ISOLATION				
1	1MS-84 (MS-V3)	MSIV (SG C)	5	1, 4, 13	NONE
1	1MS-85 (MS-F3)	MSIV BYPASS (SG C)	10	1, 6, 13	NONE
1	1MS-301 (MS-V61)	MS DRAIN TO CONDENSER	60	1, 6, 13	NONE
2	1MS-82 (MS-V2)	MSIV (SG B)	5	1, 4, 13	NONE
2	1MS-83 (MS-F2)	MSIV BYPASS (SG B)	10	1, 6, 13	NONE
2	1MS-266 (MS-V60)	MS DRAIN TO CONDENSER	60	1, 6, 13	NONE
3	1MS-80 (MS-V1)	MSIV (SG A)	5	1, 4, 13	NONE
3	1MS-81 (MS-F1)	MSIV BYPASS (SG A)	10	1, 6, 13	NONE
3	1MS-231 (MS-V59)	MS DRAIN TO CONDENSER	60	1, 6, 13	NONE
6.	MAIN FEEDWATER LINE ISOLATION				

NOTE: Refer to Attachment 8 for additional requirements for Main Feedwater valves.

4	1FW-159 (FW-V26)	FEEDWATER LOOP A	8	1, 6, 12, 13	NONE
5	1FW-277 (FW-V27)	FEEDWATER LOOP B	8	1, 6, 12, 13	NONE
6	1FW-217 (FW-V28)	FEEDWATER LOOP C	8	1, 6, 12, 13	NONE

<< Containment Isolation Valves >>

PENETRATION NO.	VALVE NO. CP&L (EBASCO)	FUNCTION	MAXIMUM ISOLATION TIME (SEC)	APPLICABLE NOTES	REDUNDANT VALVE(S)

7. AUXILIARY FEEDWATER ISOLATION

> **NOTE:** AFW flow control valves are not classified as containment isolation valves; refer to Specification 3.7.1.2.

PENETRATION NO.	VALVE NO. CP&L (EBASCO)	FUNCTION	MAXIMUM ISOLATION TIME (SEC)	APPLICABLE NOTES	REDUNDANT VALVE(S)
108	1AF-55 (AF-V10)	AUXILIARY FEEDWATER TO SG A	24	1, 6, 13	NONE
108	1AF-137 (AF-V116)	AUXILIARY FEEDWATER TO SG A	24	1, 6, 13	NONE
109	1AF-93 (AF-V19)	AUXILIARY FEEDWATER TO SG B	24	1, 6, 13	NONE
109	1AF-143 (AF-V117)	AUXILIARY FEEDWATER TO SG B	24	1, 6, 13	NONE
110	1AF-74 (AF-V23)	AUXILIARY FEEDWATER TO SG C	24	1, 6, 13	NONE
110	1AF-149 (AF-V118)	AUXILIARY FEEDWATER TO SG C	24	1, 6, 13	NONE

8. REMOTE MANUAL VALVES

PENETRATION NO.	VALVE NO. CP&L (EBASCO)	FUNCTION	MAXIMUM ISOLATION TIME (SEC)	APPLICABLE NOTES	REDUNDANT VALVE(S)
1	1MS-72 (MS-V9)	MAIN STEAM C TO AUXILIARY FW TURBINE	N/A	1, 2, 6	NONE
1	1MS-62 (MS-P20)	SG PORV C	N/A	1, 2, 6	1MS-63
2	1MS-70 (MS-V8)	MAIN STEAM B TO AUXILIARY FW TURBINE	N/A	1, 2, 6	NONE
2	1MS-60 (MS-P19)	SG PORV B	N/A	1, 2, 6	1MS-61
3	1MS-58 (MS-P18)	SG PORV A	N/A	1, 2, 6	1MS-59
9	1CS-341 (CS-V522)	CVCS SEAL WATER TO RCP A	N/A	2, 7	1CS-344
10	1CS-382 (CS-V523)	CVCS SEAL WATER TO RCP B	N/A	2, 7	1CS-385
11	1CS-423 (CS-V524)	CVCS SEAL WATER TO RCP C	N/A	2, 7	1CS-426
13	1SI-340 (SI-V579)	SI-LOW HEAD TO COLD LEGS	N/A	1, 2, 7	1SI-346
14	1SI-341 (SI-V578)	SI-LOW HEAD TO COLD LEGS	N/A	1, 2, 7	1SI-347

<< Containment Isolation Valves >>

PENETRATION NO.	VALVE NO. CP&L (EBASCO)	FUNCTION	MAXIMUM ISOLATION TIME (SEC)	APPLICABLE NOTES	REDUNDANT VALVE(S)
8.	REMOTE MANUAL VALVES (continued)				
15	1RH-2 (RH-V503)	RHR PUMP A SUCTION FROM HOT LEG	N/A	1, 2, 8	NONE
16	1RH-40 (RH-V501)	RHR PUMP B SUCTION FROM HOT LEG	N/A	1, 2, 8	NONE
17	1SI-3 (SI-V505)	SI-HIGH HEAD TO COLD LEGS	N/A	1, 2, 7	1SI-8, 9, and 10
17	1SI-4 (SI-V506)	SI-HIGH HEAD TO COLD LEGS	N/A	1, 2, 7	1SI-8, 9, and 10
18	1SI-359 (SI-V587)	SI-LOW HEAD TO HOT LEGS	N/A	1, 2, 7	1SI-134 and 135
20	1SI-107 (SI-V500)	SI-HIGH HEAD TO HOT LEGS	N/A	1, 2, 7	1SI-127, 128, and 129
21	1SI-86 (SI-V501)	SI-HIGH HEAD TO HOT LEGS	N/A	1, 2, 7	1SI-104, 105, and 106
22	1SI-52 (SI-V502)	SI-HIGH HEAD TO COLD LEGS	N/A	1, 2, 7	1SI-72, 73, and 74
23	1CT-50 (CT-V21)	CONTAINMENT SPRAY A	N/A	2, 7	1CT-53
24	1CT-88 (CT-V43)	CONTAINMENT SPRAY B	N/A	2, 7	1CT-91
25	1SW-92 (SW-B46)	SERVICE WATER TO FAN COOLER AH-3	N/A	1, 2, 6	NONE
26	1SW-91 (SW-B45)	SERVICE WATER TO FAN COOLER AH-2	N/A	1, 2, 6	NONE
27	1SW-225 (SW-B52)	SERVICE WATER TO FAN COOLER AH-1	N/A	1, 2, 6	NONE
28	1SW-227 (SW-B51)	SERVICE WATER TO FAN COOLER AH-4	N/A	1, 2, 6	NONE
29	1SW-97 (SW-B47)	SERVICE WATER FROM FAN COOLER AH-3	N/A	1, 2, 6	NONE
30	1SW-109 (SW-B49)	SERVICE WATER FROM FAN COOLER AH-2	N/A	1, 2, 6	NONE
31	1SW-98 (SW-B48)	SERVICE WATER FROM FAN COOLER AH-1	N/A	1, 2, 6	NONE
32	1SW-110 (SW-B50)	SERVICE WATER FROM FAN COOLER AH-4	N/A	1, 2, 6	NONE

<< Containment Isolation Valves >>

PENETRATION NO.	VALVE NO. CP&L (EBASCO)	FUNCTION	MAXIMUM ISOLATION TIME (SEC)	APPLICABLE NOTES	REDUNDANT VALVE(S)
8. REMOTE MANUAL VALVES (continued)					
47	1SI-300 (SI-V571)	CONTAINMENT SUMP TO RHR PUMP A	N/A	1, 2, 8	NONE
48	1SI-301 (SI-V570)	CONTAINMENT SUMP TO RHR PUMP B	N/A	1, 2, 8	NONE
49	1CT-105 (CT-V6)	CONTAINMENT SUMP TO CT PUMP A	N/A	1, 2, 8	NONE
50	1CT-102 (CT-V7)	CONTAINMENT SUMP TO CT PUMP B	N/A	1, 2, 8	NONE
63	1CM-2 (CM-B5)	HYDROGEN PURGE EXHAUST	N/A	2, 7	1CM-4

9. MANUAL VALVES

NOTE: Manual valves must be locked closed to be considered OPERABLE, except as provided in Table Notation 3.

PENETRATION NO.	VALVE NO. CP&L (EBASCO)	FUNCTION	MAXIMUM ISOLATION TIME (SEC)	APPLICABLE NOTES	REDUNDANT VALVE(S)
4	1FW-165 (FW-V89)	FEEDWATER LOOP A HYDRAZINE CONNECTION (LOCKED CLOSED)	N/A	1, 6, 13	NONE
4	1FW-163 (FW-V90)	FEEDWATER LOOP A AMMONIA CONNECTION (LOCKED CLOSED)	N/A	1, 6, 13	NONE
5	1FW-279 (FW-V91)	FEEDWATER LOOP B AMMONIA CONNECTION (LOCKED CLOSED)	N/A	1, 6, 13	NONE
5	1FW-281 (FW-V92)	FEEDWATER LOOP B HYDRAZINE CONNECTION (LOCKED CLOSED)	N/A	1, 6, 13	NONE
6	1FW-223 (FW-V93)	FEEDWATER LOOP C HYDRAZINE CONNECTION (LOCKED CLOSED)	N/A	1, 6, 13	NONE
6	1FW-221 (FW-V94)	FEEDWATER LOOP C AMMONIA CONNECTION (LOCKED CLOSED)	N/A	1, 6, 13	NONE
34	1LT-6 (LT-V2)	ILRT ROTOMETER (LOCKED CLOSED)	N/A	N/A	NONE
41	1SA-80 (SA-V14)	SERVICE AIR SUPPLY (LOCKED CLOSED)	N/A	3	1SA-82

<< Containment Isolation Valves >>

PENETRATION NO.	VALVE NO. CP&L (EBASCO)	FUNCTION	MAXIMUM ISOLATION TIME (SEC)	APPLICABLE NOTES	REDUNDANT VALVE(S)
8.	MANUAL VALVES (continued)				
42	1ED-119 (WL-D651)	RCDT PUMP DISCH BYPASS (LOCKED CLOSED)	N/A	3	1ED-125
44	1SF-145 (SF-D164)	REFUELING CAVITY CLEANUP (LOCKED CLOSED)	N/A	N/A	1SF-144
44	1SF-144 (SF-D165)	REFUELING CAVITY CLEANUP (LOCKED CLOSED)	N/A	N/A	1SF-145
45	1SF-118 (SF-D25)	REFUELING CAVITY CLEANUP (LOCKED CLOSED)	N/A	N/A	1SF-119
45	1SF-119 (SF-D26)	REFUELING CAVITY CLEANUP (LOCKED CLOSED)	N/A	N/A	1SF-118
51	1BD-270 (BD-V183)	SG 1A 1BD-11 BYPASS CIV (LOCKED CLOSED)	N/A	1, 3, 6	NONE
52	1BD-272 (BD-V184)	SG 1B 1BD-30 BYPASS CIV (LOCKED CLOSED)	N/A	1, 3, 6	NONE
53	1BD-274 (BD-V185)	SG 1C 1BD-49 BYPASS CIV (LOCKED CLOSED)	N/A	1, 3, 6	NONE
61	1CM-5 (CM-B6)	H2 PURGE MAKEUP (LOCKED CLOSED)	N/A	3	1CM-7
62	1LT-10 (LT-V4)	ILRT (LOCKED CLOSED)	N/A	N/A	NONE
63	1CM-4 (CM-B4)	H2 PURGE EXHAUST (LOCKED CLOSED)	N/A	3	1CM-2
79	1FP-355 (FP-V44)	FIRE WATER STANDPIPE SUPPLY (LOCKED CLOSED)	N/A	3	1FP-357
90	1DW-63 (DW-V120)	DEMIN WATER SUPPLY (LOCKED CLOSED)	N/A	3	1DW-65
96	1LT-4 (LT-V1)	ILRT (LOCKED CLOSED)	N/A	N/A	NONE

<< Containment Isolation Valves >>

PENETRATION NO.	VALVE NO. CP&L (EBASCO)	FUNCTION	MAXIMUM ISOLATION TIME (SEC)	APPLICABLE NOTES	REDUNDANT VALVE(S)
9. MANUAL VALVES (continued)					
108	1AF-174 (AF-V189)	WET LAY-UP TO SG A AFW HEADER (LOCKED CLOSED)	N/A	1, 6	NONE
108	1AF-155 (AF-V162)	AUX FW LOOP A HYDRAZINE CONNECTION (LOCKED CLOSED)	N/A	1, 6	NONE
108	1AF-153 (AF-V163)	AUX FW LOOP A AMMONIA CONNECTION (LOCKED CLOSED)	N/A	1, 6	NONE
109	1AF-173 (AF-V190)	WET LAY-UP TO SG B AFW HEADER (LOCKED CLOSED)	N/A	1, 6	NONE
109	1AF-159 (AF-V164)	AUX FW LOOP B HYDRAZINE CONNECTION (LOCKED CLOSED)	N/A	1, 6	NONE
109	1AF-157 (AF-V165)	AUX FW LOOP B AMMONIA CONNECTION (LOCKED CLOSED)	N/A	1, 6	NONE
110	1AF-175 (AF-V191)	WET LAY-UP TO SG C AFW HEADER (LOCKED CLOSED)	N/A	1, 6	NONE
110	1AF-163 (AF-V166)	AUX FW LOOP C HYDRAZINE CONNECTION (LOCKED CLOSED)	N/A	1, 6	NONE
110	1AF-161 (AF-V167)	AUX FW LOOP C AMMONIA CONNECTION (LOCKED CLOSED)	N/A	1, 6	NONE

<< Containment Isolation Valves >>

PENETRATION NO.	VALVE NO. CP&L (EBASCO)	FUNCTION	MAXIMUM ISOLATION TIME (SEC)	APPLICABLE NOTES	REDUNDANT VALVE(S)
10. CHECK VALVES					
8	1CS-477 (CS-V515)	CVCS NORMAL CHARGING	N/A	7	1CS-238
9	1CS-344 (CV-V25)	CVCS SEAL WATER TO RCP A	N/A	7	1CS-341
10	1CS-385 (CS-V26)	CVCS SEAL WATER TO RCP B	N/A	7	1CS-382
11	1CS-426 (CS-V27)	CVCS SEAL WATER TO RCP C	N/A	7	1CS-423
12	1CS-471 (CS-V67)	CVCS SEAL WATER RETURN & EXCESS LETDOWN	N/A	7	1CS-472
13	1SI-346 (SI-V581)	SI-LOW HEAD TO COLD LEGS	N/A	1, 7	1SI-340
14	1SI-347 (SI-V580)	SI-LOW HEAD TO COLD LEGS	N/A	1, 7	1SI-341
17	1SI-8 (SI-V17)	SI-HIGH HEAD TO LOOP A COLD LEG	N/A	1, 7	1SI-3, 4, and 43
17	1SI-9 (SI-V23)	SI-HIGH HEAD TO LOOP B COLD LEG	N/A	1, 7	1SI-3, 4, and 43
17	1SI-10 (SI-V29)	SI-HIGH HEAD TO LOOP C COLD LEG	N/A	1, 7	1SI-3, 4, and 43
18	1SI-134 (SI-V510)	SI-LOW HEAD TO LOOP A HOT LEG	N/A	1, 7	1SI-359
18	1SI-135 (SI-V511)	SI-LOW HEAD TO LOOP B HOT LEG	N/A	1, 7	1SI-359
20	1SI-127 (SI-V84)	SI-HIGH HEAD TO LOOP A HOT LEG	N/A	1, 7	1SI-107
20	1SI-128 (SI-V90)	SI-HIGH HEAD TO LOOP B HOT LEG	N/A	1, 7	1SI-107
20	1SI-129 (SI-V96)	SI-HIGH HEAD TO LOOP C HOT LEG	N/A	1, 7	1SI-107
21	1SI-104 (SI-V39)	SI-HIGH HEAD TO LOOP A HOT LEG	N/A	1, 7	1SI-86
21	1SI-105 (SI-V45)	SI-HIGH HEAD TO LOOP B HOT LEG	N/A	1, 7	1SI-86
21	1SI-106 (SI-V51)	SI-HIGH HEAD TO LOOP C HOT LEG	N/A	1, 7	1SI-86

<< Containment Isolation Valves >>

PENETRATION NO.	VALVE NO. CP&L (EBASCO)	FUNCTION	MAXIMUM ISOLATION TIME (SEC)	APPLICABLE NOTES	REDUNDANT VALVE(S)
10. CHECK VALVES (continued)					
22	1SI-72 (SI-V63)	SI-HIGH HEAD TO LOOP A COLD LEG	N/A	1, 7	1SI-52
22	1SI-73 (SI-V69)	SI-HIGH HEAD TO LOOP B COLD LEG	N/A	1, 7	1SI-52
22	1SI-74 (SI-V75)	SI-HIGH HEAD TO LOOP C COLD LEG	N/A	1, 7	1SI-52
23	1CT-53 (CT-V27)	CONTAINMENT SPRAY TRAIN A	N/A	7	1CT-50
24	1CT-91 (CT-V51)	CONTAINMENT SPRAY TRAIN B	N/A	7	1CT-88
35	1CC-211 (CC-V171)	CCW TO RCPS	N/A	7	1CC-208
36	1CC-298 (CC-V51)	CCW FROM RCP BEARING OIL HSX	N/A	7	1CC-299
39	1CC-250 (CC-V50)	CCW FROM RCP THERMAL BARRIER HXS	N/A	7	1CC-251
40	1RC-164 (RC-V525)	DEMIN WATER TO PRT	N/A	7	1RC-161
41	1SA-82 (SA-V15)	SERVICE AIR SUPPLY	N/A	7	1SA-80
59	1CB-3 (CB-V1)	CONTAINMENT VACUUM RELIEF	N/A	7	1CB-2
61	1CM-7 (CM-V1)	HYDROGEN PURGE MAKEUP	N/A	7	1CM-5
76A	1SI-182 (SI-V150)	ACCUMULATOR FILL FROM RWST	N/A	7	1SI-179
77A	1SI-290 (SI-V188)	NITROGEN SUPPLY	N/A	7	1SI-287
79	1FP-357 (FP-V48)	FIRE WATER STANDPIPE SUPPLY	N/A	7	1FP-355
80	1IA-220 (1A-V33)	INSTRUMENT AIR SUPPLY	N/A	7	1IA-819
90	1DW-65 (DW-V121)	DEMIN WATER SUPPLY	N/A	7	1DW-63
92	1SW-233 (SW-V142)	SERVICE WATER TO NNS FAN COILS	N/A	7	1SW-231

<< Containment Isolation Valves >>

PENETRATION NO.	VALVE NO. CP&L (EBASCO)	FUNCTION	MAXIMUM ISOLATION TIME (SEC)	APPLICABLE NOTES	REDUNDANT VALVE(S)
10. CHECK VALVES (continued)					
94A	PDT-01CB-7680BISB-CV (B)	EXCS FLOW CHK VLV FOR CNMT VACUUM RELIEF SENSING	N/A	1, 10	NONE
94B	PDT-01CB-7680BSB-CV (B)	EXCS FLOW CHK VLV FOR CNMT VACUUM RELIEF SENSING	N/A	1, 10	NONE
94C	PDT-01CP-7611S-CV (B)	EXCS FLOW CHK VLV FOR CNMT VACUUM RELIEF SENSING	N/A	1, 10	NONE
95A	PDT-01CB-7680ASA-CV (B)	EXCS FLOW CHK VLV FOR CNMT VACUUM RELIEF SENSING	N/A	1, 10	NONE
95B	PDT-01CB-7680AISA-CV (B)	EXCS FLOW CHK VLV FOR CNMT VACUUM RELIEF SENSING	N/A	1, 10	NONE

<< Containment Isolation Valves >>

PENETRATION NO.	VALVE NO. CP&L (EBASCO)	FUNCTION	MAXIMUM ISOLATION TIME (SEC)	APPLICABLE NOTES	REDUNDANT VALVE(S)

11. RELIEF VALVES

NOTE: SG Safety Relief Valves are governed by Specification 3.7.1.1.

PENETRATION NO.	VALVE NO. CP&L (EBASCO)	FUNCTION	MAXIMUM ISOLATION TIME (SEC)	APPLICABLE NOTES	REDUNDANT VALVE(S)
7	1CS-10 (CS-R500)	CVCS NORMAL LETDOWN	N/A	7, 9	1CS-11
15	1RH-7 (RH-R501)	RHR SUCTION FROM HOT LEG	N/A	1, 8, 9	NONE
16	1RH-45 (RH-R500)	RHR SUCTION FROM HOT LEG	N/A	1, 8, 9	NONE
29	1SW-95 (SW-R1)	SERVICE WATER FROM FAN COOLER AH-3	N/A	1, 6, 9	NONE
30	1SW-107 (SW-R3)	SERVICE WATER FROM FAN COOLER AH-2	N/A	1, 6, 9	NONE
31	1SW-96 (SW-R2)	SERVICE WATER FROM FAN COOLER AH-1	N/A	1, 6, 9	NONE
32	1SW-108 (SW-R4)	SERVICE WATER FROM FAN COOLER AH-4	N/A	1, 6, 9	NONE
38	1CC-194 (CC-R6)	CCW FROM EXCESS LETDOWN HEAT EXCHANGER	N/A	1, 7, 9	1CC-202 and 176
38	1CC-186 (CC-R5)	CCW FROM RCDT HEAT EXCHANGER	N/A	1, 7, 9	1CC-202 and 176
91	1SW-1494 (SW-R18)	NSW CONT FAN UNITS RETURN HEADER RELIEF VLV (AH-37, AH-38, AND AH-39)	N/A	7, 9	1SW-242

<< Containment Isolation Valves >>

TABLE NOTATIONS	
(1)	This valve is not subject to Type C leakage tests.
(2)	Remote manual valves may be opened as required for plant operations.
(3)	Manual valves in this penetration may be unlocked and opened as allowed under the action requirements, or on an intermittent basis under administrative controls established by the Plant Nuclear Safety Committee for each particular situation. The administrative controls shall include as a minimum stationing a dedicated operator at the valve controls, who is in continuous communication with the control room.
(4)	The Main Steam Isolation Valves (MSIVs) are included for table completeness. The requirements of Technical Specification 3.6.3 do not apply because the OPERABILITY requirements for the MSIVs are governed by Technical Specification 3.7.1.5.
(5)	This valve may be opened only as permitted by Technical Specification 3.6.1.7.
(6)	For this valve, the closed system in which it is located is considered to be an OPERABLE isolation valve for purposes of compliance with the initial ACTION statement of Specification 3.6.3 which states "maintain at least one isolation valve OPERABLE. . ." Further action under Specification 3.6.3 is still required to isolate the affected penetration or to shut down in accordance with Actions a, b, c, or d. Reopening of a valve declared INOPERABLE to comply with Tech Spec ACTIONS is allowed to permit surveillance testing to demonstrate its operability or the operability of other equipment per Specification 3.0.5. The following guidance is provided for complying with the follow-up action requirement, specified in Actions a, b, or c, to isolate the penetration: • Either the INOPERABLE valve must be closed (and de-activated, if applicable for power-operated valves), OR • A valve having the same safety class and seismic design class in series with the INOPERABLE valve must be closed (and de-activated, if applicable for power-operated valves). If the piping branches, each branch must be isolated. • Check valves may not be used to isolate a penetration beyond the four-hour period.

<< Containment Isolation Valves >>

TABLE NOTATIONS

(7) For this valve, the valves listed in the REDUNDANT VALVE column are the valves which are used to meet the initial ACTION statement of Specification 3.6.3 which states "maintain at least one isolation valve OPERABLE. . ." Further action under Specification 3.6.3 is still required to isolate the affected penetration or to shut down in accordance with Actions a, b, c, or d. Reopening of a valve declared INOPERABLE to comply with Tech Spec ACTIONS is allowed to permit surveillance testing to demonstrate its operability or the operability of other equipment per Specification 3.0.5.

The following guidance is provided for complying with the follow-up action requirement, specified in Actions a, b, or c, to isolate the penetration:

- Either the INOPERABLE valve, or all containment isolation valves listed under "REDUNDANT VALVE(S)" column, must be closed (and de-activated, if applicable, for power-operated valves), OR
- A valve having the same safety class and seismic design class in series with the INOPERABLE valve must be closed (and de-activated, if applicable for power-operated valves). If the piping branches, each branch must be isolated.
- Check valves may not be used to isolate a penetration beyond the four-hour period.

(8) For this valve, the closed, water-sealed system outside containment is considered to be an OPERABLE isolation valve for purposes of compliance with the initial ACTION statement of Specification 3.6.3 which states "maintain at least one isolation valve OPERABLE. . ." Further action under Specification 3.6.3 is still required to isolate the affected penetration or to shut down in accordance with Actions a, b, c, or d. Reopening of a valve declared INOPERABLE to comply with Tech Spec ACTIONS is allowed to permit surveillance testing to demonstrate its operability or the operability of other equipment per Specification 3.0.5.

The following guidance is provided for complying with the follow-up action requirement, specified in Actions a, b, or c, to isolate the penetration:

- Either the INOPERABLE valve must be closed (and de-activated, if applicable for power-operated valves), OR
- A valve having the same safety class and seismic design class in series with the INOPERABLE valve must be closed (and de-activated, if applicable for power-operated valves). If the piping branches, each branch must be isolated.
- Check valves may not be used to isolate a penetration beyond the four-hour period.

<< Containment Isolation Valves >>

TABLE NOTATIONS	
(9)	For relief valves, the "REDUNDANT VALVE(s)" column applies to the action statement whenever the relief is unable to isolate (that is, excessive leakage or failed open). When a relief is unable to open or cannot otherwise adequately relieve design overpressure conditions, the penetration must be isolated, and the penetration and closed system (if Table Notation 6 or 8 is applicable) drained to eliminate the potential for an over-pressurization event.
(10)	For this valve, no redundant valve or closed system is available for purposes of compliance with the initial ACTION statement of Specification 3.6.3 which states "maintain at least one isolation valve OPERABLE. . ." Immediate action to isolate the penetration must be initiated or Technical Specification 3.0.3 should be applied.
(11)	Deleted
(12)	Engineering review required when maximum isolation time exceeds 8 seconds to ensure the corresponding Engineered Safety Features Response Time meets the ten second requirement.
(13)	If the valve is INOPERABLE, perform Technical Specification Surveillance Requirement 4.6.1.1.a at least once every 31 days.

<< Containment Penetration Conductor Overcurrent Protective Devices >>

NOTE

The following general notes apply to this table:

- If a breaker that provides containment penetration conductor over-current protection (T.S. 3.8.4.1) is found tripped and there is no reason to suspect it is INOPERABLE as a protection device, then it is not necessary to enter T.S. 3.8.4.1. A breaker found in the tripped condition does not automatically make it INOPERABLE for this Technical Specification.
- If it is suspected that the breaker may not be capable of performing its over-current protection function, then it should be declared INOPERABLE per T.S. 3.8.4.1. For example, if a breaker is tripped free but the trip coil has burned up, then T.S. 3.8.4.1 must be entered.
- Amperage rating of the device is enclosed in parentheses ( ). Fuses are listed for table completeness only; there are no surveillance requirements. The number listed with a fuse is the control wiring diagram (2166-B-401 series) on which the fuse is shown. Circuits with fuses for both primary and secondary protection are not included. When the two protection devices are on separate load centers, the item is duplicated in the table.

NOTE

DC Control power is required for breakers to function. A relay trips the breaker.

Equipment Description	Primary Protection EDBS Tag #	Secondary Protection EDBS Tag #
	6900-V Breakers	
6.9-kV Bus 1A-NNS		
REACTOR COOLANT PUMP 1A-SN	1A-5:002 (REDUNDANT TRIP COILS)	1A-3:012 (UAT A to Aux Bus 1A) and 1A 1:010 (SUT A to Aux Bus 1A)
6.9-kV Bus 1B-NNS		
REACTOR COOLANT PUMP 1B-SN	1B-9:002 (REDUNDANT TRIP COILS)	1B-5:011 (UAT B to Aux Bus 1B) and 1B-3:012 (SUT B to Aux Bus 1B)
6.9-kV Bus 1C-NNS		
REACTOR COOLANT PUMP 1C-SN	1C-2:002 (REDUNDANT TRIP COILS)	1A-4:007 (Aux Bus 1A to Aux Bus 1C Tie Bkr) and 1B-10:007 (Aux Bus 1B to Aux Bus 1C Tie Bkr)

<< Containment Penetration Conductor Overcurrent Protective Devices >>

NOTE

DC Control power is required for breakers to function.

Equipment Description	Primary Protection EDBS Tag #	Secondary Protection EDBS Tag #	
	480-V Bus Breakers		
480-V Bus 1D1			
CONTAINMENT FAN COOLER AH-39 1A-NNS	1D1-1A:003 (1600 A w/200 A Sensor)	FUSE	FU7/2715 (400 A) FU8/2715 (400 A) FU9/2715 (400 A)
CONTAINMENT FAN COOLER AH-38 1A-NNS	1D1-1B:003 (1600 A w/200 A Sensor)	FUSE	FU7/2709 (400 A) FU8/2709 (400 A) FU9/2709 (400 A)
CONTAINMENT FAN COOLER AH-37 1A-NNS	1D1-1C:003 (1600 A w/200 A Sensor)	FUSE	FU7/2703 (400 A) FU8/2703 (400 A) FU9/2703 (400 A)
480-V Bus 1E1			
CONTAINMENT FAN COOLER AH-37 1B-NNS	1E1-7A:003 (1600 A w/200 A Sensor)	FUSE	FU7/2704 (400 A) FU8/2704 (400 A) FU9/2704 (400 A)
CONTAINMENT FAN COOLER AH-38 1B-NNS	1E1-7B:003 (1600 A w/200 A Sensor)	FUSE	FU7/2710 (400 A) FU8/2710 (400 A) FU9/2710 (400 A)
CONTAINMENT FAN COOLER AH-39 1B-NNS	1E1-7C:003 (1600 A w/200 A Sensor)	FUSE	FU7/2716 (400 A) FU8/2716 (400 A) FU9/2716 (400 A)

<< Containment Penetration Conductor Overcurrent Protective Devices >>

Equipment Description	Primary Protection EDBS Tag #	Secondary Protection EDBS Tag #
	480-V Bus Breakers	
480-V Bus 1A3-SA		
CONT. FAN COOLER AH-3 (1A-SA)	1A34-SA-1A:002 (225 A) (300 A after completion of WO 2270769)	1A3-SA-4A:002 (1600 A)
CONT. FAN COOLER AH-3 (1B-SA)	1A34-SA-2A:002 (225 A) (300 A after completion of WO 2270772)	1A3-SA-4A:002 (1600 A)
CONT. FAN COOLER AH-2 (1B-SA)	1A22-SA-1A:002 (225 A) (300 A after completion of WO 2270762)	1A3-SA-4B:002 (1600 A)
CONT. FAN COOLER AH-2 (1A-SA)	1A22-SA-2A:002 (225 A) (300 A after completion of WO 2270765)	1A3-SA-4B:002 (1600 A)
480-V Bus 1B3-SB		
CONT. FAN COOLER AH-1 (1A-SB)	1B22-SB-2A:002 (225 A) (300 A after completion of WO 2270775)	1B3-SB-4C:002 (1600 A)
CONT. FAN COOLER AH-1 (1B-SB)	1B22-SB-3A:002 (225 A) (300 A after completion of WO 2270779)	1B3-SB-4C:002 (1600 A)
CONT. FAN COOLER AH-4 (1A-SB)	1B34-SB-2A:002 (225 A) (300 A after completion of WO 2270781)	1B3-SB-5A:002 (1600 A)
CONT. FAN COOLER AH-4 (1B-SB)	1B34-SB-3A:002 (225 A) (300 A after completion of WO 2270783)	1B3-SB-5A:002 (1600 A)

<< Containment Penetration Conductor Overcurrent Protective Devices >>

Equipment Description		Primary Protection EDBS Tag #	Secondary Protection EDBS Tag #
480-V Motor Control Centers and Power Panels			
PHPP-1A			
PRESSURIZER HEATERS GROUP A	FUSE	FU1/176 (100 A) FU2/176 (100 A) FU3/176 (100 A)	PHPP-1A-1 (90 A)
	FUSE	FU4/176 (100 A) FU5/176 (100 A) FU6/176 (100 A)	PHPP-1A-2 (90 A)
	FUSE	FU7/176 (100 A) FU8/176 (100 A) FU9/176 (100 A)	PHPP-1A-3 (90 A)
	FUSE	FU10/176 (100 A) FU11/176 (100 A) FU12/176 (100 A)	PHPP-1A-4 (90 A)
	FUSE	FU1/177 (100 A) FU2/177 (100 A) FU3/177 (100 A)	PHPP-1A-5 (90 A)
	FUSE	FU4/177 (100 A) FU5/177 (100 A) FU6/177 (100 A)	PHPP-1A-6 (90 A)
	FUSE	FU7/177 (100 A) FU8/177 (100 A) FU9/177 (100 A)	PHPP-1A-7 (90 A)
	FUSE	FU10/177 (100 A) FU11/177 (100 A) FU12/177 (100 A)	PHPP-1A-8 (90 A)

<< Containment Penetration Conductor Overcurrent Protective Devices >>

Equipment Description	Primary Protection EDBS Tag #		Secondary Protection EDBS Tag #
480-V Motor Control Centers and Power Panels			
PHPP-1B			
PRESSURIZER HEATERS GROUP B	FUSE	FU1/178 (100 A) FU2/178 (100 A) FU3/178 (100 A)	PHPP-1B-1 (90 A)
	FUSE	FU4/178 (100 A) FU5/178 (100 A) FU6/178 (100 A)	PHPP-1B-2 (90 A)
	FUSE	FU7/178 (100 A) FU8/178 (100 A) FU9/178 (100 A)	PHPP-1B-3 (90 A)
	FUSE	FU10/178 (100 A) FU11/178 (100 A) FU12/178 (100 A)	PHPP-1B-4 (90 A)
	FUSE	FU1/179 (100 A) FU2/179 (100 A) FU3/179 (100 A)	PHPP-1B-5 (90 A)
	FUSE	FU4/179 (100 A) FU5/179 (100 A) FU6/179 (100 A)	PHPP-1B-6 (90 A)
	FUSE	FU7/179 (100 A) FU8/179 (100 A) FU9/179 (100 A)	PHPP-1B-8 (90 A)
	FUSE	FU10/179 (100 A) FU11/179 (100 A) FU12/179 (100 A)	PHPP-1B-1 (90 A)

<< Containment Penetration Conductor Overcurrent Protective Devices >>

Equipment Description		Primary Protection EDBS Tag #	Secondary Protection EDBS Tag #
480-V Motor Control Centers and Power Panels			
PHPP-1C			
PRESSURIZER HEATERS GROUP C	FUSE	FU1/174 (100 A) FU2/174 (100 A) FU3/174 (100 A)	PHPP-1C-1 (90 A)
	FUSE	FU4/174 (100 A) FU5/174 (100 A) FU6/174 (100 A)	PHPP-1C-2 (90 A)
	FUSE	FU7/174 (100 A) FU8/174 (100 A) FU9/174 (100 A)	PHPP-1C-3 (90 A)
	FUSE	FU10/174 (100 A) FU11/174 (100 A) FU12/174 (100 A)	PHPP-1C-4 (90 A)
	FUSE	FU1/175 (100 A) FU2/175 (100 A) FU3/175 (100 A)	PHPP-1C-5 (90 A)
	FUSE	FU4/175 (100 A) FU5/175 (100 A) FU6/175 (100 A)	PHPP-1C-6 (90 A)
PHPP-1D			
PRESSURIZER HEATERS GROUP D	FUSE	FU1/180 (100 A) FU2/180 (100 A) FU3/180 (100 A)	PHPP-1D-1 (90 A)
	FUSE	FU4/180 (100 A) FU5/180 (100 A) FU6/180 (100 A)	PHPP-1D-2 (90 A)
	FUSE	FU7/180 (100 A) FU8/180 (100 A) FU9/180 (100 A)	PHPP-1D-3 (90 A)

<< Containment Penetration Conductor Overcurrent Protective Devices >>

Equipment Description	Primary Protection EDBS Tag #	Secondary Protection EDBS Tag #
480-V MCC 1A21-SA		
REACTOR SUPPORTS COOLING FAN S-4 1A-SA	1A21-SA-1D:002 (100 A)	1A21-SA-1D:005 (100 A)
1CC-249 CCW FROM RCP THERMAL BARRIER HXS	1A21-SA-3C:002 (15 A)	1A21-SA-3C:006 (15 A)
1SI-248 ACCUMULATOR C DISCHARGE	1A21-SA-3D:002 (40 A)	1A21-SA-3D:003 (40 A)
1CS-470 RCP SEAL WTR RETURN 1A21-SA-4B:002 (15A) 1A21-SA-4B:005 (15 A) & EXCESS LTDN	1A21-SA-4B:002 (15 A)	1A21-SA-4B:005 (15 A)
PRIMARY SHIELD COOLING FAN S-2 1A-SA	1A21-SA-4C:002 (100 A)	1A21-SA-4C:003 (100 A)
1CC-297 CCW FROM RCP BEARING OIL HXS	1A21-SA-5B:002 (15 A)	1A21-SA-5B:005 (15 A)
1SI-246 ACCUMULATOR A DISCHARGE	1A21-SA-5C:002 (40 A)	1A21-SA-5C:003 (40 A)
1ED-94 CNMT SUMP PUMP DISCH	1A21-SA-7A:002 (15 A)	1A21-SA-7A:005 (15 A)
1RH-2 RHR PUMP A SUCTION FROM HOT LEG	1A21-SA-7B:002 (15 A)	1A21-SA-7B:003 (15 A)
1SI-300 CONTAINMENT SUMP TO RHR PUMP A	1A21-SA-7C:002 (30 A)	1A21-SA-7C:003 (30 A)
1RH-40 RHR PUMP B SUCTION FROM HOT LEG	1A21-SA-8A:002 (15 A)	1A21-SA-8A:003 (15 A)
1CT-105 CONTAINMENT SUMP TO CT PUMP A	1A21-SA-8C:002 (15 A)	1A21-SA-8C:005 (15 A)
LIGHTING PANEL LP-106	1A21-SA-14ER:002 (50A)	1A21-SA-14EL:002 (50A)

<< Containment Penetration Conductor Overcurrent Protective Devices >>

Equipment Description	Primary Protection EDBS Tag #	Secondary Protection EDBS Tag #
480-V MCC 1A21-SA (continued)		
1RH-1 ALTERNATE POWER SUPPLY	1A21-SA-6A:002 (15 A)	1A21-SA-6A:003 (15A)
480-V MCC 1A22-SA		
CONTAINMENT FAN COOLER AH-2 1B-SA	1A22-SA-1A:002 (225 A) (300 A after completion of WO 2270762-03)	1A3-SA-4B:002 (1600 A)
CONTAINMENT FAN COOLER AH-2 1A-SA	1A22-SA-2A:002 (225 A) (300 A after completion of WO 2270765-03)	
480-V MCC 1A24		
1RC-113 PRESSURIZER PORV BLOCK	1A24-3A:002 (15 A)	1A24-3A:005 (15 A)
RCP 1A-SN BEARING OIL LIFT PUMP	1A24-6A:002 (30 A)	1A24-6A:005 (30 A)
RCP 1C-SN BEARING OIL LIFT PUMP	1A24-6B:002 (30 A	1A24-6B:005 (30 A)
CRDM FAN E-80 1A-NNS	1A24-7B:002 (100 A)	1A24-7B:003 (100 A)
CRDM FAN E-81 1A-NNS	1A24-7C:002 (100 A)	1A24-7C:003 (100 A)
480-V MCC 1A34-SA		
CONTAINMENT FAN COOLER AH-3 1A-SA	1A34-SA-1A:002 (225 A) (300 A after completion of WO 2270769-03)	1A3-SA-4B:002 (1600 A)
CONTAINMENT FAN COOLER AH-3 1B-SA	1A34-SA-2A:002 (225 A) (300 A after completion of WO 2270772-03)	1A3-SA-4A:002 (1600 A)

<< Containment Penetration Conductor Overcurrent Protective Devices >>

Equipment Description	Primary Protection EDBS Tag #	Secondary Protection EDBS Tag #
480-V MCC 1B21-SB		
PRIMARY SHIELD COOLING FANS-2 1B-SB	1B21-SB-4B:002 (100 A)	1B21-SB-4B:003 (100 A)
REACTOR SUPPORTS COOLING FAN S-4 1B-SB	1B21-SB-4C:002 (100 A)	1B21-SB-4C:004 (100 A)
1RH-1 RHR PUMP A SUCTION FROM HOT LEG	1B21-SB-5B:002 (15 A)	1B21-SB-5B:003 (15 A)
1SI-247 ACCUMULATOR B DISCHARGE	1B21-SB-5C:002 (40 A)	1B21-SB-5C:003 (40 A)
1CT-102 CONTAINMENT SUMP TO CT PUMP B	1B21-SB-6A:005 (15 A)	1B21-SB-6A:002 (15 A)
1RH-39 RHR PUMP B SUCTION FROM HOT LEG	1B21-SB-11A:002 (15 A)	1B21-SB-11A:003 (15 A)
RHR ISOL VA 1-8701B ALTERNATE PWR SUPPLY FROM AN "SB" SOURCE	1B21-SB-8B:002 (15 A)	1B21-SB-8B:006 (15 A)
1SI-301 CONTAINMENT SUMP TO RHR PUMP B	1B21-SB-11B:002 (30 A)	1B21-SB-11B:003 (30 A)
LIGHTING PANEL LP-107	1B21-SB-13AR:002 (50A)	1B21-SB-13AL:002 (50 A)
480-V MCC 1B22-SB		
CONTAINMENT FAN COOLER AH-1 1A-SB	1B22-SB-2A:002 (225 A) (300 A after completion of WO 2270775-03)	1B3-SB-4C:002 (1600 A)
CONTAINMENT FAN COOLER AH-1 1B-SB	1B22-SB-3A:002 (225 A) (300 A after completion of WO 2270779-03)	1B3-SB-4C:002 (1600 A)

<< Containment Penetration Conductor Overcurrent Protective Devices >>

Equipment Description	Primary Protection EDBS Tag #	Secondary Protection EDBS Tag #
480-V MCC 1B24		
CRDM FAN E-80 1B-NNS	1B24-1B:002 (100 A)	1B24-1B:003 (100 A)
CRDM FAN E-81 1B-NNS	1B24-2B:002 (100 A)	1B24-2B:003 (100 A)
1RC-115 PRESSURIZER PORV BLOCK	1B24-2C:002 (15 A)	1B24-2C:003 (15 A)
1RC-117 PRESSURIZER PORV BLOCK	1B24-3B:002 (15 A)	1B24-3B:003 (15 A)
RCP 1B-SN BEARING OIL LIFT PUMP	1B24-4B:002 (30 A)	1B24-4B:005 (30 A)
480-V MCC 1B34-SB		
CONTAINMENT FAN COOLER AH-4 1A-SB	1B34-SB-2A:002 (225 A) (300 A after completion of WO 2270781-03)	1B3-SB-5A:002 (1600 A)
CONTAINMENT FAN COOLER AH-4 1B-SB	1B34-SB-3A:002 (225 A) (300 A after completion of WO 2270783-03)	1B3-SB-5A:002 (1600 A)
480-V MCC 1D11		
CNMT BLDG SUMP PUMP 1A-NNS	1D11-1B:002 (50 A)	1D11-1B:003 (50 A)
POWER RECEPTACLES 1-1 & 1-5	1D11-1C:002 (60 A)	1D11-1C:003 (60 A)
POWER RECEPTACLES 1-9 & 1-13	1D11-1D:002 (60 A)	1D11-1D:003 (60 A)
POWER RECEPTACLES 1-2 & 1-6	1D11-1E:002 (60 A)	1D11-1E:003 (60 A)
AIRBORNE RAD REMOVAL FAN S-1 1A-NNS	11D11-2B:002 (90 A)	1D11-2B:003 (90 A)
CNMT BLDG ELEVATOR	1D11-2C:002 (100 A)	1D11-2C:003 (100 A)
CNMT ACCESS HOIST 5-TON MONORAIL	1D11-2D:002 (50 A)	1D11-2D:003 (50 A)

<< Containment Penetration Conductor Overcurrent Protective Devices >>

Equipment Description	Primary Protection EDBS Tag #	Secondary Protection EDBS Tag #
480-V MCC 1D11 (continued)		
POWER RECEPTACLES 1-18 & 1-75	1D11-3C:002 (60 A)	1D11-3C:003 (60 A)
CNMT JIB CRANE RECEPTACLES	1D11-3D:002 (60 A)	1D11-3D:003 (60 A)
POWER RECEPTACLES 1-10 & 1-14	1D11-4A:002 (60 A)	1D11-4A:003 (60 A)
REACTOR COOLANT DRAIN TANK PUMP 1A-NNS	1D11-4C:002 (90 A)	1D11-4C:003 (90 A)
POWER RECEPTACLE 1-76	1D11-4DR:002 (60 A)	1D11-4DL:002 (60 A)
LIGHTING PANEL LP-105	LP-105:003 (150 A)	1D11-4EL:002 (70 A)
LIGHTING PANEL LP-101	LP-101:003 (125 A)	1D11-4ER:002 (60 A)
LIGHTING PANEL LP-102	LP-102:003 (125 A)	1D11-5DL:002 (60 A)
POWER RECEPTACLES 1-17 & 1-74	1D11-5E:002 (60 A)	1D11-5E:003 (60 A)
CNMT POLAR BRIDGE CRANE	1D11-6D:002 (225 A)	1D11-6D:003 (225 A)
480-V MCC 1D12		
IRVH CABLE BRIDGE HOIST	1D12-7BR:002 (15 A)	1D12-7BL:002 (15 A)
480-V MCC 1E11		
FUEL TRANSFER MANIPULATOR CRANE	1E11-1A:002 (30 A)	1E11-1A:003 (30 A)
FUEL TRANSFER RX SIDE CONTROL (PUMP MOTOR)	1E11-1B:002 (15 A)	1E11-1B:003 (15 A)
AIRBORNE RAD REMOVAL FAN S-1 1B-NNS	1E11-1E:002 (90 A)	1E11-1E:003 (90 A)
REACTOR COOLANT DRAIN TANK PUMP 1B-NNS	1E11-2E:002 (90 A)	1E11-2E:003 (90 A)
POWER RECEPTACLES 1-77 & 1-78	1E11-3BR:002 (60 A)	1E11-3BL:002 (60 A)
LIGHTING PANEL LP-103	LP-103:003 (110 A)	1E11-3DL:002 (50 A)

<< Containment Penetration Conductor Overcurrent Protective Devices >>

Equipment Description	Primary Protection EDBS Tag #	Secondary Protection EDBS Tag #
480-V MCC 1E11 (continued)		
LIGHTING PANEL LP-123	LP-123:003 (125 A)	1E11-3DR:002 (60 A)
LIGHTING PANEL LP-104	LP-104:003 (150 A)	1E11-4CR:002 (70 A)
CNMT BLDG SUMP PUMP 1B-NNS	1E11-5C:002 (50 A)	1E11-5C:003 (50 A)
INCORE INSTRUMENT DRIVE ASSEMBLES	1E11-5D:002 (15 A)	1E11-5D:003 (15 A)
POWER RECEPTACLES 1-12 & 1-16	1E11-6AR:002 (60 A)	1E11-6AL:002 (60 A)
POWER RECEPTACLES 1-4 & 1-8	1E11-6BR:002 (60 A)	1E11-6BL:002 (60 A)
POWER RECEPTACLES 1-3 & 1-7	1E11-6CR:002 (60 A)	1E11-6CL:002 (60 A)
POWER RECEPTACLES 1-11 & 1-15	1E11-6DR:002 (60 A)	1E11-6DL:002 (60 A)
IRVH STUD TENSIONER HOIST (B1263)	1E11-6ER:002 (15 A)	1E11-6EL:002 (15 A)
RCCA CHANGE FIXTURE HOIST	1E11-6FR:002 (15 A)	1E11-6FL:002 (15 A)
120-V Breakers		

Motor Space Heaters with Breakers in 6900-V and 480-V Bus Breakers

NOTE: The primary protection and/or secondary protection for the fan heaters are breakers located at the bus breaker cubicle corresponding to the listed equipment.

Equipment Description	Primary Protection EDBS Tag #	Secondary Protection EDBS Tag #
Reactor Coolant Pumps		
RCP 1A-SN MOTOR SPACE HEATER	1A-5:028 (15 A)	PP-1D213-4 (30 A/phase)
RCP 1B-SN MOTOR SPACE HEATER	1B-9:030 (15 A)	PP-1E213-4 (30 A/phase)
RCP 1C-SN MOTOR SPACE HEATER	1C-2:031 (15 A)	PP-1D213-10 (20 A/phase)

<< Containment Penetration Conductor Overcurrent Protective Devices >>

Containment Fan Coil Units

AH-37 1A-NNS MOTOR SPACE HEATER	PP-1D213-40-1 (15 A)		PP-1D213-40-2 (15 A)
AH-38 1A-NNS MOTOR SPACE HEATER	PP-1D213-40-3 (15 A)		PP-1D213-40-4 (15 A)
AH-39 1A-NNS MOTOR SPACE HEATER	PP-1D213-40-5 (15 A)		PP-1D213-40-6 (15 A)
AH-37 1B-NNS MOTOR SPACE HEATER	PP-1E213-22-1 (15 A)		PP-1E213-22-2 (15 A)
AH-38 1B-NNS MOTOR SPACE HEATER	PP-1E213-22-3 (15 A)		PP-1E213-22-4 (15 A)
AH-39 1B-NNS MOTOR SPACE HEATER	PP-1E213-22-5 (15 A)		PP-1E213-22-6 (15 A)

PP-1 (Rod Position Indication)

DRPI PANELS 1A AND 1B POWER	PP-1:002 (100 A)	and	PP-1E211-18 (100 A)
		OR	
	PP-1:003 (100 A)	and	PP-1D211-18 (100 A)

PP-1A211-SA

AH-2 DAMPER CV-D3SA	FUSE-L1/2674 (6 A)		PP-1A211-SA-7 (20 A)
AH-3 DAMPER CV-D5SA	FUSE-L3/2742 (6 A)		PP-1A211-SA-7 (20 A)
AH-2 1A-SA MOTOR SPACE HEATER	PP-1A211-SA-35 (15 A)		PP-1A211-SA-33 (15 A)
AH-2 1B-SA MOTOR SPACE HEATER	PP-1A211-SA-36 (15 A)		PP-1A211-SA-34 (15 A)

PP-1A212-SA

AH-3 1A-SA MOTOR SPACE HEATER	PP-1A212-SA-9 (15 A)		PP-1A212-SA-7 (15 A)
AH-3 1B-SA MOTOR SPACE HEATER	PP-1A212-SA-10 (15 A)		PP-1A212-SA-8 (15 A)

<< Containment Penetration Conductor Overcurrent Protective Devices >>

Equipment Description	Primary Protection EDBS Tag #	Secondary Protection EDBS Tag #
PP-1A212-SA (continued)		
CNMT HYDROGEN ANALYZER SA VALVES	PP-1A212-SA-16 (20 A)	PP-1A212-SA-14 (20 A)
S-4 1A-SA MOTOR SPACE HEATER	PP-1A212-SA-39 (15 A)	PP-1A212-SA-37 (15 A)
S-2 1A-SA MOTOR SPACE HEATER	PP-1A212-SA-40 (15 A)	PP-1A212-SA-38 (15 A)
INLET ISOL VA 1-8701A INDICATING LIGHT CIRCUIT	Fuse FU3/325 (3 A)	PP-1A212-SA-30 (15 A)
INLET ISOL VA 1-8701B INDICATING LIGHT CIRCUIT	Fuse FU3/326 (3 A)	PP-1A212-SA-32 (15 A)
INLET ISOL VA 1-8702A INDICATING LIGHT CIRCUIT	Fuse FU3/336 (3 A)	PP-1A212-SA-34 (15 A)
PP-1A311-SA		
1RC-900 RX VESSEL HEAD VENT	Fuse-L3/134 (6 A)	PP-1A311-SA-4 (20 A)
1RC-902 PRZ STEAM SPACE VENT	Fuse-L4/136 (6 A)	PP-1A311-SA-4 (20 A)
1SP-12 & 941 HYDROGEN ANALYZER A	Fuse-J1/701 (6 A)	PP-1A311-SA-4 (20 A)
1SP-916 & 918 RADIATION MONITOR REM-3502A	Fuse-L1/703 (6 A)	PP-1A311-SA-4 (20 A)
1SP-944 RCS HOT LEG LOOP C SAMPLE	Fuse-L4/2435 (6 A)	PP-1A311-SA-4 (20 A)
1CP-5 & 9 CNMT NORMAL PURGE DISCHARGE INLET	Fuse-L4/2706 (6 A)	PP-1A311-SA-14 (20 A)
1CP-10 & 4 CNMT P/E PURGE INLET/DISCHARGE	Fuse-L5/2713 (6 A)	PP-1A311-SA-14 (20 A)
1CM-2 HYDROGEN PURGE INLET	Fuse-L5/3074 (6 A)	PP-1A311-SA-14 (20 A)

<< Containment Penetration Conductor Overcurrent Protective Devices >>

Equipment Description	Primary Protection EDBS Tag #	Secondary Protection EDBS Tag #
PP-1A312-SA		
1RC-904 RVH & PRZ VENT TO ATMOS	Fuse-FU5/137 (6 A)	PP-1A312-SA-11 (20 A)
PP-1B211-SB		
AH-1 DAMPER CV-D1SB	Fuse-L1/2670 (6 A)	PP-1B211-SB-14 (20 A)
AH-4 DAMPER CV-D7SB	Fuse-L6/2746 (6 A)	PP-1B211-SB-14 (20 A)
AH-1 1A-SB MOTOR SPACE HEATER	PP-1B211-SB-35 (15 A)	PP-1B211-SB-33 (15 A)
AH-1 1B-SB MOTOR SPACE HEATER	PP-1B211-SB-36 (15 A)	PP-1B211-SB-34 (15 A)
PP-1B212-SB		
AH-4 1A-SB MOTOR SPACE HEATER	PP-1B212-SB-9 (15 A)	PP-1B212-SB-7 (15 A)
AH-4 1B-SB MOTOR SPACE HEATER	PP-1B212-SB-10 (15 A)	PP-1B212-SB-8 (15 A)
CNMT HYDROGEN ANALYZER SB VALVES	PP-1B212-16 (20 A)	PP-1B212-SB-14 (20 A)
S-4 1B-SB MOTOR SPACE HEATER	PP-1B212-SB-39 (15 A)	PP-1B212-SB-37 (15 A)
S-2 1B-SB MOTOR SPACE HEATER	PP-1B212-SB-40 (15 A)	PP-1B212-SB-38 (15 A)
INLET ISOL VA 1-8702A INDICATING LIGHT CIRCUIT	Fuse FU3/327 (3 A)	PP-1B212-SB-30 (15 A)
INLET ISOL VA 1-8702B INDICATING LIGHT CIRCUIT	Fuse FU3/328 (3 A)	PP-1B212-SB-32 (15 A)
INLET ISOL VA 1-8701B INDICATING LIGHT CIRCUIT	Fuse FU3/337 (3 A)	PP-1B212-SB-34 (15 A)

<< Containment Penetration Conductor Overcurrent Protective Devices >>

Equipment Description	Primary Protection EDBS Tag #		Secondary Protection EDBS Tag #
PP-1B311-SB			
AH-1 DAMPER CV-D1SB & CV-D2SB REMOTE SHUTDOWN POWER)	Fuse-FU1A-15/2670 (5 A)		PP-1B311-SB-16 (20 A)
AH-4 DAMPER CV-D7SB & CV-D8SB REMOTE SHUTDOWN POWER)	Fuse-1A-16/2746 (5 A)		PP-1B311-SB-16 (20 A)
PP-1B312-SB			
1RC-905 RVH & PRZ VENT TO ATMOS	Fuse-FU21/138 (6 A)		PP-1B312-SB-11 (20 A)
PP-1D121			
INST. RACK C1-R1 (CNMT COOLER SW TEMP)	PP-1D121-13 (20 A)		PP-1D121-13-BU (20 A)
INST. RACK C1-R-18	PP-1D121-16 (15 A)		PP-1D121-16-BU (15 A)
PP-1D211			
ELEVATOR EQUIP RM EXHAUST FAN E-3 1X-NNS	PP-1D211-2 (20 A)		PP-1D211-2BU (20 A)
DRPI PANELS 1A AND 1B POWER	PP-1:002 (100 A)	and	PP-1E211-18 (100 A)
		OR	
	PP-1:003 (100 A)	and	PP-1D211-18 (100 A)

<< Containment Penetration Conductor Overcurrent Protective Devices >>

Equipment Description	Primary Protection EDBS Tag #		Secondary Protection EDBS Tag #
PP-1D212			
CNMT FAN COOLERS (NNS) DAMPERS CV-D9, D11 & D13	Fuse-L1/2728 (6 A)		PP-1D212-8 (15 A)
CNMT FAN COOLERS (NNS) DAMPERS CV-D10, D12 & D14	Fuse-L2/2729 (6 A)		PP-1D212-8 (15 A)
1SI-246 & 248 ACCUMULATORS A&C ALARM CKT	Fuse-FU-41/448 (3 A)		PP-1D212-16 (15 A)
1SI-247 ACCUMULATOR B ALARM CKT	Fuse-FU-41/447 (3 A)		PP-1D212-18 (15 A)
PP-1D213			
RCP 1A-SN MOTOR SPACE HEATER	1A-5:028 (15 A)		PP-1D213-4 (30 A/phase)
RCP 1C-SN MOTOR SPACE HEATER	1C-2:031 (15 A)		PP-1D213-10 (20 A/phase)
PP-1E121			
FUEL TRANSFER CONSOLE REACTOR SIDE POWER	PP-1E121-1 (20 A)		PP-1E121-1-BU (20 A)
PP-1E211			
E-81 1B-NNS MOTOR SPACE HEATER	PP-1E211-10 (20 A)		PP-1E211-10-BU (20 A)
E-80 1B-NNS MOTOR SPACE HEATER	PP-1E211-17 (20 A)		PP-1E211-17-BU (20 A)
DRPI PANELS 1A AND 1B POWER	PP-1:002 (100 A)	and	PP-1E211-18 (100 A)
		OR	
	PP-1:003 (100 A)	and	PP-1D211-18 (100 A)

<< Containment Penetration Conductor Overcurrent Protective Devices >>

Equipment Description	Primary Protection EDBS Tag #	Secondary Protection EDBS Tag #
PP-1E212		
E-80 1A-NNS CRDM FAN DAMPER	Fuse-L1/472 (6 A)	PP-1E212-10 (15 A)
E-80 1B-NNS CRDM FAN DAMPER	Fuse-L2/473 (6 A)	PP-1E212-10 (15 A)
E-81 1A-NNS CRDM FAN DAMPER	Fuse-L3/474 (6 A)	PP-1E212-10 (15 A)
E-81 1B-NNS CRDM FAN DAMPER	Fuse-L4/475 (6 A)	PP-1E212-10 (15 A)
S-1 1A-NNS FLOW SW FIS-1AR-7647A	Fuse-L1/2661 (6 A)	PP-1E212-10 (15 A)
S-1 1B-NNS FLOW SW FIS-1AR-7647B	Fuse-L2/2662 (6 A)	PP-1E212-10 (15 A)
S-1 1A-NNS DAMPER AR-D3	Fuse-L3/2663 (6 A)	PP-1E212-10 (15 A)
S-1 1B-NNS DAMPER AR-D4	Fuse-L4/2664 (6 A)	PP-1E212-10 (15 A)
S-1 1A-NNS TEMP DET TAS-1AR-7644AV	Fuse-L2/2677 (6 A)	PP-1E212-10 (15 A)
S-1 1B-NNS TEMP DET TAS-1AR-7644BV	Fuse-L3/2678 (6 A)	PP-1E212-10 (15 A)
PP-1E213		
RCP 1B-SN MOTOR SPACE HEATER	1B-9:030 (15 A)	PP-1E213-4 (30 A/phase)
PP-1-4A10221		
S-1 1B-NNS MOISTURE DET MIS-1AR-7644BV	PP-1-4A10221-2 (20 A)	PP-1-4A10221-2-BU (20 A)
PP-1-4A111		
S-1 1A-NNS MOISTURE DET MIS-1AR-7644AV	PP-1-4A111-36 (15 A)	PP-1-4A111-34 (15 A)

<< Containment Penetration Conductor Overcurrent Protective Devices >>

Equipment Description	Primary Protection EDBS Tag #	Secondary Protection EDBS Tag #

PP-1-4B241

Deleted

<< Motor-Operated Valves Thermal Overload Protection Bypass >>

VALVE NO. CP&L (EBASCO)	FUNCTION
1AF-55 (AF-V10)	AUXILIARY FEEDWATER TO SG A *
1AF-74 (AF-V23)	AUXILIARY FEEDWATER TO SG C *
1AF-93 (AF-V19)	AUXILIARY FEEDWATER TO SG B *
1AF-137 (AF-V116)	AUXILIARY FEEDWATER TO SG A *
1AF-143 (AF-V117)	AUXILIARY FEEDWATER TO SG B *
1AF-149 (AF-V118)	AUXILIARY FEEDWATER TO SG C *
1CC-99 (CC-B19)	CCW A NONESSENTIAL SUPPLY ISOL
1CC-113 (CC-B20)	CCW B NONESSENTIAL SUPPLY ISOL
1CC-127 (CC-B6)	CCW A NONESSENTIAL RETURN ISOL
1CC-128 (CC-B5)	CCW B NONESSENTIAL RETURN ISOL
1CC-147 (CC-V165)	RHR HX A CCW OUTLET
1CC-167 (CC-V167)	RHR HX B CCW OUTLET
1CC-176 (CC-V172)	CCW TO RCDT & EXCESS LTDN HEAT EXCHS
1CC-202 (CC-V182)	CCW FROM RCDT & EXCESS LTDN HEAT EXCHS
1CC-207 (CC-V169)	CCW TO RCPS
1CC-208 (CC-V170)	CCW TO RCPS
1CC-249 (CC-V191)	CCW FROM RCP THERMAL BARRIER HXS
1CC-251 (CC-V190)	CCW FROM RCP THERMAL BARRIER HXS
1CC-297 (CC-V184)	CCW FROM RCP BEARING OIL HXS
1CC-299 (CC-V183)	CCW FROM RCP BEARING OIL HXS
1CS-165 (CS-L520)	VCT TO CSIPS ISOLATION
1CS-166 (CS-L521)	VCT TO CSIPS ISOLATION
1CS-168 (CS-V588)	CSIP SUCTION ISOLATION
1CS-169 (CS-V589)	CSIP SUCTION ISOLATION
1CS-170 (CS-V587)	CSIP SUCTION ISOLATION
1CS-171 (CS-V590)	CSIP SUCTION ISOLATION
1CS-182 (CS-V600)	CSIP A MINIFLOW ISOLATION
1CS-196 (CS-V602)	CSIP B MINIFLOW ISOLATION
1CS-210 (CS-V601)	CSIP C MINIFLOW ISOLATION
1CS-214 (CS-V585)	CSIPS MINIFLOW ISOLATION
1CS-217 (CS-V604)	CSIP DISCHARGE ISOLATION
1CS-218 (CS-V605)	CSIP DISCHARGE ISOLATION
1CS-219 (CS-V603)	CSIP DISCHARGE ISOLATION
1CS-220 (CS-V606)	CSIP DISCHARGE ISOLATION
1CS-235 (CS-V609)	CVCS NORMAL CHARGING
1CS-238 (CS-V610)	CVCS NORMAL CHARGING
1CS-240 (CS-V611)	RCP SEAL WATER INJECTION
1CS-278 (CS-V586)	BORIC ACID PUMPS TO CSIPS
1CS-291 (CS-L523)	RWST TO CSIPS ISOLATION

<< Motor-Operated Valves Thermal Overload Protection Bypass >>

VALVE NO. CP&L (EBASCO)	FUNCTION
1CS-292 (CS-L522)	RWST TO CSIPS ISOLATION
1CS-341 (CS-V522)	CVCS SEAL WATER TO RCP A
1CS-382 (CS-V523)	CVCS SEAL WATER TO RCP B
1CS-423 (CS-V524)	CVCS SEAL WATER TO RCP C
11CS-470 (CS-V516)	CVCS SEAL WATER RETURN & EXCESS LTDN
1CS-472 (CS-V517)	CVCS SEAL WATER RETURN & EXCESS LTDN
1CS-745 (CS-V758)	CSIP MINIFLOW TO RWST
1CS-746 (CS-V757)	CSIP MINIFLOW TO RWST *
1CS-752 (CS-V759)	CSIP MINIFLOW TO RWST *
1CS-753 (CS-V760)	CSIP MINIFLOW TO RWST
1CT-11 (CT-V88)	NAOH ADDITIVE ISOLATION
1CT-12 (CT-V85)	NAOH ADDITIVE ISOLATION
1CT-24 (CT-V8)	CNMT SPRAY PUMP A EDUCTOR TEST
1CT-26 (CT-V2)	CNMT SPRAY PUMP A RWST SUPPLY
1CT-25 (CT-V145)	CNMT SPRAY PUMP B EDUCTOR TEST
1CT-47 (CT-V25)	CNMT SPRAY HDR A RECIRC
1CT-50 (CT-V21)	CONTAINMENT SPRAY A
1CT-71 (CT-V3)	CNMT SPRAY PUMP B RWST SUPPLY
1CT-88 (CT-V43)	CONTAINMENT SPRAY B
1CT-95 (CT-V49)	CNMT SPRAY HDR B RECIRC
1CT-102 (CT-V7)	CONTAINMENT SUMP TO CT PUMP B
1CT-105 (CT-V6)	CONTAINMENT SUMP TO CT PUMP A
1ED-94 (MD-V36)	CNMT SUMP PUMPS DISCH
1ED-95 (MD-V77)	CNMT SUMP PUMPS DISCH
1MS-70 (MS-V8)	MAIN STEAM B TO AUXILIARY FW TURBINE*
1MS-72 (MS-V9)	MAIN STEAM C TO AUXILIARY FW TURBINE*
1RH-1 (RH-V502)	RHR PUMP A SUCTION FROM HOT LEG
1RH-2 (RH-V503)	RHR PUMP A SUCTION FROM HOT LEG
1RH-25 (RH-V507)	RHR TO CSIP SUCTION
1RH-31 (RH-F513)	RHR PUMP A MINIFLOW
1RH-39 (RH-V500)	RHR PUMP B SUCTION FROM HOT LEG
1RH-40 (RH-V501)	RHR PUMP B SUCTION FROM HOT LEG
1RH-63 (RH-V506)	RHR TO CSIP SUCTION
1RH-69 (RH-F512)	RHR PUMP B MINIFLOW
1SI-3 (SI-V505)	SI-HIGH HEAD TO COLD LEGS
1SI-4 (SI-V506)	SI-HIGH HEAD TO COLD LEGS
1SI-52 (SI-V502)	SI-HIGH HEAD TO COLD LEGS
1SI-86 (SI-V501)	SI-HIGH HEAD TO HOT LEGS
1SI-107 (SI-V500)	SI-HIGH HEAD TO HOT LEGS
1SI-246 (SI-V537)	ACCUMULATOR A DISCHARGE ISOLATION

<< Motor-Operated Valves Thermal Overload Protection Bypass >>

VALVE NO. CP&L (EBASCO)	FUNCTION
1SI-247 (SI-V536)	ACCUMULATOR B DISCHARGE ISOLATION
1SI-248 (SI-V535)	ACCUMULATOR C DISCHARGE ISOLATION
1SI-300 (SI-V571)	CONTAINMENT SUMP TO RHR PUMP A
1SI-301 (SI-V570)	CONTAINMENT SUMP TO RHR PUMP B
1SI-310 (SI-V573)	CONTAINMENT SUMP TO RHR PUMP A
1SI-311 (SI-V572)	CONTAINMENT SUMP TO RHR PUMP B
1SI-322 (SI-V575)	RWST TO RHR PUMP A ISOL
1SI-323 (SI-V574)	RWST TO RHR PUMP B ISOLATION
1SI-326 (SI-V577)	SI-LOW HEAD CROSS CONNECT
1SI-327 (SI-V576)	SI-LOW HEAD CROSS CONNECT
1SI-340 (SI-V579)	SI-LOW HEAD TO COLD LEGS
1SI-341 (SI-V578)	SI-LOW HEAD TO COLD LEGS
1SI-359 (SI-V587)	SI-LOW HEAD TO HOT LEGS
1SW-39 (SW-B5)	NORMAL SW HDR A SUPPLY ISOLATION
1SW-40 (SW-B6)	NORMAL SW HDR B SUPPLY ISOLATION
1SW-91 (SW-B45)	SERVICE WATER TO FAN COOLER AH-2
1SW-92 (SW-B46)	SERVICE WATER TO FAN COOLER AH-3
1SW-97 (SW-B47)	SERVICE WATER FROM FAN COOLER AH-3
1SW-98 (SW-B48)	SERVICE WATER FROM FAN COOLER AH-1
1SW-109 (SW-B49)	SERVICE WATER FROM FAN COOLER AH-2
1SW-110 (SW-B50)	SERVICE WATER FROM FAN COOLER AH-4
1SW-121 (SW-B74)	SW HDR A TO AFW PUMP A
1SW-123 (SW-B75)	SW HDR A TO AFW PUMP A
1SW-124 (SW-B70)	SW HDR A TO AFWTD PUMP
1SW-126 (SW-B71)	SW HDR A TO AFWTD PUMP
1SW-127 (SW-B72)	SW HDR B TO AFWTD PUMP
1SW-129 (SW-B73)	SW HDR B TO AFWTD PUMP
1SW-130 (SW-B76)	SW HDR B TO AFW PUMP B
1SW-132 (SW-B77)	SW HDR B TO AFW PUMP B
1SW-225 (SW-B52)	SERVICE WATER TO FAN COOLER AH-1
1SW-227 (SW-B51)	SERVICE WATER TO FAN COOLER AH-4
1SW-270 (SW-B15)	SW HDR A TO AUX RSVR ISOLATION
1SW-271 (SW-B16)	SW HDR B TO AUX RSVR ISOLATION
1SW-274 (SW-B14)	NORMAL SW HDR B RETURN ISOLATION
1SW-275 (SW-B13)	NORMAL SW HDR A RETURN ISOLATION
1SW-276 (SW-B8)	NORMAL SW HDR RETURN ISOLATION
1AV-11 (AC-B1)	RAB SWGR A EXHAUST
1AV-12 (AC-B2)	RAB SWGR B EXHAUST
1AV-13 (AC-B3)	RAB SWGR B EXHAUST
1AV-1 (AV-B1)	RAB EMER EXHAUST A INLET

<< Motor-Operated Valves Thermal Overload Protection Bypass >>

VALVE NO. CP&L (EBASCO)	FUNCTION
1AV-2 (AV-B2)	RAB EMER EXHAUST A OUTLET
1AV-3 (AV-B3)	RAB EMER EXHAUST A BLEED**
1AV-4 (AV-B4)	RAB EMER EXHAUST B INLET
1AV-5 (AV-B5)	RAB EMER EXHAUST B OUTLET
1AV-6 (AV-B6)	RAB EMER EXHAUST B BLEED**
1CZ-1 (CZ-B1)	CONTROL ROOM NORMAL SUPPLY ISOLATION*
1CZ-2 (CZ-B2)	CONTROL ROOM NORMAL SUPPLY ISOLATION*
1CZ-3 (CZ-B3)	CONTROL ROOM NORMAL EXHAUST ISOLATION*
1CZ-4 (CZ-B4)	CONTROL ROOM NORMAL EXHAUST ISOLATION*
1CZ-5 (CZ-B5)	RAB ELEC PROT INLET*
1CZ-6 (CZ-B6)	RAB ELEC PROT INLET*
1CZ-7 (CZ-B7)	RAB ELEC PROT EXHAUST*
1CZ-8 (CZ-B8)	RAB ELEC PROT EXHAUST*
1CZ-9 (CZ-B9)	CNTL RM EMER FLTR OUTSIDE AIR INTAKE*
1CZ-10 (CZ-B10)	CNTL RM EMER FLTR OUTSIDE AIR INTAKE*
1CZ-11 (CZ-B11)	CNTL RM EMER FLTR OUTSIDE AIR INTAKE*
1CZ-12 (CZ-B12)	CNTL RM EMER FLTR OUTSIDE AIR INTAKE*
1CZ-13 (CZ-B13)	CONTROL ROOM PURGE EXHAUST*
1CZ-14 (CZ-B14)	CONTROL ROOM PURGE EXHAUST*
1CZ-17 (CZ-B17)	CONTROL ROOM PURGE MAKE UP*
1CZ-18 (CZ-B18)	CONTROL ROOM PURGE MAKE UP*
1CZ-19 (CZ-B19)	CONTROL ROOM EMER FLTR DISCHARGE*
1CZ-20 (CZ-B20)	CONTROL ROOM EMER FLTR DISCHARGE*
1CZ-21 (CZ-B21)	CONTROL ROOM EMER FLTR DISCHARGE*
1CZ-22 (CZ-B22)	CONTROL ROOM EMER FLTR DISCHARGE*
1CZ-23 (CZ-B23)	CONTROL ROOM EMER FLTR A INLET*
1CZ-24 (CZ-B24)	CONTROL ROOM EMER FLTR B INLET*
1CZ-25 (CZ-B25)	CONTROL ROOM NORMAL SUPPLY A DISCHARGE*
1CZ-26 (CZ-B26)	CONTROL ROOM NORMAL SUPPLY B DISCHARGE*
1CZ-32 (CZ-B32)	RAB ELEC PROT PURGE MAKE-UP
1CZ-33 (CZ-B33)	RAB ELEC PROT PURGE MAKE-UP
1CZ-34 (CZ-B34)	RAB ELEC PROT PURGE INLET
1CZ-35 (CZ-B35)	RAB ELEC PROT PURGE INLET
1FV-2 (FV-B2)	FUEL HANDLING EXHAUST A INLET*
1FV-4 (FV-B4)	FUEL HANDLING EXHAUST B INLET*

<< Motor-Operated Valves Thermal Overload Protection Bypass >>

TABLE NOTATIONS	
*	Thermal Overload Protection Bypass for these valves is accomplished by contacts on the safeguards actuation circuit relays. These actuation relays are tested as a part of the Engineered Safety Features Actuation System instrumentation in accordance with the requirements of Technical Specification Table 4.3-2, or as part of FHB Emergency Exhaust System in accordance with the requirements of Specification 4.9.12.d.2. Verification of the Thermal Overload Protection Bypass circuit for each of these MOVs requires stroking the valve during safeguards actuation testing with normal control circuit power interrupted to simulate a thermal overload condition.
**	Valves are functional; however their ability to open and close is no longer required for system operability due to the blind flanges installed by EC 260241.

ATTACHMENT 8
Page 1 of 2

<< Safeguards Systems Isolation Valves in Closed Systems >>

VALVE NO. CP&L (EBASCO)	FUNCTION	REDUNDANT ISOL. VALVE NO. CP&L (EBASCO)	APPLICABLE MODES
1BD-1 (BD-P6)	SG A BLDN ISOL	1BD-11 (BD-V11)	1-3
1BD-20 (BD-P7)	SG B BLDN ISOL	1BD-30 (BD-V15)	1-3
1BD-39 (BD-P8)	SG C BLDN ISOL	1BD-49 (BD-V19)	1-3
1SP-214 (SP-V90)	SG A SHELL SAMPLE	1SP-217 (SP-V120)	1-3
1SP-216 (SP-V91)	SG A TUBE SAMPLE	1SP-217 (SP-V120)	1-3
1SP-219 (SP-V85)	SG B SHELL SAMPLE	1SP-222 (SP-V121)	1-3
1SP-221 (SP-V86)	SG B TUBE SAMPLE TUBE SHT ISO	1SP-222 (SP-V121)	1-3
1SP-224 (SP-V80)	SG C SHELL SAMPLE SHELL ISO	1SP-227 (SP-V122)	1-3
1SP-226 (SP-V81)	SG C TUBE SAMPLE TUBE SHT ISO	1SP-227 (SP-V122)	1-3
1FW-133 (FW-F3)	SG A MF REG VALVE	1FW-159 (FW-V26)	1-4
1FW-140 (FW-F6)	SG A MF BYPASS REG VALVE	1FW-159 (FW-V26)	1-4
1FW-249 (FW-F4)	SG B MF REG VALVE	1FW-277 (FW-V27)	1-4
1FW-256 (FW-F7)	SG B MF BYPASS REG VALVE	1FW-277 (FW-V27)	1-4
1FW-191 (FW-F5)	SG C MF REG VALVE	1FW-217 (FW-V28)	1-4
1FW-198 (FW-F8)	SG C MF BYPASS REG VALVE	1FW-217 (FW-V28)	1-4

<< Safeguards Systems Isolation Valves in Closed Systems >>

All safeguards systems isolation valves shall be functional in the modes specified.

With one or more valves non-functional, maintain the redundant isolation valve(s) functional for each line which is not isolated. Restore the non-functional valve to functional status or isolate the affected line within 72 hours. If the valve(s) is not restored or the associated line is not isolated then place the unit in a mode for which the isolation function is not required within the next 48 hours.

The following guidance is provided for complying with the requirement to isolate the penetration:

- Either the non-functional valve, or all valves listed under the Redundant Valves column must be closed (and de-activated, if applicable for power-operated valves), or a valve having the same safety class and seismic design class in series with the non-functional valve must be closed (and de-activated, if applicable for power-operated valves). If the piping branches, each branch must also be isolated.

- Penetration flow path(s) may be un-isolated intermittently under administrative controls. These administrative controls consist of stationing a dedicated operator at the valve controls, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for containment isolation is indicated.

<< Harris Unit 1 Cycle 21 Core Operating Limits Report - Rev. 0 >>

1.0 CORE OPERATING LIMITS REPORT

This Core Operating Limits Report (COLR) for Shearon Harris Unit 1 Cycle 21 has been prepared in accordance with the requirements of Technical Specification 6.9.1.6.

The Technical Specifications affected by this report are listed below:

3/4.1.1.2 SHUTDOWN MARGIN - Modes 3, 4, and 5

3/4.1.1.3 Moderator Temperature Coefficient

3/4.1.3.5 Shutdown Rod Insertion Limit

3/4.1.3.6 Control Rod Insertion Limits

3/4.2.1 Axial Flux Difference

3/4.2.2 Heat Flux Hot Channel Factor - FQ(Z)

3/4.2.3 Nuclear Enthalpy Rise Hot Channel Factor - $F_{\Delta H}$

3/4.9.1.a Boron Concentration During Refueling Operations

2.0 OPERATING LIMITS

The cycle-specific parameter limits for the specifications listed in Section 1.0 are presented in the following subsections. These limits have been developed using NRC approved methodologies specified in Technical Specification 6.9.1.6 and given in Section 3.0.

2.1 SHUTDOWN MARGIN - MODES 3, 4, and 5 (Specification 3/4.1.1.2)

The SHUTDOWN MARGIN versus RCS boron concentration - Modes 3, 4, and 5 is specified in Figure 1.

2.2 Moderator Temperature Coefficient (Specification 3/4.1.1.3)

1. The Moderator Temperature Coefficient (MTC) limits are:

   The Positive MTC Limit (ARO/HZP) shall be less positive than +5.0 pcm/°F for power levels up to 70% RTP with a linear ramp to 0 pcm/°F at 100% RTP.

   The Negative MTC Limit (ARO/RTP) shall be less negative than 50 pcm/°F.

<< Harris Unit 1 Cycle 21 Core Operating Limits Report - Rev. 0 >>

2.2 Moderator Temperature Coefficient (Specification 3/4.1.1.3) (continued)

2. The MTC Surveillance limit is:

   The 300 ppm/ARO/RTP-MTC should be less negative than or equal to 44.8 pcm/°F.

   where:

   - ARO stands for All Rods Out
   - HZP stands for Hot Zero THERMAL POWER
   - RTP stands for RATED THERMAL POWER

2.3 Shutdown Rod Insertion Limit (Specification 3/4.1.3.5)

Fully withdrawn for all shutdown rods shall be greater than or equal to 225 steps.

2.4 Control Rod Insertion Limit (Specification 3/4.1.3.6)

The control rod banks shall be limited in physical insertion as specified in Figure 2. Fully withdrawn for all control rods shall be greater than or equal to 225 steps.

2.5 Axial Flux Difference (Specification 3/4.2.1)

The AXIAL FLUX DIFFERENCE (AFD) target band is specified in Figure 3.

2.6 Heat Flux Hot Channel Factor - $F_Q(Z)$ (Specification 3/4.2.2)

1. The $F_Q(Z)$ Limit as referenced in TS 3.2.2 is:

   $F_Q(Z) \leq F_Q^{RTP} * K(Z)/P$ for $P > 0.5$

   $F_Q(Z) \leq F_Q^{RTP} * K(Z)/0.5$ for $P \leq 0.5$

   where:

   a. P = THERMAL POWER/RATED THERMAL POWER

   b. $F_Q^{RTP} = 2.41$ for all Fuel

   c. K(Z) = the normalized $F_Q(Z)$ as a function of core height, as specified in Figure 4. K(Z) is set equal to 1.0 for all axial elevations.

<< Harris Unit 1 Cycle 21 Core Operating Limits Report - Rev. 0 >>

2.6 Heat Flux Hot Channel Factor - FQ(Z) (Specification 3/4.2.2) (continued)

2. V(Z) Curves versus core height for PDC-3 Operation, as used in T.S. 4.2.2, are specified in Figures 5 through 6. The first V(Z) curve (Figure 5) is valid for Cycle 21 burnups from 0 up to but not including 15000 MWD/MTU. The second V(Z) curve (Figure 6) is valid for Cycle 21 burnups greater than or equal to 15000 MWD/MTU to a maximum cycle energy of 21935 MWD/MTU.

2.7 Nuclear Enthalpy Rise Hot Channel Factor - $F_{\Delta H}$ (Specification 3/4.2.3)

$F_{\Delta H} \leq F_{\Delta H}^{RTP} * (1 + PF_{\Delta H} * (1 - P))$

where:

1. P = THERMAL POWER/RATED THERMAL POWER

2. $F_{\Delta H}^{RTP}$ = $F_{\Delta H}$ Limit at RATED THERMAL POWER = 1.66 For all Fuel

3. $PF_{\Delta H}$ = Power Factor Multiplier for $F_{\Delta H}$ = 0.35 For all Fuel

$F_{\Delta H}$ = Enthalpy rise hot channel factor obtained by using the movable incore detectors to obtain a power distribution map, with the measured value of the nuclear enthalpy rise hot channel factor ($F_{\Delta H}^{N}$) increased by an allowance of 4% to account for measurement uncertainty.

2.8 Boron Concentration During Refueling Operations (Specification 3/4.9.1.a)

Through the end of Cycle 21, the boron concentration required to maintain Keff less than or equal to 0.95 is equal to 2222 ppm. Boron concentration must be maintained greater than or equal to 2222 ppm during refueling operations.

3.0 METHODOLOGY REFERENCES

1. XN-75-27(P)(A) (June 1975) and Supplements 1 (September 1976), 2 (December 1977), 3 (November 1980), 4 (December 1985), and 5 (February 1987), "Exxon Nuclear Neutronics Design Methods for Pressurized Water Reactors," Exxon Nuclear Company, Richland, WA 99352. (Not used for Cycle 21.)

   (Methodology for Specification 3.1.1.2 - SHUTDOWN MARGIN - Modes 3, 4, and 5, 3.1.1.3 - Moderator Temperature Coefficient, 3.1.3.5 - Shutdown Bank Insertion Limits, 3.1.3.6 - Control Bank Insertion Limits, 3.2.1 Axial Flux Difference, 3.2.2 - Heat Flux Hot Channel Factor, 3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor, and 3.9.1 - Boron Concentration).

2. ANF-89-151(P)(A), "ANF-RELAP Methodology for Pressurized Water Reactors: Analysis of Non-LOCA Chapter 15 Events," Advanced Nuclear Fuels Corporation, Richland, WA 99352, May 1992.

   (Methodology for Specification 3.1.1.3 - Moderator Temperature Coefficient, 3.1.3.5 - Shutdown Bank Insertion Limits, 3.1.3.6 - Control Bank Insertion Limits, 3.2.1 - Axial Flux Difference, 3.2.2 - Heat Flux Hot Channel Factor, and 3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor).

3. XN-NF-82-21(P)(A), Revision 1, "Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations," Exxon Nuclear Company, Richland, WA 99352, September 1983.

   (Methodology for Specification 3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor).

4. XN-75-32(P)(A), (April 1975) Supplements 1 (July 1979), 2 (July 1979), 3 (January 1980), and 4 (October 1983), "Computational Procedure for Evaluating Fuel Rod Bowing," Exxon Nuclear Company, Richland, WA 99352.

   (Methodology for Specification 3.2.2 - Heat Flux Hot Channel Factor, and 3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor).

5. EMF-84-093(P)(A), Revision 1, "Steam line Break Methodology for PWRs," Siemens Power Corporation, May 1999.

   (Methodology for Specification 3.1.1.3 - Moderator Temperature Coefficient, 3.1.3.5 - Shutdown Bank Insertion Limits, 3.1.3.6 - Control Bank Insertion Limits, and 3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor).

<< Harris Unit 1 Cycle 21 Core Operating Limits Report - Rev. 0 >>

3.0 METHODOLOGY REFERENCES (continued)

6. ANP-3011(P), Revision 1, "Harris Nuclear Plant Unit 1 Realistic Large Break LOCA Analysis," as approved by NRC Safety Evaluation dated May 30, 2012, issued August 2011.

   (Methodology for Specification 3.2.1 - Axial Flux Difference, 3.2.2 Heat Flux Hot Channel Factor, and 3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor).

7. XN-NF-78-44(NP)(A), "A Generic Analysis of the Control Rod Ejection Transient for Pressurized Water Reactors," Exxon Nuclear Company, Richland, WA 99352, October 1983.

   (Methodology for Specification 3.1.3.5 - Shutdown Bank Insertion Limits, 3.1.3.6 - Control Bank Insertion Limits, and 3.2.2 - Heat Flux Hot Channel Factor).

8. ANF-88-054(P)(A), "PDC-3: Advanced Nuclear Fuels Corporation Power Distribution Control for Pressurized Water Reactors and Application of PDC-3 to H. B. Robinson Unit 2," Advanced Nuclear Fuels Corporation, Richland, WA 99352, October 1990.

   (Methodology for Specification 3.2.1 - Axial Flux Difference, and 3.2.2 Heat Flux Hot Channel Factor).

9. EMF-92-081(P)(A), Revision 1, "Statistical Setpoint/Transient Methodology for Westinghouse Type Reactors," Siemens Power Corporation, July 2000.

   (Methodology for Specification 3.1.1.3 - Moderator Temperature Coefficient, 3.1.3.5 - Shutdown Bank Insertion Limits, 3.1.3.6 - Control Bank Insertion Limits, 3.2.1 - Axial Flux Difference, 3.2.2 - Heat Flux Hot Channel Factor, and 3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor).

10. EMF-92-153(P)(A), Revision 1, "HTP: Departure from Nucleate Boiling Correlation for High Thermal Performance Fuel," Siemens Nuclear Power Corporation, Richland, WA 99352, January 2005.

    (Methodology for Specification 3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor).

3.0 METHODOLOGY REFERENCES (continued)

11. BAW-10240 (P)(A),Revision 0, "Incorporation of M5TM Properties in Framatome ANP Approved Methods," Framatome ANP, May 2004

    (Methodology for Specification 3.1.1.2 - SHUTDOWN MARGIN - MODES 3, 4 and 5, 3.1.1.3- Moderator Temperature Coefficient, 3.1.3.5 - Shutdown Bank Insertion Limits, 3.1.3.6- Control Bank Insertion Limits, 3.2.1 - Axial Flux Difference, 3.2.2 - Heat Flux Hot Channel Factor, 3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor, and 3.9.1 - Boron Concentration).

12. EMF-96-029(P)(A), Volumes 1 and 2, "Reactor Analysis Systems for PWRs, Volume 1 - Methodology Description, Volume 2 - Benchmarking Results," Siemens Power Corporation, January 1997.

    (Methodology for Specification 3.1.1.2 - SHUTDOWN MARGIN - MODES 3, 4, and 5, 3.1.1.3 - Moderator Temperature Coefficient, 3.1.3.5 - Shutdown Bank Insertion Limits, 3.1.3.6 - Control Bank Insertion Limits, 3.2.1 Axial Flux Difference, 3.2.2 - Heat Flux Hot Channel Factor, 3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor, and 3.9.1 - Boron Concentration).

13. EMF-2328(P)(A), Revision 0, "PWR Small Break LOCA Evaluation Model, S RELAP5 Based," Framatone ANP, May 2001, and Errata, January 2008.

    (Methodology for Specification 3.2.1 - Axial Flux Difference, and 3.2.2 Heat Flux Hot Channel Factor), and 3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor).

14. EMF -2310 (P)(A), Revision 1, "SRP Chapter 15 Non-LOCA Methodology for Pressurized Water Reactors," Framatome ANP, June 2004.

    (Methodology for Specification 3.1.1.3 - Moderator Temperature Coefficient, 3.1.3.5 - Shutdown Bank Insertion Limits, 3.1.3.6 - Control Bank Insertion Limits, 3.2.1- Axial Flux Difference, 3.2.2 - Heat Flux Hot Channel Factor, and 3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor).

3.0 METHODOLOGY REFERENCES (continued)

15. Mechanical Design Methodologies

    XN-NF-81-58(P)(A), Revision 2 and Supplements 1 and 2, "RODEX2 Fuel Rod Thermal-Mechanical Response Evaluation Model," Exxon Nuclear Company, March 1984.

    ANF-81-58(P)(A), Revision 2 and Supplements 3 and 4, "RODEX2 Fuel Rod Thermal Mechanical Response Evaluation Model," Advanced Nuclear Fuels Corporation, June 1990.

    XN-NF-82-06(P)(A), Revision 1 and Supplements 2, 4, and 5, "Qualification of Exxon Nuclear Fuel for Extended Burnup," Exxon Nuclear Company, October 1986.

    ANF-88-133(P)(A), and Supplement 1, "Qualification of Advanced Nuclear Fuels' PWR Design Methodology for Rod Burnups of 62 GWd/MTU," Advanced Nuclear Fuels Corporation, December 1991.

    XN-NF-85-92(P)(A), "Exxon Nuclear Uranium Dioxide/Gadolinia Irradiation Examination and Thermal Conductivity Results," Exxon Nuclear Company, November 1986.

    EMF-92-116(P)(A), Revision 0 and Supplement 1(P)(A)-000, "Generic Mechanical Design Criteria for PWR Fuel Designs," Siemens Power Corporation, February 1999 and May 2015.

    (Methodologies for Specification 3.2.1 - Axial Flux Difference, 3.2.2 Heat Flux Hot Channel Factor, and 3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor).

16. DPC-NE-2005-P-A, "Thermal-Hydraulic Statistical Core Design Methodology," Revision 5, NRC Safety Evaluation: ML 16049A630 (Not used for Cycle 21.)

    (Methodology for Specification 3.2.3 -Nuclear Enthalpy Rise Hot Channel Factor)

4.0 OTHER REQUIREMENTS

4.1 Movable Incore Detection System

1. Functionality: The Movable Incore Detection System shall be functional with:

   a. At least 38 detector thimbles at the beginning of cycle (where the beginning of cycle is defined in this instance as a flux map determination that the core is loaded consistent with design),

   b. A minimum of 38 detector thimbles for the remainder of the operating cycle,

   c. A minimum of two detector thimbles per core quadrant, and

   d. Sufficient movable detectors, drive, and readout equipment to map these thimbles.

2. Applicability: When the Movable Incore Detection System is used for:

   a. Recalibration of the Excore Neutron Flux Detection System, or

   b. Monitoring the QUADRANT POWER TILT RATIO, or

   c. Measurement of $F_{\Delta H}$ and $F_Q(Z)$

3. Surveillance Requirements: The Movable Incore Detection System shall be demonstrated functional, within 24 hours prior to use, by irradiating each detector used and determining the acceptability of its voltage curve when required for:

   a. Recalibration of the Excore Neutron Flux Detection System, or

   b. Monitoring the QUADRANT POWER TILT RATIO, or

   c. Measurement of $F_{\Delta H}$ and $F_Q(Z)$

<< Harris Unit 1 Cycle 21 Core Operating Limits Report - Rev. 0 >>

4.0 OTHER REQUIREMENTS (continued)

4. Bases:

The functionality of the movable incore detectors with the specified minimum complement of equipment ensures that the measurements obtained from use of this system accurately represent the spatial neutron flux distribution of the core. The functionality of this system is demonstrated by irradiating each detector used and determining the acceptability of its voltage curve.

For the purpose of measuring $F_Q(Z)$ or $F_{\Delta H}$, a full incore flux map is used.

Quarter-core flux maps, as defined in WCAP-8648, June 1976, may be used in recalibration of the Excore Neutron Flux Detection System, and full incore flux maps or symmetric incore thimbles may be used for monitoring QUADRANT POWER TILT RATIO when one Power Range channel is INOPERABLE.

5. Evaluation Requirements:

In order to change the requirements concerning the number and location of functional detectors, the NRC staff deems that a rigorous evaluation and justification is required. The following is a list of elements that must be part of a 50.59 determination and available for audit if the licensee wishes to change the requirements:

a. How an inadvertent loading of a fuel assembly into an improper location will be detected,

b. How the validity of the tilt estimates will be ensured,

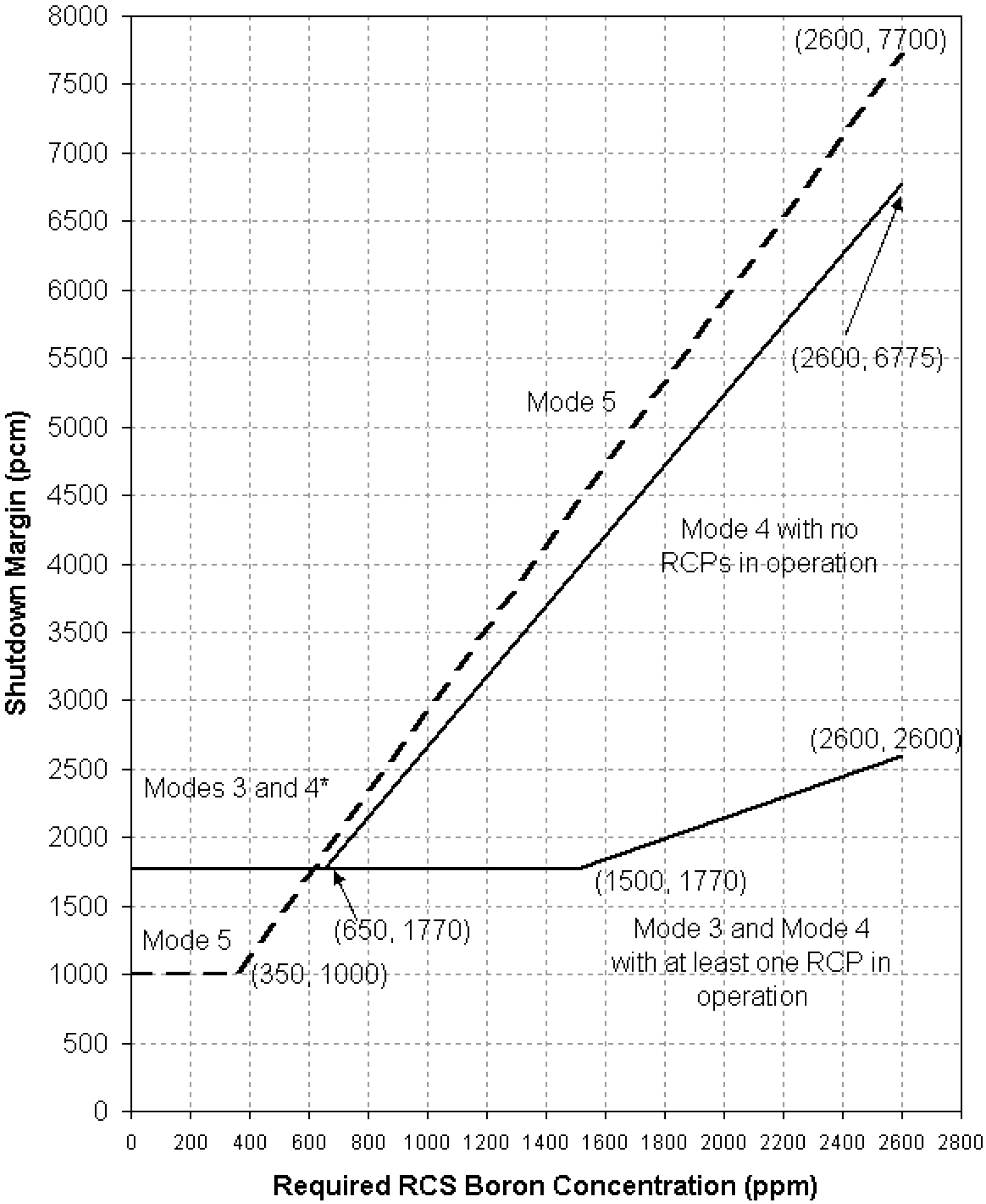
c. How adequate core coverage will be maintained,

d. How the measurement uncertainties will be assured and why the added uncertainties are adequate to guarantee that measured nuclear heat flux hot channel factor, nuclear enthalpy rise hot channel factor, radial peaking factor and quadrant power tilt factor meet Technical Specification limits, and

e. How the Movable Incore Detection System will be restored to full (or nearly full) service before the beginning of each cycle.

<< Harris Unit 1 Cycle 21 Core Operating Limits Report - Rev. 0 >>

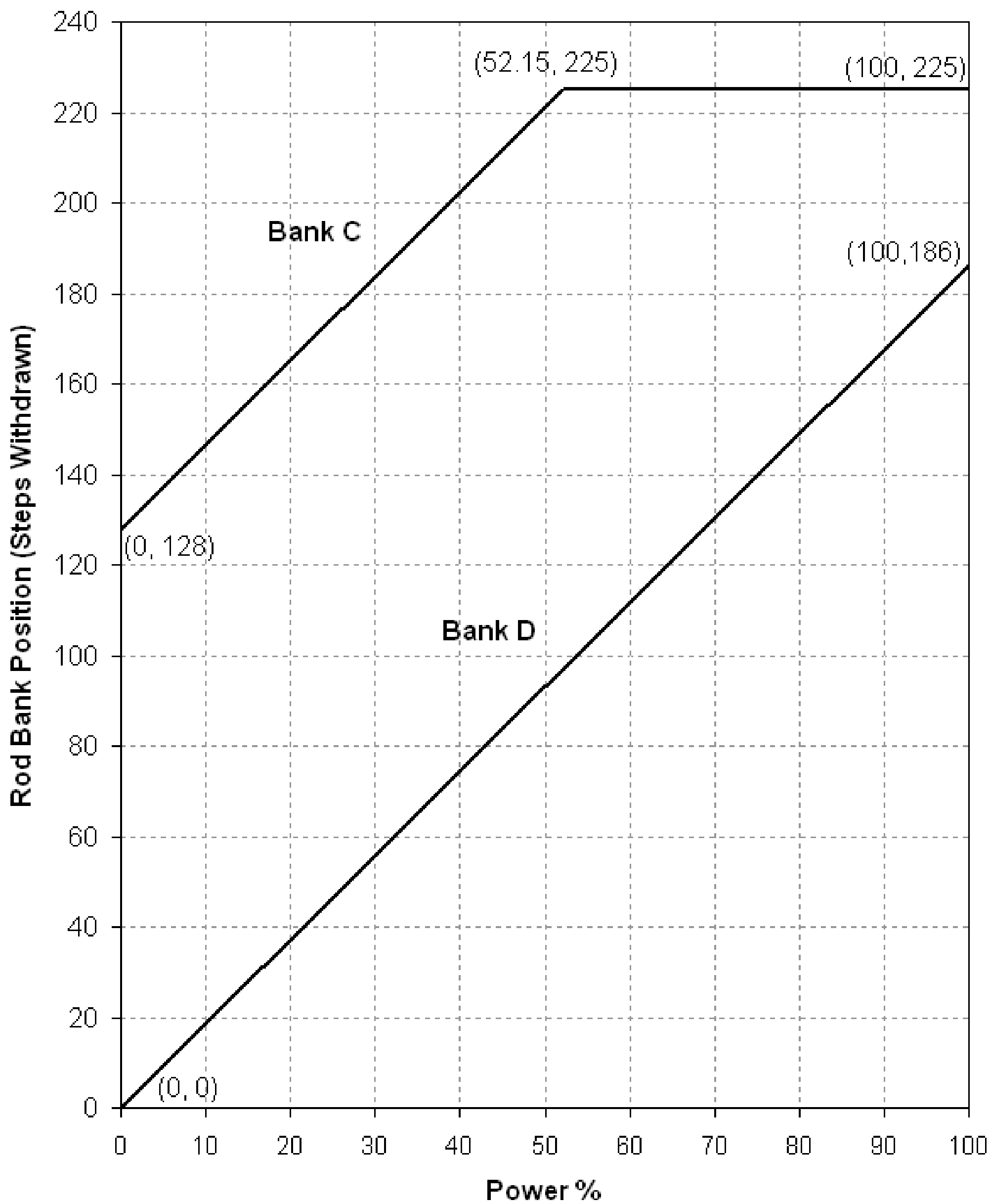
Figure 1, Shutdown Margin Versus RCS Boron Concentration
Modes 3, 4, and 5/Drained



* Applicable to MODE 4, with or without RCPs in operation

<< Harris Unit 1 Cycle 21 Core Operating Limits Report - Rev. 0 >>

Figure 2, Rod Group Insertion Limits Versus Thermal Power (Three Loop Operation)

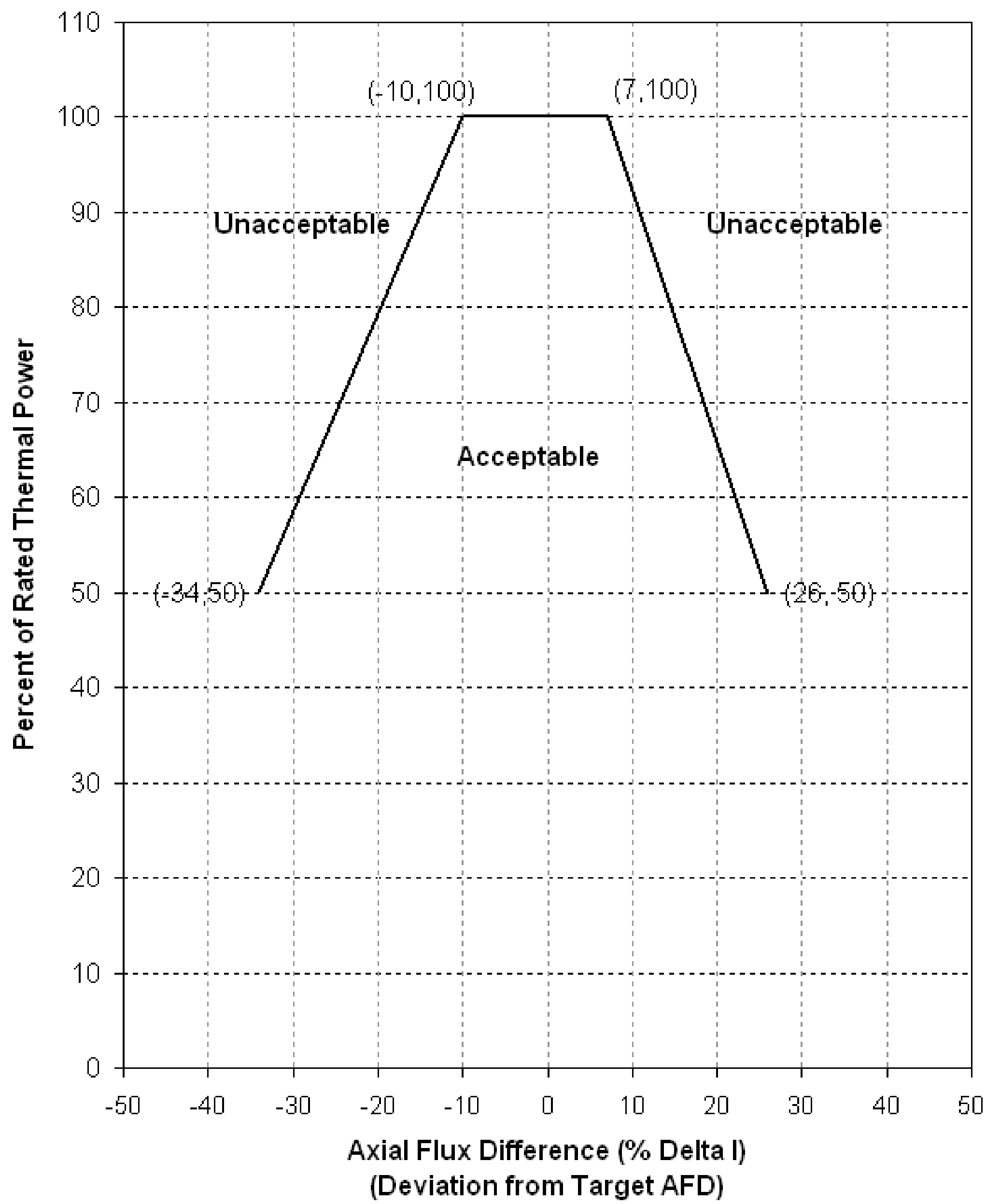


Notes:

1. Fully withdrawn position shall be greater than or equal to 225 steps.
2. Control Banks A and B must be withdrawn from the core prior to power operation.

<< Harris Unit 1 Cycle 21 Core Operating Limits Report - Rev. 0 >>

Figure 3, Axial Flux Difference Limits as a Function of Rated Thermal Power

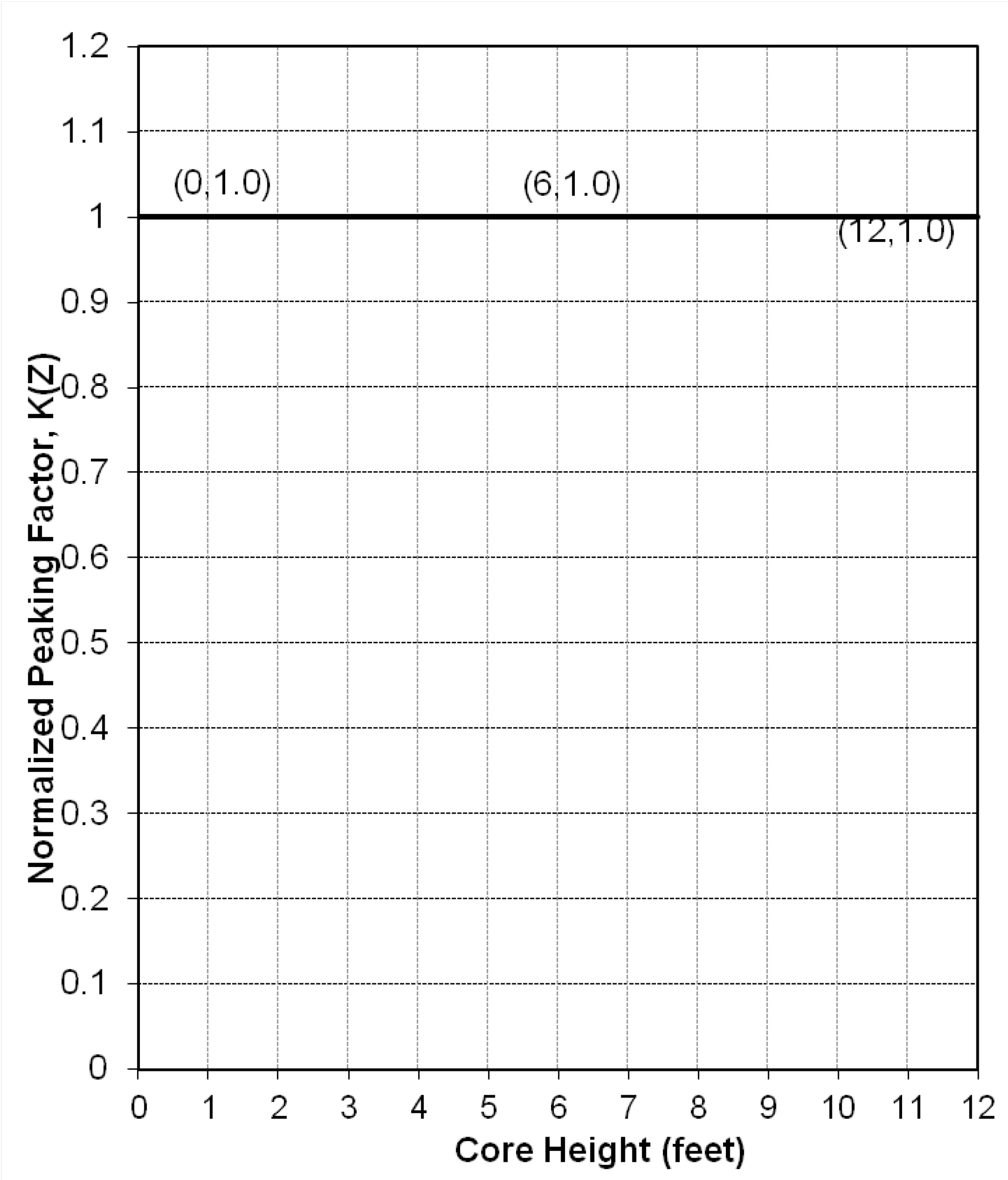


Note:

At power levels less than HFP, the deviation is applied to the target AFD appropriate to that power level. The target AFD varies linearly between the HFP target and zero at zero power.

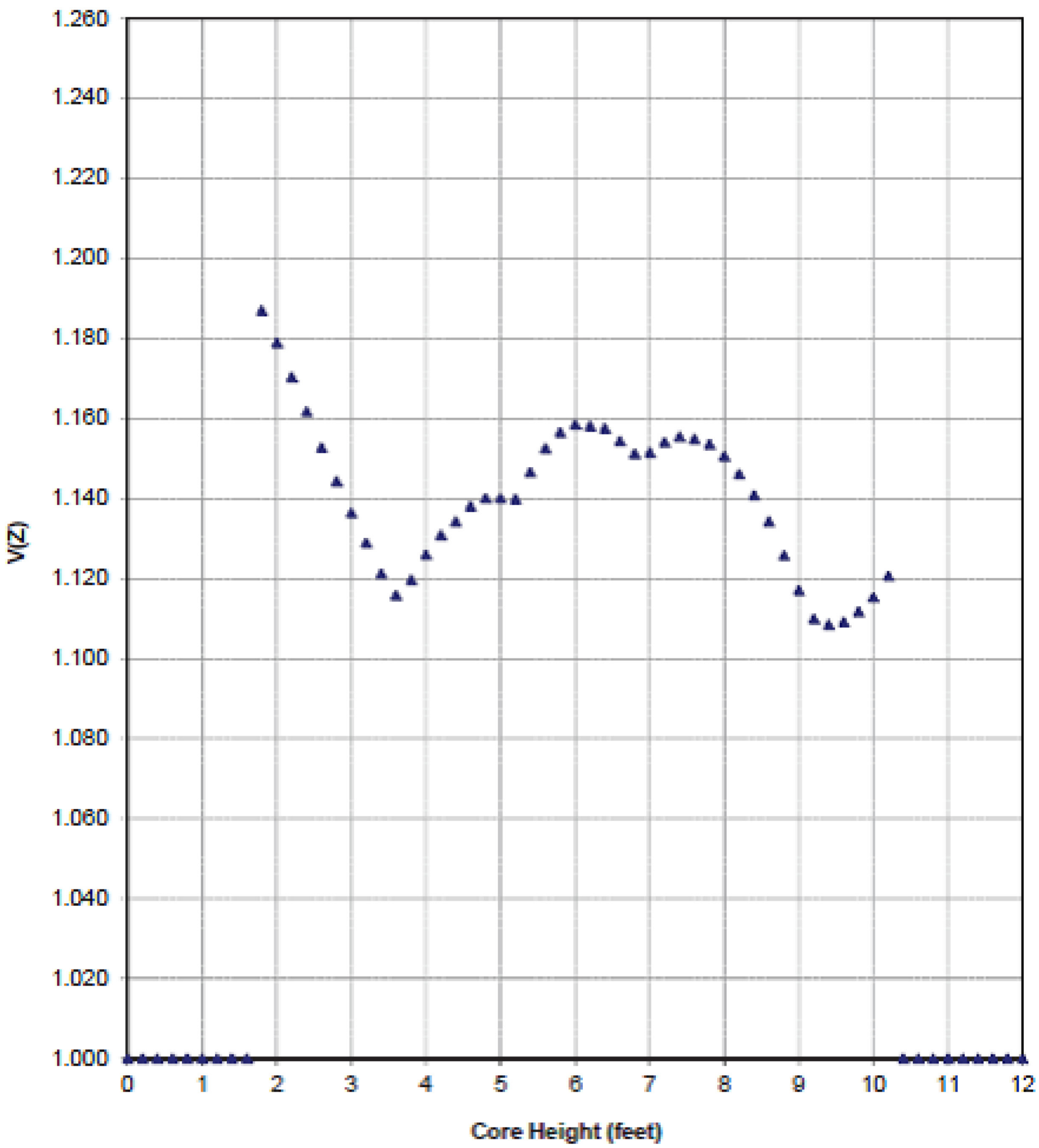
<< Harris Unit 1 Cycle 21 Core Operating Limits Report - Rev. 0 >>

Figure 4, K(Z) - Local Axial Penalty Function for $F_Q(Z)$



<< Harris Unit 1 Cycle 21 Core Operating Limits Report - Rev. 0 >>

Figure 5, Cycle 21 V(Z) Versus Core Height 0 MWD/MTU ≤ burnup < 15000 MWD/MTU



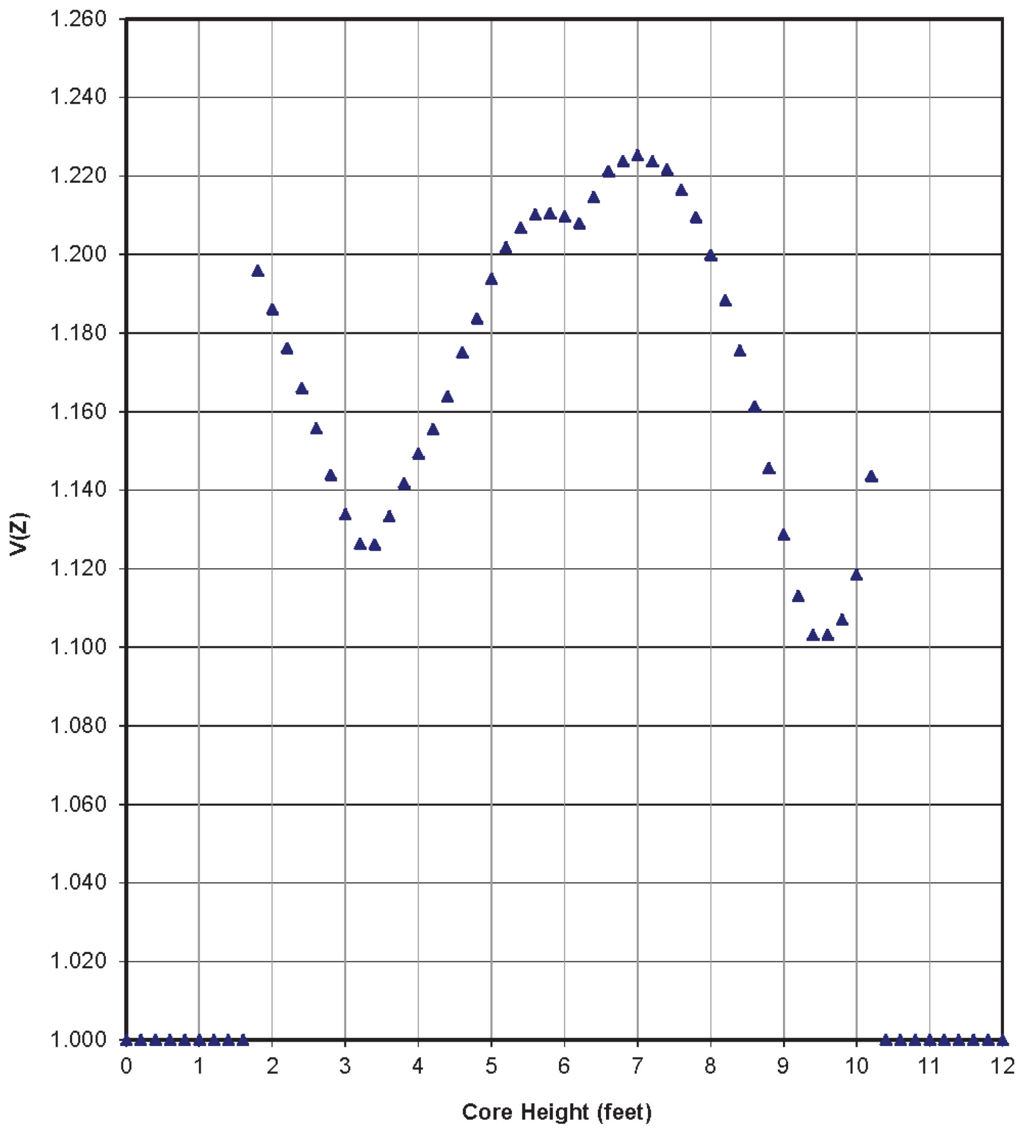
Height (feet)		V(Z)
0.0	•	1.0000
0.2	•	1.0000
0.4	•	1.0000
0.6	•	1.0000
0.8	•	1.0000
1.0	•	1.0000
1.2	•	1.0000
1.4	•	1.0000
1.6	•	1.0000
1.8		1.1870
2.0		1.1790
2.2		1.1704
2.4		1.1618
2.6		1.1528
2.8		1.1443
3.0		1.1364
3.2		1.1290
3.4		1.1213
3.6		1.1159
3.8		1.1197
4.0		1.1260
4.2		1.1309
4.4		1.1343
4.6		1.1381
4.8		1.1401
5.0		1.1401
5.2		1.1399
5.4		1.1466
5.6		1.1526
5.8		1.1565
6.0		1.1585
6.2		1.1582
6.4		1.1576
6.6		1.1544
6.8		1.1512
7.0		1.1516
7.2		1.1541
7.4		1.1555
7.6		1.1549
7.8		1.1536
8.0		1.1506
8.2		1.1462
8.4		1.1409
8.6		1.1343
8.8		1.1258
9.0		1.1171
9.2		1.1100
9.4		1.1085
9.6		1.1092
9.8		1.1118
10.0		1.1154
10.2		1.1207
10.4	•	1.0000
10.6	•	1.0000
10.8	•	1.0000
11.0	•	1.0000
11.2	•	1.0000
11.4	•	1.0000
11.6	•	1.0000
11.8	•	1.0000
12.0	•	1.0000

Top and bottom 15% excluded per Technical Specification 4.2.2.2.g.

For all power levels below 50% RTP, the V(Z) data at all axial levels is 1.0. It is conservative to apply the above figure to power levels below 50% RTP.

<< Harris Unit 1 Cycle 21 Core Operating Limits Report - Rev. 0 >>

Figure 6, Cycle 21 V(Z) Versus Core Height 15000 MWD/MTU ≤ burnup ≤ 21935 MWD/MTU



Height (feet)		V(Z)
0.0	•	1.0000
0.2	•	1.0000
0.4	•	1.0000
0.6	•	1.0000
0.8	•	1.0000
1.0	•	1.0000
1.2	•	1.0000
1.4	•	1.0000
1.6	•	1.0000
1.8		1.1959
2.0		1.1861
2.2		1.1762
2.4		1.1660
2.6		1.1557
2.8		1.1439
3.0		1.1338
3.2		1.1264
3.4		1.1262
3.6		1.1333
3.8		1.1418
4.0		1.1494
4.2		1.1555
4.4		1.1639
4.6		1.1750
4.8		1.1837
5.0		1.1938
5.2		1.2018
5.4		1.2068
5.6		1.2101
5.8		1.2105
6.0		1.2096
6.2		1.2080
6.4		1.2146
6.6		1.2212
6.8		1.2238
7.0		1.2252
7.2		1.2237
7.4		1.2216
7.6		1.2165
7.8		1.2095
8.0		1.1999
8.2		1.1883
8.4		1.1755
8.6		1.1613
8.8		1.1456
9.0		1.1286
9.2		1.1131
9.4		1.1031
9.6		1.1033
9.8		1.1070
10.0		1.1185
10.2		1.1436
10.4	•	1.0000
10.6	•	1.0000
10.8	•	1.0000
11.0	•	1.0000
11.2	•	1.0000
11.4	•	1.0000
11.6	•	1.0000
11.8	•	1.0000
12.0	•	1.0000

Top and bottom 15% excluded per Technical Specification 4.2.2.2.g.

For all power levels below 50% RTP, the V(Z) data at all axial levels is 1.0. It is conservative to apply the above figure to power levels below 50% RTP.

ATTACHMENT 10
Page 1 of 2

<< Instrument Uncertainties Associated with Reactor Vessel Pressure - Temperature Limits and Low Temperature Overpressure Protection System >>

1. Reactor Vessel P-T Limits:

The P-T limits provided in Technical Specification Figures 3.4-2 and 3.4-3 do not include instrument uncertainties. Plant procedures implementing the P-T limits shall include the following minimum pressure and temperature uncertainties in a conservative manner.

	ERFIS	MCB/RECORDERS
Pressure (psig) Temperature (°F)	± 80 ± 11.5	± 120 ± 20.5

Instrumentation used to monitor the above RCS variables for compliance with Technical Specifications 3.4.9.1 and 3.4.9.2 shall have a maximum loop instrument uncertainty (element to indication) at or within the values stated above.

2. Low Temperature Overpressure Protection System (LTOPS):

The LTOPS setpoints provided in Technical Specification Figure 3.4-4 are the maximum nominal setpoints. They do not include instrument uncertainties. LTOP instrument uncertainty (element to actuation/arming) shall be at or within the following values:

- Pressure (actuation): ± 65 psi
- Temperature (actuation): ± 5°F
- Temperature (arming): ± 7°F

ATTACHMENT 10
Page 2 of 2

<< Instrument Uncertainties Associated with Reactor Vessel Pressure - Temperature Limits and Low Temperature Overpressure Protection System >>

3. Temperature Range for Heatup and Cooldown Rates:

The temperature ranges provided in Technical Specification Table 4.4-6 assume ERFIS temperature indication, which is normally available for plant heatup and cooldown, is utilized. If MCB/Recorder temperature indication is utilized, the instrument uncertainties are increased. The following table provides temperature ranges when utilizing MCB/Recorder temperature indication during heatup and cooldown:

HEATUP OR COOLDOWN	RATE (°F/HR)	RCS COLD LEG TEMPERATURE (°F)	
		USING ERFIS	USING MCB OR RECORDER
HU	50	≤350 [2]	≤ 350 [2]
CD	50	350-120 [2]	350-129 [2]
CD	30	< 120 [1]	< 129 [1]

Footnotes:

1. The lower bound temperature which LTOPS may be credited is 90°F using ERFIS per TS 3.4.9.4(b) and 99°F using MCB or recorder indication.
2. Instrument uncertainties at an indicated temperature of 350°F were also considered in the development of the heatup and cooldown pressure and temperature limits using either ERFIS or MCB indication.

ATTACHMENT 11
Page 1 of 1

<< Reactor Trip System Instrumentation Setpoint As-Found/As-Left Tolerances >>

	FUNCTIONAL UNIT	TRIP SETPOINT	AS-FOUND TOLERANCE	AS-LEFT TOLERANCE
1.	Manual Reactor Trip	N/A	N/A	N/A
2.	Power Range, Neutron Flux			
	a. High Setpoint	≤ 108% of RTP	1.12% Span	0.50% Span
	b. Low Setpoint	≤ 25% of RTP	1.12% Span	0.50% Span
3.	Power Range, Neutron Flux High Positive Rate	≤ 5% of RTP with a time constant ≥ 2 seconds	1.12% Span	0.50% Span
4.	Power Range, Neutron Flux High Negative Rate	≤ 5% of RTP with a time constant ≥ 2 seconds	1.12% Span	0.50% Span
5.	Pressurizer Water Level - High	≤ 87% of instrument span	Sensor Only -1.46% Span Rack Only -1.14% Span	Sensor Only -0.50% Span Rack Only -0.50% Span

NOTE: The following general note applies to the above table:

A discussion of the As-Found/As-Left tolerances is located in the Technical Specification Bases for the Reactor Trip System Instrumentation Setpoints. In the Harris Technical Specifications, the term Trip Setpoint is analogous to the Nominal Trip Setpoint (NTSP). Notes 7 and 8 have been added to Technical Specification Table 2.2-1 for the Power Range Neutron Flux and Pressurizer Water Level High Instruments that require verifying both the trip setpoint setting as-found and as-left values during surveillance testing. Note 7 requires a channel performance evaluation when the as-found setting is outside its as-found tolerance. Note 8 requires that the as-left channel setting be reset to a value that is within the as-left tolerances about the trip setpoint in Table 2.2-1 of the Technical Specifications. The actual field setpoint and the associated as-found/as-left tolerances for the Nuclear Instrumentation Power Range and Pressurizer Water Level High channels are specified in this attachment. The bases for the as-found/as-left tolerances are contained within calculation HNP-I/INST-1010. The bases for adding Notes 7 and 8 is to provide implementation of the TSTF-493 recommendations
(Option A) for the Nuclear Instrumentation Power Range and Pressurizer Water Level High setpoints.

R
Reference
Use

SHEARON HARRIS NUCLEAR POWER PLANT

Plant Operating Manual

VOLUME 1

PART 2

Plant Programs (PLP)

PLP-114

Relocated Technical Specifications and Design Basis Requirements

Table of Contents

R 1.0 PURPOSE

This procedure identifies and controls regulatory requirements previously contained in the Shearon Harris Technical Specifications. The relocation of those requirements to the attachments contained in this procedure has been approved by the NRC through the issuance of license amendments. Since these requirements have been relocated to this licensee-controlled document, any future changes will require a 10CFR50.59 evaluation.

Additionally, this procedure identifies and controls other design basis requirements identified by CP&L and which are not otherwise contained in the Technical Specifications, plant procedures, or other CP&L controlled documents.

2.0 REFERENCES

1. SHNPP Technical Specifications
2. SHNPP FSAR
3. Amendment No. 55 to Facility Operating License No. NPF-63
4. Amendment No. 61 to Facility Operating License No. NPF-63
5. Amendment No. 62 to Facility Operating License No. NPF-63
6. AD-DC-ALL-0201
7. AD-LS-ALL-0008
8. AP-013
9. AD-PI-ALL-0100
10. REG-NGGC-0101
11. AD-EG-ALL-1202
12. PLP-621
13. ESR-95-00687

2.0 REFERENCES (continued)

14. ESR-94-00198

15. Letter (HNP-95-083) dated September 23, 1995 from CP&L to NRC, Reactor Auxiliary Building Emergency Exhaust System Design and Licensing Basis Issues

16. PNSC Meeting Minutes No. 92-36

17. Amendment No. 64 to Facility Operating License No. NPF-63

18. ESR 96-00284

19. ESR 96-00126

20. ESR 00-00046, SFP Heatload Analysis for RFO9 and Cycle 10

21. ESR 00-00137, Engineering Disposition regarding CSIP Room Temperatures

22. NRC Regulatory Guide 1.133, Loose-Part Detection Program For The Primary System of Light-Water-Cooled Reactors

23. ESR 94-00001

24. EC 248760

25. EC 251445

26. Amendment No. 115 to Facility Operating License No. NPF-63

27. EC 248676

28. EC 272144

29. EC 274914

30. NRC Inspection Manual Part 9900: Technical Guidance

31. EC 300656, Revise Temperature Limit for 286' EL. A PIC Room

32. EC 402748, Increase RAB Battery Room Upper Temp Limit from 79 °F to 85 °F

33. AD-OP-ALL-0105, Operability Determinations and Functionality Assessments

3.0 DEFINITIONS

None

4.0 GENERAL

1. Specific attachments to this procedure have been generated to fulfill the requirements of license amendments to Facility Operating License NPF-63 which allows the removal and relocation of specific Technical Specifications requirements for the Shearon Harris Nuclear Power Plant into licensee-controlled documents. Additionally, other attachments have been generated to control other design basis requirements identified by CP&L and not controlled elsewhere.

2. The controls maintained on this procedure will exceed those normally required by AD-DC-ALL-0201, Procedure Review and Approval.

   a. In addition to the reviews required by AD-DC-ALL-0201, this procedure will require PNSC concurrence before approval.

   b. Changes to this procedure may also require a concurrent change to the FSAR per REG-NGGC-0101.

3. This procedure is incorporated by reference into the Harris Final Safety Analysis Report (FSAR) and is therefore made a part of the FSAR, which is part of the Harris current licensing basis. This procedure cannot be exempted from 50.59 screening.

4. Operability of Structures, Systems, or Components (SSC) described in Technical Specifications:

   The scope of the SSCs considered in the operability determination process includes the following:

   a) SSCs required to be operable by Tech Specs. These SSCs may perform required support functions for other SSCs required to be operable by Tech Specs (example – emergency diesel and service water)

   b) SSCs that are not explicitly required to be operable by Tech Specs, but that perform required support functions (as specified by the TS definition of operability) for SSCs required to be operable by Tech Specs.

5.0 IMPLEMENTATION

5.1 Criteria for Implementing Relocated Technical Specifications and Design Basis Requirements

Each Surveillance Requirement shall be performed within the specified surveillance interval with a maximum allowable extension not to exceed 25% of the specified surveillance interval.

5.2 Additions, Changes, and Deletions to the Attachments

If the attachments to this procedure are revised or deleted or if new attachments are added, the following process shall be performed. This process exceeds the normal procedure review process as indicated in AD-DC-ALL-0201, Procedure Review and Approval.

1. Prepare a revision to the procedure per AD-DC-ALL-0201 for review by plant personnel.

2. Upon completion of the final revision draft, the proposed revision shall be submitted to the PNSC for their concurrence per AP-013.

3. Before approval by the General Manager - Harris Plant, Licensing/Regulatory Programs shall:

   - Ensure procedure revisions or new procedures are prepared to incorporate changes made to the attachments, or

   - Establish action requests per AD-PI-ALL-0100 for changes not requiring immediate implementation.

4. Upon PNSC concurrence of the proposed revision, the procedure revision shall be submitted to the General Manager - Harris Plant for final approval along with an FSAR revision (if required) which incorporates the changes made to the Attachments per REG-NGGC-0101.

5. Upon final approval of the procedure revision, ensure that a task sheet is revised or created per AD-EG-ALL-1202, if appropriate, for testing and tracking purposes.

6.0 ATTACHMENTS

Attachment 1 - Turbine Overspeed Protection

Attachment 2 - Refueling Operations

R Attachment 3 - ECCS Leakage (Design Basis)

Attachment 4 - Area Temperature Monitoring

Attachment 5 - Gas Storage Tanks

Attachment 6 - Seismic Instrumentation

Attachment 7 - Meteorological Instrumentation

Attachment 8 - Metal Impact Monitoring System

Attachment 9 - Explosive Gas Monitoring Instrumentation

Attachment 10 - Feedwater Leading Edge Flow Meter (LEFM) Calorimetric

Turbine Overspeed Protection

1.0 OPERATIONAL REQUIREMENTS

1.1 At least one Turbine Overspeed Protection System shall be functional.

APPLICABILITY: MODES 1, 2, and 3

NOTE: Not applicable in MODE 2 or 3 with all main steam isolation valves and bypass valves in the closed position and all other steam flow paths to the turbine isolated.

ACTION:

a. With one throttle valve or one governor valve per high pressure turbine steam line non-functional and/or with one reheat stop valve or one reheat intercept valve per low pressure turbine steam line non-functional, restore the non-functional valve(s) to functional status within 72 hours, or close at least one valve in the affected steam line(s) or isolate the turbine from the steam supply within the next 6 hours.

b. With the above required Turbine Overspeed Protection System otherwise non-functional, within 6 hours isolate the turbine from the steam supply.

2.0 SURVEILLANCE REQUIREMENTS

2.1 The above required Turbine Overspeed Protection System shall be demonstrated functional:

* a. At least once semiannually by direct observation of the movement of each of the following valves through at least one complete cycle from the running position:

(1) Four high pressure turbine throttle valves,

(2) Four high pressure turbine governor valves,

(3) Four low pressure turbine reheat stop valves, and

(4) Four low pressure turbine reheat intercept valves.

* The provision of Section 5.1, Criteria for Implementing Relocated Technical Specifications and Design Basis Requirements, maximum allowable extension not to exceed 25% of the specified surveillance interval does not apply.

Turbine Overspeed Protection

2.0 SURVEILLANCE REQUIREMENTS (continued)

b. At least once per 18 months by performance of a CHANNEL CALIBRATION on the Turbine Overspeed Protection Systems, and

c. Every refueling outage at least two low pressure turbine inlet valves, two governor valves, and two throttle valves will be swapped with rotational spares. The removed valves will be dismantled and inspected during non-outage periods. The non-outage dismantle inspections will as a minimum consist of surface examinations on the disks and stems. These non-outage inspected valves will then be used as rotational spares for the next refueling outage. During the non-outage inspection, if any attribute is found that would cause the valve function to be lost, then plans will be made for the upcoming refueling outage to inspect the other valves of the same group. Valve seats of the removed governor valves and throttle valves will be inspected for flaws during the refueling outage. If any attribute of the governor or throttle valve seats are found that would cause the valve function to be lost, the other remaining governor and throttle valve seats will be inspected during the same refueling outage. The low pressure turbine inlet valves do not have seats and are designed with some clearance between the disk and valve body. Under this turbine valve inspection schedule, all low pressure turbine inlet valves will be inspected over a four cycle period and all throttle valves and governor valves will be inspected over a two fuel cycle period.

Refueling Operations

1.0 OPERATIONAL REQUIREMENTS - DECAY TIME

1.1 The reactor shall be subcritical for a minimum period of time as determined by Table A.

APPLICABILITY: During movement of irradiated fuel in the reactor vessel.

ACTION:

With the reactor subcritical for a time less than determined by Table A, suspend all operations involving movement of irradiated fuel in the reactor vessel. Fuel movement in the reactor vessel may continue provided the minimum decay time is greater than the time shown on Table A.

2.0 SURVEILLANCE REQUIREMENTS

2.1 The reactor shall be determined to have been subcritical for a minimum period of time as determined using Table A by verification of the date and time of subcriticality prior to movement of irradiated fuel in the reactor vessel.

2.2 CCW temperature shall be monitored every 12 hours during the movement of fuel in the reactor vessel to ensure the temperature used to determine decay time is not exceeded.

Table A

Time from Reactor Subcritical (Hours)	**Effective CCW Temperature (°F)**
100	**96.9**
120	**99.3**
144	**101.7**
168	**103.8**
192	**105.6**
216	**107.2**
240	**108.6**

NOTE 1: - Linear interpolation between listed points is acceptable.
NOTE 2: - These delay times are applicable to end of cycle full core off-loads only. A mid-cycle core off-load assumes two CCW and Fuel Pool Cooling trains available and does NOT require compliance with these limits.
NOTE 3: - Effective CCW temperature refers to actual CCW heat exchanger outlet temperature plus 5°F.
NOTE 4: - The table assumes the core off-load duration is 30 hours or greater. Spent Fuel Pool Cooling analysis assumes full core off-load occurs no sooner than the earliest allowed time to start core off-load after reactor subcritical (based on CCW temperature) plus 30 hours.

Refueling Operations

3.0 OPERATION REQUIREMENTS - COMMUNICATIONS

3.1 Direct communications shall be maintained between the control room and personnel at the refueling station in containment.

APPLICABILITY: During CORE ALTERATIONS.

ACTION:

When direct communications between the control room and personnel at the refueling station cannot be maintained, suspend all CORE ALTERATIONS.

4.0 SURVEILLANCE REQUIREMENTS:

4.1 Direct communications between the control room and personnel at the refueling station in containment shall be demonstrated within 1 hour prior to the start of and at least once per 12 hours during CORE ALTERATIONS.

Refueling Operations

5.0 OPERATIONAL REQUIREMENTS - REFUELING MACHINE

5.1 The refueling machine and auxiliary hoist shall be used for movement of drive rods or fuel assemblies and shall be functional with:

a. The refueling machine, used for movement of fuel assemblies, having:

1. A minimum capacity of 4000 pounds, and

2. An automatic overload cutoff limit less than or equal to 2700 pounds.

b. The auxiliary hoist, used for latching and unlatching drive rods, having:

1. A minimum capacity of 3000 pounds, and

2. A 0 - 2000 pound digital load indicator that shall be used to monitor loads to prevent lifting more than 600 pounds.

APPLICABILITY: During movement of drive rods or fuel assemblies within the reactor vessel.

ACTION:

With the requirements for the refueling machine and/or auxiliary hoist functionality not satisfied, suspend use of any non-functional refueling machine and/or auxiliary hoist from operations involving the movement of drive rods and fuel assemblies within the reactor vessel.

6.0 SURVEILLANCE REQUIREMENTS

6.1 The refueling machine used for movement of fuel assemblies within the reactor vessel shall be demonstrated functional, within 30 days prior to the start of such operations, by performing a load test of at least 4000 pounds and demonstrating an automatic load cutoff at less than or equal to 2700 pounds.

6.2 The auxiliary hoist and associated load indicator used for movement of drive rods within the reactor vessel shall be demonstrated functional within 30 days prior to the start of such operations by performing a load test of at least 900 pounds.

Refueling Operations

7.0 OPERATIONAL REQUIREMENTS - CRANE TRAVEL / FUEL HANDLING BUILDING

7.1 Loads in excess of 2300 pounds shall be prohibited from travel over fuel assemblies in the storage pool.

APPLICABILITY: With irradiated fuel assemblies in the storage pool.

ACTION:

With the requirements of the above specification not satisfied, place the crane load in a safe condition.

8.0 SURVEILLANCE REQUIREMENTS

8.1 Crane interlocks and physical stops which prevent crane travel with loads in excess of 2300 pounds over fuel assemblies shall be demonstrated functional within 7 days prior to crane use and at least once per 7 days thereafter during crane operation.

9.0 OPERATIONAL REQUIREMENTS

9.1 Spent Fuel Pool loads used for plant operations scenarios assume that the refueling outage duration (reactor shutdown to re-synchronization) is no shorter than 15 days.

10.0 SURVEILLANCE REQUIREMENTS

10.1 Prior to Entry into MODE 1 following a refueling outage, it must be confirmed that the duration of a refueling outage is greater than 15 days.

R ECCS Leakage (Design Basis)

1.0 OPERATIONAL REQUIREMENTS

1.1 External leakage from the Emergency Core Cooling System (ECCS) recirculation flow path pressure boundary located outside the Reactor Auxiliary Building (RAB) Emergency Exhaust System boundary shall be limited to a cumulative total of 2 gallons per hour.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTION:

With the above limit exceeded, reduce the leakage rate to within the limit within 24 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

2.0 SURVEILLANCE REQUIREMENTS

2.1 Areas outside the RAB Emergency Exhaust System boundary, excluding the CVCS filter room, that contain components (valves, flanges, strainers) in the ECCS recirculation flow path pressure boundary shall be inspected for indications of external leakage at least every 72 hours.

2.2 Components in the CVCS filter room shall be inspected for indications of external leakage at least every 31 days.

2.3 Any noticeable external leakage found while performing 2.1 or 2.2 above shall be measured or estimated to ensure total leakage is within the limit.

2.4 This portion of the ECCS system shall be leak tested in accordance with the Leakage Reduction Program requirements of PLP-621 at refueling cycle intervals or less.

REFERENCE:

ESR-95-00687

P&L Letter (HNP-95-083) to NRC, dated September 23, 1995

Area Temperature Monitoring

1.0 OPERATIONAL REQUIREMENTS

1.1 The temperature of each area shown in Table A shall not be exceeded for more than 8 hours or by more than 30°F.

APPLICABILITY: Whenever the equipment in an affected area is required to be functional.

ACTION:

a. With one or more areas exceeding the temperature limit(s) shown in Table A for more than 8 hours, prepare within 30 days an evaluation to demonstrate the continued functionality of the affected equipment.

b. With one or more areas exceeding the temperature limit(s) shown in Table A by more than 30°F, prepare an evaluation as required by Action a. above and within 4 hours either restore the area(s) to within the temperature limit(s) or declare the equipment in the affected area(s) non-functional.

2.0 SURVEILLANCE REQUIREMENTS

2.1 The temperature in each of the areas shown in Table A shall be determined to be within its limit at least once per 12 hours.

Area Temperature Monitoring

TABLE A

	AREA	MAXIMUM TEMPERATURE LIMIT (°F)
	REACTOR AUXILIARY BUILDING	
1.	Control Room Envelope (El 305')	75
2.	Process I&C, Room (El 305')	80
3.	Rod Control Cabinets Area (El 305')	104
4.	Auxiliary Relay Cabinet Room (El 305')*	80
5.	AH-15 Ventilation Room (El 305')*	104
6.	A&B Battery Rooms (El 286')	85***
7.	A&B Switchgear Rooms (El 286')	88****
8a.	Process I&C Room A (El 286')*	85
8b.	Process I&C Room B (El 286')*	85
9.	Auxiliary Transfer Panel Room (El 286')*	104
10.	Auxiliary Control Panel Room (El 286)*	88
11.	Main Steam, Feedwater Pipe Tunnel	122
12.	SA&SB Electrical Penetration Areas (El 261' & 286')	104
13.	E-6 Rooms (El 261')*	104
14.	Area with MCC 1A35SA and 1B35SB (El 261')	104
15.	HVAC Chillers, Auxiliary FW Piping & Valve Area (El 261')	104
16.	CCW Pumps, CCW Hx, Auxiliary FW Pumps Area (El 236')	104
17.	1A-SA, 1B-SB, and 1C-SAB Charging Pump Rooms (El 236')	104**
18.	Service Water Booster Pump 1B-SB (El 236')	104
19.	Mechanical and Electrical Penetration Areas (El 236')	104
20.	Containment Spray Additive Tank, and H&V Equipment Area (El 216')	104
21.	Trains A&B Containment Spray Pump, RHR Pump, H&V Equipment Areas (El 190')	104

See “Notes” on next page

Area Temperature Monitoring

TABLE A

	AREA	MAXIMUM TEMPERATURE LIMIT (°F)
	FUEL HANDLING BUILDING	
22.	Trains A&B Emergency Exhaust System Areas (El 261')	104
23.	Spent Fuel Pool Cooling Pump Room (El 236’)	115.5
	WASTE PROCESSING BUILDING	
24.	H&V Equipment Room (El 236')	104
	MISCELLANEOUS	
25.	Tank Area (El 236')	104
26.	Diesel Fuel Oil Storage Building (El 242')	122
27.	Emergency Service Water Electrical Equipment Room	116
28.	Emergency Service Water Pump Room	122
29.	1A-SA & 1B-SB H&V Equipment Rooms (El 292')	122
30.	1A-SA & 1B-SB H&V Equipment Rooms (El 280')	118
31.	1A-SA & 1B-SB Electrical Rooms (El 261')	116
32.	1A-SA & 1B-SB Diesel Generator Rooms (El 261')	120

Notes:

* Areas 4, 5, 8, 9, 10, and 13 were added per PNSC Meeting 92-36.

** An Engineering Disposition has been performed regarding the selection of these setpoints. Reference ED ESR 00-00137 for additional information. This note added per AR# 3744.

*** Battery Room temperature of 85°F was established per EC 402748.

**** Ambient temperature of up to 104°F in the “A & B” Switchgear Room is acceptable whenever ventilation is not available during maintenance outage activities. (Ref. EC 278851)

Gas Storage Tanks

1.0 OPERATIONAL REQUIREMENTS

1.1 The quantity of radioactivity contained in each gas storage tank shall be limited to less than or equal to 1.05×10^5 Curies of noble gases (considered as Xe-133 equivalent).

NOTE: The limit on the quantity of radioactive material stored in each gas storage tank will also be used as the limit on the total curie content in any portion of the Waste Gas System that is interconnected. Therefore, prior to interconnecting portions of the system, the influents to the system shall be isolated and the total curie content (considered as Xe-133 equivalent) in the tanks to be interconnected shall be determined to be within the limit.

The 1.05×10^5 curie limit is based on restricting the quantity contained in each gas storage tank to provide assurance that in the event of an uncontrolled release of the tank's contents the resulting whole body exposure to a member of the public will not exceed 0.5 rem. This is consistent with Standard Review Plan 11.3, Branch Technical Position ETSB 11-5, "Postulated Radioactive Releases Due to a Waste Gas System Leak or Failure," in NUREG-0800, July 1981. Interpretation of the limit to apply to any portion of the system that could be released due to single failure allows flexibility in operation of the system while ensuring any uncontrolled releases meet the above limit.

APPLICABILITY: At all times.

ACTION:

With the quantity of radioactive material in any gas storage tank exceeding the above limit, immediately suspend any additions of radioactive material to the tank, within 48 hours reduce the tank contents to within the limit, and describe the events leading to this condition in the next Annual Radioactive Effluent Release Report, pursuant to Technical Specification 6.9.1.4.

2.0 SURVEILLANCE REQUIREMENTS

2.1 The quantity of radioactive material contained in each gas storage tank shall be determined to be within the above limit at least once every 7 days whenever radioactive materials are added to the tank, and at least once every 24 hours during primary coolant system degassing operations.

Seismic Instrumentation

1.0 OPERATIONAL REQUIREMENTS

1.1 The seismic monitoring instrumentation shown in Table A Attachment 6 shall be functional.

APPLICABILITY: At all times.

ACTION:

a. With one or more of the above required seismic monitoring instruments non-functional for more than 30 days, prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within the next 10 days outlining the cause of the malfunction and plans for restoring the instrument(s) to functional status.

2.0 SURVEILLANCE REQUIREMENTS

2.1 Each of the above required seismic monitoring instruments shall be demonstrated functional by the performance of the CHANNEL CHECK, CHANNEL CALIBRATION, and an ANALOG CHANNEL OPERATION TEST at the frequencies shown in Table B Attachment 6.

2.2 Each of the above required seismic monitoring instruments actuated during a seismic event greater than or equal to 0.01 g shall be restored to functional status within 24 hours and a CHANNEL CALIBRATION performed within 10 days following the seismic event. Data shall be retrieved from actuated instruments and analyzed to determine the magnitude of the vibratory ground motion. A Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 14 days describing the magnitude, frequency spectrum, and resultant effect upon facility features important to safety.

Seismic Monitoring Instrumentation

TABLE A

Instruments and Sensor Locations	Measurement Range	Minimum Instruments Functional
1. Triaxial Time-History Accelerographs		
a. Containment Mat (El 221 ft)	0.01-1.0 g	1**
b. Containment (El 286 ft)	0.01-1.0 g	1**
c. Diesel Fuel Oil Storage Tank Building (El 242 ft)	0.01-1.0 g	1**
2. Triaxial Peak Accelerograph Recorders		
a. Reactor Coolant Pipe (Loop B)	±10 g	1
b. Steam Generator 1A Pedestal (El 238 ft)	± 2 g	1
c. Reactor Auxiliary Building (El 236 ft)	± 10 g	1
3. Triaxial Seismic Switches		
a. Starter Unit for Time History Accelerograph System - Containment Mat (El 221 ft)	0.005 - 0.05	1*
b. Triaxial Seismic Switch- Containment Mat (El 221 ft)	0.025 - 0.25	1*
4. Triaxial Response-Spectrum Recorders		
a. Steam Generator 1B Pedestal (El 238 ft)	± 2 g	1
b. Reactor Auxiliary Building (El 216 ft)	± 2 g	1
c. Diesel Fuel Oil Storage Tank Building (El 242 ft)	± 2 g	1
d. Containment Building (El 221 ft)	± 2 g	1*

* With Main Control Room Indication

** With Main Control Room Recording

Seismic Monitoring Instrumentation Surveillance Requirements

TABLE B

Instruments and Sensor Locations	Channel Check	Channel Calibration	Analog Channel Operational Test
1. Triaxial Time-History Accelerographs			
a. Containment Mat (El 221 ft)	M*	R	SA***
b. Containment (El 286 ft)	M*	R	SA***
c. Diesel Fuel Oil Storage Tank Building (El 242 ft)	M*	R	SA***
2. Triaxial Peak Accelerograph Recorders			
a. Reactor Coolant Pipe (Loop B)	N.A.	R	N.A.
b. Steam Generator 1A Pedestal (El 238 ft)	N.A.	R	N.A.
c. Reactor Auxiliary Building (El 236 ft)	N.A.	R	N.A.
3. Triaxial Seismic Switches			
a. Starter Unit for Time History Accelerograph System - Containment Mat (El 221 ft)**	M	R	SA***
b. Triaxial Seismic Switch- Containment Mat (El 221 ft)**	M	R	SA***

See NOTES on Next Page

Seismic Monitoring Instrumentation Surveillance Requirements

TABLE B (continued)

Instruments and Sensor Locations	Channel Check	Channel Calibration	Analog Channel Operational Test
4. Triaxial Response-Spectrum Recorders			
a. Containment Building (Active) (El 221 ft)**	M	R	SA***
b. Steam Generator (Passive) 1B Pedestal	N.A.	R	N.A.
c. Reactor Auxiliary Building (Passive) (El 216 ft)	N.A.	R	N.A.
d. Diesel Fuel Oil Storage Tank Building (Passive)(El 242 ft)	N.A.	R	N.A.

* Except seismic starter unit

** With Main Control Room Alarms

*** The bistable trip setpoint need not be determined during the performance of a channel operational test

Meteorological Instrumentation

1.0 OPERATIONAL REQUIREMENTS

1.1 The meteorological monitoring instrumentation channels shown in Table A Attachment 7 shall be functional.

APPLICABILITY: At all times.

ACTION:

a. With one or more required meteorological monitoring channels non-functional for more than 7 days, prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within the next 10 days outlining the cause of the malfunction and plans for restoring the channel(s) to functional status.

2.0 SURVEILLANCE REQUIREMENTS

2.1 Each of the above meteorological monitoring instrumentation channels shall be demonstrated functional by the performance of the CHANNEL CHECK and CHANNEL CALIBRATION at the frequencies shown in Table B Attachment 7.

Meteorological Monitoring Instrumentation

Table A

Instrument	Location	Minimum Functional
1. Wind Speed		
	Nominal Elev. 12.5 meters	1
	Nominal Elev. 61.4 meters	1
2. Wind Direction	Nominal Elev. 12.5 meters	1
	Nominal Elev. 61.4 meters	1
3. Air Temperature - Differential Temperature	11.0 meter and 59.9 meters	1

Meteorological Monitoring Instrumentation Surveillance Requirements

Table B

Instrument	Channel Check	Channel Calibration
1. Wind Speed		
a. Nominal Elev. 12.5 meters	D	SA
b. Nominal Elev. 61.4 meters	D	SA
2. Wind Direction		
a. Nominal Elev. 12.5 meters	D	SA
b. Nominal Elev. 61.4 meters	D	SA
3. Differential Air Temperature Between 11.0 meters and 59.9 meters	D	SA

Metal Impact Monitoring System

1.0 OPERATIONAL REQUIREMENTS

1.1 The metal impact monitoring system shall be functional.

APPLICABILITY: Modes 1 and 2.

ACTION:

a. With both metal impact monitoring system channels in a region* non-functional for more than 30 days, prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within the next 10 days outlining the cause of the malfunction and plans for restoring the channel(s) to functional status.

2.0 SURVEILLANCE REQUIREMENTS

2.1 Each channel of the metal impact monitoring system shall be demonstrated functional by the performance of:

a. A channel check at least once per 24 hours.

b. An analog channel operational test, except for verification of setpoint, at least once per 31 days, and a channel calibration at least once per 18 months.

* Note: MIMS regions are defined as follows:

- Reactor Vessel Upper
- Reactor Vessel Lower
- Steam Generator "A"
- Steam Generator "B"
- Steam Generator "C"

Explosive Gas Monitoring System

1.0 OPERATIONAL REQUIREMENTS

1.1 The explosive gas monitoring instrumentation channels shown in Table A Attachment 9 shall be functional with their alarm/trip Setpoints set to ensure that the limits of Specification 3.11.2.5 are not exceeded.

APPLICABILITY: As shown in Table A Attachment 9.

ACTION:

a. With an explosive gas effluent monitoring instrumentation channel alarm/trip setpoint less conservative than required by the above specification declare the channel non-functional and take the action shown in Table A Attachment 9.

b. With the number of functional explosive gas monitoring instrumentation channels less than the minimum channels functional , take action shown in Table A Attachment 9. Restore the non-functional instrumentation to functional status within 30 days, and if unsuccessful, prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 to explain why this non-functionality was not corrected in a timely manner.

2.0 SURVEILLANCE REQUIREMENTS

Each explosive gas monitoring instrumentation channel shall be demonstrated functional by the performance of a Channel Check, Channel Calibration and Analog Channel operational test at the frequencies shown in Table B Attachment 9.

Explosive Gas Monitoring Instrumentation

TABLE A

Instrument	Minimum Channels Functional	Applicability	Action
1. Gaseous Waste Processing System - Hydrogen and Oxygen Analyzers			
a. Recombiner Outlet Hydrogen Monitor	1/recombiner	*	50
b. Recombiner Outlet Oxygen Monitor	1/recombiner	*	48
c. Compressor Discharge Oxygen Monitor	1	*	48

Table Notations

*During GASEOUS WASTE PROCESSING SYSTEM Operation

Action Statements

Action 45 (Not used)

Action 46 (Not used)

Action 47 (Not used)

Action 48 With the number of channels functional less than the minimum channels functional requirement, operation may continue provided grab samples are taken and analyzed at least once per 4 hours during degassing operations and at least once per 12 hours during other operations.

Action 49 (Not used)

Action 50 With the number of channels functional one less than required by the minimum channels functional requirement, suspend oxygen supply to the recombiner.

Action 51 (Not used)

Action 52 (Not used)

Explosive Gas Monitoring Instrumentation Surveillance Requirements

TABLE B

Instrument	Channel Check	Channel Calibration	Analog Channel Operational Test	Modes for Which Surveillance is required
1. Gaseous Waste Processing System-Hydrogen and Oxygen Analyzers				
a. Recombiner Outlet Hydrogen Monitor	D	Q(4)	M	*
b. Recombiner Outlet Oxygen Monitor	D	Q(5)	M	*
c. Compressor Discharge Oxygen Monitor	D	Q(5)	M	*

Table Notations

*During GASEOUS WASTE PROCESSING SYSTEM operation.

(1) (Not Used)

(2((Not Used)

(3) (Not Used)

(4) The CHANNEL CALIBRATION shall include the use of standard gas samples containing hydrogen and nitrogen.

(5) The CHANNEL CALIBRATION shall include the use of standard gas samples containing oxygen and nitrogen.

Feedwater Leading Edge Flow Meter (LEFM) Calorimetric

1.0 OPERATIONAL REQUIREMENTS

1.1 The Feedwater LEFM Calorimetric shall be functional with:

a. The Feedwater LEFM System in the Normal mode.

b. The ERFIS calorimetric program functional.

APPLICABILITY: MODE 1 with THERMAL POWER > 2900 MWt (98.4% RTP)

ACTION:

a. With the Feedwater LEFM System in the Fail mode, change the calorimetric program from the Feedwater LEFM System to the Normalized Feedwater Venturi System within 1 hour and either:

(1) Restore the Feedwater LEFM System to the Normal mode within 72 hours, or reduce THERMAL POWER to ≤ 2900 MWt (98.4% RTP) and change the calorimetric program from the Normalized Feedwater Venturi System to the Feedwater Venturi System. If the plant experiences a power decrease below 2900 MWt (98.4% of RTP) during the 72 hour allowed outage time, the maximum permitted power level will be 2900 MWt until the LEFM is restored to either Normal or Maintenance mode operation.

OR

(2) Restore the Feedwater LEFM System to the Maintenance mode within 72 hours and reduce THERMAL POWER to ≤ 2943 MWt (99.86% RTP). The plant can operate at this power level indefinitely.

b. With the Feedwater LEFM System in the Maintenance mode, restore the Feedwater LEFM System to the Normal mode within 72 hours, or reduce THERMAL POWER to ≤ 2943 MWt (99.86% RTP). The plant can operate at this power level indefinitely.

c. With the ERFIS calorimetric program non-functional for reasons other than the LEFM System, restore the ERFIS calorimetric program to functional status prior to performing the next required power range channel calorimetric heat balance comparison per TS Table 4.3-1, channel calibration D2, or reduce THERMAL POWER to ≤ 2900 MWt (98.4% RTP) by monitoring alternate power indications.

2.0 SURVEILLANCE REQUIREMENTS

2.1 Perform the power range channel calorimetric heat balance comparison per TS Table 4.3-1, channel calibration D2 using the Feedwater LEFM System prior to exceeding 2900 MWt (98.4% RTP) and once per 24 hours thereafter.

2.2 Perform Channel Calibration of the Feedwater LEFM System instrumentation once per 18 months.

Revision Summary

General (Revision 026)

This revision (PRR 1984085), incorporates the following:

PRR 1984085: Section 6.0, Step 6.1 currently requires the refueling machine to perform an overload test within 100 hours of fuel movement. Other Duke Energy Sites require this test within 30 days of fuel movement.

Section 6.0 Step 6.2 currently requires an auxiliary hoist overload test within 100 hours of CRDM latching / unlatching operations. Other Duke Energy Sites require this test within 30 days of latching/unlatching.

The changes in PLP-114 would require changes in OST-1817, OST-1818 and GP-009. SUPPORTING/REFERENCE DOCUMENTS:

- McGuire Nuclear Station Selected Licensee Commitments Manual Section 16.9.19
- Catawba Nuclear Station Selected Licensee Commitments Manual Section 16.9-19.

REASON FOR CHANGE: Refueling Equipment surveillance requirements in PLP-114 are more restrictive at HNP than at other Duke Nuclear sites which can result in Refueling Outage schedule delays.

The overload tests for the Manipulator Crane and for the Aux Hoist could be performed prior to unlatching CRDMs and would not be required again unless 30 days has elapsed since the first tests performance. RISKS: BENEFITS: Allows each of the overload tests to be performed once per outage minimizing potential outage schedule delays/ critical path impact.

PRR 503000: PLP-114 Attachment 4 lists Area Temperature Monitoring requirements. During RFO16, the 'A' Switchgear Room temperature exceeded the temperature listed in TABLE A for greater than 8 hours during the 'A' Train bus outages. EC 78851 was written to address this occurrence. The conclusion for the EC included "ambient temperature of up to 104F in the 'A' Switchgear Room is acceptable whenever ventilation is not available during maintenance outage activities." Update TABLE A of PLP-114 Attachment 4 with a NOTE for the 'A' and 'B' Switchgear Rooms to allow the ambient temperature to reach 104F as described in the EC.

PRR 539658: Add the following to the Purpose Section: PLP-114, Relocated Technical Specifications and Design Basis Requirements, is incorporated by reference into the Harris Final Safety Analysis Report (FSAR) and is therefore made a part of the FSAR, which is part of the Harris current licensing basis. This procedure is subject to the update and reporting requirements of 10 CFR 50.71(E) and change controls of 10 CFR 50.59. This procedure cannot be exempted from 50.59 screening.

PRR 731725: The following items in the definitions need to be fixed:

1) acronyms listed unnecessarily in the definitions section
2) abbreviation should be removed from the definitions header
3) move item 3 to general section

(continued)

PRR 563397: Attachment 1, Step 2.1.a states to perform turbine valve test semiannually. Need to add that Section 5.1 of PLP-114 does not apply in allowing a 25% grace period for turbine valve testing.

Basis for Change: Passport PMID 21983 for OPT-1014 Turbine Valve Test was changed from every 6 months plus 25% grace period to every 6 months with no grace period per AR STR 313345 which states: The "LATE" grace period allows for the valve testing to be extended beyond the technical basis utilized to support the 50.59 evaluation developed when the valve test interval was extended to 6 months (in PLP-114)

PRR 709297: Per CORR 471988-07, PLP-114 needs to be revised to use "functional" instead of "operable" where appropriate. Regulatory Affairs has prepared a mark-up to demonstrate the changes needed and has placed a copy in the world folder of this PRR.

PRR 743243: PLP-114 Attachment 4 should have the same NOTE that is located inside OP-172 Attachment 7. It should read: Battery Room temperature may be elevated above 79°F (up to 85°F) for up to one week per year for ventilation maintenance periods. Operation at these temperatures for short periods of time has no significant impact on the annual average temperature (approximately 77°F) or on effective battery life. (EC 73252, NCR 332136) Basis for Change: PLP-114 does not mention the evaluation of being above 79°F and that it has already been evaluated.

Description of Changes

Page	Section	Change Description
All	All	Certain specifications were changed from 'OPERABLE/OPERABILITY' to 'functional/functionality' as provided by Licensing & Regulatory Affairs.
5	3.0	Removed the definitions. Two were acronyms and the other referenced Tech Spec definitions. These were not necessary or applicable.
5	4.0.3	Added: (PRR 539658) This procedure is incorporated by reference into the Harris Final Safety Analysis Report (FSAR) and is therefore made a part of the FSAR, which is part of the Harris current licensing basis. This procedure cannot be exempted from 50.59 screening.
8	Attachment 1 Sheet 1	Added to Step 2.1.a: (PRR 563397) The provision of Section 5.1, Criteria for Implementing Relocated Technical Specifications and Design Basis Requirements, maximum allowable extension not to exceed 25% of the specified surveillance interval does not apply.

Revision Summary

Page	Section	Change Description
13	Attachment 2 Sheet 4 Section 6.1 Section 6.2	Changed the following: (PRR 1984085) From The refueling machine used for movement of fuel assemblies within the reactor vessel shall be demonstrated OPERABLE, within 100 hours prior to the start of such operations, To: The refueling machine used for movement of fuel assemblies within the reactor vessel shall be demonstrated OPERABLE, within 30 days prior to the start of such operations,
17 18	Attachment 4 Sheets 2 & 3	Added *** to TABLE A item #6 (A&B Battery Rooms (El 286'). (PRR 743243) *** Battery Room temperature of 85°F was established per EC 402748.
17 18	Attachment 4 Sheets 2 & 3	Added **** to TABLE A item #7 (A&B Switchgear Rooms - El 286'). (PRR 503000) **** Ambient temperature of up to 104F in the "A & B" Switchgear Room is acceptable whenever ventilation is not available during maintenance outage activities. (Ref. EC 278851 for A Switchgear Room, expanded to cover both A & B Switchgear Rooms)

	I **Information Use**

NUCLEAR GENERATION GROUP
BNP/HNP/RNP

STANDARD PROCEDURE

VOLUME 99

BOOK/PART 99

EGR-NGGC-0153

ENGINEERING INSTRUMENT SETPOINTS

REVISION 12

TABLE OF CONTENTS

ATTACHMENTS

1.0 PURPOSE

The purpose of this procedure is to implement NGG's program requirements for both methodology and scope concerning instrument uncertainty and scaling calculations for each of the NGG plants. The methodology requirements are intended to provide NGG's Engineering, and other interested organizations, with a description of the detailed rules and plant specific criteria involved in instrument loop uncertainty analysis and setpoint determination. The scoping criteria defines those instrument loops that, as a minimum, shall have documented instrument uncertainty and scaling calculations completed to ensure these vital systems are operating within established safety limits.

Section 9.10 establishes criteria to support implementation of TSTF-493 for those specific Technical Specification functions for which TSTF-493 applicability has been committed within an NGG facility's Operating License.

This document applies to NGG personnel, NGG managed contract personnel, and any plant personnel who require an understanding and / or use of the concepts involved in instrument loop uncertainty analysis and setpoint determination.

NOTE: The uncertainty combination methodology described within this procedure is based primarily on ISA RP67-04 Method 3. Selected cases may arise in which it is advantageous to utilize alternate uncertainty combination techniques based on either ISA RP67-04 Method 1 or 2. Upon concurrence from the EGR-NGGC-0153 Sponsor, usage of an agreed-upon alternate method is permitted.

1.1 Background

The need for a documented, consistent basis for calculating instrument uncertainties and setpoints is an industry issue. Both INPO and the NRC have conducted audits / inspections of various nuclear facilities to ensure the adequacy of instrument setpoints and designs to be able to achieve their functions. Individual plant commitments relative to instrument uncertainties and setpoints are discussed in documents such as the FSAR, Technical Specifications, Licensing Dockets and DBDs; however, see Attachment 4 to this procedure for site-specific commitments made to utilize a specific methodology. It is considered prudent to establish a consistent methodology for determining and documenting instrument uncertainties and setpoints. This procedure sets forth the methodology to ensure NGG's design practices remain compatible with industry practices in this area.

R2.1, R2.30 This procedure, in its entirety, implements, in part, the Harris commitment to Regulatory Guide 1.105, “Instrument Setpoints”, Revision 1, as described in the Harris FSAR, Section 1.8.

2.0 REFERENCES

R2.1 2.1 [HNP - Regulatory Guide 1.105, "Instrument Setpoints", Revision 1]

2.2 ANSI/ISA-67.04.01-2000, "Setpoints for Nuclear Safety-Related Instrumentation"

2.3 ISA-RP67.04.02-2000, "Methodologies for the Determination of Setpoints for Nuclear Safety-Related Instrumentation"

2.4 INPO 84-026, "Setpoint Change Control Program", Revision 1, Good Practice TS-405, June, 1986.

2.5 Title 10, Part 50, Section 36, of the Code of Federal Regulations (10CFR50), as of January 1, 1990.

2.6 IE Information Notice 82-11, "Potential Inaccuracies in Wide Range Pressure Instruments Used in Westinghouse Designed Plants", April 9, 1982.

2.7 IE Information Notice 84-54, "Deficiencies in Design Base Documentation and Calculations Supporting Nuclear Power Plant Design", July 5, 1984.

2.8 NRC Information Notice 89-68, "Evaluation of Instrument Setpoints During Modifications", September 25, 1989.

2.9 NRC Information Notice 91-29, "Deficiencies Identified During Electrical Distribution System Functional Inspections", April 15, 1991.

2.10 NRC Information Notice 91-75, "Static Head Corrections Mistakenly Not Included in Pressure Transmitter Calibration Procedures", November 25, 1991.

2.11 NRC Information Notice 92-12, "Effects of Cable Leakage Currents on Instrument Settings and Indications", February 10, 1992.

2.12 NRC Inspection Report of San Onofre Units 2 & 3, Report Numbers 50-361/91-01 and 50-362/91-01, dated April 12, 1991.

2.13 NRC Systems Based Instrumentation and Control Inspection at the Pilgrim Nuclear Power Station Unit 1, Report No. 50-293/91-201, dated January 6, 1992.

2.14 NRC Systems-Based Instrumentation and Control Inspection at the Haddam Neck Plant, Report No. 50-213/92-902, dated April 23, 1992.

2.15 ANSI/ISA-S51.1-1979, "Process Instrumentation Terminology".

2.16 ANSI/ASME PTC 19.1-1985, Part I, "Measurement Uncertainty", Instruments and Apparatus, Supplement to ASME Performance Test Code.

2.17 ASME PTC 19.5, Part II, "Application of Fluid Meters", Instruments and Apparatus, Sixth Edition, 1971.

2.18 ASME MFC-3M-1985, "Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi".

2.19 Considine, Douglas M., Process Instruments and Controls Handbook, McGraw-Hill, 1957.

2.20 Liptak, Bela G. and Venczel, Kriszta, Process Measurement Instrument Engineers Handbook, Chilton Book Company, 1982.

2.21 Magison, E.C., Temperature Measurement in Industry, Instrument Society of America, 1990.

2.22 NUREG/CR-3659 - A Mathematical Model for Assessing the Uncertainties of Instrumentational Measurements for Power and Flow of PWR Reactors, February, 1985.

2.23 Fluid Meters - Their Theory and Application - 6th Edition, 1971.

2.24 Spiegel, M.R., Theory and Problems of Probability and Statistics, Appendix C, Schaums Outline Series, New York; Mcgraw Hill, 1975

2.25 ASME B&PV Code, Sect III Div 1, Appendices, 1986 Edition, Nominal Coefficients of Thermal Expansion, Material Group a, Coefficient C.

2.26 GE Information Letter, SIL No. 470, dated 9/16/88, and Supplement 1, dated 4/20/89.

2.27 ISA Technical Report TR-9, Graded Approach To Setpoint Determination, Draft Revision, dated 12/1/93.

2.28 NRC Information Notice 96-22, "Improper Equipment Settings Due to the Use of Nontemperature-Compensated Test Equipment"

2.29 EPRI Technical Report TR-103335-R1, October 1998, “Guidelines for Instrument Calibration Extension/Reduction - Revision 1: Statistical Analysis of Instrument Calibration Data”.

R2.30 2.30 Shearon Harris Nuclear Power Plant Final Safety Analysis Report.

2.31 HNP document 1364-53067, “Westinghouse Setpoint Methodology for Protection Systems, Shearon Harris”.

R2.32 2.32 Shearon Harris Nuclear Power Plant Technical Specifications Bases.

2.33 [BNP - General Electric Instrument Trending Analysis System (GEITAS), Version 1.0b]

2.34 [BNP - User Manual, General Electric Instrument Trending Analysis System (GEITAS), GE-NE-901-010-0293, February 1993]

2.35 (Deleted)

2.36 (Deleted)

2.37 EGR-NGGC-0017, Preparation and Control of Design Analyses and Calculations

2.38 Generic Letter 87-02, Enclosure 1, Supplemental Safety Evaluation Report No. 2, on Seismic Qualification Utility Group's Generic Implementation Procedure, Revision 2, Corrected February 14, 1992, for Implementation of GI 87-02 (USI A-46), Verification Of Seismic Adequacy Of Equipment In Older Operating Nuclear Plants

2.39 CPL-89-634, HBR - The potential for formation of air entraining vortices in the Aux. Feed Pump Suction from the Condensate Storage Tank

R2.40 2.40 [RNP – LER 95-009-01, 2/1/96, “Condition Prohibited by Technical Specification Due to Inoperable Safety Injection”]

2.41 TSTF-493, Rev. 4 with Errata, April 23, 2010: Technical Specification Task Force – Improved Standard Technical Specifications Change Traveler, Clarify Application of Setpoint Methodology for LSSS Functions

2.42 NRC Regulatory Issue Summary (RIS) 2006-17, NRC Staff Position on the Requirements of 10 CFR 50.36, “Technical Specifications,” Regarding Limiting Safety System Settings During Periodic Testing and Channel Calibrations of Instrument Channels

3.0 DEFINITIONS

3.1 Abnormally Distributed Uncertainty

A term used by Reference 2.3 to denote uncertainties that do not have a normal distribution. For the purpose of this document, abnormally distributed uncertainties are treated as biases.

3.2 Accuracy

A measure of the degree by which the actual output of a device approximates the output of an ideal device nominally performing the same function. Error, inaccuracy, or uncertainty represent the difference between the measured value and the ideal value.

3.3 Allowable Setpoint

A setpoint with no margin applied. (see Setpoint and Margin)

3.4 Allowable Value

A limiting value that the trip setpoint may have when tested periodically, beyond which appropriate action shall be taken.

3.5 Ambient Temperature

The temperature of the medium surrounding a device. For field mounted devices, this is typically the room temperature at the device. For panel mounted devices, this is typically the temperature inside the panel which can be different from the room temperature.

3.6 Analytical Limit

Limit of a measured or calculated variable established by the safety analysis to ensure that a safety limit is not exceeded.

3.7 As Found

The condition in which a channel, or portion of a channel, is found after a period of operations and before calibration (if necessary).

3.8 As Left

The condition in which a channel, or portion of a channel, is left after calibration or final actuation device setpoint verification.

3.9 Bias

The fixed or systematic error within a measurement. The bias error is the fixed difference between the true value and the actual measurement. The bias error can be of (1) known sign and known magnitude, (2) known sign but an unknown magnitude (with a maximum), or (3) unknown magnitude (with a maximum) and unknown sign. Often times the sign and magnitude vary in some relationship with another parameter.

3.10 Bistable

A device that changes state when a preselected signal value is reached. For example, for BWRs electronic trip units are considered bistables.

3.11 Calibration

The comparison of a standard (or device of known accuracy) with equal or better accuracy with a device under test to detect, record, or eliminate by adjustment any variation in the accuracy of the device under test.

3.12 Components

Discrete items from which a system is assembled. For example, wire, resistors, transmitters, converters, etc. would all be considered components.

3.13 Conformity

The closeness that the output of an instrument approximates (or conforms to) a specified preprogrammed curve (e.g., logarithmic, parabolic, cubic, etc.).

NOTE:	This measurement is usually determined in terms of non-conformity but expressed as conformity; e.g., the maximum deviation between an average curve and a specified curve. The average curve is determined after making two or more full range traverses in each direction. The value of conformity is referenced to the output unless otherwise stated.

3.14 Dead Band

The range through which an input can be varied upon reversal of direction without initiating an observable output response. See Figure 3-1.

3.15 Dependent Uncertainty

Uncertainties are dependent on each other if they possess a significant correlation, for whatever cause, known or unknown. Typically, dependencies form when effects share a common cause.

3.16 Design Bases

That information that identifies the specific functions to be performed by an SSC and the specific values or ranges of values chosen for controlling parameters as reference bounds for design. These values may be (1) restraints derived from generally accepted "state of the art" practices for achieving functional goals, or (2) requirements derived from analysis (based on calculation and/or experiments) of the effects of a postulated accident for which an SSC must meet its functional goals (10CFR50.2, NGGM-PM-0007) or (3) requirements derived from analysis of operating and anticipated transient conditions in which the SSC is expected to perform its function.

3.17 Design Limit

The limit of a measured or calculated variable established to prevent undesired conditions (e.g., equipment or structural damage, spurious trip or initiation signals, challenges to plant safety signals, etc.). It is used in setpoint calculations for which there is no true Analytical Limit.

3.18 Device

An apparatus for performing a prescribed function (i.e., an instrument). The discrete items which make up an instrument loop/channel.

3.19 Drift

An undesired change in output over a period of time, which change is unrelated to the input, environment, or load.

3.20 Dynamic Response

The behavior of the output of a device as a function of the input, both with respect to time.

3.21 Effect

A change in output produced by some outside phenomena, such as elevated temperature, pressure, humidity, or radiation.

3.22 Error

The algebraic difference between the indication and the ideal value of the measured signal. (A "positive" error denotes that the indication of the instrument is greater than the ideal (actual) value.)

3.23 Final Actuation Device

A component or assembly of components that directly controls the motive power (electricity, compressed air, hydraulic fluid, etc.) for actuated equipment. Examples of final actuation devices are: bistables, relays, pressure switches, and level switches.

3.24 Foldover

A device characteristic exhibited when a further change in the input produces an output signal that reverses its direction from the specified input-output relationship.

3.25 Full Scale

The 100% value of the measured parameter on an instrument. Full scale is equal to the span for zero-based instruments.

3.26 Harsh Environment

This term refers to the worst environmental conditions to which an instrument is exposed during transient, accident or post-accident conditions, out to the point in time when the device is no longer called upon to serve any monitoring or trip function. It may also be referred to as the accident environment, or trip environment, and is the converse of mild environment.

3.27 Hysteresis

That property of an element evidenced by the dependence of the value of the output, for a given excursion of the input, upon the history of prior excursions and the direction of the current traverse.

NOTE 1: This measure is usually determined by subtracting the value of dead band from the maximum measured separation between upscale going and downscale going indications of the measured variable (during a full range traverse, unless otherwise specified) after transients have decayed. This measurement is sometimes called hysteresis error or hysterectic error. See Figure 3-1.

NOTE 2: Some reversal of output may be expected for any small reversal of input; this distinguishes hysteresis from dead band.

3.28 Independent Uncertainty

Uncertainties are independent of each other if their magnitudes or algebraic signs are not significantly correlated, and they do not share a common source.

3.29 Indicated Value

A predetermined value of an indicator or recorder at which a manual action will be taken. An indicated value is similar to a setpoint except that a setpoint assumes an action will be taken by a device and an indicated value assumes an action will be taken by an individual.

3.30 Instrument

A single device that may be utilized alone or interconnected with other instruments for the purpose of observation, control and/or protection of a process or parameter.

3.31 Instrument Channel

An arrangement of components and modules as required to generate a single protective action signal when required by a plant condition. A channel loses its identity where single protective action signals are combined. For example, if three channels are input into a comparator, at the comparator the three individual signals lose their identity. Thus, the three channels are only channels up to the comparator.

3.32 Instrument Range

The region between the limits within which a quantity is measured, received, or transmitted, expressed by stating the lower and upper range values.

3.33 Insulation Resistance (IR) Effect

The change in measurement signal due to an increase in leakage current between the conductors of instrument signal transmission components such as cables, connectors, splices, etc. The increased leakage is caused by the decrease of component insulation resistance due to extreme changes in environmental conditions.

3.34 Lead Wire Effect

The effect on measured RTD signals due to ambient temperature changes on the RTD signal wire.

3.35 Limiting Safety System Setting (LSSS)

Settings for automatic protective devices in nuclear reactors that are related to those variables having significant safety functions. A LSSS is chosen to begin protective action before the analytical limit is reached to ensure that the consequences of a design basis event are not more severe than the safety analysis predicted. Limiting Safety System Settings are identified in Section 2.0 of the Technical Specifications.

3.36 Linearity

The closeness to which a curve approximates a straight line. Note: The measurement determines non-linearity and expresses it as linearity; e.g., a maximum deviation between an average curve and a straight line. The average curve is determined after making two or more full range traverses in each direction. The value of linearity is referenced to the output unless otherwise stated.

3.37 Loop

A loop or instrument loop is the generic name given to a set of instrument devices which perform a specific function.

3.38 Loop Uncertainty

The instrument loop uncertainty is the combined effect of all instrument/device uncertainties in that loop. Depending on the function of the loop, this uncertainty could be an uncertainty in indication or an actuation uncertainty.

3.39 Lower Setpoint Limit

The lowest value for a setpoint which when used in conjunction with the upper setpoint limit, describes the tolerance band (no adjustment required) which allows for safe function operation and also minimizes the frequency of readjustment.

3.40 Margin

In setpoint determination, an allowance added to the instrument loop uncertainty. Margin moves the setpoint farther away from the analytical limit.

NOTE:	An additional expression, operating margin, should not be confused with margin. Adding or increasing operating margin has the effect of moving a setpoint closer to the analytical limit to increase the region of operation prior to reaching a setpoint.

3.41 Measurement and Test Equipment (M&TE) Effect

The effect on the uncertainty of a device or loop due to the accuracy ratings of reference measurement (test) equipment. When the accuracy rating of the reference measuring equipment is one tenth or less than that of the device under test, the accuracy rating of the reference measuring equipment may be ignored in the loop uncertainty calculation and in design of test/calibration procedures. When the accuracy rating of the measuring equipment is greater than one tenth that of the device under test, the accuracy rating of the reference measuring equipment shall be taken into account in the loop uncertainty calculation and in development of test/calibration procedures. Examples of measuring and test equipment are deadweight testers, resistor decade boxes, multimeters, current sources, etc.

3.42 Mild Environment

An environment that would at no time be more severe than the environment that would occur during normal plant operation, including any anticipated operational occurrences. It may also be referred to as the normal environment.

3.43 Module

Any assembly of interconnected components that constitutes an identifiable device, instrument, or piece of equipment. A module can be 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, a drawout circuit breaker, or other subassembly of a larger device, provided it meets the requirements of this definition. For the purpose of this document, a module is the same as a device.

3.44 Nuclear Safety-Related Instrumentation

That instrumentation which is essential to:

a) Provide emergency reactor shutdown
b) Provide containment isolation
c) Provide reactor core cooling
d) Provide for containment or reactor heat removal, or
e) Prevent or mitigate a significant release of radioactive material to the environment; or otherwise essential to provide reasonable assurance that a nuclear power plant can be operated without undue risk to the health and safety of the public.

3.45 Operating Conditions

Conditions to which a device is subjected, other than the variable measured by the device. Examples of operating conditions include: ambient pressure, ambient temperature, electromagnetic fields, gravitational force, inclination, power supply variation (voltage, frequency, harmonics), radiation, shock, and vibration. Both static and dynamic variations in these conditions should be considered.

3.46 Operating Influence

The change in a performance characteristic caused by a change in a specified operating condition from a reference operating condition, all other conditions being held within the limits of reference operating conditions.

NOTE:	The specified operating conditions are usually the limits of the normal operating conditions. Operating influence may be stated in either of two ways: (1) As the total change in performance characteristics from reference operating condition to another specified operating condition, or (2) As a coefficient expressing the change in a performance characteristic corresponding to unit change of the operating condition, from a reference operating condition to another specified operating condition.

3.47 Percent Full Scale

Percent full scale is the ratio of a specific value compared to the full scale value, expressed as a percentage.

$$\frac{\text{Specific Value}}{\text{Full Scale Value}} * 100\% = \text{Percent Full Scale}$$

3.48 Primary Element

The system element that quantitatively converts the measured variable energy into a form suitable for measurement.

3.49 Process Effects

This is the general name given to all errors which affect the basic process measurements. The process effects are not instrument related but are due to characteristics of the process signal received by a sensor. The process effects include such things as fluid density variation effects, improper flow development effects, pressure variation effects, etc.

3.50 Process Measurement Instrumentation

An instrument, or group of instruments, that converts a physical process parameter such as temperature, pressure, etc. to a useable, measurable signal such as current, voltage, etc.

3.51 Random

A variable whose value at a particular future instant cannot be predicted exactly but can only be estimated by a probability distribution function. As used in this document, random means approximately normally distributed. The algebraic sign of a random uncertainty is equally likely to be positive or negative with respect to some median value. Thus, random uncertainties are eligible for square-root-sum-of-the-squares combination.

3.52 Range

The area between the upper and lower limits for which a device is designed to operate. A device may only be calibrated over a portion of its range (i.e its span) or calibrated over its entire range. For the latter case, the span would equal its range. Some vendors provide uncertainties in terms of span versus range, and clarification should be obtained as to whether the value is in range or span.

3.53 Reference Accuracy

A number or quantity that defines the limit that errors will not exceed when the device is used under reference operating conditions. Reference accuracy typically includes the combined effects of conformity (or linearity), hysteresis, dead band and repeatability. See Figure 3-2.

3.54 Repeatability

The closeness of agreement among a number of consecutive measurements of the output for the same value of the input under the same operating conditions, approaching from the same direction, for full range traverses.

NOTE: This measurement is usually determined as non-repeatability and expressed as repeatability in percent of span. It does not include hysteresis. See Figure 3-3.

3.55 Reproducibility

The closeness of agreement among repeated measurements of the output for the same value of input made under the same operating conditions over a period of time, approaching from both directions.

NOTE 1: This measurement is usually determined as non-reproducibility and expressed as reproducibility in percent of span for a specified time period. Normally, this implies a long period of time, but under certain conditions the period may be a short interval for which drift would not be included.

NOTE 2: Reproducibility typically includes hysteresis, dead band, drift, and repeatability.

NOTE 3: Between repeated measurements the input may vary over the range and operating conditions may vary within normal operating conditions.

3.56 Response Time

The delay in the actuation of a trip function following the time when a measured process variable reaches the actual trip value due to the time response characteristics of the instrument loop, including the sensor. It may be expressed as the time taken by a device or loop to respond to a selected step input for testing or surveillance purposes.

3.57 Safety Limit

A limit on an important process variable that is necessary to reasonably protect the integrity of physical barriers that guard against uncontrolled release of radioactivity.

3.58 Saturation

A device characteristic exhibited when a further change in the input signal produces no additional change in the output.

3.59 Sensor

The portion of an instrument loop that responds to changes in a plant variable or condition and converts the measured process variable into a signal, e.g., electric or pneumatic.

3.60 Setpoint

A predetermined value at which a device changes state to indicate that the quantity under surveillance has reached the selected value.

3.61 Signal Conditioning

One or more modules that perform signal conversion, buffering, isolation, or mathematical operations on the signal as needed.

3.62 Signal Interface

The physical means (cable, connectors, etc.) by which the process signal is propagated from the process measurement module through the signal conditioning module of the instrument channel to the module which initiates the actuation.

3.63 Span

The algebraic difference between the upper and lower values of a calibrated range. If a device is calibrated over its entire range, the span equals its range.

3.64 Test Interval

The elapsed time between the initiation (or successful completion) of tests on the same sensor, load group, safety group, safety system, or other specified system of device.

3.65 Tolerance

The allowable deviation from a specified or true value.

3.66 Transient Overshoot

The difference in magnitude of a process variable over time, taken from the point of initial trip actuation to the point at which the magnitude is a maximum or minimum.

3.67 Turndown Factor

The upper range limit divided by the span of the device. Sometimes referred to as the turndown ratio.

$$\frac{\text{Upper Range Limit}}{\text{Span}} = \text{Turndown Factor}$$

3.68 Uncertainty

The amount to which an instrument loop's output is in doubt (or the allowance made therefore) due to possible errors either random or systematic which have not been corrected for. The uncertainty is generally identified within a probability and confidence level. For the purpose of this document, uncertainties shall include the broad spectrum of terms such as error, accuracy, effect, etc. (A “positive” error denotes that the indication of the instrument is greater than the ideal value.)

3.69 Upper Setpoint Limit

The highest value for a setpoint which when used in conjunction with the lower setpoint limit, describes the setpoint tolerance band which allows for safe function operation but minimizes the frequency of readjustment.

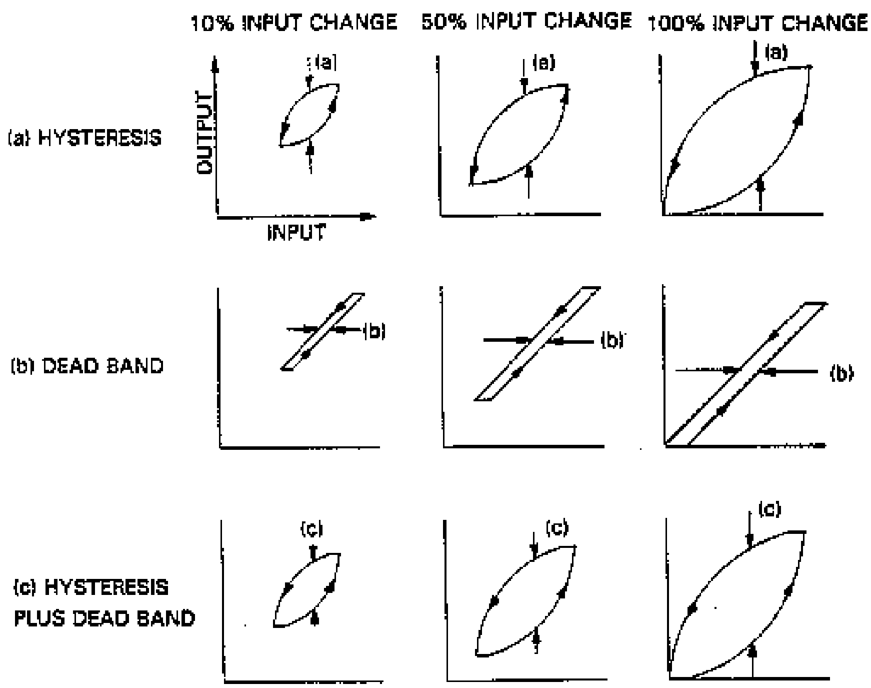


FIGURE 3-1
HYSTERESIS AND DEAD BAND

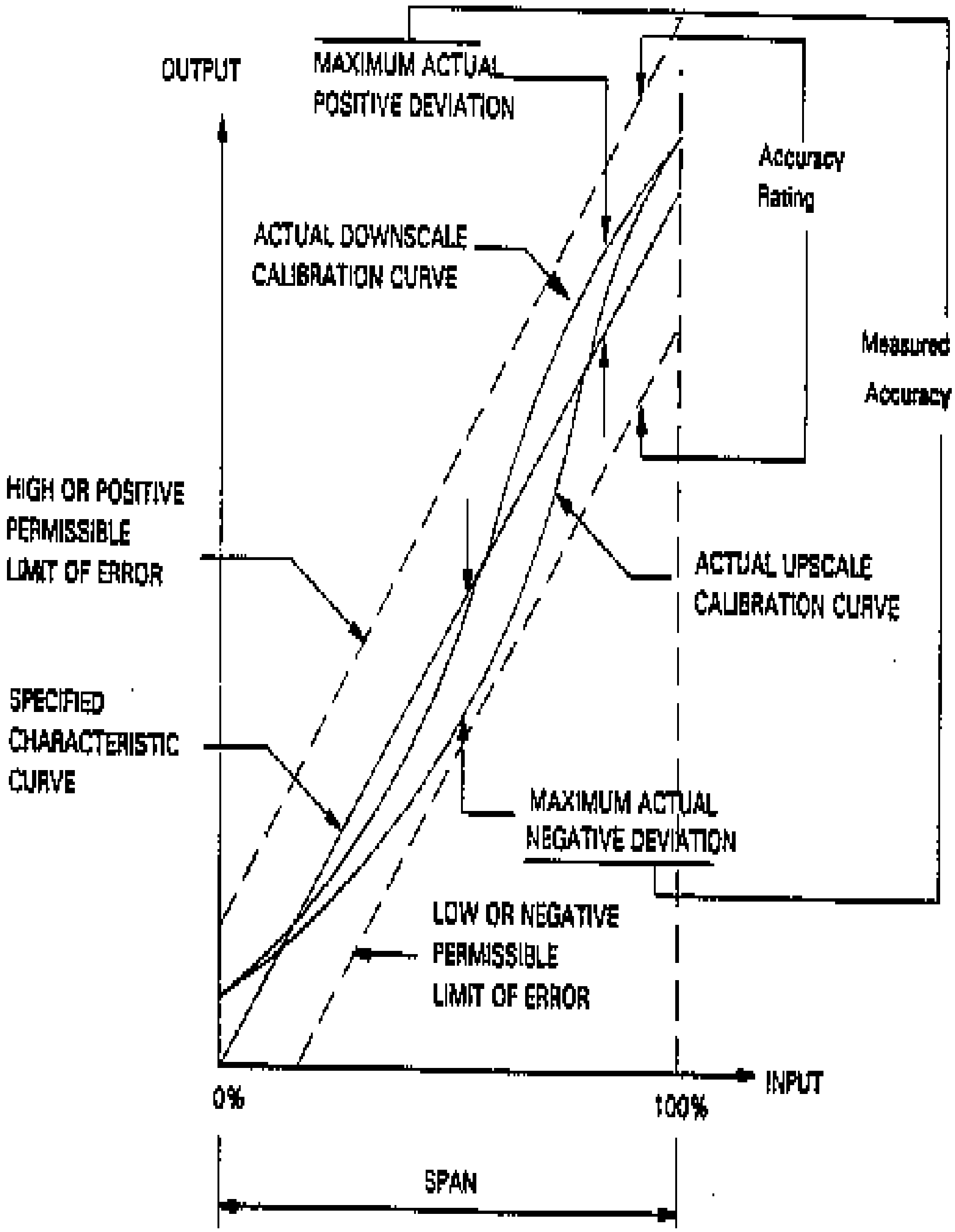


FIGURE 3-2
REFERENCE ACCURACY

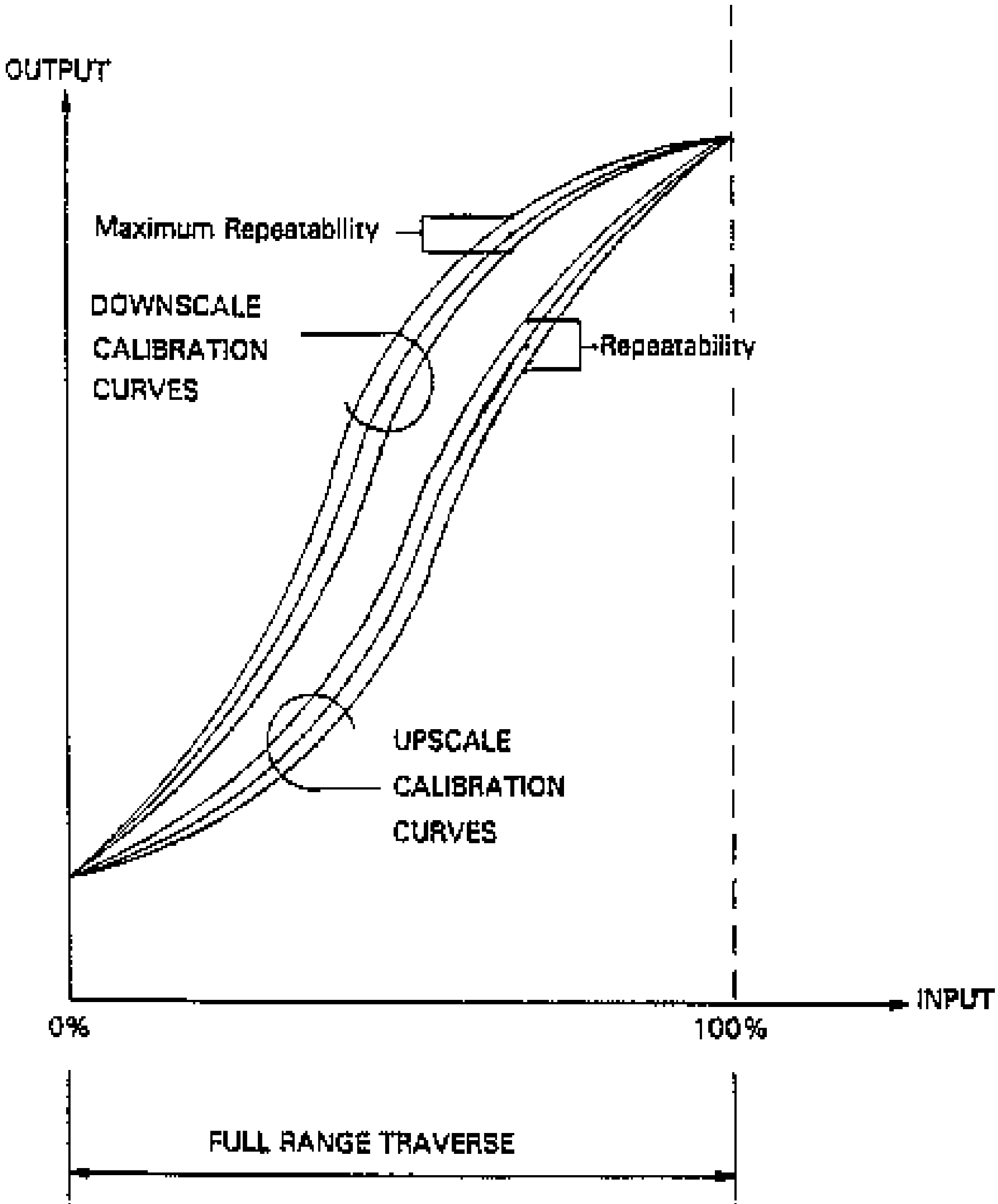


FIGURE 3-3
REPEATABILITY

3.70 Acronyms

AE	-	Accident Effect
AL	-	Analytical Limit
AMMS	-	Automated Maintenance Management System
ANSI	-	American National Standards Institute
APE	-	Accident Pressure Effect
ARE	-	Accident Radiation Effect
ASME	-	American Society of Mechanical Engineers
ASP	-	Allowable Setpoint
ATE	-	Accident Temperature Effect
AV	-	Allowable Value
BNP	-	Brunswick Nuclear Plant
BWR	-	Boiling Water Reactor
CAL	-	Calibration Tolerance
CFR	-	Code of Federal Regulations
CNAF	-	Calibration Nonconformance Action Form
COL	-	Channel Operability Limit
CSE	-	Conduit Seal Effect
DBA	-	Design Basis Accident
DBD	-	Design Basis Document
DL	-	Design Limit
DNBR	-	Departure from Nuclear Boiling Ratio
DP	-	Differential Pressure
DR	-	Drift
EDBS	-	Equipment Data Base System
EL	-	Elevation Difference
EOP	-	Emergency Operating Procedure
EQ	-	Environmental Qualification
EQDP	-	Environmental Qualification Data Package
ESFAS	-	Engineered Safety Features Actuation System
FSAR	-	Final Safety Analysis Report
GAFT	-	Group As-Found Tolerance
GPM	-	Gallons Per Minute
HELB	-	High Energy Line Break
HL	-	Height of Liquid
HNP	-	Harris Nuclear Plant
HP	-	Hydrostatic Pressure
HPCI	-	High Pressure Coolant Injection
HR	-	Height of Reference Leg
HV	-	Height of Vapor
HVAC	-	Heating, Ventilating and Air Conditioning
I&C	-	Instrumentation & Controls
IE	-	Inspection and Enforcement
IND	-	Indicator
INPO	-	Institute of Nuclear Power Operations
IR	-	Insulation Resistance

ISA	-	International Society of Automation (formerly Instrument Society of America)
I / V	-	Current to Voltage Converter
LAFT	-	Loop As-Found Tolerance
LALT	-	Loop As-Left Tolerance
LER	-	Licensee Event Report
LOCA	-	Loss of Coolant Accident
LP	-	Loop Calibration Procedure
LSL	-	Lower Setpoint Limit
LSSS	-	Limiting Safety System Setting
LV	-	Loop Value
LW	-	Lead Wire Effect
M	-	Margin
M&TE	-	Measurement & Test Equipment
MFC	-	Measurement of Fluid Flow in Closed Conduits
MFR	-	Maintenance Feedback Report
MM	-	Multimeter
MMM	-	Maintenance Management Manual
MSLB	-	Main Steam Line Break
MST	-	Maintenance Surveillance Test Procedure
MTE	-	Measurement & Test Equipment Error
NBS	-	National Bureau of Standards
NGG	-	Nuclear Generation Group
NIST	-	National Institute of Standards and Technology
NRC	-	Nuclear Regulatory Commission
NUREG	-	Nuclear Regulation
OL	-	Operational Limit
OP	-	Overpressure Effect
P	-	Pressure
P&ID	-	Piping & Instrument Diagram
PB	-	Pressure Bistable
PE	-	Primary Element
PI	-	Pressure Indicator
PIC	-	Process Instrument Calibration Procedure
PME	-	Process Measurement Effect
PSE	-	Power Supply Effect
PT	-	Pressure Transmitter
PTC	-	Performance Test Code (ASME)
PWR	-	Pressurized Water Reactor
QDP	-	Qualification Data Package
RA	-	Reference Accuracy
RCS	-	Reactor Coolant System
RE	-	Readability
RNP	-	Robinson Nuclear Plant
RPS	-	Reactor Protection System
RTD	-	Resistance Temperature Detector
SAR	-	Safety Analysis Report
SC	-	Signal Conditioner
SE	-	Seismic Effect

SG	-	Specific Gravity
SGL	-	Specific Gravity of Liquid
SGR	-	Specific Gravity of Reference Leg
SGV	-	Specific Gravity of Vapor (or Gas)
SH	-	Self Heating Effect
SI	-	Safety Injection
SL	-	Safety Limit
SP	-	Setpoint
SPE	-	Static Pressure Effect
SRSS	-	Square-Root-Sum-of-the-Squares
SSC	-	Structure, System, or Component
STP	-	Standard Temperature and Pressure
STSS	-	Surveillance Test Scheduling System
SVF	-	Specific Volume of Fluid
TDF	-	Turndown Factor
TE	-	Temperature Effect
TID	-	Total Integrated Dose
TLU	-	Total Loop Uncertainty
TMM	-	Technical Support Management Manual
TRX	-	Transmitter
TV	-	True Value
URL	-	Upper Range Limit
USL	-	Upper Setpoint Limit
V/I	-	Voltage to Current Converter
VQP	-	Vendor Qualification Package
WC	-	Water Column

4.0 RESPONSIBILITIES

4.1 Responsible Engineers

4.1.1 Engineer instrument setpoints using this procedure when preparing new designs / design changes that effect setpoints, and when evaluating setpoint problems.

4.1.2 Review the fuel vendor's fuel reload analyses and changes to fuel vendor accident analyses via the Nuclear Fuels Section fuel reload EC.

4.1.2.1 Identify impacted instrument uncertainty and setpoint calculations.

4.1.2.2 Revise affected calculations and implement the results into the plant settings as necessary using applicable plant processes such as the EC and procedure change processes.

4.2 Setpoint Policy

NGG 's Instrument Setpoint and Control Processes have been established as a systematic method for capturing, specifying, documenting, reviewing, and controlling Instrument Setpoints at our four nuclear plants.

The Engineering Section at each site is responsible for ensuring that adequate documentation and implementation of instrument setpoints takes place commensurate with importance to safety and production. This includes preparing, reviewing, approving, and controlling instrument uncertainty and scaling calculations for selected instruments and ensuring that these results are properly implemented through acceptable maintenance practices and procedures. Lesser levels of rigor and documentation are expected to be applied to instruments of lesser importance to safety and production.

Changes to instrumentation systems and instrument setpoints shall be accomplished through approved design change processes to ensure that such changes are appropriately reviewed, approved, and controlled and so that effected documentation and data bases are revised to maintain configuration control.

Adequate awareness shall be maintained among applicable personnel so it is generally known that changes affecting the accuracies of post accident indications can impact values used in the determination of indicator driven operator actions specified in the Emergency Operating Procedures possibly requiring revision to the procedures.

5.0 PREREQUISITES

N/A

6.0 PRECAUTIONS AND LIMITATIONS

N/A

7.0 SPECIAL TOOLS AND EQUIPMENT

N/A

8.0 ACCEPTANCE CRITERIA

N/A

9.0 INSTRUCTIONS

9.1 Setpoint Methodology

This procedure is to be utilized when preparing instrument uncertainty calculations for the NGG plants, however, the NSSS vendors use their own NRC approved methodology that may have differences from the instructions provided in this document. The NGG, GE, Westinghouse, or B&W methodologies are acceptable when properly applied, and it is acceptable to use the NSSS vendor's methodology when revising instrument uncertainty calculations originally prepared by them.

R2.32 [HNP - When performing setpoint calculations for the Reactor Trip System Instrumentation Trip Setpoints (Technical Specifications Table 2.2-1) and/or the Engineered Safety Features Actuation System Instrumentation Trip Setpoints (Technical Specifications Table 3.3-4), generate results in accordance with the format described in the Technical Specifications Bases (i.e., either 5 column or 2 column, as appropriate).]

Applicable instrument loops may be either safety related or non-safety-related and encompass loops used for protection, control, or indication functions. Since this document is intended to address all types of loops, portions of the methodology may not be applicable to every individual loop. For example, instruments that are not safety related or exposed to a harsh environment, do not need to incorporate accident environment uncertainties into their overall loop uncertainty. Conversely, instruments used for personnel safety, may need to include additional margins or conservatism not generally applied. Each user of this document must evaluate individual uncertainties for their relevance to the user's application. Specific instructions for the application of these criteria are included in the text of this procedure.

It is not the intent of this procedure to supersede any calculations performed previously by NGG or its vendors. Such calculations and analyses were performed in accordance with the methods and assumptions in effect at the time of their development and are considered to be valid. Differences in methodology between this procedure and existing calculations that need to be revised due to plant changes should be identified to the appropriate NGG I&C Supervisor for resolution.

Although this document is intended to be utilized for process instrumentation, it may be applied to other equipment as well. Specifically excluded from the scope of this methodology, however, are:

- Mechanical Safety or Relief Valves
- Self Contained Regulating Valves
- Breaker Trip Settings
- Protective Relays
- Valve Torque or Limit Switches

9.1.1 Scope

Application of the methodology described in this procedure is appropriate for Limiting Safety System Settings as defined in 10CFR 50.36, and for operator indications when required by the emergency response guidelines. Where Limiting Safety System Settings have been established for nuclear plant instruments by the plant Technical Specifications, the settings are to be chosen so that automatic protective action will occur to protect against the most severe abnormal situation without exceeding analytical safety limits. Instruments that are utilized to ensure that these safety limits are not exceeded will provide adequate margins to safety which are to be documented through the use of instrument uncertainty and scaling calculations. Approved documentation shall also exist to support instrument uncertainty values used in the determination of indicator driven operator actions specified in the Emergency Operating Procedures when required by the Emergency Response Guidelines.

Application of the complete methodology outside of the above defined scope may not be warranted and will require engineering experience and judgment on a case by case basis. Judgment would typically consider the following:

- Instances where existing designs can be justified to prevent equipment modifications.
- Situations where settings need to be made with a minimum margin to maintain reliability and it is desired to quantify the margin.
- Cases where instrumentation design inadequacies are being evaluated to determine an optimum solution to a specific problem.

9.1.2 Surveillance Test Acceptance Values

Surveillance requirements are requirements relating to test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions for operation will be met. (Ref. 10 CFR 50.36)

It is generally not necessary to apply allowances for instrument uncertainties to surveillance test values that are not Limiting Safety System Settings or automatic protective functions because:

1. Surveillance test acceptance criteria are typically specified close to system process parameter optimal performance limits so that degraded equipment performance is identified in a timely manner. This leaves little or no margin of system capability remaining for conservative application of instrument uncertainties.

9.1.2 Surveillance Test Acceptance Values (cont'd)

2. Typically the analyses or calculations on which the surveillance test values are based have conservatism built into them which are greater than normal instrument uncertainties.

3. Industry standards for the design and accuracy of industrial instrumentation were used when plant instruments were specified and constructed so the instrument uncertainties are limited.

4. Plant instruments, which are used for surveillance tests, are included in standard periodic instrument maintenance or calibration programs that check instrument performance at specified intervals.

5. Surveillance tests, not involving Limiting Safety System Settings or automatic protective functions, are not encompassed by specific 10 CFR 50.36, Reg. Guide 1.105, and ISA Std. 67.04 requirements to account for instrument uncertainties.

9.1.3 Settings of Lesser Importance

Lesser levels of rigor and documentation are expected to be applied to instruments of lesser importance to safety and production. The recommended method of documenting settings of lesser importance is to load the setpoint data and any reference document number into the Equipment/Component/UTC Parameters panel of PassPort, per applicable plant procedures. Database loading can be accomplished electronically or by using paper forms, as specified by plant procedures. Section 9.1.4 describes the goals that can be achieved through use of our setpoint database.

9.1.4 Setpoint Databases

The goal of our electronic setpoint database is to achieve a single point reference for instrument setpoints. A fully functional setpoint database can be used by Engineering, Maintenance, and Operations on a continuous basis so that all tasks involving setpoints are based on the same information and so all setpoint changes are consistently controlled and implemented.

All types of setpoints should eventually be captured in, and controlled by, the database. To accomplish this goal, it is necessary to systematically load and approve the setpoint information. The recommended method of loading information is to integrate the loading process into the engineering evaluation and change processes, and into the instrument calibration process so that data is routinely entered. Data base loading can be accomplished electronically or by using paper forms, as specified by plant procedures.

A routine setpoint data approval process should also exist in Engineering so that the data gets reviewed and approved as it is entered, thus avoiding creation of a backlog of unapproved setpoints. This engineering approval process, however,

9.1.4 Setpoint Databases (cont'd)

needs to apply a graded approach because the vast majority of setpoints already exist in approved plant procedures, and have been proven through time in service, making it unnecessary to evaluate each one from scratch. When an approved reference document such as a procedure or an EC exists, and the setpoint under review is not a Limiting Safety System Setting (10CFR50.36), no separate calculation or significant review documentation should be required when approving the setpoint data for database use. Setpoint changes and new setpoints, however, shall continue to be evaluated and approved through the EC process with the results being loaded into the database.

9.2 Loop Error Analysis

9.2.1 Overview

Proper plant operation is achieved through the continuous monitoring and adjustment of process variables, either automatically or manually, via plant instrumentation and controls. The ability of the instrumentation and control (I&C) systems and equipment to properly monitor and control these variables is directly dependent upon the ability of the I&C systems to predictably and consistently measure and act on these processes. This ability is a measure of the accuracy of an I&C system.

The design of plant systems and equipment must take into account the realistic capabilities and limitations of the I&C systems available. The accuracy of an I&C system is affected by the system's ability to measure the process conditions and discern true variations in the process from a desired or set condition. This set condition, generally known as a setpoint, is the primary basis of process control. Setpoints can be actual process control settings, points of equipment actuation (commonly referred to as interlocks or trip setpoints), points of initiation of an alarm, etc. In other words, any predetermined point that requires an action to be initiated can be considered a setpoint.

Typically, setpoints are considered to be applicable to automatic devices such that upon reaching the predetermined value, an automatic action occurs. Sometimes setpoints are considered in a broader sense, and are considered to be points at which an automatic or manually initiated action occurs. When the term "setpoint" is used to describe a manually initiated action, it is usually used in conjunction with another descriptive term such as "EOP Setpoint" or "Operator Setpoint" to differentiate it from those setpoints that initiate automatic actions. For the purposes of this document, the term "indicated value" will be used to describe those points at which a manual action is expected. The following discussion is applicable to both setpoints and indicated values, although just the term "setpoint" is used for brevity. Whenever an issue only applies to just setpoints or just indicated values, it will be specifically noted.

9.2.1 **Overview** (cont'd)

Proper selection of setpoints is important to the safe, reliable and efficient operation of a plant. For proper determination of setpoints, a good understanding of system dynamic responses, interrelationships of system components, and analyses of anticipated abnormal occurrences (including accidents and environmental effects) is essential. In addition, the capabilities of the instrumentation must be considered.

All instruments have limits to their accuracy, stability, and repeatability. These limits are also affected by external influences such as calibration, environment, power supply fluctuations, process conditions, etc. These external influences must be considered in the determination of a setpoint. The accuracy of an instrument is generally expressed in terms of inaccuracy, error, or uncertainty. These three terms are used interchangeably in industry to describe the limitations in the performance of an instrument.In a nuclear power facility, special care must be taken in the development and selection of plant setpoints. This is especially true for setpoints which are related to plant quality-related systems and equipment. Setpoints which affect the safety of the plant must take into consideration all aspects of plant normal, and potentially abnormal, operations. For such setpoints, a specific detailed analysis should be performed and documented to ensure that all operational aspects are appropriately addressed.

Plant design is based on detailed system and equipment analyses which establish safety limits on important plant process variables. Safety limits are established to protect the integrity of the physical barriers that guard against the uncontrolled release of radioactivity. An example of a safety limit would be the absolute maximum pressure allowed in a piping system that carries potentially contaminated fluid. All safety limits applicable to a plant are typically documented in the plant's Licensing Basis and Safety Analysis Report (SAR).

Plant safety analyses, or accident analyses, are performed to model the interaction of plant systems, and to establish additional analytical or safety limits on specific process variables. These analytical limits are established such that, given the most severe operating or accident transient, the plant safety limits will not be exceeded. A typical analytical limit is the maximum operating pressure in a piping system. The piping system may have a safety limit maximum pressure equal to the pipe maximum design pressure. The analytical limit maximum pressure would be set below the safety limit to ensure that the safety limit is not reached during applicable design bases accidents (DBAs).

The plant safety analyses generally take into account the specific thermodynamic, hydraulic, and mechanical interactions of systems. Response time assumptions for plant instrumentation are also modeled in the safety analyses, but the effects of instrument and measurement uncertainties are generally not explicitly quantified. Additional analyses are therefore necessary to ensure that all aspects of system

and equipment design are taken into account when establishing the final plant process setpoints. These additional analyses are the primary subject of this document. The final plant setpoints must incorporate instrumentation uncertainties which, if not considered, could allow analytical limits, and possibly safety limits, to be exceeded.

Uncertainties which exist within an instrument device/loop are classified as either random or bias errors. Random errors are, as the name implies, the basic measurement uncertainties or variations which exist in any repeated measurement. The error is caused by the combination of numerous small effects which are within any such measurement. An exact value of random error cannot be predicted for a specific measurement. Instead, it can only be said that it will exist within a normal distribution about a true mean value. Therefore, in order to account for the random errors, these unsystematic errors are enveloped by upper and lower limits around the measured value. These limits bound the most probable value for the instrumentation output at any specific instance.

Unlike random errors, bias errors do not exhibit the random normal distribution characteristics. Rather, they exhibit a correlated, predictable, fixed, or systematic behavior. A bias exists where there is a known offset of a measurement from the ideal value or where there is a known relationship between the measured parameter and another parameter.

To establish the total uncertainty in an instrument or measurement, the various random and/or bias error effects must be appropriately combined. This is accomplished through the application of basic statistical analysis. Those errors that are considered random are combined using statistical formulae such as Square-Root-Sum-of-the-Squares (SRSS). The bias errors, on the other hand, must be algebraically combined. Finally, the resultant random and bias errors are algebraically combined to yield a total uncertainty. Once the total uncertainty is known, the final plant setpoint can be established. It is calculated by placing it on the conservative side of the analytical limit by a value equal to, or greater than, the total uncertainty.

Consider again the example of the maximum piping system pressure analytical limit discussed earlier. The final plant setpoint would be established at a value lower that the analytical limit, to ensure that neither the analytical limit nor the safety limit would be exceeded.

The source and magnitude of instrument uncertainties are governed by a number of system, equipment, and installation parameters. Process variations in temperature, pressure, fluid density, etc., can cause significant errors in the basic measurement. In addition, instrument support activities, such as the accuracy of the test equipment used to calibrate an instrument, and the calibration process itself, also influence instrument and measurement uncertainties.

9.2.1 Overview (cont'd)

Many instrument errors are influenced by the environmental conditions which surround an instrument. These conditions include among others, temperature, pressure, and radiation effects. The accuracy of an instrument must be evaluated for the ambient operating conditions under which it must function. In addition, a set of base or reference ambient conditions should be established to assist in instrument design and calibration. Typically, three specific ambient operating conditions are considered: (1) calibration (reference), (2) normal, and (3) accident conditions. These are discussed in detail in Section 9.7.2.

9.2.2 Basic Concepts

The typical instrument loop consists of a field mounted transmitter or sensor connected by cabling to an instrument process cabinet containing the loop power supply and other signal conditioning modules. For loops with remote mounted devices (such as an indicator), the cabinet would contain modules to drive the remotely mounted device. Figure 9-1 depicts a typical instrument loop containing both a remote mounted indicator and an actuation/setpoint device (bistable module), and Figure 9-2 shows a block diagram for the typical loop.

Each device or component in the loop can affect the loop's performance (accuracy). These devices include the loop's power supply and interconnecting cabling. In general, the more components that exist in a loop, the greater the potential loop uncertainty since each component has a discrete uncertainty associated with it. In addition, the component uncertainties can be greatly affected by the ambient conditions under which the components function.

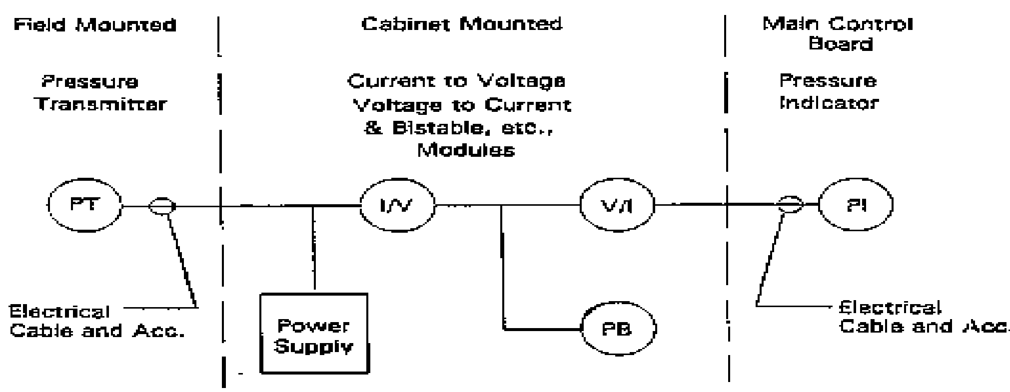


FIGURE 9-1
TYPICAL INSTRUMENT LOOP

For sensors and electronic modules such as transmitters, current converters, function generators, etc., even small variations in ambient conditions can affect their performance. On the other hand, the loop signal transmission components (cable, splices, etc.) are generally immune to small ambient variations and only affect loop performance under extreme conditions.

9.2.2 Basic Concepts (cont'd)

Instrument loops can generally be divided into four major parts for loop error analysis:

- Process measurement - This includes a loop's transmitter, a flow element or other primary element, and/or other sensors/transducers used to measure a process variable. It also includes the basic measurement process and any effects it may have on the performance of a loop, as well as, the interface with the process (tubing, etc.).

- Signal transmission - All of the loop components required to carry the measurement signal from the process measurement device to the signal processing section including the signal cable, cable connectors, splices, penetration assemblies, etc.

- Signal processing - All loop devices downstream of the process measurement section, used to condition or modify the signal from the measurement device. This would include such items as an isolator, square root extractor, function generator, etc.

- Final output - This is the final destination of a loop signal. Typically the final output is an actuating device such as a bistable module, and/or an indicating device such as an analog indicator, recorder or digital indicating device.

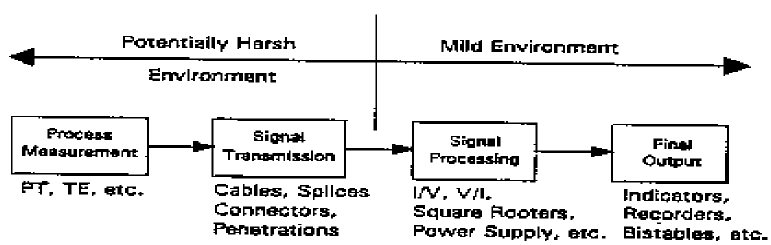


FIGURE 9-2
TYPICAL LOOP BREAKDOWN

The environmental conditions to which the various parts of a loop are exposed can be different, depending on the location of actual loop components. Typically, two major classifications of environmental conditions are defined - harsh and mild. Harsh environments cover all ambient conditions resulting from High Energy Line Breaks (HELBs), such as a loss of coolant accident (LOCA) or main steam line break (MSLB). Mild environments cover all normal operating conditions besides the harsh areas.

9.2.2 Basic Concepts (cont'd)

Different ambient conditions exist under each classification, depending on the specific location of a device. The separation between harsh and mild conditions typically occurs somewhere between the field mounted sensors and the signal processing modules. Usually only the field mounted sensors and a portion of the signal transmission components will be exposed to harsh environment conditions. However, each loop must be individually evaluated to identify which components, if any, will be exposed to a harsh environment. Only those components which are potentially exposed to a harsh environment need to be considered for other than normal environmental effects in an uncertainty analysis.

9.2.3 Error Sources

Variations in instrument or loop accuracy are the result of a number of different error components. These error components can be divided into three major classifications or classes of error based on their source:

- Process Measurement Errors
- Instrument Uncertainties
- Other Errors

Process measurement errors are, as the name implies, basic errors in the actual process signal being detected by the process measurement device (sensor). These errors are wholly a function of the characteristics of the measurement process and not a function of the performance of the instruments. Process measurement errors include such things as variations in a measurement due to sensing line fluid density changes, process pressure changes, errors in a head type flow meter measurement due to improper flow profile development or density effects, or temperature variations. Process measurement errors are discussed in detail in Section 9.3.

Instrument uncertainties, or errors, are the performance limitations (inaccuracies) associated with the actual equipment used to measure and process the measurement signal. This class of errors includes the basic accuracy of an instrument, its performance versus ambient variations, and its performance over time. Instrument uncertainties are discussed in detail in Section 9.4.

The class of "other errors" is used to account for a number of error sources that are essentially independent of the actual loop and its devices, but that can introduce significant error. This class includes such items as the uncertainty associated with the instrument calibration process and with the calibration test equipment. Additional errors are introduced into a measurement signal due to performance variations in signal transmission components exposed to a harsh environment. Section 9.5 discusses the error sources for the "other errors" class.

9.2.4 Loop Analysis

By expanding the loop block diagram shown in Figure 9-2, a basic instrument loop error analysis diagram can be established. The diagram, presented in Figure 9-3, shows the relationship of loop instruments, sources of errors, and environmental effects for a typical loop.

The basic error analysis block diagram starts with the process errors which may in a measurement. This is a subset of the process measurement errors discussed above. The next block, the primary element block, is included to account for loops which may have a true primary element such as a flow nozzle or orifice. Any errors associated with the primary element are considered part of the process measurement errors since they are integral in the variable being measured by the loop sensor. The remaining four blocks represent the four major sections of an instrument loop as defined above.

Actual loop error analysis uses the basic loop error analysis diagram as a model for identifying and calculating error values. The loop error analysis is done in a step by step calculation which builds the total loop error, or uncertainty, using a combination of the individual error effects. The process starts from the process error effects and progresses through the loop to the final output device of concern.

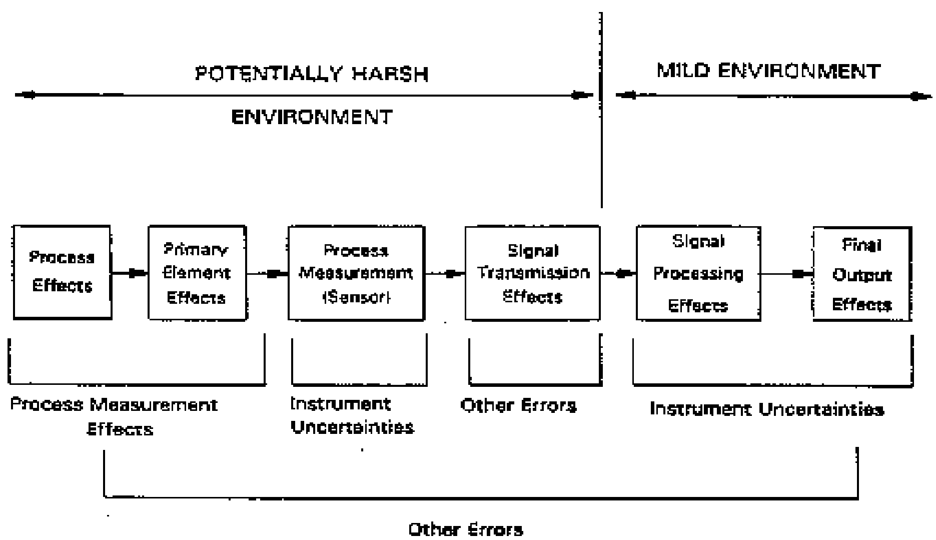


FIGURE 9-3
INSTRUMENT LOOP ERROR ANALYSIS DIAGRAM

9.2.4 Loop Analysis (cont'd)

In reference to Figure 9-3, the loop analysis typically progress from left to right. This also represents the functional flow of the measurement signal through the loop. Use of this method allows the uncertainty in a measurement signal to be determined at any point within a loop. This format also allows the calculation of uncertainty values for a loop that contains multiple signal paths or multiple signal processing. For example, both a pressure measurement signal and a temperature measurement signal, used in a temperature compensated level measurement, may be combined to establish a single level error value. By calculating the individual signal errors up to the point of combination, the total uncertainty for the loop can be calculated. The errors for the individual signal paths are determined using the same basic calculation process, and are then combined with any remaining error terms in the loop to obtain a final output error. This method is discussed in detail in Section 9.6.

9.2.5 Error Component Types

All measurements, whether as simple as a length measurement by ruler, or as complicated as a three element water level control loop, have errors associated with them. No measurement is without an associated uncertainty. In some measurements, the error is minor and need not be quantified. When measurement error becomes potentially large, or where even small amounts of error can create problems, a quantitative determination of the error must be made. The determination of the measurement error can be accomplished in several ways (algebraic, statistical, or the combination of the two). These different methods are discussed in more detail in Section 9.6.2. For now, suffice it to say that the most common method involves a combination of the algebraic and statistical derivation of the error, and this is what will be used for the NGG plants.

The statistical derivation is possible due to the inherent nature of the errors which exist for instruments and measurements. The statistical derivation provides realistic estimates of the errors which exist. A given measurement is composed of two types of error components, the random/precision error, and the bias/fixed error. These two error terms form the bases of instrument error analysis. Proper application of these terms is essential to proper error analysis.

A general discussion of random and bias errors is provided below, and defines how these error types are treated in instrument error analysis. Sections 9.3 through 9.5 of this document define the individual errors which may be present in an instrument or loop.
Each of these error terms is classified as <u>typically</u> being either random or bias in order to aid the user of this document in appropriately applying each type of error. However, the applicability of these classifications must be validated for each individual device/loop.

9.2.5 Error Component Types (cont'd)

1. Random Error

A random error is, in itself, a statistical measurement of accuracy. It is the basic variation seen in the seemingly identical, repeated measurements of a parameter. A random error is caused by the culmination of the numerous small error effects which exist in any action. The exact magnitude and sign of a random error at a specific point in time cannot be predicted. However, the error is normally distributed about the true values, and a bounding set of limits to its upper and lower value can be established.

Random errors are independent variations (not dependent on one another or on the same parameters) in a measurement and cannot be eliminated. Bounds on the magnitude of a random error are established through statistical analysis of these variations.

By obtaining repeated measurements of a parameter, a measure of the random error magnitude can be calculated. The standard deviation, sigma (σ), is used as a measurement of the random error. The standard deviation is defined as:

$$\sigma = \sqrt{\frac{\sum_{i=1}^{N}(X_i - M)^2}{N}} \qquad \textit{(Eq. 1)}$$

Where,

X = Individual measurement values
M = Mean of all measurement values
N = Number of measurements

A group of random error measurements will exhibit a bell shaped (normal) distribution about the mean, when plotted as a function of measurement frequency (see Figure 9-4). The figure illustrates the typical distribution of measurement deviations associated with random errors. As recorded deviation from the mean increases, the occurrence of measurements with that particular deviation decreases significantly.

By using the standard deviation term, a statistically acceptable measure of random error can be established.

9.2.5 Error Component Types (cont'd)

Using normal probability analysis, it can be shown that the number of measurements that will vary within one standard deviation of the mean will represent 68.27% of all the measurements. In other words, approximately 68% of the time, the recorded measurement will be within one standard deviation of the true value. Expressing this in terms of probability, there is a 68% probability that the error will be equal to or less than one standard deviation.

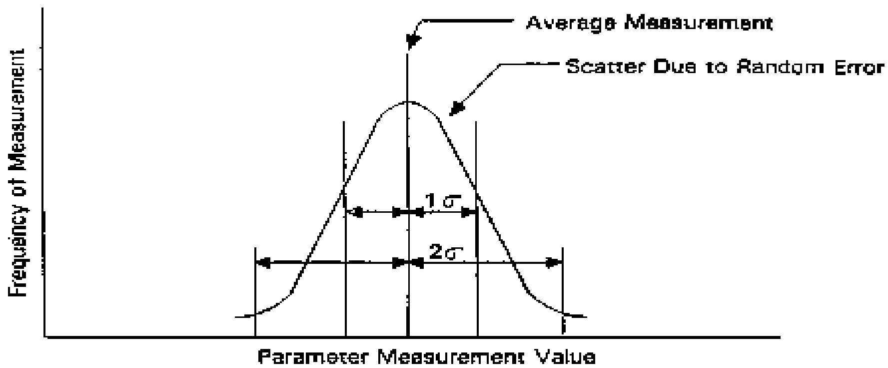


FIGURE 9-4
MEASUREMENT UNCERTAINTY

Industry and the NRC have accepted a minimum level of random error probability of 95% for instrument error analysis. This 95% probability means that the error exhibited by a component or loop must be less than or equal to its established error at least 95% of the time. The 95% probability represents the deviation value from the mean which encompasses 95% of all measurement variations. Statistically, the 95% value can be shown to be $\pm$ 1.96 times the standard deviation. For various sample sizes, refer to EPRI TR-103335-R1, Table 18-4 (Ref. 2.29) to determine the appropriate multiple to be used with the standard deviation.

When combining random uncertainties, it is important to identify whether each uncertainty is 1, 2, or 3 sigma. The resulting overall uncertainty will only be statistically equivalent to the least probable uncertainty. Thus, if one uncertainty is three sigma and the other uncertainties are two sigma, the combined uncertainty can only be two sigma. For NGG, it will be assumed that published vendor uncertainties are two sigma unless the vendor can provide a more conclusive determination. This is based on common industry practice.

As stated above, random errors are independent variations with a normal distribution about the mean. What happens though, when two or more errors are dependent? If they are not random they are treated as biases as discussed below. If, however, their combined effect is random they may be summed together and treated as a single random error the same as other random errors. This is discussed in more detail in Section 9.6.

2. Bias Error

Bias errors, also known as correlated or fixed errors, are systematic deviations in a measurement or output. A bias error does not exhibit normally distributed random behavior. The bias error exhibits a generally known behavior with respect to other parameters. A measure of total error for an instrument, or loop, can be determined by combining its bias error terms with its random error terms.

There are generally three types of bias error terms encountered in instrumentation. The first is defined as a bias with known sign and known magnitude. This type of bias is generally well defined and predictable. An example of such a bias is the reference leg heat-up effect on a filled reference leg level installation, as discussed in Section 9.3. For a known temperature change, the level signal exhibits a known (direction and magnitude) shift in output. Many biases of this nature can be calibrated out of an instrument, and thus eliminated.

A second type of bias is defined as a bias with known sign but unknown magnitude. This type of bias is less predictable due to its variable magnitude, but may be quantified by establishing a maximum (worst case) value. An example of such a bias can again be seen in a filled reference leg level installation. After an event, the reference leg may be exposed to accident temperature conditions which cause errors in the level signal. The accident temperature, though, is not a known constant change. The temperature is a variable with a calculated maximum. As a result, the actual effect on the reference leg due to the variation in temperature is not known precisely. The difference between reference leg heat-up rate and the temperature change causes the exact bias magnitude to be unknown. A maximum bias effect can be determined, though, based on the maximum temperature to bound the actual bias.

The third type of bias is defined as a bias with unknown sign and unknown magnitude. This type of bias is similar to a random error due to its unknown sign. However, it cannot be classified as random since it will not exhibit a normal distribution. An example of this type of bias is the accident environment effect on some transmitters. When subjected to accident conditions, the transmitters begin to exhibit a shift in output. The shift may be either negative or positive for a specific transmitter, but once it's initiated, the shift will remain in the same direction (negative or positive). The magnitude of the shift will generally increase with the duration and severity of the accident conditions, but its value at a specific time cannot be determined. Only its maximum error for the stated conditions can be established. Because of the unknown sign, this type of bias error must be assumed to contribute to both the negative and positive uncertainty values.

It should be noted, that for the purpose of this document, the type of error described above will be treated as a bias. Other industry documents may call this an abnormally distributed uncertainty, or some other similar term. However, the name applied to such an error is not as important as how the error is combined with the other uncertainties. Both this document and other industry documents combine the error in the same manner. That manner is to algebraically combine the error with the positive random error and positive biases, and separately to combine the error with the negative random error and negative biases.

Bias errors are normally generated by specific effects internal to, or external to, an instrument. The magnitudes and signs of the errors are decided using known correlations between variations of a parameter and its effect on the output of a device (e.g., reference leg heat-up, IR effect). Thus, while a number of bias errors may have equal and opposite effects on instrument accuracy, each must be treated separately, and not used to offset another. Unless specific links exist between bias error, each must be assumed to occur separately.

The errors which bias a measurement in the same direction can be combined to establish the worst case error in a given direction. As discussed above, a specific bias can generally be a value anywhere from zero to its maximum value. By combining the maximum bias values in a given direction, the maximum error band over which a measurement can vary in that given direction is established. This approach usually provides extremely conservative error values which may not be desirable for all applications.

Figure 9-5 illustrates the total uncertainty of a measurement or instrument output. The positive bias error (+B) is combined with the positive random error to define the largest positive error, while the negative bias error (-B) is combined with the negative random error to define the largest negative error. Based on the probability of the random error term, the uncertainty interval established will define the total error to the same degree of probability.

9.2.5 Error Component Types (cont'd)

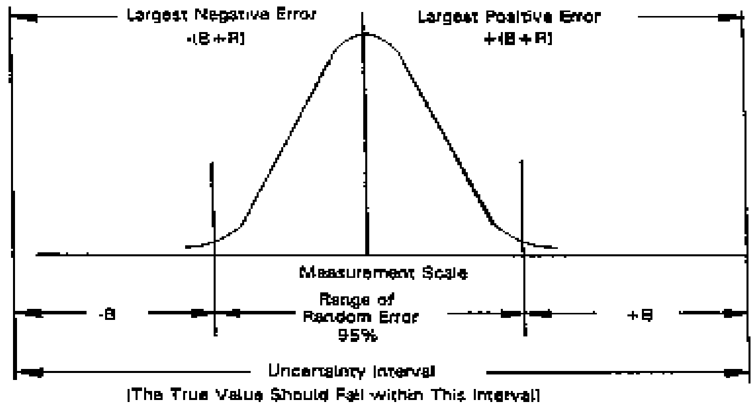


FIGURE 9-5
TOTAL UNCERTAINTY

9.3 Process Measurement Error

Process measurement requires the establishment of relationships between variables which enable the detection of changes in these relationships. The measurement of temperature by a mercury thermometer can be used to demonstrate this point. The thermometer measures room temperature by using the known relationship between the volumetric expansion of mercury and changes in temperature. As temperature increases, the volume of a fixed mass of mercury increases by a proportional amount. By placing the mercury in a tube with known graduations, the change in volume can be identified and correlated to a change in temperature.

The establishment of usable relationships between variables for measurement purposes is generally dependent upon other known influences not affecting the relationship of concern. In other words, only one variable is assumed to change at a time, so that the measured change is due solely to the variation of the parameter of concern.

9.3 Process Measurement Error (cont'd)

Using the mercury thermometer illustration again: To isolate the mercury from other influences which could be misinterpreted as a temperature influence, the mercury is enclosed in a vacuum sealed glass tube. By doing this, other parameters which can cause the mercury to vary in volume, such as pressure or humidity, are isolated. Now, the only parameter which can cause the mercury volume to change is temperature. By calibrating the change in volume for a known temperature change, an accurate temperature measurement device is obtained.

In actual process measurement however, the effects of other parameters on a given measurement relationship may not be fully isolated. This can cause errors in the measured parameter. The effects of these other influences must be either accounted for or isolated in order to obtain an accurate measurement.

The effects of these influences are known as Process Measurement Effect (PME) since they are due primarily to variations in ambient and process conditions. The process measurement errors encompass all errors within a process measurement signal prior to the loop sensing device.

In design and calibration of plant instrumentation, uniformity of all pertinent characteristics of the process fluid is assumed. However, there are many applications where uniformity is not a valid assumption. For example, changes in gas density due to pressure varying fluid density or viscosity for a head-type mass flow meter, or thermal gradients in stagnant fluids with a point temperature measurement, can cause significant measurement errors. Many of these problems can be accounted for by providing compensating measurements, proper correction factors, or special calibrations. Others though, may not be correctable and will induce additional error or uncertainty into a measurement.

9.3.1 Liquid Level Measurement

One of the most common methods for liquid level measurement uses the hydrostatic head (pressure) created by a column of liquid. The measurement of the hydrostatic head usually provides a direct link to liquid level, and it is easily measured by a pressure transmitter/switch, or a differential pressure transmitter/switch. Depending on the specific method of measurement, changes in the density of the measured process liquid, or in the pressure sensing lines can cause errors in the level measurement. This variation in density can be caused by changes in temperature, pressure, and/or chemical composition.

1. Open Vessel Measurement

The measurement of level in an open vessel is one of the simplest forms of utilization of the hydrostatic head principle.

The actual measurement can be accomplished by use of either a gauge pressure or differential pressure type device. Since the vessel is open, both devices use the local atmosphere as the common reference.

Figure 9-6 shows a typical open tank application. The pressure (P) sensed at the point of connection to the tank can be calculated by:

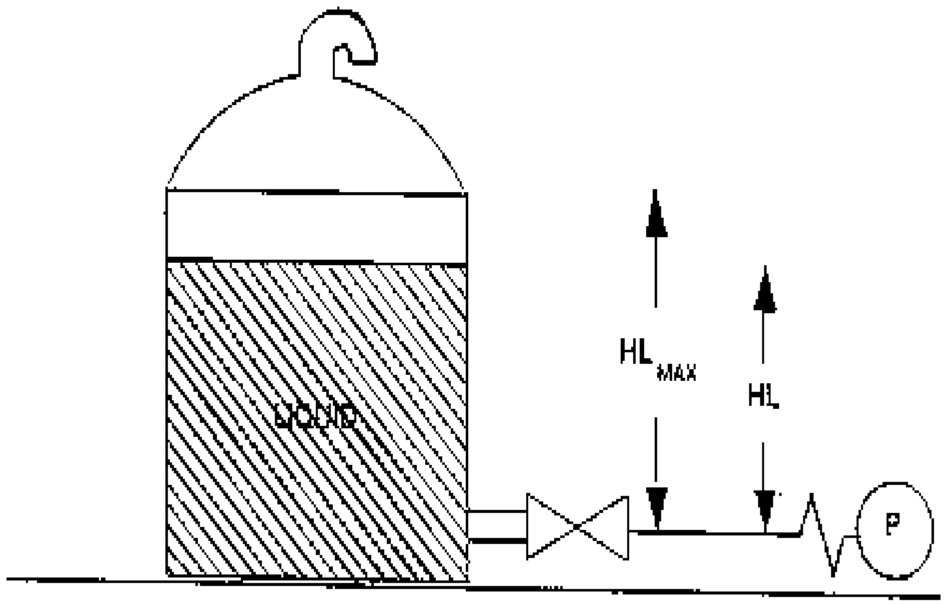
$$P = HL * SG \qquad \text{(Eq. 2)}$$

Where,

HL = Height of liquid above the connection point, in inches of water

SG = Specific gravity of the liquid

P = Pressure, in inches of water



$$P \text{ (in. WC)} = HL * SG$$

$$\Delta P = HL(SG_2 - SG_1)$$

$$\text{Error (\% span)} = \frac{HL(SG_2 - SG_1)}{HL_{MAX} * SG_1} * 100\%$$

HL = Height of liquid measured in inches

HL_{MAX} = Maximum height of liquid

SG = Specific gravity of liquid

SG_1, SG_2 = Specific gravity of liquid at temperature 1 and temperature 2 respectively

P = Pressure sensed at the bottom of HL in inches of water column.

FIGURE 9-6
HYDROSTATIC LEVEL MEASUREMENT

By using the specific gravity to calculate the pressure, the resulting pressure will be in units of inches of water column (in WC). The primary variable in the pressure equation, specific gravity, is by definition, the ratio of a fluid's density to the density of water at the standard temperature and pressure of 68°F and 1 atmosphere.

NOTE: Not all sources of SG use water at 68°F as a reference. Those must be converted to SG referenced to water at 68°F.

$$SG = \frac{\text{density of fluid}}{\text{density of water @ 68°F}} \qquad \text{(Eq. 3)}$$

In nuclear power plant applications, water constitutes the majority of the fluid applications for which measurements are made. For water, the ASME Steam Tables provide a convenient source of data for the determination of specific gravity. The Steam Tables provide the specific volume for water in its liquid (f) and vapor (g) states at various temperatures and pressures. Since specific volume is the inverse of density, the specific gravity of a fluid can be calculated from the specific volume values by:

$$SG = \frac{\text{specific vol. of water @ 68°F}}{\text{specific vol. of fluid}} \qquad \text{(Eq. 4)}$$

$$= \frac{0.01605}{Vf \text{ or } Vg}$$

Two important facts must be noted about the measurement of level using hydrostatic head:

- The relationship of hydrostatic head (P) to fluid height (HL) is directly proportional. (see Equation 2)

- The hydrostatic head produced by the fluid is dependent upon the temperature of the fluid since the temperature affects the fluid's density.

  In the initial design and establishment of calibration parameters for a level loop, a base calibration temperature of the fluid must be assumed. In this example, the base temperature is typically the temperature of the fluid at normal operating conditions. When the actual fluid temperature varies from this assumed value, errors in level measurement occur. This is because the device sensing the hydrostatic head cannot distinguish a pressure change caused by temperature variation from a change in actual level. The error can be calculated, though, by calculating the change in specific gravity.

9.3.1 Liquid Level Measurement (cont'd)

Assume for a temperature of T1, a fluid has a specific gravity of SG1. We will call this the base calibration temperature. The error calculated will be at a different temperature, T2. For temperature T2, the fluid has a specific gravity of SG2. P1 and P2 are the resulting hydrostatic heads at T1 and T2 (assuming level remains constant). Thus,

$$\text{Error (in WC)} = P2 - P1$$

$$DP = (HL * SG2) - (HL * SG1)$$

$$= HL\,(SG2 - SG1) \qquad \text{(Eq. 5)}$$

To express this error in terms of level measurement loop span, the error term in Equation 5 must be divided by the span of the loop. The span is typically equal to the difference between the maximum calibrated value and the minimum calibrated value. In this case, the span is equal to HLmax because minimum level is measured from the elevation of the level sensing nozzle (HL=0). To express the span in consistent units (in WC), it must be multiplied by the calibration specific gravity SG1.

Therefore,

$$\text{Error (\% span)} = \frac{HL\,(SG2 - SG1)}{HLmax\,(SG1)} * 100\% \qquad \text{(Eq. 6)}$$

Notice that the actual error incurred due to temperature change will vary as follows:

1. For T2<T1, SG2>SG1. The error is positive and becomes larger as T2 decreases.

2. For T2>T1, SG2<SG1. The error is negative and becomes larger as T2 increases.

3. The larger the actual level term HL, the larger the level error with the maximum error occurring when HL is equal to HLmax.

The positive and negative error annotations refer to the error with respect to actual level. A positive error will cause a measurement to be higher than actual value, while a negative error will cause a measurement to be lower than actual value.

Temperature may not be the only parameter which varies the density of a fluid. The chemical composition of the fluid can also cause the density to vary. In PWRs, the most common chemically induced variation of water density is caused by the presence of boric acid or Sodium Hydroxide. The effects of boric acid concentration, for example, can be determined using the same formulae developed above (Equations 5 and 6). The concentration of boric acid in water has a similar affect on the density of the water to that of temperature. If the density change is known, the measurement error can be calculated.

Processes for determining the densities of different boric acid solutions are described in Attachment 2.

While open vessels are normally at atmospheric conditions, during certain events this may not be so, thereby introducing measurement uncertainty. An example was addressed in RNP CR 99-00882, which evaluated an OE item from the DC Cook plant. During review of the Refueling Water Storage Tank vent piping capacity, it was determined that, at the maximum liquid outlet flow rate, a vacuum condition would be established in the tank because the vent flow rate into the tank would be insufficient to maintain atmospheric pressure. This effect would bias the level indication, making it lower than the actual level. Situations like this, involving non-atmospheric conditions in a vented tank during certain events, must be considered and their effect on level measurement uncertainty properly analyzed.

2. Closed Vessel Measurement

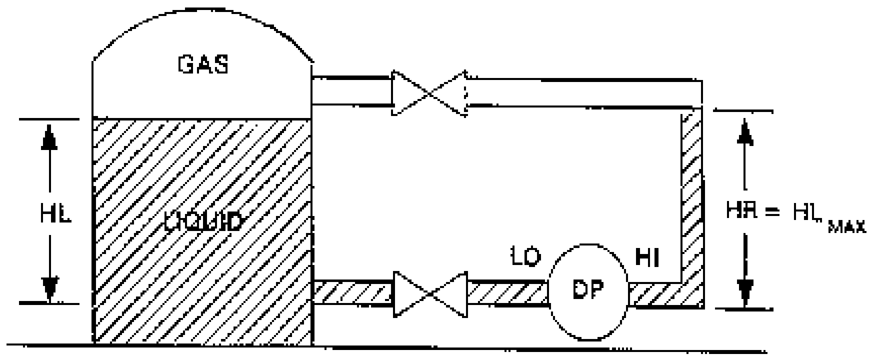
Another common level measurement application involves the detection of level in a closed vessel using the hydrostatic head measurement process. While the basic principles are the same as discussed in Section 9.3.1.1, other factors can affect the measurement process.

Figure 9-7 illustrates a typical closed vessel level measurement installation. In a closed vessel, the static pressure of the gaseous volume above the liquid must be taken into account. This requires the use of a differential pressure device which measures the pressure at both the bottom and top of the liquid. The lower sensing line, called the measurement or variable

leg, measures the hydrostatic pressure of the liquid plus the static pressure of the gas. The upper sensing line, called the reference leg, measures the static pressure of the gas above the liquid. The differential pressure device measures the difference in pressure between the measurement and reference legs, such that the resultant output is a measurement of only the liquid's hydrostatic head.

As depicted in Figure 9-7, a common practice of level measurement involves the filling of the reference leg with a liquid, typically the same liquid as found within the vessel or simple ordinary water. This provides both a seal between the contents of the upper portion of a vessel and the transmitter as well as providing a more stable reference leg measurement for certain applications.

9.3.1 Liquid Level Measurement (cont'd)



$$DP \text{ (in. WC)} = (HR * SGR) - (HL * SGL)$$

$$\Delta DP \text{ (in. WC)} = HR(SGR_4 - SGR_3) - HL(SGL_2 - SGL_1)$$

$$\text{error \% span change} = \frac{\Delta DP}{-HL_{MAX} * SGL_1} * 100\%$$

HL = Height of vessel liquid measured in inches

HR = Height of reference leg liquid column in inches

SGL = Specific gravity of vessel liquid

SGR = Specific gravity of reference leg liquid

DP = Differential pressure representing vessel liquid level in inches of water

SP = Static pressure in gas at top of vessel

SGL_1, SGL_2 = Specific gravity of liquid at temperature 1 and 2 respectively

SGR_3, SGR_4 = Specific gravity of reference leg liquid at temperature 3 and 4 respectively

NOTE: It is assumed that the gas is at negligible specific gravity conditions in this example

FIGURE 9-7
WET LEG LEVEL SYSTEM

9.3.1 Liquid Level Measurement (cont'd)

The calculations of hydrostatic head, and associated errors for a level loop, using a differential pressure device, are the same as those for an open vessel, provided that the fluid in the reference leg does not contribute to the hydrostatic head. For reference legs containing a gaseous fluid (dry reference leg), the hydrostatic head in the reference leg will generally be zero. Only when the gas is under very high pressure would the density of the gas cause a significant head effect. In this discussion it is assumed that all gases are at low pressure and do not contribute any significant hydrostatic pressure. For a wet, or filled, reference leg installation, though, the level determination and potential errors in measurement are determined differently.

The basic formula for calculating the hydrostatic head for a wet reference leg system is:

$$DP\ (\text{in WC}) = (HR*SGR + SPE) - (HL*SGL + SPE)$$

$$= (HR*SGR) - (HL*SGL) \qquad \text{(Eq. 7)}$$

Where,

DP	=	Differential pressure created by the vessel liquid level, expressed in inches of water
HR	=	Height of the reference leg liquid column above the lower connection, in inches
HL	=	Height of liquid in the vessel above the lower connection, in inches
HLmax	=	Maximum height of liquid which can be measured, in inches
SGL	=	Specific gravity of the liquid in the vessel
SGR	=	Specific gravity of the liquid in the reference leg
SPE	=	Static pressure effect of the gas above the liquid, in inches of water

9.3.1 Liquid Level Measurement (cont'd)

The resulting equation contains two components of potential error, SGR and SGL. As discussed in Section 9.3.1.1, the specific gravity is affected by changes in temperature. In order to account for differences in temperatures, assumed calibration temperatures for both the vessel fluid and the reference leg fluid must be established. Variations in actual temperature induce errors into the measured level signal. The error can be calculated by comparing the changes in specific gravity in a manner similar to that shown in Section 9.3.1.1:

- Assumed base (calibration) temperature T3, with a reference leg fluid specific gravity of SGR3.

- Actual temperature T4, with a reference leg fluid specific gravity SGR4.

If only the reference leg temperature varies, the error is determined by calculating the change (or error) in DP due to the change in reference leg specific gravity, assuming HL and SGL remain constant.

Error (in WC) = DP(Actual Conditions) - DP(Base Conditions)

DP = HR (SGR4 - SGR3) (Eq. 8)

If both the vessel liquid and the reference leg liquid temperatures vary, the error is:

Error (in WC) = HR(SGR4-SGR3) - HL(SGL2-SGL1) (Eq. 9)

If only the reference leg is affected by changes in temperature, the maximum error will occur at the maximum temperature variation. Since HR does not vary, it will not affect the maximum error. Equation 8 reveals that the DP error is negative if T4>T3 (since specific gravity decreases as temperature increases).

9.3.1 Liquid Level Measurement (cont'd)

To express these errors in terms of level measurement loop span, the error terms in Equations 8 and 9 must be divided by the span of the loop. As was done for Equation 6, the span is equal to the maximum level HLmax, multiplied by the selected specific gravity of the liquid level, SGL1. Thus Equation 8 becomes,

$$\text{Error (\% span)} = \frac{HR\,(SGR4 - SGR3)}{HLmax * SGL1} * 100\% \qquad \text{(Eq. 10)}$$

And Equation 9 becomes,

$$\text{Error (\% span)} = \frac{HR\,(SGR4 - SGR3) - HL\,(SGL2 - SGL1)}{HLmax * SGL1} * 100\% \qquad \text{(Eq. 11)}$$

If both the reference leg fluid temperature and the vessel fluid temperature vary, the maximum error will occur when one temperature is at a maximum with the other at a minimum.

The above example is for an installation with the "low" side of the transmitter connected to the lower tap, and the "high" side connected to the upper tap. A similar process could be used for a transmitter whose "low" side is connected to the upper tap and whose "high" side is connected to the lower tap.

Note in the example above, that though the DP error is negative for T4>T3, the corresponding % span level error would be positive. This is due to the inverse relationship that exists between differential pressure and the liquid level in the tank. That is, a reduction in DP is equivalent to an increase in liquid level in the tank.

The effects of temperature variation on level measurement can cause significant amounts of error to be introduced into a loop. Thus, it is essential that the effects of process and reference leg temperature changes be considered in an overall setpoint or loop error analysis.

3. High Temperature/Pressure Vessel Level Measurement

The measurement of level by use of a differential pressure device can become very complex when measuring the level in a vessel containing process liquids at high temperature or pressure, or both. The high temperature causes a portion of the process to become vapor and fill the upper portion of the vessel. The resultant changes in the density of the vapor, as well as, of the liquid, can have a significant effect on the accuracy of a level measurement. In a similar manner, high pressure can compress the gas in the upper portion of a vessel causing significant changes in gas density, thus affecting the resulting accuracy.

Figure 9-8 shows a typical closed vessel level measurement setup where the area above the liquid contains a fluid whose density can vary. For nuclear power applications the process liquid is generally water, such as in a pressurizer, a steam generator, or the reactor vessel, with the area above the liquid containing saturated steam. For this discussion two examples are presented, in example 1 we will assume the liquid in Figure 9-8 is water and the area above the liquid is steam. In example 2 we will assume the liquid is borated water, the area above the liquid is pressurized Nitrogen, and the reference line is a dry leg of Nitrogen gas.

The basic formula for calculating the differential pressure or level, where the effects of both fluid densities must be included, is:

$$\text{DP (in WC)} = (HR*SGR + SPE) - (HL*SGL + HV*SGV + SPE)$$

$$= HR*SGR - HL*SGL - HV*SGV \qquad \text{(Eq. 12)}$$

Where,

HR, HV & HL	=	Heights of the reference leg, vapor region, and liquid, respectively, in inches
SGR, SGV & SGL	=	Specific gravity of the reference leg liquid, vapor, and vessel water, respectively
SPE	=	Static pressure effect within the vessel, in inches of water
HLmax	=	Measurable level within the vessel, in inches

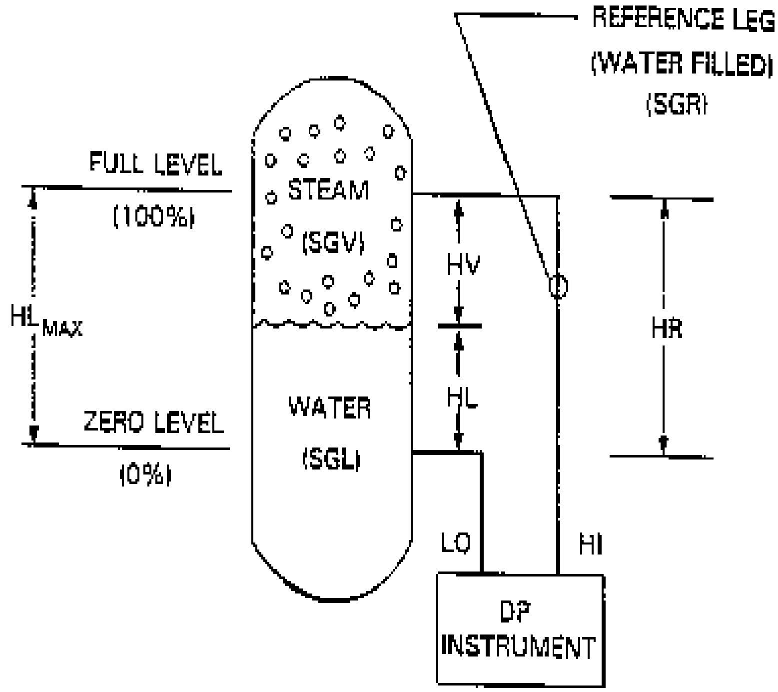
For this example, the measurable level (HLmax) within the vessel is equal to the height between the upper and lower sensing connections. This is also the height of the wet leg of concern. Those portions of the sensing lines (high and low) below the lower connection points are not of concern since, they will impart equal and opposite influences which cancel each other, assuming both lines are filled with the same fluid at approximately equal temperatures. Generally, HLmax will not be equal to the reference leg height, but will be at some level below the upper tap of the reference leg. However, for this example,

$$HLmax = HR = HL + HV \qquad \text{(Eq. 13)}$$

Substituting Equation 13 into Equation 12 yields DP in terms of HR and HL only.

$$\begin{aligned} DP \text{ (in WC)} &= HR*SGR - HL*SGL - (HR - HL)SGV \\ &= HR(SGR - SGV) + HL(SGV - SGL) \qquad \text{(Eq. 14)} \end{aligned}$$

9.3.1 Liquid Level Measurement (cont'd)



EXPLANATION OF SYMBOLS:

HL - Height of liquid (See note 1)

HV - Height of gas or vapor

HR - Height of reference leg (See note 1)

SGL - Specific gravity of liquid at saturation temperature

SGV - Specific gravity of vapor at saturation temperature

SGR - Specific gravity of reference leg

DP - Differential pressure in inches of water where

$$DP = HR(SGR-SGV) + HL(SGV-SGL)$$

NOTES:

1. All heights (except HV) are referenced above centerline of lower level sensing nozzle

FIGURE 9-8
SATURATED LIQUID / VAPOR LEVEL MEASUREMENT

9.3.1 Liquid Level Measurement (cont'd)

For the more general case where HLmax does not equal the reference leg height, HLmax may be substituted for HL. Provided that the vessel and reference leg conditions (temperature/ pressure) remain the same as the base calibration conditions, the indicated level is a linear function of the measured differential pressure, and no vessel/reference leg density effect errors are created.

To assess the effects of density variations (typically caused by temperature variation) on the level measurement, Equation 14 is rewritten in the form:

$$DP \text{ (in WC)} = (HR*SGR) - (HR*SGV) - (HL*SGL) + (HL*SGV) \quad \text{(Eq. 15)}$$

As in the previous sections, let

T1 = Assumed base temperature of the liquid and vapor
T2 = Actual temperature of the liquid and vapor
T3 = Assumed base temperature of the reference leg
T4 = Actual temperature of the reference leg

Each temperature has a corresponding specific gravity value:

SGL1 & SGV1 = Specific gravity of liquid and vapor at T1
SGL2 & SGV2 = Specific gravity of liquid and vapor at T2
SGR3 = Specific gravity of ref. leg liquid at T3
SGR4 = Specific gravity of ref. leg liquid at T4

The change in differential pressure signal (ΔDP) at the instrument due to a change in density caused by variations in temperature from the assumed calibrated condition, can be determined by:

$$\begin{aligned}\Delta DP \text{ (in WC)} &= DP \text{ (Actual Conditions)} - DP \text{ (Base Conditions)} \\ &= HR(SGR4 - SGR3) - HR(SGV2 - SGV1) - \\ &\quad HL(SGL2 - SGL1) + HL(SGV2 - SGV1) \\ &= HR(SGR4 - SGR3 - SGV2 + SGV1) - \\ &\quad HL(SGL2 - SGL1 - SGV2 + SGV1) \qquad \text{(Eq. 16)}\end{aligned}$$

To convert the change in differential pressure, or error value, to error in percent of span, the ΔDP must be divided by the base span of the loop.

$$\text{Error (\% span)} = \frac{\text{Error (in WC)}}{\text{DP Span}} * 100\% \qquad \text{(Eq. 17)}$$

The span is the difference between the full scale (100%) value for level and the zero (0%) value for level. In terms of DP,

$$\text{DP span} = (DP_{100\%}) - (DP_{0\%}) \qquad \text{(Eq. 18)}$$

Where,

$DP_{0\%}$ = the differential pressure when level is 0%
$DP_{100\%}$ = the differential pressure when level is 100%

Substituting Equation 14 into Equation 18,

$$\begin{aligned} \text{DP span} &= [HR(SGR3 - SGV1) - HL_{100\%}(SGL1 - SGV1)] - [HR(SGR3 - SGV1) - HL_{0\%}(SGL1 - SGV1)] \\ &= HL_{100\%}(SGV1 - SGL1) - HL_{0\%}(SGV1 - SGL1) \qquad \text{(Eq.19)} \end{aligned}$$

From Figure 9-8, HL_0 is equal to 0; therefore,

$$\text{DP span} = HL_{100\%}(SGV1 - SGL1) \qquad \text{(Eq. 20)}$$

Therefore, substituting Equation 16 into Equation 17 yields the error equation, expressed in percent of span, of:

$$\Delta DP = \frac{HR(SGR4-SGR3-SGV2+SGV1)-HL(SGL2-SGL1-SGV2+SGV1)}{HL_{100\%}\,(SGV1-SGL1)} \qquad \text{(Eq. 21)}$$

The above formulae for calculating the variation in level can be applied to a number of different types of level loops.

9.3.1 Liquid Level Measurement (cont'd)

These equations represent the general formulae for calculating differential pressure level measurement error due to variations in density. The equations apply for density variations in any of the fluids which can affect the measurement. By equating the effects of certain specific gravity terms to zero (e.g., SGV1 = SGV2 = 0 in a simple closed vessel), the equations can be shown to be equivalent to those for the open vessel and simple closed vessel.

While many loops only measure level, and are calibrated for specific conditions, other more complicated loops may have automatic temperature compensation circuitry. Such circuitry can adjust a level instrument's calibration parameters to account for the changes in fluid density. Temperature compensation can be used for either process temperature variations, reference leg temperature variations, or both. Utilization of temperature compensation in a level loop will eliminate the errors in measurement caused by density variations.

The effects of both process and reference leg temperature variations must be considered in the analysis of a level loop's accuracy. Since the magnitude of the error is governed by both the level and the magnitude of temperature change, care must be taken when defining the conditions under which the accuracy must be determined. While the maximum, or worst case, error can easily be calculated for a level equal to 100%, the actual levels of concern may be considerably less than 100% and thereby have much less potential error. In a similar manner, the actual process and reference leg temperatures expected at the time a level measurement is needed may greatly decrease the potential error in comparison to worst case temperature conditions.

Consider the following examples:

Example 1

Calculate the worst case and specific error due to temperature variations in the process and reference leg of the vessel in
Figure 9-8.

Assume:

- Process and reference leg fluid is water
- Normal and calibrated process temperature = 532°F
- Normal and calibrated reference leg temperature = 120°F
- Distance between level connections (HLmax & HR) = 169 in

9.3.1 Liquid Level Measurement (cont'd)

- Specific error conditions:
  - 40% level
  - 500°F process temperature
  - 250°F reference leg temperature
- Process temperature minimum 400°F
- Reference leg temperature maximum 280°F
- All conditions are saturated steam/water

Using the basic level formula (Eq. 14), the level signals in inches of water at Standard Temperature and Pressure (STP) at 68°F are determined for normal operation using (ASME) Steam Tables (See specific gravity conversion from specific volume in Section 9.3.1.1):

$$DP = HR(SGR - SGV) + HL(SGV - SGL)$$

DP for 100% of level (DP_{100}):

$$HL = HLmax = 169 \text{ in}$$

$$DP_{100\%} = (169 \text{ in})(0.990249 - 0.032047) + (169 \text{ in})(0.032047 - 0.755817)$$

$$= (169 \text{ in})(0.958202) - (169 \text{ in})(0.723770)$$

$$= (161.936 - 122.317) \text{ in}$$

$$= 39.619 \text{ in}$$

DP for 40% of level ($DP_{40\%}$):

$$HL = 40\% \; HLmax$$

$$40\% \text{ level} = (40\%)(169 \text{ in}) = 67.6 \text{ in}$$

$$DP_{40\%} = (169 \text{ in})(0.958202) - (67.6 \text{ in})(0.723770)$$

$$= 113.009 \text{ in}$$

These represent the calibrated DP values for the loop. No process error would exist in the loop as long as the process temperature remained at 532°F and the reference leg temperature remained at 120°F.

9.3.1 Liquid Level Measurement (cont'd)

The worst case error within the loop will always occur when level is at a maximum and both the process and reference leg temperatures are at their opposite extremes. The worst case error for this loop is calculated using the general formula for differential pressure change (Eq. 16).

$$\Delta DP = HR(SGR4 - SGR3 - SGV2 + SGV1) - HL(SGL2 - SGL1 - SGV2 + SGV1)$$

HL = 100% = 169 in
HR = 169 in
SGR3 = Specific gravity of ref. leg water at 120°F
SGR4 = Specific gravity of ref. leg water at 280°F
SGL1 = Specific gravity of process water at 532°F
SGL2 = Specific gravity of process water at 400°F
SGV1 = Specific gravity of steam at 532°F
SGV2 = Specific gravity of steam at 400°F

$$\Delta DP = (169\ in)(0.929449 - 0.990249 - 0.008613 + 0.032047) - (169\ in)(0.860837 - 0.755817 - 0.008613 + 0.032047)$$

$$= (169\ in)(-0.037366) - (169\ in)(0.128454)$$

$$= -6.32\ in - 21.71\ in$$

$$= -28.02\ in\ WC$$

Therefore, the worst case error causes the measurement by the level loop to be off by 28.02 in WC in the negative direction. Differential pressure level installations that have a wet reference leg have an inverse relationship between DP and actual vessel level. As the vessel level increases, DP decreases, and as the vessel level decreases, DP increases.

Expressed in percent span,

$$DP\ Span = HL_{100\%}\ (SGV1 - SGL1)$$

$$= (169\ in)(0.032047 - 0.755817)$$

$$= -122.32\ in.$$

$$Error = \frac{(-28.02\ in)}{(-122.32\ in)} * 100\% = +22.9\%\ of\ span$$

Therefore, the negative (or decrease) error of - 28.02 in WC differential pressure represents a level error of +22.9% span. In other words, an indicator would read 123% even though the actual level is only 100%.

The error within the loop measurement at the specific level of concern and conditions would be:

ΔDP	=	HR(SGR4 - SGR3 - SGV2 + SGV1) - HL(SGL2 – SGL1 - SGV2 + SGV1)
HL	=	40% = 67.6 in
HR	=	169 in
SGR3	=	Specific gravity of ref. leg water at 120°F
SGR4	=	Specific gravity of ref. leg water at 250°F
SGL1	=	Specific gravity of process water at 532°F
SGL2	=	Specific gravity of process water at 400°F
SGV1	=	Specific gravity of steam at 532°F
SGV2	=	Specific gravity of steam at 400°F
ΔDP	=	(169 in)(0.943549 - 0.990249 - 0.023775 + 0.032047) - (67.6 in)(0.785414 - 0.755817 - 0.023775 + 0.032047)
	=	(169 in)(-0.038428) - (67.6 in)(0.037869)
	=	-6.49 in - 2.56 in
	=	-9.05 in WC

$$\text{Error} = \frac{(-9.05\text{ in})}{(-122.32\text{ in})} * 100\% = +7.4\%\text{ of span}$$

Therefore, the actual error at 40% is -9.05 in WC differential pressure or +7.4% actual level. Thus, the level loop would indicate 47.4% while actual level would be 40%.

Example 2

Calculate the required span for an Accumulator Level Instrument which measures liquid level in a tank pressurized with Nitrogen to compensate for the effects of the pressurized cover gas.

The differential pressure transmitter is connected with a wet variable leg and a dry reference leg.

Assume that the system is designed to measure a span of 14 physical inches in height with an offset of + 8.5 inches (0% span is 8.5 inches above the transmitter and 100% span is 22.5 inches above the transmitter). For the purposes of this calculation it is assumed that the accumulators are at 104 degrees F and 660 psig.

On one side of the transmitter we have borated water at 104 degrees F and 660 psig. On the other side of the transmitter we have nitrogen at 104 degrees F and 660 psig. Since we are comparing liquid and gas, we will use weight instead of specific gravity in our calculation. The equation for DP with a dry reference leg design is:

$$DP = HL * (W_{bw} - W_n)$$

DP	=	differential pressure
HL	=	height of vessel liquid (above the transmitter)
W_{bw}	=	weight of pressurized borated water
W_n	=	weight of pressurized nitrogen

The differential pressure scaling calculation is as follows:

The specific gravity of the borated water is 1.0001762 at 104 degrees F and 660psig. The weight of water at reference temperature and pressure is 62.3441 lbs/cu ft therefore:

$$W_{bw} = 1.0001762 \times 62.3441 = 62.3551 \text{ lbs/ cu ft}$$

The density of nitrogen at 0 degrees C and 14.7 psia is:

1.2506 grams/liter = 0.0781 lbs/cu ft

The general law for gases is:

$d_0 = d\,(1 + \alpha t)\,760/H$, solving for d we get:

$$d = d_0\,(1/(1 + \alpha t))\,H/760$$

Where:

d	= density at some temperature and pressure
d_0	= density at 0 deg. C and 760 millimeters of mercury (14.7 psia)
α	= 0.00367
t	= temperature in degrees C.
H	= pressure in millimeters of mercury

Substituting into $d = d_0 (1/(1 + \alpha t)) H/760$, we get:

d_0	=0.0781 lbs/cu ft
t	= 104 degrees F = 40 degrees C
H	= 660 psig = 34,892.043 millimeters of mercury
d	= 0.0781 lbs/cu ft (1/(1 + 0.00367 x 40)) (34,892.043/760)
d	= 0.0781 (0.872) (45.9106)
d	= 3.1266 lbs/cu ft

Therefore the weight of nitrogen at 104 degrees F and 660 psig is:

W_n = 3.1266 lbs/cu ft

Recalling that $DP = HL \times (W_{bw} - W_n)$, at 100% of transmitter span:

HL = 14 + 8.5 = 22.5 inches = 1.875 feet

DP = 1.875 ft (62.3551 - 3.1266) lbs/cu ft
DP = 111.0534 lbs/sq ft = 1.7791 feet of water
= 21.3489 inches of water

At 0% of transmitter span:

HL = 8.5 inches = 0.7083 feet

DP = 0.7083 ft (62.3551 - 3.1266) lbs/cu ft

DP = 41.9535 lbs/sq ft = 0.6721 feet of water = 8.0651 inches of water

Therefore, the transmitter span, rounded to one decimal place is:

8.1 to 21.3 inches of water or 13.2 inches of water

This method compensates the input pressures for the weight of the pressurized nitrogen on the low side of the transmitter.

4. Vessel Growth

Large pressure vessels exposed to large temperature changes experience significant thermal expansion called vessel growth. This growth can be as much as 2 inches in BWR reactor pressure vessels and PWR pressurizers. The amount of growth at any point along the vessel depends on the thermal expansion coefficient of the material the vessel is made of, the distance from a reference point (either the bottom of the vessel or the variable leg tap) to the point in question, and the temperature change. There are two types of vessel growth errors of concern: Errors when the condensate pot (top of reference leg) is stationary; and Errors when the condensate pot moves with the vessel upper tap (reference leg tap).

Stationary Condensate Pot

When the reference leg condensate pot is stationary, vessel growth effectively moves the variable leg tap upwards resulting in a smaller distance between the variable leg tap and the condensate pot than that which existed under cold conditions. A bias in water level measurement of up to +2 inches (actual water level is lower than the sensed water level) can result, thereby reducing low level setpoint margins. To compensate for this effect, the scaling calculation for the level instrument calibrated range needs to account for the thermal expansion of that portion of the vessel between the variable leg tap and the bottom of the vessel. In other words, determine how much the lower tap will move due to thermal expansion of the vessel material between the variable leg tap and the bottom of the vessel and then compensate the transmitter calibrated range accordingly, (compensated range less than uncompensated).

Moveable Condensate Pot

When the reference leg condensate pot is designed to move along with the upper tap on the vessel (reference leg tap), vessel growth that causes the variable leg tap to move upwards is offset by a corresponding upward movement of the condensate pot. However, the condensate pot upward movement is greater than that of the variable leg tap because the condensate pot elevation is effected by the thermal growth of the vessel material between the upper tap and the variable leg tap in addition to the thermal growth of the material between the variable leg tap and the bottom of the vessel. A negative bias in water level measurement of some amount (actual water level is higher than the sensed water level) can result, thereby reducing high level setpoint margins. To compensate for this effect, the scaling calculation for the level instrument calibrated range needs to account for the thermal expansion of that portion of the vessel between the variable leg tap and the reference leg tap. In other words, determine how much the reference leg tap will move due to thermal expansion of the vessel material between the reference leg tap and the variable leg tap and then compensate the transmitter calibrated range accordingly, (compensated range greater than uncompensated). For some applications these errors are significant and should be compensated for in the scaling calculation. In other applications, it may not be necessary to consider this growth in the scaling if sufficient margin exists for it to be accounted for in the uncertainty analysis or, if the distance between the taps is small the effects may be negligible.

BWR specifics

In September 1988, General Electric issued Service Information Letter (SIL) 470, titled reactor Water Level Mismatches. Supplement 1 to this SIL was issued April 20, 1989, that provided additional detailed information. This Section covers the design considerations for Vessel Growth in BWRs that was addressed in this SIL 470 and its supplements.

EXAMPLE:	BNP Units 1 and 2, an expansion coefficient is obtained from Reference 2.25, when going from 70°F to vessel operating temperature. For consistency, a nominal value of 545°F will be selected as the operating temperature, which produces an expansion coefficient of 0.0413 in/ft or 0.00344 in/in.

9.3.2 Pressure Measurement

The point at which the measurement for a process variable is made must be considered when establishing a setpoint. The point of measurement for a process variable can require an actual setpoint value to be increased or decreased to satisfy the specific setpoint function. Many times, a specific process variable cannot be measured precisely at the point of concern within the process. This is a particular problem for pressure measurements. When a setpoint limit exists for this situation, the pressure effects of process flow and hydrostatic head must be evaluated.

Fluids flowing through a piping system experience a drop in pressure due to fluid friction. Many factors affect the actual pressure loss including length of piping, number of bends, diameter of piping, fluid viscosity, fluid velocity, etc. This pressure drop is generally referred to as "line loss".

The line loss at a specific point in a piping system configuration can be determined by analysis of the specific piping system, and the application of standard industry formulae. Line loss effects for a specific application should be calculated. Obtain assistance, as necessary, from other design disciplines.

Hydrostatic pressure effects can exist when the measurement point for an installation is at an elevation different than that of the point of concern. This elevation difference induces a hydrostatic head difference proportional to the height and the specific gravity of the process fluid.

The true measurement point elevation is the elevation of the loop sensing device, and not the elevation of the connection to the process. However, many times this elevation difference is accounted for in the calibration process. Hydrostatic pressure effects, therefore, can be the result of process piping elevation differences or instrument sensing line elevation differences (from process connection to sensing device), or both.

Therefore,

$$HP = EL * SG \qquad \text{(Eq. 22)}$$

Where,

HP = Hydrostatic head pressure
EL = Elevation difference
SG = Specific gravity of fluid

Consider the following example:

EXAMPLE	Referring to Figure 9-9, a low pressure trip is to be initiated on the pump when the pump suction pressure (Point B) falls below 50 psig. The instrument used to monitor suction pressure senses the pressure at a point 35 feet upstream and 15 feet below the actual suction. The instrument itself is 5 feet above the sensing line connection on the pipe.

Process fluid = Water
Process temperature = 150°F (Saturated Conditions)

The line loss effect between point A and point B could be calculated from the actual piping and fluid conditions. In this example we will assume a line loss effect of 4.0 psi.

With elevation (EL) for the example being equal to the 10 foot difference between the measurement point elevation and point B, the hydrostatic pressure effect (HP), or head effect, is:

$$
\begin{aligned}
HP &= EL * SG \\
&= (10\text{ ft})(0.98183) \\
&= (9.82\text{ ft})(0.433\text{ psi/ft}) \\
&= 4.25\text{ psi}
\end{aligned}
$$

The setpoint for the pressure loop at point A must be corrected for both effects:

$$
\begin{aligned}
\text{Actual setpoint} &= \text{Desired setpoint at B + Line loss effect + Hydrostatic pressure effect} \\
&= (50 + 4.0 + 4.25)\text{ psi} \\
&= 58.25\text{ psi}
\end{aligned}
$$

This would be the required setpoint at point A to ensure that the pump tripped when actual suction pressure, at point B, was 50 psi. An additional increase of the setpoint may also be included to account for other uncertainty effects in the actual instrument loop.

9.3.2 Pressure Measurement (cont'd)

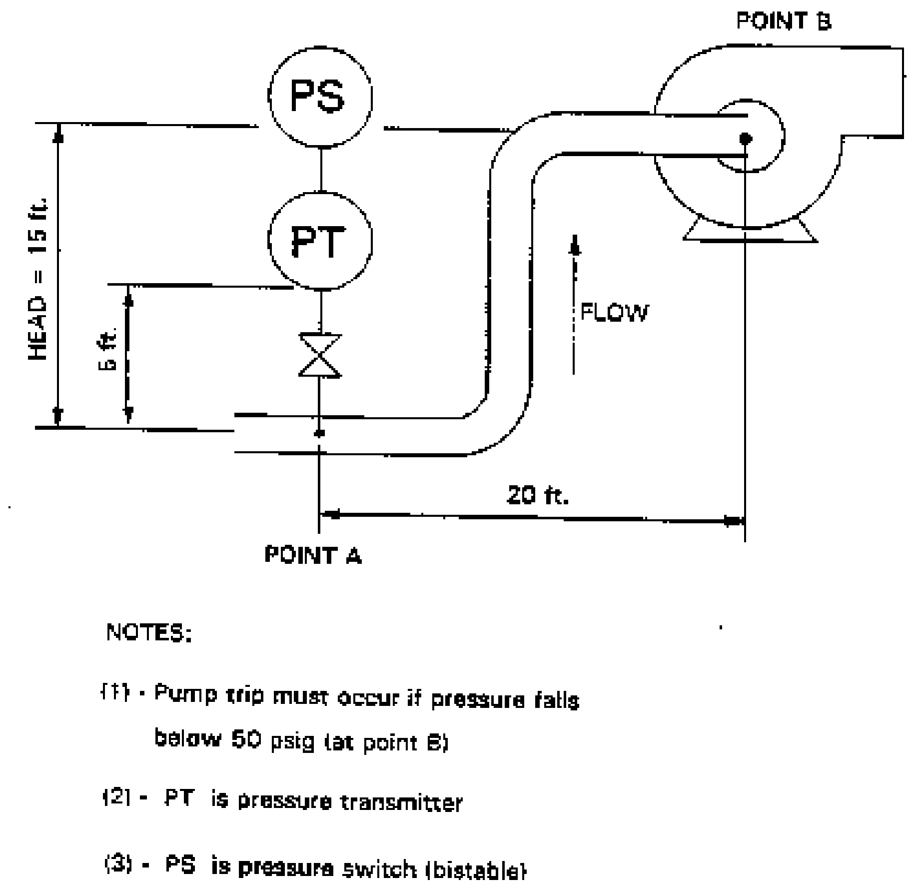


FIGURE 9-9
LINE PRESSURE LOSS HEAD EFFECT EXAMPLE

In the example presented above, the line loss must be added to the 50 psi limit in order to obtain a conservative setpoint. For example, if the line loss and head effect were neglected, using a value of 50 psi at point A would not be conservative since the pump trip would occur when pressure at point B was 46 psi, i.e below the 50 psi limit. The head effect also has to be added, as shown above, to effectively take credit for making the desired setpoint less restrictive, since the head pressure above the point of measurement reduces the available pump suction pressure.

NOTE:	The head effect/line loss errors are known fixed error terms. The error must be added, or subtracted, from the desired setpoint depending on the particular circumstances. This is discussed in more detail in Section 9.8.

9.3.2 Pressure Measurement (cont'd)

As noted above, hydrostatic pressure (head) effects may be accounted for in the calibration process, or in the determination of the overall loop uncertainty. It is important to specify for each application, where such effects are incorporated, either via the calibration process or the loop uncertainty. Otherwise, the effects may not be addressed, or may be addressed twice.

9.3.3 Flow Measurement

The most common form of flow measurement is the head type flowmeter. These flowmeters operate on the principle that placing a restriction in a flowing fluid causes a pressure drop in the fluid across the restriction. By measuring the pressure drop across the restriction with a differential pressure device, flow can be derived. Flow orifices, nozzles, and venturies are all forms of head type flowmeters.

The accurate measurement of flow is affected by a number of design factors. These factors include the assumed sizing and calibration attributes of the flow meter and piping loop, adherence to installation requirements, and potential process influence. Each of these factors must be reviewed and accounted for in the analysis of a flow loop.

1. Basic Flow Accuracy Influences

In the initial selection and sizing of a flow meter, design assumptions are made as to the pressure, temperature, flow range and chemical composition of the fluid to be metered. These design assumptions become the bases of a meter's sizing, and the differential pressure profile versus flow characteristics for the meter.

The basic formula for determining the volumetric flow from a head type flowmeter is:

$$Q = (K)(C)(Y)(Fa)(d)^2 (h/D)^{0.5} \qquad \text{(Eq.23)}$$

Where,

Q = Flow rate
K = Correction constant for a specific installation
C = Coefficient of discharge ratio
Y = Expansion factor
Fa = Thermal expansion factor
d = Flow meter orifice diameter
h = Differential pressure produced across the meter
D = Density of the flowing fluid

9.3.3 Flow Measurement (cont'd)

The correction constant (K) is generally a true constant for a particular flow meter. This factor includes the effects of Beta ratio (orifice size vs. pipe size) and unit conversion values which are fixed values for an installation.

The coefficient of discharge ratio (C) is a correction factor for the pressure sensing taps on a meter. The coefficient of discharge is a function of the Reynolds number calculated for an installation and the specific pressure tap arrangement employed. For most flows at the NGG plants, the Reynolds number is between 10,000 and 1,000,000 and the ratio is a fixed value. It would only require analysis consideration if major changes in the assumed flow conditions take place (e.g., a ten-fold increase or decrease in base flow rate).

The expansion factor (Y) accounts for changes in a meter's performance when metering compressible fluids such as air, steam, and nitrogen. The value is a fixed constant of one (1.0) for non-compressible fluids. In its liquid state, water is considered to be a non-compressible fluid.

The thermal expansion factor (Fa), or area expansion factor, as it is sometimes referred to, is a correction factor which accounts for the thermal expansion of a flow meter orifice due to a change in temperature. The thermal expansion factor is generally a very small value, varying from 1.000 to 1.0187 over a 900°F temperature change. Temperature variations of 200°F have less than a 0.5% effect on the actual flow measurement. In some applications, it may be considered negligible.

The flow meter orifice size (d) is the diameter of the actual orifice within a flow meter. It is generally considered a constant except for the effects of thermal expansion as discussed above. In some applications though, wear within the orifice may occur, causing the orifice size to change. Meters in severe service conditions should be evaluated for potential wear or erosion, and suitable allowances made.

The differential pressure (h) is the difference in static pressure between the fluid upstream and downstream of the meter. This difference is a function of the square of the flow; therefore, the square root of the signal must be taken to obtain actual flow. A differential pressure device measures this parameter in a flow loop installation.

The density (D) of the flowing fluid directly affects the differential pressure produced by a meter. As discussed in Section 9.3.1.1, density may vary due to changes in temperature or chemical composition. The primary cause of a variation in density is the change in temperature of the fluid. However, an evaluation should be made for any possible density changes due to all potential sources.

An important fact to remember when utilizing head flow elements such as an orifice is, that because the flow rate is proportional to the square root of the differential pressure, the rangeability of the device is rather limited. The effective operating range is about 25-100% full flow. This is a limit imposed by the differential pressure meter, not the accuracy of the orifice discharge coefficients. For example, consider the case where 10% of rated maximum flow produced 1% of rated differential pressure. If the differential pressure transmitter accuracy was ± 0.5% of full scale differential pressure, the transmitter itself could introduce an error of ± 25% nominal at the 10% rated flow value.

The measurement of flow with head type flow meters is a well documented, but complicated subject. The specific factors discussed above are the factors which affect a meter's accuracy once it is sized for a particular application. This methodology document will limit its discussion to those factors which affect the accuracy of a meter after installation.

Specific values for the uncertainty of the head flow device should be obtained from the vendor, design specifications, etc. Where no specific values can be located, a typical value for the basic uncertainty of such a device is ± 1% of differential pressure. Any other process or installation effects, such as those discussed below, would be in addition to the basic accuracy of the device.

2. Density Variation Effects

Variations in the density of a process fluid to be metered can be the biggest source of potential process measurement error in a flow loop. The density variation is normally caused by variations in the process fluid's temperature. A simplified version of the flow formula will be used to determine the effects of density variation on flow measurement accuracy:

$$Q = k\,(h/D)^{0.5} \qquad \text{(Eq.24)}$$

Where,

k = Combined value of all other factors and constants

If the volumetric flowrate, Q, is held constant, it is seen that a decrease in density (D), due to an increase in temperature, will cause a decrease in differential pressure, (h), thus resulting in an error in the transmitter reading. This error occurs because the differential pressure transmitter was calibrated for a particular differential pressure corresponding to that flowrate at a lower temperature. The lower "h" value causes the transmitter to indicate a lower flowrate.

Assuming Q remains constant between a base density condition, D1, for which the instrument is calibrated, and an actual process condition, D2, an equality can be written between the base flowrate, Q1, and actual process flowrate, Q2, as shown below:

$$Q2 = Q1 \qquad \text{(Eq.25)}$$

Substituting Equation 24 into Equation 25 yields

$$k(h2/D2)^{0.5} = k(h1/D1)^{0.5} \qquad \text{(Eq.26)}$$

or,

$$h2/D2 = h1/D1$$

$$h2/h1 = D2/D1$$

A fluid's density and temperature have an inverse relationship. That is, the density of a fluid decreases as temperature increases and vice versa. As can be seen in Equations 24 and 26, as the density decreases, the corresponding differential pressure must decrease to maintain the relationship. Since the density is the reciprocal of specific volume of fluid (SVF), the equation may be rewritten as,

$$h2/h1 = SVF1/SVF2 \qquad \text{(Eq.27)}$$

Therefore, as temperature increases, the differential pressure produced by a meter will decrease for the same flow rate. The opposite is true for a decrease in temperature. The differential pressure error (eh) produced by the change in density can be written as:

$$eh = h2 - h1 \qquad \text{(Eq.28)}$$

Rewriting Equation 27 as,

$$h2 = h1(SVF1/SVF2)$$

and substituting this into Equation 28 yields,

$$eh = h1(SVF1/SVF2 - 1) \qquad \text{(Eq.29)}$$

It can be observed in Equation 29 (which is the process error equation for density effect on volumetric flow), that the absolute error is maximized when "h1" is maximized. This occurs at the upper end of the calibrated differential pressure span for which the transmitter is calibrated. This is also the maximum calibrated flow. The error varies from negative values for temperatures above the base value (SVF2>SVF1), to zero for temperatures equal to the base value (SVF2=SVF1), and finally to positive values for temperatures below the base value (SVF2<SVF1).

Once the differential pressure error has been determined, the actual flow rate error can be determined. The actual flow rate error will vary for a given differential pressure error due to the square root relationship between "h" and "Q". The error of a flow loop is dependent on the specific flow of concern. While the maximum error of a loop can be calculated at 100% flow conditions, application of this error to lower flows may be overly conservative. The density error should be calculated for the specific flows of concern. The calculated "eh" can then be factored into the differential pressure error for the given flow condition and the true impact on flow evaluated.

Consider the following example:

Example

The error in a flow loop due to density effects is to be determined for the following:

Assume an orifice plate is used to measure flow in a water system that is normally at 80°F. The orifice is sized to produce a differential pressure of 100 inches of water for a flow rate of 5000 GPM at 80°F. Assume further that under accident conditions the temperature rises to 200°F at an actual flow of 2000 GPM.

9.3.3 **Flow Measurement** (cont'd)

The first step is to determine the relationship between "Q" and "h". Given that,

$$Q \quad = \quad k(h/D)^{0.5}$$

the constant k for the flow/DP relationship at 80°F can be determined from the design parameters as follows by setting the density term, D=1.

$$5000 \text{ GPM} \quad = \quad k\ (100 \text{ in WC}/1)^{0.5}$$

$$k = 5000/10 = 500$$

Thus,

$$Q = 500(h)^{0.5}$$

Now, using the established constant, and the accident flowrate of 2000 GPM, we can solve for h1, or the differential pressure that would be present for the normal 80°F condition for which the orifice is sized.

$$Q1 = k(h1)^{0.5}$$

$$Q1 = 500(h1)^{0.5}$$

$$2000 = 500(h1)^{0.5}$$

or,

$$h1 = (2000)^2/(500)^2 = 16 \text{ inches of water}$$

Using the thermodynamic steam tables and assuming saturation conditions,

$$\text{SVF1 (at 80°F)} \quad = \quad 0.016072 \text{ ft}^3/\text{lbm}$$
$$\text{SVF2 (at 200°F)} \quad = \quad 0.016637 \text{ ft}^3/\text{lbm}$$

Substituting these into the error formulae equation 29:

$$eh \quad = \quad h1(SVF1/SVF2-1)$$

$$eh \quad = \quad 16\ (0.016072/0.016637-1)$$

$$= \quad -0.54 \text{ in WC}$$

Therefore, the rise in temperature reduces the actual differential pressure (h2) created by the orifice to,

$$eh = h2 - h1$$

$$h2 = eh + h1$$

$$= (-0.54 \text{ in}) + (16 \text{ in})$$

$$= 15.46 \text{ in WC}$$

This yields an indicated flow of,

$$Q = 500\ (15.46)^{0.5} = 1966 \text{ GPM}$$

The error induced by the density change is the difference between the indicated flow at the higher temperature condition (Q2) and the indicated flow at the normal temperature condition (Q1),

$$Q2 - Q1 = 1966 \text{ GPM} - 2000 \text{ GPM} = -34 \text{ GPM}$$

This represents an error, expressed in percent of reading, of,

$$\frac{-34 \text{ GPM}}{2000 \text{ GPM}} * 100\% = -1.7\% \text{ of reading}$$

or, as expressed in percent of span,

$$\frac{-34 \text{ GPM}}{5000 \text{ GPM}} * 100\% = -0.68\% \text{ of span}$$

The density variation effect from a base, or calibration, condition to an actual condition of interest is a known predictable effect. As such, the effect is treated as a bias type error.

3. Effects of Piping Configuration

The actual installation of a head type flow device can affect the measurement accuracy of a flow loop. Bends, fittings, and valves in piping systems cause turbulence in the flowing fluid. This turbulence can cause errors to be induced into the differential pressure measurement.

9.3.3 Flow Measurement (cont'd)

ASME has published results of extensive testing of piping systems and guidance for various types of installations. The ASME recommendations provide the minimum acceptable upstream and downstream lengths of straight pipe needed for a specific flow meter installation to keep the effects of this turbulence from significantly decreasing a flow meter's accuracy. The piping arrangement showing locations of valves, bends, fittings, piping planes, etc. must be reviewed to verify that an installation meets the minimum requirements. Typically locations can be obtained from piping isometric drawings.

As established by Reference 2.17, if the minimum pipe lengths are met, the resultant flow measurement error due to piping configuration will be less than ±0.5% of reading. If the minimum criteria cannot be met, an additional tolerance of ±0.5% of reading must be applied to the flow measurement error allowance.

The effects of the piping configuration on accuracy is considered to be a bias error term, since their sign is calculable.

Typically, the minimum pipe lengths for orifices are as follows:

a. On the downstream side of the device, five pipediameters of straight run pipe is sufficient.

b. On the upstream side of the device, ten pipe diameters of straight run pipe is sufficient if the disturbance is due to flanges, collars, wide open gate valves, reducers, or bends, elbows, or tees in the same plane. Fifty pipe diameters is sufficient if the disturbance is due to piping angle turns in two planes. Seventy-five pipe diameters is sufficient if the disturbance is due to pressure regulators, valves, or similar apparatus.

   To determine the minimum pipe lengths for venturis, flow nozzles, etc., consult either vendor specific recommendations, reference books, or ASME guidelines. The Mechanical Engineering Group should also be contacted, as necessary.

4. Thermal Expansion Factor Effect

The basic flow equation discussed in Section 9.3.3.1 includes a correction factor for expansion of the flow meter orifice or primary element due to temperature change. The correction factor is known as the Area Factor, or Thermal Expansion Factor (Fa). The factor, Fa, is dependent on the material composition of the primary element. This factor provides for changes in the flow meter orifice size due to the thermal expansion or contraction of the primary element material.

While the thermal expansion of the flow element generally has little effect on the flow measurement, the effects of large temperature gradients must be evaluated.

The values of Fa for various materials is shown in Reference 2.17, Figure II-I-3. For a 300 Series stainless steel flow meter, a 200°F temperature change results in less than a 0.5% change in Fa. Therefore, for most applications, the effects of Fa variation need not be considered for temperature variations less than 200°F. For greater temperature variations, the effects of Fa should be evaluated. Errors induced by Fa are considered to be bias errors since their direction can be determined.

Generally, the orifice plate and the pipe are made of similar materials. Thus, the thermal expansion factor for the pipe will be very similar to that of the orifice plate, and no changes in the d/D, or Beta ratio, will occur. Significant errors may occur if this material conformity does not exist.

The following example is provided to illustrate how errors associated with Fa variation can be established.

Example

Determine the percentage error in reading, caused by the Fa factor alone, for the following:

Initial flow rate	1000 GPM
Process calibration temperature	100°F
Process accident temperature	300°F
Orifice plate material	316 SS

9.3.3 **Flow Measurement** (cont'd)

From Reference 2.17, Figure II-I-3,

Fa initial = 1.0005
Fa accident = 1.0042

If all other parameters remain constant, the basic flow formula can be written as,

Q = (Fa)(Constant)

Solving for a constant for the conditions defined above,

Constant = Q1/Fa

= 1000/1.0005

= 999.5

Assuming no other effects on flow are present, the change in flow due to the change in Fa is,

Q2 = (1.0042)(999.5)

= 1,003.7 GPM

or an increase of 3.7 GPM. This corresponds to an error of,

$$\% \text{ Error} = \frac{3.7 \text{ GPM}}{1000 \text{ GPM}} * 100\% = 0.37\% \text{ of reading}$$

9.3.4 Temperature Measurement

When measuring temperature, we assume that the temperature at the sensor is the same temperature as the gas, liquid, or solid whose temperature we want to know. In most situations, we do not think about whether that assumption is true. But for some applications it is necessary to ensure that the sensed temperature is really the process temperature. Heat flows from a hot region to a cooler one by conduction, convection, and radiation. An accurate temperature measurement ensures that the amount of heat flowing between the point being measured and the point of concern is not sufficient to cause a significant temperature difference.

Where the differences in temperature within a medium are significant, it is referred to as temperature stratification and can affect the accuracy of the temperature measurement.

Consider the measurement of temperature, via a thermocouple, of a stirred liquid in a tank. For practical purposes, we can consider the entire volume of liquid to be at the same temperature. If we insert a thermocouple assembly with a half-inch diameter stainless steel protecting tube into the tank, heat flows along the protecting tube towards the colder thermocouple head. If the tube is immersed only one-half inch, we can sense that the thermocouple junction is probably colder than the liquid because of the temperature stratifying along the protecting tube.

As the depth of immersion is increased, the hot junction temperature more nearly equals the liquid temperature. This is because more of the protecting tube is at the same temperature as the liquid and there is little or no heat flowing in the region of the hot junction. If no heat flows, there is no temperature difference. For this reason, it is generally considered that the depth of immersion of a well or protecting tube in a tank should be at least 10 times its diameter.

The above example shows temperature stratification due to the actual measurement. In other applications, the stratification is a result of the process being monitored. A typical pressurizer for example, may employ two different temperature detectors - one for the pressurizer liquid and one for the pressurizer steam. Both are needed to provide a representative measurement of the actual temperatures within the pressurizer.

Other examples of where temperature may be stratified are: rooms or large areas of a building, large diameter piping, tanks, piping or vessels that are heat traced or only partially insulated.

Regardless of the reason for the stratification, the potential for it to exist must be recognized and addressed in order to ensure an accurate temperature measurement. Corrections are treated as a bias, similar to head effects, to account for any temperature difference between the point of measurement and the point of concern.

9.4 Instrument Uncertainties

All instruments have limits on their ability to accurately perform their function. These limits of accuracy, generally expressed as inaccuracies or errors, vary, based on the specific design capabilities of the instrument, and the service within which it is used. By evaluating the various effects on instrument accuracy, a total uncertainty limit can be established for the instrument.

Each instrument has a basic accuracy established by its manufacturer. In addition, various types of instruments have different parameters which affect their basic accuracy. While one type of instrument may be greatly affected by a change in humidity, another may show no effect. The instrument's basic accuracy, and all of the applicable parameters which can affect its accuracy, must be taken into account in performing loop uncertainty analyses.

The information described below must typically be obtained from the vendor, either through product data sheets, test reports, technical manuals, etc. In order to maintain consistency between calculations that utilize the same types of devices, it is recommended that the vendor data be obtained from the same common sources. Ideally, the information should come from the plant's vendor technical manuals since these are controlled. However, some information may not be within these reports and other sources may need to be utilized. Whenever possible, the vendor technical manuals should be updated to include any information obtained from supplemental sources. Whenever the vendor is contacted, the information obtained via letter, telecon, telecopy, etc. should be documented and maintained in a manner that will allow subsequent calculations to utilize the same information.

The major parameters which govern an instrument's accuracy are discussed below. Additional parameters may be identified, by a manufacturer, as having an influence on the specific instrumentation. These parameters, and their effects, would be handled in the same manner as those described below.

Each of the major parameters which affect an instrument's accuracy has been assigned an abbreviation to aid in the identification of error terms within a specific error analysis. The abbreviations are indicated in the individual sections discussing the error, and a complete listing can be found in Section 3.70.

9.4.1 Reference Accuracy (RA)

The Reference Accuracy (RA) of a device is the base performance accuracy of a device, typically established by the manufacturer. The RA should include the effects of hysteresis, repeatability and linearity for an instrument. Where these effects are not included, the individual effects of the omitted components should be included separately, or resolved with the vendor to be not applicable. For example, one instrument's manufacturer may provide separate values for accuracy and repeatability. If the accuracy value does not include the repeatability value, they must be combined to determine the overall reference accuracy. The vendor may provide guidance on how they should be combined, either algebraically or SRSS. If no guidance is given, they should be combined via SRSS. Figure 3-2 provides a graphic representation of RA.

For some devices such as bistables, no reference accuracy is provided by the vendor. Instead, the vendor may only provide a value for repeatability. If the vendor states that this is the only applicable term for the device, then it can be used as the reference accuracy.

Reference accuracy is considered to be a random error component unless specifically indicated otherwise by a manufacturer, and is normally stated in terms of percent of span for the instrument.

The RA is the accuracy that an instrument can meet, and it defines the limits of acceptable performance in normal operation. The RA typically can only be met over a small band of operating conditions specified by the manufacturer.

The RA value is generally established by a manufacturer based on equipment testing. The results of the testing allow a manufacturer to statistically define the performance of an instrument, and develop an RA value with a high degree of confidence. While some disagreement exists on the degree of statistical confidence a manufacturer's RA value should have, for the purposes of this document a 95% confidence factor (or 2 σ) will be assumed. Thus, a vendor should be contacted to determine whether his published reference accuracy values represent 1, 2, 3, or some other σ value. If such information cannot be provided by the vendor, the values will be assumed to be 2σ. This is based on common industry practice. Refer to Section 9.2.5 for additional discussions on statistics.

9.4.1 Reference Accuracy (RA) (cont'd)

Reference accuracies should be established based on vendor information applicable to the specific equipment. In some cases, the vintage of the equipment at the plants may preclude the identification of equipment specific reference accuracies. Where no specific information can be obtained, the value for the calibration tolerance may be used as the reference accuracy. Another option may be to use the following values as reasonable representations of reference accuracy. However, the calibration tolerance or the default values should be used for the reference accuracy only after a valid effort has been made to obtain specific vendor values.

Equipment	Representative Ref. Accuracies
Thermocouples	±1.0% of span
RTDs	±0.5% of span
Pressure transmitters (incl. d/p)	±1.0% of span
Recorders	±2.0% of span
Indicators (Analog - PWRs)	±2.0% of span
(Analog - BWRs)	±3.0% of span
(Digital)	±0.5% of span

Values are based on References 2.21, 2.22, and common industry values.

9.4.2 Drift (DR)

Drift (DR) is a natural phenomenon exhibited by instrumentation, and is caused by the changing properties of instrument components due to aging or other naturally occurring phenomena. The individual elements of an instrument all have characteristics which may vary with time. The culmination of these changes imparts a specific drift characteristic to an instrument. Drift is a measure of an instrument's stability over time, and is often referred to as stability by a vendor.

For most instruments, drift is typically considered proportional to a given period of time. As more time is allowed, the potential error due to drift increases. Some instrument manufacturers though, are able to put a bounding value on drift. This bounding allows increased time periods without incurring additional inaccuracies beyond a maximum drift value.

9.4.2 Drift (DR) (cont'd)

In a nuclear power facility, drift for a loop is generally broken into two parts, sensor drift, and signal processing drift. The two are separated to allow periodic verification of loop calibration parameters. Many times, a loop's sensor is inaccessible for calibration/verification during operation while the remaining components are accessible. By maintaining separate drift components, additional flexibility is provided for maintaining accurate instrumentation systems.

Drift is usually specified in terms of a limiting value per unit of time, and is considered a random error component unless otherwise indicated by a manufacturer. The actual drift value for a loop must be determined using the anticipated time interval between calibrations for a loop. The nominal calibration frequency of instruments is identified in [BNP, HNP, RNP - the PassPort PM Requirement Panel]. With regard to surveillances, the Technical Specifications allow a grace period of the nominal frequency, by an amount of 25% of the specified interval. For example, if a surveillance's frequency is specified as each refueling (i.e. 18 months), the actual frequency could be up to 18 ± 25% months, or 22.5 months. Therefore, the interval taken as the calibration interval must be the maximum interval allowed by a plant's program, and not just the nominal interval.

In many cases, the drift value specified by a manufacturer may be less than the actual calibration interval. If possible, the manufacturer should be contacted to determine if more recent drift data is available, or if he can provide guidance on how it should be applied to longer intervals than what is published. Otherwise, the drift value should be extrapolated out to encompass the calibration interval.

Consider the following example:

Example

A manufacturer specifies a drift value of ±0.25% span for 6 months for his device. The range of the device is 0-500 psig and is calibrated from 0-440 psig. The nominal surveillance interval is 18 months.

The simplest and most conservative approach is to assume that the drift is linear with respect to time. This would provide a drift value of,

$$18 \text{ months} \pm 25\% = 22.5 \text{ months}$$

$$\frac{(22.5 \text{ months})}{(6 \text{ months})} * \frac{(500 \text{ psig})}{(440 \text{ psig})} * 0.25\% = \pm 1.07\% \text{ cal. span}$$

Note that the manufacturer specified a drift value of ±0.25% span. Frequently, vendors specify a value in terms of span which correlates to range, not calibrated span. That was the case here. Thus the range of the instrument, 500 psig, is divided by the calibrated span the instrument is used for this application, 440 psig. This factor is frequently referred to as the Turndown Factor (TDF) or turndown ratio. Anytime a value is being converted from units of range of an instrument to its span, the turndown factor must be applied.

As stated above, treating the drift linearly is a rather simple and conservative approach. A more realistic assumption is that the drift is random and independent with respect to each time interval. Based on this assumption, the drift may be calculated using the SRSS method. Using the SRSS method, the drift would be calculated as follows,

18 months ± 25% = 22.5 months or, ~ 4 separate 6 month intervals

$$DR = [\ (0.25)^2 + (0.25)^2 + (0.25)^2 + (0.25)^2\ ]^{0.5} * \frac{(500)}{(440)}$$

$$DR = (4)^{0.5} * (0.25) * \frac{(500)}{(440)}$$

DR = ± 0.57% cal. span

Although either method may be used, the SRSS method is the preferred method for the NGG plants.

The drift value for a device should primarily be obtained from vendor information. However, there may be some instances where either vendor data does not exist, or the vendor data is rather conservative and it is desirable to try to use another method. A drift value for a particular device can be inferred from an analysis of the device's calibration history. The overall methodology for calculating drift in this manner is described in both Section 6.2.7 and Appendix E of Reference 2.3. Reference 2.29 contains detailed guidelines for analysis of instrument drift based on calibration history. [BNP - References 2.33 and 2.34 may be used to analyze historical as-found/as-left data for the purpose of determining instrument drift, either for the existing calibration interval or for interval extension.]

There are several important points which must be understood however, prior to determining drift from as-left/as-found data. First, it should be recognized that the use of as-left/as-found data may actually provide a higher drift value than provided by the manufacturer. Another potential issue is that the analysis may identify that the actual drift for a device is not random, and normally distributed. Thus, instead of being able to SRSS the drift value, it may have to be treated as a bias.

9.4.2 Drift (DR) (cont'd)

Another factor to consider when assessing whether to determine device specific drift values from as-left/as-found data, is that such an analysis may be rather time consuming. To establish a proper population size often requires collecting numerous surveillance/calibration test results. Each application must also be evaluated for any factors which may cause its data to be different from other applications. As noted in References 2.3 and 2.29, the as-left/as-found data typically includes uncertainties other than drift, such as temperature effects, humidity, power supply variations, complete M&TE etc. Thus, if possible, such effects should be separated from the as-left/as-found data to provide a value that is more representative of just the drift uncertainty.

When drift values cannot be obtained from a vendor, and analysis of as-left/as-found data is not feasible, default values for drift can be used. However, these should only be used after a reasonable effort has been made to obtain a drift value via another method. Per Reference 2.22, typical values which may be assumed for drift are ±1.0% full scale for 18 months nominal for a sensor and ±1.0% full scale for 18 months for the total rack, or signal processing equipment.

If default values are used for safety-related applications, then once enough as-left/as-found data is available to calculate a drift value, such data should be used to either validate or replace the default values. If the default value bounds a calculated drift value, the default value can be retained.

9.4.3 Temperature Effect (TE)

Temperature effect (TE) is the term given to the change in an instrument's accuracy due to changes in ambient temperature. Generally, all instruments exhibit some form of TE. The temperature effect is normally stated by a manufacturer in terms of accuracy change per unit change in temperature within the normal operating limits of the device. The TE is caused by changes in temperature between the ambient temperature at time of calibration, and the ambient temperature in normal operation.

The temperature effect is normally stated as an additional percent of span error per unit of temperature. For an instrument transmitter, though, the TE may be stated in terms of the transmitter range. For example, a typical Rosemount Model 1153D transmitter has a TE of,

$$TE = \pm(0.75\% \text{ Upper Range Limit} + 0.5\% \text{ of span}) \text{ per } 100°F \text{ change}$$

9.4.3 Temperature Effect (TE) (cont'd)

In this case, the resulting error from the Upper Range Limit (URL), must be calculated and corrected to a percent of span limit before the true TE can be determined. The 1153D transmitter can have any of eight different URLs varying from 30 inches of water to 4000 psi. The proper URL value must be multiplied by 0.75% and divided by the actual span for the transmitter to convert the value to percent of span.

For example, if the URL was 1000 psi and the actual span was 800 psi, the resulting TE would be:

$$TE = \pm\left[(0.75) * \frac{(1000)}{(800)} + (0.5)\right]$$

$$TE = \pm 1.44\% \text{ span per } 100^{\circ}F$$

In addition to the TE for normal operating limits, many field mounted devices have an accident temperature effect. The accident temperature effect provides the limits of uncertainty for an instrument when operated outside its normal operating limits. This is discussed further in Section 9.4.7.

The temperature effect is considered a random error term unless otherwise specified by a manufacturer. The TE should be calculated from the maximum range of temperatures for a given location, unless otherwise justified.

The normal temperature bands for plant areas at each of the NGG plants is presented in the following documents:

[BNP - Drawing D-3056]

[HNP - FSAR Table 9.4.0-1, FSAR Section 3.11B, and FSAR Section 6.2.2]

[RNP - Drawing HBR2-11260]

The temperature band an instrument is normally expected to be exposed to can be determined from the entire design range of temperatures in its location (which is very conservative), or determined from the difference between its assumed calibration temperature and the ranges of temperatures identified in the above

documents. For panel mounted enclosed equipment, the normal temperature band for an instrument's location should be considered and may be increased by 10°F, unless it has been determined that minimal heat rise exists, or the heat rise is included in the vendor temperature effect value i.e. (±% per 100°F change in ambient). This is to account for the elevated temperatures above the ambient room temperatures inside the racks/panels.

It should be noted that the temperatures identified in the above documents are intended to bound all locations within the stated area. Thus, after further evaluation, these temperatures could potentially be reduced for a specific location.

As an example of how to use the temperature bands and the assumed calibration temperature, consider the Rosemount 1153D transmitter discussed above, located in the Brunswick Reactor Building. Per Brunswick Drawing D-3056, the normal ambient temperature inside the Reactor Building is between 40 and 104°F. An assumed calibration temperature for a sensor, is taken to be 65-90°F. Therefore, the expected normal temperature change for such a transmitter is,

$$\Delta T = 90 - 40 = 50°F \quad \text{and,}$$

$$\Delta T = 104 - 65 = 39°F$$

The largest expected temperature difference is 50°F and is combined with the vendor specified temperature effect per 100°F determined above to provide the specific normal temperature effect for this application.

$$TE = \pm 1.44\% \text{ cal. span} * \frac{(50°F)}{(100°F)}$$

$$TE = \pm 0.72\% \text{ cal. span}$$

Larger temperature effect errors would be expected under accident conditions when the accident temperature effects at the time of trip are analyzed.

As with the other instrument uncertainties, the TE should be obtained from vendor specific information, combined with the ambient temperature change for a given location. However, in some instances such data may not be available. If, after a reasonable effort has been made to obtain vendor specific data, no such data can be identified, default values can be utilized.

Based on the temperature bands for each of the plants, a typical default value of TE for components located within [BNP - the Reactor Building] [HNP, RNP - Containment] would be ± 1.00% full scale. For instruments in other plant locations, a typical default value for TE is ± 0.50% full scale.

9.4.4 Static Pressure Effect (SPE)

Some differential pressure transmitters exhibit an error related to the static pressure (SPE) imposed by the process. The static pressure effect can cause changes in a transmitter's calibration parameters (at both full and zero span) which affect its basic accuracy. Some manufacturers quote the SPE in terms of basic accuracy changes, while others indicate changes in both a transmitter's zero, and full span calibration parameters. Care must be taken in determining the actual SPE for a transmitter, as it often requires the review of both the manufacturers specifications, and the plant calibration procedures.

The static pressure effect is only applicable to differential pressure transmitters in high static pressure service. For process static pressures less than 200 psi, the SPE is generally not considered, since the resultant error is negligible. If, for a particular manufacturer, the SPE can be determined to be greater than 0.05% of span at less than 200 psi, the effect should be included. There are three terms that are applicable when considering SPE effects. They are:

1) Zero Correction (If not corrected during calibration)
2) Span Correction/Process Effect (If not corrected during calibration)
3) Span Correction/Uncertainty

1. Zero Correction

The zero effect occurs at rated pressure with zero input differential to a transmitter. In this case the effects of the static pressure on both the high and low sides tend to cancel each other, but, the slight remaining shift in output is called static pressure effect on zero or zero effect. This effect is a bias error. While the maximum magnitude of the zero effect is predictable its direction is not. There are two ways to account for this zero effect in pressure loop calibrations.

a. Calibrate The Shift Out. The static pressure zero effect can be trimmed out after installation with the unit at operating pressure. Equalize pressure to both process connections, and turn the zero adjustment until the ideal output at zero differential input is observed. Another method is to determine the zero effect for a specific instrument via bench testing and then incorporating that value in the scaling calculation or calibration procedure. The uncertainty calculation may still need to include an additional allowance for variations in system operating pressures different from the assumed reference pressure.

b. Account For Shift In Uncertainty Calculations. If the zero effect is neither trimmed out at operating pressure nor specifically bench-measured for a unique transmitter, the manufacturers specified uncertainty effects have to be included in the transmitter uncertainty calculation. As an example, the Rosemount 1153 Series, specifies two effects, ±0.2% URL per 1000 psi or ±0.5% URL per 1000 psi, depending on the range code.

2. Span Correction (Process Effects)

To understand the differential pressure effects for a particular transmitter, one must review that manufacturers data sheets. But, in general when differential pressure is applied to a transmitter the movement is toward zero differential pressure or center position. With this in mind one can see the effect is to decrease output as static pressure is increased. In other words as static pressure increases, a slightly higher differential pressure is required to move the sensing element a given amount. This shift is called static pressure effect on span or span effect, which is systematic or predictable, repeatable, a bias and linear. Because the effect is systematic it can be calibrated out for any given static pressure and span. As an example, the Rosemount 1153 Series this effect is +0.75% of input/1000 psi. This shift can be used in the scaling calculation to adjust the span for the difference between calibration and operating pressures. If this is not calibrated out, this term has to be included in the uncertainty calculation. The uncertainty calculation may still need to include an allowance for variations in system operating pressures different from the assumed reference pressure.

3. Span Correction (Uncertainty Effect)

The last term to be considered for differential pressure effects is the overall uncertainty value. This number is available from the manufacturer. As an example, the Rosemount 1153 Series is ±0.5% reading/1000 psi. This term is in the same category as the transmitters reference accuracy, drift, temp. effects, etc., cannot be calibrated out and has to be included in the uncertainty calculation when appropriate.

When performing an uncertainty calculation for a device and differential pressure is applicable, each of the above three terms have to be considered. The first two have to be included in the uncertainty calculation if not calibrated out. The third item has to be included in the uncertainty calculation. When any more than one term is used in a calculation, the terms must be treated as dependent terms and added algebraically before being combined with the other uncertainty terms.

9.4.5 Overpressure Effect (OP)

The overpressure effect accounts for errors in a transmitter's performance after exposure to process pressures in excess of its normal design range. In general, the overpressure effect is not required to be included in loop error analysis. Most loops are designed to operate within their worst case process conditions, which include the worst case process pressure.

Overpressure can affect all types of transmitters. If the process pressure exceeds the URL of the transmitter during Normal or Accident operation of the plant, then the Overpressure Effect needs to be accounted for in the Analysis/Calculation.

Overpressure effects for differential pressure transmitters are not considered to occur from valving the transmitter into service. Plant procedures control the proper method of valving transmitters into service.

9.4.6 Power Supply Effect (PSE)

All electronic instrument loops are powered by low voltage power supplies designed to maintain the loop voltage and current for the loop devices. Power supplies vary from loop to loop with some supplied from unregulated sources while others have precision regulated supplies. Variations in the loop voltage can cause variations in an instrument's accuracy. This variation is called the power supply effect (PSE).

The instrument loops which contain transmitters are generally 4-20 mA current loops, which require a driving potential of 12 to 45 VDC. Selection of the power supply for a specific loop is based on the configuration of the loop, and the required voltages of the individual devices in the loop. Once set, the voltage is generally not changed unless loop performance is unsatisfactory.

The PSE is determined based on the variation in the power supply voltage. Consider the following example,

A Rosemount 1153D transmitter has a PSE value of less than 0.005% of output span per volt of change. For an unregulated power supply with a voltage variation of ± 4 VDC, the PSE becomes,

$$PSE = \pm (0.005\%) * (4)$$

$$PSE = \pm 0.02\% \text{ output span}$$

For instruments with regulated power supplies, the PSE may be negligible because the regulation keeps the voltage variations small. This, coupled with the generally minor effects of the power supply per volt, may allow the PSE to be ignored.

9.4.6 Power Supply Effect (PSE) (cont'd)

Since some loops may have unregulated power supplies, the PSE cannot be totally ignored for all loops. The variations in individual loop power supplies should be determined from the following sources:

[BNP, HNP	-	Vendor information for the applicable loop power supply.]
[RNP	-	Calculation RNP-E-1.005 can be used to determine the voltage variations for instrument busses. Other individual electrical calculations can be used for determining the variations of all other power supplies.]

The PSE s considered a random error due to the generally random variation in actual supply voltage. Where the PSE is found to be less than ±0.05% of span, the effect can be ignored. Since this is typically the case, if no device specific data for the PSE can be found, it can be ignored. If however, device specific information is found, it should be compared to the ±0.05% of span to determine whether or not it should be included in the uncertainty calculation.

9.4.7 Accident Effects

Instruments which can be exposed to severe ambient conditions as a result of an accident, and which are required to remain functional during or after an accident, may have additional accident related error terms which must be considered in a loop accuracy analysis. These additional terms account for the effects of extreme temperature, radiation, pressure, and seismic/vibration conditions.

Environmentally qualified (EQ) instruments make up the largest portion of the instruments exposed to severe ambient conditions. However, additional instruments may also exist, besides just the EQ instrumentation. The effects are generally applied only to the field mounted devices, but some accident related errors may also be experienced by other instruments in the loop. For example, a loop device mounted in a controlled environment which experiences a temperature rise after an accident due to changes in HVAC performance should be included in an accident error analysis.

The accident error effects are a separate set of accuracy values generally derived from the environmental qualification testing of an instrument. Based on this testing, manufacturers establish worst case performance specifications for the instruments. These specifications are based on generic accident temperature, pressure, and radiation profiles which envelope values at multiple nuclear facilities. As a result, the profiles are worst case conditions which should meet or exceed the specific design requirements at each of the NGG plants. Typically, Engineering will evaluate test data submitted by the vendor during the procurement process to ensure that vendor test data envelops site-specific design requirements.

9.4.7 Accident Effects (cont'd)

The applicability of accident error effects in a specific loop analysis is based on the loop's functional requirements. Accident error effects are time dependent, occurring from the initiation of an accident/event through long term recovery. The effects are normally not instantaneous. Many instrument loops, primarily those in the Reactor Protection System (RPS) and Engineered Safety Features Actuation System (ESFAS), meet their intended function before being significantly affected by accident environmental conditions. For such loops, the accident error effects may not have to be included in the analysis. Care must be taken, though, to ensure that all functional requirements are evaluated against potential accident conditions. Many loops perform accident mitigation functions (not requiring accident effect consideration) initially, and then perform additional post accident functions which require accident effect considerations.

For most instrument loops, the manufacturer's accident performance specification is utilized for the accident effects. When more specific Accident Effect (AE) data is available, more realistic terms can be developed. Accident error terms can be developed based on the actual qualification test results, and plant specific accident parameters. The extrapolation of accident terms should, where possible, be based on actual test data rather than being based on manufacturer's performance specifications.

However, care must be taken when reviewing, and establishing, specific accident effects based on actual test data. In general, the accuracy of test data is limited by both the number of tests performed, and the sample size (number of instruments tested). These limitations can lead to many unexplained variations in test results, and raise questions as to the validity of the test data. The use of actual EQ test data should be limited to cases where sufficient test data exists to clearly substantiate an interpolation/extrapolation.

The format in which the accident error is supplied can vary from manufacturer to manufacturer. One manufacturer may provide an uncertainty based on the consolidation of multiple accident effects (temperature, pressure, humidity, etc.). Another manufacturer may provide an uncertainty for each accident effect. If the accident effects are consolidated into one uncertainty value, it may be necessary to segregate the accident radiation effects from the other effects. This may be necessary if the device is in a radiation harsh environment only (i.e. it is not exposed to the other effects). It may also be necessary because the total of all accident effects results in an extremely high value, and are not all applicable to a specific application.

Following an accident inside containment , all of the accident effects except radiation will be present rather quickly. The radiation effect is typically contingent upon the total integrated dose (TID) rather than the dose rate, but on occasion can be contingent upon the dose rate. For those instances where the radiation effect is contingent on the TID, it may not become a significant factor until quite sometime following the accident. Once the radiation effect does become significant, the other

accident effects typically have been reduced to near normal conditions. Therefore, it may only be necessary to incorporate one of these effects, either the accident radiation effect or the combination of the other accident effects.

Evaluating the "timing" of the different accident effects, as discussed above, is normally done for Limiting Safety System Settings within an instrument loop. This method is employed to prevent inclusion of unnecessarily large uncertainties into the setpoint analysis. When the allowance between a setpoint and an analytical limit is increased to accommodate unnecessarily large uncertainties, the setpoint is moved closer to the normal operating range of the sensed process variable. This makes it more likely that a process transient, process noise, or spurious signal variation will cause an unwanted actuation under normal conditions and challenge plant safety systems increasing the risk of unwanted safety system actuation under normal conditions.

The increased risk of unwanted actuation under normal conditions is larger than any reduction of risk gained by accounting for uncertainties that are not expected to exist at the time of a trip.

If a manufacturer only lists one accident uncertainty and it is not necessary to segregate the individual effects, the effect will be referred to as the accident temperature effect.

1. Accident Temperature Effects (ATE)

Frequently, the ATE is the largest contributor to an instrument's inaccuracy during an accident. While a field mounted device, such as a transmitter, may be able to perform well under design temperatures of up to 200°F, an accident temperature of near 300°F can cause severe changes in performance. Typical inaccuracies of 5% to 10% are not uncommon.

The accident temperature effect (ATE) is generally obtained from the manufacturer's performance specifications. For a Rosemount Model 1153D transmitter, for example, the accident temperature effect (given as Steam Pressure/Temperature) is:

ATE = ±(4.5% Upper Range Limit + 3.5% span)

The specification sheet details the temperature, pressure, and duration of the test accident profile on which the performance is based. The actual worst case error can be calculated by substituting the upper range limit value for a specific transmitter, converting to percent span, then adding the 3.5% span. The temperature profile used by the vendor should be compared with the plant specific accident temperature profiles. The plant's specific profiles should be fully enveloped by the actual test profiles, or differences evaluated for acceptability, for the specification to be valid.

9.4.7 Accident Effects (cont'd)

The accident temperature profiles for each plant can be found in the documents identified below:

[BNP - Drawing D-3056 (All areas except Primary Containment and Reactor Building)

DR-227 (For Primary Containment and Reactor Building Areas)]

[HNP - Section 3.11B of the FSAR]

[RNP - Drawing HBR2-11260]

As another example, consider a Foxboro Model N-E11 transmitter, whose specification sheet shows three different error terms related to temperature. Each term is valid at a different temperature, causing the error term to change with time after an event. Based on the functional requirements of the specific loop, the accident temperature effect can be minimized since the error varies from ±8% to ±3% over the duration of the test.

The acceptability of a particular device's environmental qualification should be documented in a [BNP - Qualification Data Package (QDP)] [HNP, RNP – Environmental Qualification Data Package (EQDP)]. The applicable QDP/VQP/EQDP should be reviewed to ensure that all assumptions, constraints, etc. documented for the device's qualification are consistent with the device's usage and design basis. The EQ Program Manager should be notified if it is suspected that a device is required to operate in an accident environment but does not have a qualification package. If this suspicion is confirmed, then a Condition Report shall be initiated.

The components that have a qualification package are identified in PassPort Equipment Database (EDB).

The accident temperature effects are considered to be random error terms unless otherwise indicated by a manufacturer. When an accident temperature effect is included in an error analysis, the normal temperature effect (TE) would not be included in the portion of the calculation addressing accident effects. Note that an increase in the temperature may yield a Bias condition in a Reference Leg, for example, that needs to be accounted for.

2. Accident Pressure Effects (APE)

Accident pressure effects can occur for some instrumentation because of the large increase in ambient/atmospheric pressure associated with an accident. While most instrumentation is not affected by changes in atmospheric pressure, devices which use local pressure as a reference of measurement can be greatly affected. Of primary concern are pressure transmitters which may use the containment pressure as the reference atmospheric pressure. Loop error analysis must take into account the containment pressure over time following an accident for the transmitter. If the transmitter uses a sealed reference, the additional error will be minimized and may be ignored.

Accident pressure effects will generally not be included in an error analysis except for the reason cited above. The accident pressure effect is only to be included if specifically required by an instrument manufacturer. The effect can be treated as either a random error, or bias error, depending on the manufacturer's specifications, and the level of predictability of the error. In other words, for the example cited above, the error would be treated as a bias if it is known that the pressure increase causes the transmitter to read less than actual pressure.

The QDP/EQDP/VQPs should also be reviewed and evaluated when identifying the APE, as discussed above for the ATE. The accident pressure profiles for each plant are identified in the same documents that list the accident temperature profiles, as noted above.

3. Accident Radiation Effect (ARE)

High radiation levels caused by an accident are yet another effect which can greatly influence an instrument's accuracy. Electronic instrumentation may be affected by both the rate of radiation, and the total radiation dose to which it is exposed. In normal operation, radiation effects are small and can be calibrated out during periodic calibrations. Accident radiation levels can exceed an instrument's normal life time radiation dose by a factor of 10 to 100. This high radiation exposure can increase instrument error by as much as 10%.

Accident radiation effects are also determined as part of a manufacturer's environmental qualification testing. Generally, the effect is stated as a maximum error effect for a given integrated radiation dose, typically 10^7 or 10^8 Rads. The accident radiation levels used for testing are chosen so as to envelope maximum dose levels expected at a large sampling of plants.

Because of the irradiation process used in EQ testing, very little interpolation of error effect versus radiation is possible. When an instrument must function during or following exposure to high radiation levels, the manufacturer's performance specification values should typically be used. Comparison of manufacturer tested radiation levels to the plant specific radiation levels should be made, to ensure the dose rates and TIDs used for the tests envelope the plant profiles. These profiles are identified in the same documents as noted above that contain the accident temperature and pressure profiles.

The accident radiation effect is considered to be a random error component unless otherwise determined by a manufacturer.

4. Seismic Effects (SE)

Some instrumentation experiences a change in accuracy performance when exposed to equipment or seismic vibration. The vibration can cause minor changes in instrument calibration settings, component connections and/or sensor response. The seismic effect may have different values for seismic and post-seismic events. Care must be taken when establishing loop functional requirements so as to establish loop accuracy under the anticipated conditions. Refer to Generic Letter 87-02 Enclosure 1, for guidance concerning design basis accidents caused by or coincident with seismic events. Some of these scenarios are not within the licensing basis of our nuclear plants and therefore, consideration of both accident and seismic effects simultaneously may not be required.

The seismic effect is considered to be a random error term unless otherwise indicated by a manufacturer.

If the vendor specifications give an instrument uncertainty for seismic vibration, this uncertainty should be included in the uncertainty calculation unless the instrument is not used in an application requiring seismic qualification.

If the application does not require seismic qualification, then any seismic vibration induced uncertainty can be ignored.

If an instrument is used in an application requiring seismic qualification but no specific seismic uncertainty is specified by the vendor it is usually considered to be included in the reference accuracy term as long as the device is seismically qualified.

Assumptions concerning seismic uncertainties should be verified by contacting the instrument manufacturer if the specifications are not clearly understood. As noted earlier, it is essential that test data submitted or published by the vendor be evaluated to ensure that vendor test profiles envelop site-specific design requirements

9.4.8 Readability (RE)

In instrument loops in which the final output device is an indicator or recorder, the readability of the output device must be taken into account in the analysis. The readability of an analog indicator/recorder is based on the interval between scale demarcations. The indicator's/recorder's scale demarcations, and span, are used to define the readability of the device.

It is important here to differentiate the difference between the readability of the indicator/recorder for calibration purposes and its readability during operation. When calibrating an indicator/recorder, an input test signal will be provided by M&TE and the "output" will be directly read from the indicator/recorder. The output is typically aligned on the scale demarcations during the calibration process. If so, no additional M&TE error must be considered for reading the value. Otherwise, an additional readability error, as discussed below, must be considered for the M&TE error.

For an indicator/recorder, however, there is a separate readability that must be included for its use by an operator. An actual signal will not always line up on the scale demarcations. The operator is forced to interpret the indication as a function of how close the indicated signal is to the demarcations. Operator A may interpret the signal as closer to the higher demarcation, Operator B may interpret the signal to the lower demarcation, and Operator C may take the mean between the demarcations. Thus, an error is introduced into the total loop uncertainty based upon an individual operator's ability to interpret the indication. This is the readability uncertainty of concern.

For linear analog indicators and recorders, readability (RE) is generally defined as one half of the smallest scale increment, however 1/4 the smallest increment can be used if the increments are 1/2 inch apart or more.

$$RE = 1/2 \text{ smallest scale demarcation} \qquad \text{(Eq. 30)}$$

This definition is based on limited interpolation of process values between specific scale markings. This interpolation is limited by scale pointers, potential parallax, and operator judgment.

While some indicators and recorders may allow more detailed interpolation of readings between scale markings, it cannot be ascertained that an operator will accurately perform this interpolation on a consistent basis. The plasma type indicators are a good example. While the indicators are actually comprised of approximately 200 discrete scaled segments, an operator does not count the segments to determine a reading. Most readings are obtained from a distance which makes the segments indiscernible. Therefore, unless an instrument has a specific evaluation and justification identifying why its readability can be some other value, readability will be considered to be one-half the smallest increment scale.

9.4.8 Readability (RE) (cont'd)

Consider the following example,

A control board indicator displays a pressure signal. The indicator is scaled from 0 to 1000 psi and has minor scale marking every 20 psi. The indicator uses a pointer to show pressure, and it is located somewhere between 520 psi and 540 psi. Whenever the pointer is between scale markings, an operator reading the indicator generally only has the ability to determine one of three possible values for the parameter, 520 psi, 530 psi or 540 psi. The ability to interpolate more precisely than 10 psi is limited. The operator can judge whether the pointer is closer to the 520 psi mark or the 540 psi mark, or is approximately halfway between the two marks. The readability of the indicator is therefore 1/2 of 20 psi, or, 10 psi.

The readability defines the highest degree of accuracy (smallest error) that a loop can have through an indicator or recorder. That is, the smallest error for an instrument, or loop, cannot be less than the final output device's readability.

Indicators or recorders with digital displays do not follow the same definition of readability as analog displays. Since no scale is used for the digital display, no interpolation is necessary by an operator. The readability of digital displays is equal to the value of the least significant digit in the display.

Readability is typically considered a random error term.

9.4.9 Setpoints With A Single Side Of Interest

Setpoints which are approached from only one direction may have an adjustment applied which converts the uncertainty determined for a bidirectional approach to a smaller value which still retains the 95% confidence level determined for the bidirectional uncertainty. In these cases the critical region is a region to one side of the distribution, with an area equal to the desired level of confidence. The method to calculate these smaller uncertainty values is as follows.

For normally distributed 95% probability uncertainties, standardized area distribution tables, Reference 2.24, shows that 95% of the population will have uncertainties between ± 1.96 sigma, with 2.5% falling below -1.96 sigma and 2.5% falling above +1.96 sigma. If there are increasing and decreasing trip limits, the appropriate limits to use are ± 1.96 sigma.

For normally distributed uncertainties, the same tables show that 95% of the population will have uncertainties less than +1.645 sigma (50% below the median and 45% between the median and +1.645 sigma) and that 95% of the population will have uncertainties greater than -1.645 sigma. If interest is only in the probability that a single value of the process parameter is not exceeded and the single value is approached only from one direction, the appropriate limit to use for 95% probability is +1.645 sigma or -1.645 sigma as appropriate.

9.4.9 Setpoints With A Single Side Of Interest (cont'd)

Using this technique, a positive uncertainty that has been calculated for a symmetrical case can be reduced while maintaining 95% coverage of the population when a single parameter is approached from one direction. For example, if the original symmetric value was based on 2 sigma members, the reduction factor is 1.645/2.00=0.8225; if the original symmetric value was based on 1.96 sigma values, the reduction factor is 1.645/1.96=0.839. This adjustment is applicable only to random uncertainties which are normally distributed.

9.4.10 Vortex Considerations for Tank Levels

Level measurements can be effected by vortices when they form either by a mixing action such as in a blender, or by suction such as during a draining or pumping operation. When a vortex forms, the level measurement can become in error because the volume of liquid in the tank no longer conforms to the shape of the tank. If the level measurement depends on the height of liquid above a level tap located on the wall of the tank (DP or Pressure measurement) then a positive level error will exist with a magnitude dependent upon the severity of the vortex. If the level measurement depends on the distance between the sensor and the liquid surface (ultra sonic beam measurement) then a positive or negative level error could exist, or level detection could be lost, depending on the location of the sensor relative to the vortex. Other types of level measuring systems such as float switches, capacitance probes, or bubblers are similarly affected.

The main concern relating to vortices at nuclear power stations is that air would be sucked into the suction pumps (such as Safety Injection or AFW pumps) causing loss of suction during pumping operations if the switchover from tank supplied water to an alternate water source or makeup to the tank does not occur prior to formation of an air entrained vortex. Since loss of suction due to air entrained vortex formation is not acceptable, it is necessary to determine the level required that prevents vortex formation and then to use this minimum level as the analytical limit when determining low level setpoints for tanks.

Based on the above, it is generally not necessary to include vortex considerations as a level instrument uncertainty but it is necessary to consider vortex formation when setting analytical limits for tank low level setpoints. See section 9.8.1.2. When this information is required to be generated, the Mechanical discipline should be consulted and an approved input obtained for use as the low level analytical limit because other considerations besides vortexing may apply. The following general relationship is presented for information: (See attachment to letter CPL-89-634, HBR- The potential for formation of air entraining vortices in the Aux. Feed Pump Suction from the Condensate Storage Tank)

Harleman Equation: $S_c/d = 0.625\ FR^{0.4}$ where:

S_c = Critical submergence, or minimum level above the top of the intake nozzle which precludes the formation of air entraining vortices.

d = Diameter of the intake nozzle

FR = Froude number = $V/(gd)^{1/2}$

g = Gravitational constant

V = Fluid velocity into nozzle

9.5 Other Errors

In addition to the basic performance uncertainties of process measurement, external influences on the loop can affect accuracy. These influences are totally independent of loop process and instrument errors, but impart an additional level of uncertainty to a loop's measurement, and as such, must be considered in any error analysis calculation.

9.5.1 Calibration Errors

The cornerstone of all instrumentation performance, and accuracy, is the calibration process. The instrument and loop calibration(s) establish the baseline parameters necessary for accurate measurement and presentation of information. The calibration process consists of two important facets; 1) the calibration procedure itself, and the tolerances that are allowed in calibrating the device (or loop segment); 2) the measurement and test equipment used during calibration. Both of these directly affect the performance of an instrument and/or loop and are discussed in detail below.

1. Calibration Tolerances

The calibration process is used to adjust an instrument, or loop, to ensure that it functions within an acceptable set of limits. Calibration tolerances are the defined limits, above and below a desired value, within which an instrument or loop signal may vary and not require adjustment. Calibration tolerances are established to aid technicians in the calibration of instrument loops and devices. Adjustment to ideal values within the tolerance may or may not be attempted during calibration depending upon the standard calibration methods applied by the technicians.

For example, if a device has a reference accuracy of ±0.25%, requiring calibration of the device to a tolerance less than its reference accuracy (say ±0.1%) cannot increase its accuracy. Since the output of the device may vary continuously by ±0.25%, calibration adjustment of the device to tolerances set less than the RA would be futile in that the device cannot maintain calibration to these tight tolerances. Even if possible during the calibration process, the device cannot be assumed to maintain performance to these tight tolerances between successive calibrations. Therefore, the minimum requirement for calibration tolerance should normally be equal to the reference accuracy. In uniquely analyzed applications, AL and AF tolerances may be to set at values less than the RA based on conclusive past calibration data.

Calibration tolerances define for the instrument technician the acceptable band of operation for a device or loop. The calibration tolerance is defined for each calibration point of a loop. Usually, the calibration tolerance included within the loop uncertainty/setpoint calculation is obtained directly from the device's/loop's calibration procedure.

9.5.1 Calibration Errors (cont'd)

For the NGG plants, the calibration tolerances for a device are generally established within the calibration procedures as follows:

[BNP - MMM-002 describes how calibration tolerances should generally be established equal to a device's reference accuracy.]

[HNP - Ultimately the setpoint document specifies tolerances to a scaling document which specifies all tolerances for calibration procedures. Where there is no scaling document, the setpoint document or MMM-005 specifies a tolerance. Therefore, the list of priority is (1) Setpoint Document, (2) Scaling Document, (3) MMM-005, (4) MMM-04. MMM-005 also specifies device tolerances for generic device types for any devices which do not have a calculation or worksheet.]

[RNP - MMM-006 describes how calibration tolerances should be established in accordance with the type of device, and provides tolerances for specific device types.]

Calibration tolerances must be established for all instruments, devices, and loops, including setpoint bistable devices, and output indicators. The upper and lower setpoint limits, discussed later in Section 9.8.2.3, are tolerances.

The calibration tolerance does not necessarily have to be limited to a component's reference accuracy. Additional margin or tolerance is acceptable in selected instrument or loop calibrations, as long as the functional requirements can still be satisfied.

Thus, the Calibration Tolerance (CAL) can be defined as that uncertainty allowance that is applied to a loop error analysis to compensate for the reference accuracy (RA) of the instrument (or loop segment) which is being calibrated, as well as, for any additional potential calibration setting uncertainties allowed.

As described above, each plant has its own guidelines for establishing a calibration tolerance. However, each plant also has a policy that states that the measuring and test equipment error should be less than or equal to the tolerance of the device/loop being calibrated. While this policy is discussed further in Section 9.5.1.2 below, it directly affects the establishment of the calibration tolerance.

9.5.1 Calibration Errors (cont'd)

For each calibration, the calibration tolerance is used to account for the reference accuracy of a device. Thus, the error attributable to the test equipment should be less than or equal to the calibration tolerance of the device/loop being calibrated. If the test equipment error is higher than the device/loop being calibrated, two options are generally available - either utilize more accurate test equipment, or if this is impractical, increase the calibration tolerance.

Therefore, the guidelines for calibration tolerance should be as follows:

1. The measuring and test equipment accuracy should be better than or equal to the calibration tolerance of the device/loop being measured.

2. If the calibration tolerance is greater than or equal to the reference accuracy it may be used in place of the reference accuracy.

One assumption that is inherent in replacing the reference accuracy with the calibration tolerance is that the calibration process verifies all of the attributes of reference accuracy. As previously discussed in Section 9.4.1, the reference accuracy represents the combined effects of linearity, hysteresis, and repeatability. If the calibration checks multiple points along the span of the device, it verifies the linearity. If the calibration checks these points in both an increasing and decreasing direction, it verifies the hysteresis. If the calibration checks the points in both directions several (i.e., three or more) times, it verifies the repeatability.

All of the calibrations used for the NGG plants verify linearity, and most verify hysteresis; however, few verify repeatability. The individual calibration procedure should be reviewed to identify for each calibrated device, which specific attributes are verified during calibration.

If all of the attributes are not verified during the calibration, then the attributes that are not verified must somehow be compensated for within the uncertainty calculation. Reference 2.3 provides four separate ways of addressing this problem. Although any of the methods described in Reference 2.3 may be used, the simplest method is to include both the calibration tolerance and the reference accuracy within the uncertainty calculation. However, this may be too conservative an approach for many devices. An alternate method would be to assume that each of the three attributes affects the reference accuracy equally such that the SRSS of the three attributes would equal the reference accuracy,

$$RA = (x^2 + x^2 + x^2)^{1/2} \qquad \text{(Eq. 31)}$$

where x represents each attribute. If the calibration procedure did not verify one attribute, then the value for x could be substituted for the reference accuracy and used with the calibration tolerance. Similarly, if the calibration procedure did not verify two attributes, then the SRSS of x and x could be substituted for the reference accuracy and used with the calibration tolerance.

Consider the following example,

A transmitter has a reference accuracy of ±0.25% and a calibration tolerance of ±0.50%. The calibration procedure only checks 5 points of the transmitter's span in one direction.

If there is enough margin in the uncertainty calculation, both the reference accuracy and the calibration tolerance should be used. If not, the value that could be substituted for the reference accuracy could be determined as follows,

$$\pm 0.25\% \quad = \quad (x^2 + x^2 + x^2)^{1/2}$$

$$x \quad = \quad \pm 0.144\%$$

Since the calibration did not verify two attributes (i.e., hysteresis and repeatability), then the substitute reference accuracy term would need to account for both of these attributes.

$$\text{Substitute RA} \quad = \quad \pm(0.144^2 + 0.144^2)^{1/2}$$
$$\text{Substitute RA} \quad = \quad \pm 0.20\%$$

Thus, the uncertainty of the device would be determined by SRSS of the ±0.20% value for the substitute reference accuracy, the ±0.50% for the calibration tolerance, and any other applicable device uncertainty terms. It should be noted that not all terms are random. Only random terms are included in the SRSS calculation.

2. Measurement and Test Equipment

Measurement and Test Equipment is the general name given to all of the equipment required to calibrate instrumentation. The test equipment includes voltmeters, ammeters, resistance decade boxes, test gauges, test point or test resistors, deadweight testers, etc. All test equipment must be controlled and calibrated to known standards. The calibration of test equipment must be done using highly accurate precision standards which are traceable to the National Institute of Standards and Technology (NIST), formerly the National Bureau of Standards (NBS). This standardization provides known bases for test equipment accuracy, and allows for the.

determination of the test equipment effects on plant instrumentation. All test equipment used for the NGG plants is controlled by site-specific programs to ensure that traceability is maintained. Test equipment is periodically re-calibrated and verified to be within known limits. Each of the NGG plants has established a policy that requires all test equipment used in the calibration of instrumentation to be at least as accurate as the instrument being calibrated. For example, if an instrument has a reference accuracy of ±0.25% of span and is calibrated to ±0.25% of span, the combined accuracies of the test equipment used in calibrating the instrument must be less than or equal to ±0.25% of span.

The basic accuracy of test equipment is generally not documented in relation to the accuracy of the instrument or loop being calibrated. Instead, test equipment accuracy must be converted to an equivalent instrument or loop accuracy value, by factoring in the test equipment range in terms of the instrument (or loop) span.

Consider the following example,

A multimeter (MM) with an accuracy of ±0.25% of its range is to be used to calibrate a pressure transmitter. Transmitter span is 4-20 mA. The MM has a 0-20 mA and a 0-50 mA range. The accuracy of the multimeter can vary depending on the MM range used.

MM accuracy = (0.25% of MM Range)/(Transmitter Span)

Therefore, MM accuracy on the 0-20 mA range is,

$$\frac{0.25\% * 20\text{ mA}}{16\text{ mA}} = 0.31\%\text{ of span}$$

The MM accuracy on the 0-50 mA range is,

$$\frac{0.25\% * 50\text{ mA}}{16\text{ mA}} = 0.78\%\text{ of span}$$

As can be seen, the basic accuracy of the test equipment and the proper selection of test equipment range is important. The final test equipment accuracy, expressed in equivalent instrument or loop accuracy units, must have an overall accuracy less than or equal to the accuracy (i.e., calibration tolerance) of the device/loop being calibrated. Thus, for this example the calibration tolerance would have to be greater than or equal to 0.31% to account for the multimeter or, a more accurate multimeter used.

9.5.1 Calibration Errors (cont'd)

The Measurement and Test Equipment Error (MTE) is that uncertainty allowance included in the loop uncertainty calculation, to account for the uncertainty imposed into a loop component, or loop, as a result of the calibration using imperfect measurement and test equipment. The MTE term is, in essence, the uncertainties associated with measurement and test equipment used to calibrate the loop, or component. When a component is calibrated, the reference accuracy errors associated with the test equipment are imposed on the component. That is, reference accuracy errors associated with the test equipment are transferred to the loop component being calibrated. These additional errors bias the future performance of the component, after calibration. As such, the MTE error and the CAL, are conservatively treated as random, but dependent, terms. For conservatism, in the uncertainty analysis, these two terms would be algebraically combined with each other before being statistically (SRSS) combined with the other random terms.

In order to determine the MTE for a device/loop, the applicable calibration procedure should be reviewed. The calibration procedure will identify the test equipment to be used for the calibration. The test equipment may be identified specifically via manufacturer and model (i.e., Fluke 8600) or only generically as to type of test equipment (i.e., Digital Voltmeter). Typically, the MTE error is determined from the "worst case" accuracy for the types of M&TE specified, in order to provide the I&C technicians the most flexibility in performing the tests. If there is not sufficient margin in the total loop uncertainty to accommodate this flexibility, the MTE error can be calculated for specific M&TE. If this changes the calibration procedure, the plant I&C staff should be contacted and this matter discussed with them to ascertain if any other options are available.

When specific M&TE are required to meet instrument uncertainty needs, the test equipment should be evaluated to determine if it is subject to a temperature effect. This effect is the error caused by temperature on the M&TE accuracy. Some M&TE devices can be affected by the difference in temperature between the shop and the field. When this is the case the M&TE error should include an allowance for this temperature effect.

For new or revised loops, the calibration procedure may not exist prior to performing the uncertainty/setpoint calculation. In this case, the calculation should be developed using assumed test equipment that is used in similar types of existing loops. The assumed equipment must be identified to the preparers of the calibration procedure, so that such equipment, or better, may be incorporated into the calibration.

9.5.1 Calibration Errors (cont'd)

The listing of measuring and test equipment available for a plant and its associated accuracy, is maintained in the following locations:

[BNP - Test Equipment Room Bar Code Computer, kept by the Site Test Equipment Room Attendants.]

[HNP - Required Test Equipment Accuracy in MST and LP, as well as guidelines for determining, are in MMM-005, Instrument Loop Calibration Procedure.]

[RNP - The RNP Test Equipment Shop can provide a listing of the test equipment available at RNP and its associated range and accuracy.]

When multiple measurement and test equipment devices are used in the calibration of a component, the MTE error imposed on the component is determined by combining, using SRSS, the individual MTE errors associated with each individual M&TE device.

Consider the following example,

Assume a transmitter, with a reference accuracy (and calibration tolerance) of ±0.50% of span, is calibrated using a deadweight tester and a multimeter, each with a reference accuracy error equal to ±0.25%. The MTE error is:

$$MTE = \pm (0.25^2 + 0.25^2)^{0.5} = \pm 0.354\%$$

When combining the errors for test equipment, one device that is frequently overlooked is a test resistor. This includes any such resistors that may be installed in the loop to facilitate testing/calibration, as well as any resistors provided by the technician for performing a specific calibration. Whenever any such resistor is used as part of a device's/loop's calibration, it should be evaluated for inclusion in the determination of the MTE term. (Typically, the effect due to resistors accurate to ±0.01%, will be negligible.)

As an illustration of MTE error, consider a device used to measure an absolute value such as a primary standard, or to measure barometric pressure, at sea level, on a perfect day (29.92 in Hg = 0.000 psig). If this device has an accuracy of ±0.5% of span, then its output can vary by as much as 0.5% from its ideal value, with the input held at this absolute value. Therefore, the output has a bandwidth of 1.0% span, centered about the absolute value, see Figure 9-10.

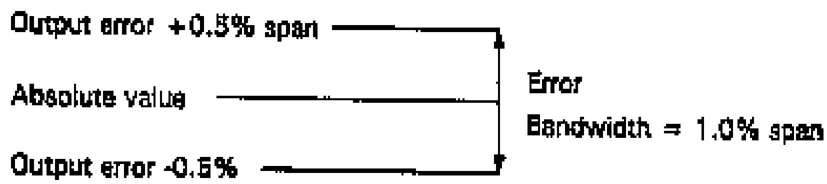


FIGURE 9-10
DEVICE ERROR BAND

Now, instead of an absolute calibration device, the device is calibrated using test equipment that has a combined error of ±0.25% of the device's span. The MTE error can bias the device's accuracy above or below the absolute value to a new reference value. In other words, if at the instant of device calibration adjustment, the test equipment output was +0.25% span, the device's error band would be adjusted such that it was centered on a new reference value -0.25% span below the absolute value. The device's error bandwidth is still 1.0% of span but it is now centered about the new reference value rather than about the absolute value. By superimposing the additional error on Figure 9-10, the result is shown in Figure 9-11. The device output deviates from the ideal by the amount of test equipment error. Note that comparison of Figures 9-10 and 9-11 reveals an increase in the error bandwidth when the effects of MTE are considered.

Like RA, MTE error is a random error, but due to the interdependence between MTE and CAL, it may be combined with CAL before being included in an overall error analysis.

MTE error must be considered for each instrument, or device, within a loop, which is calibrated independently. Generally, calibrations are performed device-by-device or by performing "string" calibrations of multiple devices at one time. The method of calibration selected determines how the MTE will be included in the overall loop uncertainty.

For example, if a loop contains 8 devices and each device is calibrated individually, the overall loop uncertainty must include provisions for 8 MTE errors. Each of these would be added to the calibration tolerance of the device and SRSSed with the other uncertainties. Alternatively, the calibration could be performed by a "string" calibration whereby all 8 devices would be treated as one device, with regard to the MTE. For this case, the overall MTE would only have to be applied once, thereby decreasing the total loop uncertainty.

9.5.1 Calibration Errors (cont'd)

The MTE, when applied to each component, can impose an excessively conservative penalty on plant operations. Implementing partial loop tuning of all components checked during a periodic calibration (i.e., after individual component calibration) or performing just a "string" calibration (i.e., not calibrating the devices individually) are two viable alternatives. These techniques minimize the number of times the overall MTE must be applied to the total loop uncertainty.

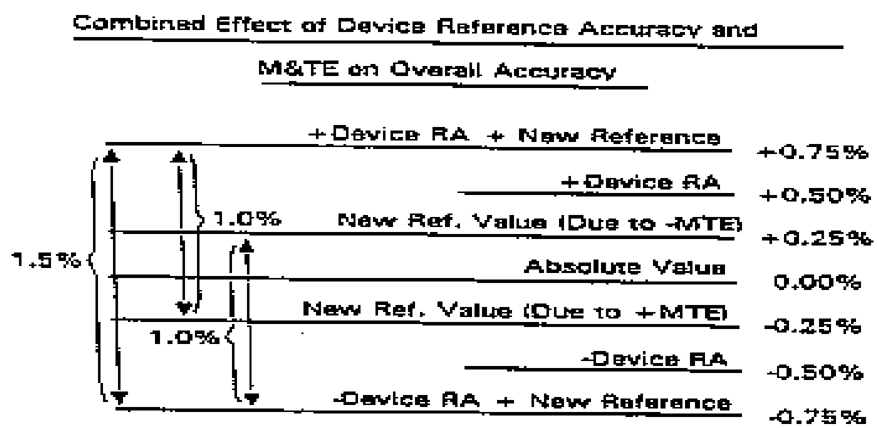


FIGURE 5-11
DEVICE ERROR BAND BIAS

9.5.1 Calibration Errors (cont'd)

In summary, the general rules for calibration error are:

- Calibration error, CAL, is typically equal to the RA for a device/loop, plus any additional tolerance deemed necessary to aid in the calibration of the device/loop.

- Component accuracies are conservatively considered to be dependent on the test equipment used to calibrate the component. Therefore, the applicable MTE error is normally algebraically summed with the CAL error prior to being combined with other loop errors.

- All MTE errors must be converted to units consistent with the loop error analysis.

- The MTE error should include the MTE_{in} and MTE_{out} as SRSS terms.

- The MTE error should be applied to each calibrated component, or group of components, in a loop depending upon whether the calibration is performed device-by-device or via a "string" calibration.

- If all of the attributes of a component's reference accuracy are not verified during its calibration, then the reference accuracy or a portion of the reference accuracy must be included in the uncertainty calculation as a random, independent term. If all of the attributes of a component's reference accuracy are verified during calibration, and the calibration tolerance is greater than or equal to the reference accuracy, then the reference accuracy term can be ignored.

- The MTE error should be less than or equal to the CAL error for a component, or group of components.

3. Calibration Temperature

The calibration temperature refers to the ambient temperature for an instrument at the time of calibration. The calibration temperature may be used as the initial temperature for determining errors based on temperature variation such as, instrument temperature effects, etc.

As discussed in Section 9.4.3, for error calculation purposes, an assumed calibration temperature (for example, 65-90°F) may be used on a case-by-case basis. If a calibration temperature is not assumed, the temperature effects are determined from the spectrum of design temperatures for a given location. If calibration procedures record the ambient temperature, then the mean temperature for previous calibrations can be used as the calibration temperature for calculation purposes.

9.5.2 Insulation Resistance Error (IR)

During accident conditions, when temperature, pressure, and humidity are well above their normal operating conditions for certain areas, electrical signal components can experience degradation in their electrical insulation. This phenomenon is known as Insulation Resistance (IR) Degradation, or IR loss. Such a reduction in IR can cause an increase in leakage currents between conductors, and terminals, of an instrument loop, resulting in potential degradation of loop performance.

In normal operation, changes in electrical insulation performance are so small that typically no effect on instrument loop performance can be seen. Even as the electrical signal component's (primarily cable, splices, and connectors) IR characteristics change with age, the periodic calibration process corrects the loop to eliminate any effects of leakage currents.

However, plant design basis accidents can impose extreme changes in ambient operating conditions on the components, primarily increases in ambient temperature and radiation. All electrical insulating materials experience some decrease in electrical insulation resistance properties with increasing temperature or radiation. The resulting decrease in electrical resistance, while not generally a concern for power applications, can cause significant changes in low level signal wiring or control loops.

The effects of IR can be determined by analyzing the changes in resistance, through the use of equivalent instrument loop circuit models. The following section provides a synopsis of the IR effects on various types of instrument loops.

1. **Current Loop IR Effect**

   The insulation resistance degradation of electrical signal components in an ungrounded instrument current loop causes an increase in the apparent signal for the loop. The loop signal current will increase as a result of reduced insulation resistance between the signal conductors of the loop. A leakage current between the conductors causes an increase in the signal current to the downstream loop devices. The magnitude of this leakage current, and that of the subsequent signal error, are directly proportional to the change in insulation resistance.

The magnitude of the IR error for an ungrounded current loop is directly affected by the following parameters:

- Loop supply voltage - The error is directly related to the value of the loop supply voltage. The higher the voltage, the higher the error is and vice versa.

- Loop load resistance - As the loop load resistance increases, the error is reduced.

- Loop current range - The error current generated is inversely related to the loop current. The highest error occurs at the minimum value of loop current.

- Cable length - The majority of the leakage current comes from the actual length of cable exposed to the accident environment. The shorter the cable length, the lower the IR error effect.

The IR error effect for an ungrounded current loop always causes an increase in current.

Since the IR error has a known effect on instrument performance, the IR error is considered a bias error, and as such, it must always be algebraically added to a loop's uncertainty. However, the IR error is a bias with known sign but unknown magnitude.

Many variables (environmental temperature, cable length, cable type, etc.) determine the magnitude of IR error, and it cannot be predicted to occur for every type of event. As such, IR error should be calculated as a "worst case" value for "worst case" conditions. [HNP, RNP - Generic IR calculations exist as part of the cable EQDPs and may be used for determining the IR error for the applicable instrument loops.]

The above discussion applies for the typical case where the loop is ungrounded. If, however, the loop is grounded, the IR degradation may cause either an increase or a decrease in the apparent signal for the loop, depending upon the specific circuit configuration.

2. RTD Loop IR

The degradation of electrical signal components in an ungrounded RTD sensing loop causes a different type of error than in the current loop. In the RTD loop, the total resistance of the RTD for a given temperature is known. Changes in the total resistance are assumed to be changes due only to changes in the RTD sensor as a result of temperature change. When the signal wiring also experiences a change in resistance characteristics between conductors, the loop mistakes this change for a change in sensor resistance. Changes in signal wiring IR will have the same effect as changes in sensor resistance. The signal wiring insulation provides a parallel resistance path to the RTD thus causing an apparent decrease in RTD sensor resistance as signal wiring IR decreases. Therefore as IR decreases, the loop will exhibit a negative error in measured temperature, since RTD resistance increases with temperature.

The magnitude of the IR error for an ungrounded RTD sensing loop is directly affected by the following parameters:

- Cable length - The majority of the leakage current comes from the actual length of cable exposed to the accident environment. The shorter the cable length, the lower the IR effect error.

- RTD values - The higher the RTD ice point resistance (R0, or resistance at 32°F), the higher the error.

- 3-wire RTDs vs 4-wire RTDs - A 4-wire RTD will demonstrate more IR effect error than a comparable 3-wire RTD, due to the increased leakage paths.

- IR effect error for an RTD loop is always a negative error.

Since the IR error has a known effect on instrument performance, the IR error is considered a bias error, and must always be algebraically combined with a loop's uncertainty. As discussed above for the current loop, the IR error is a bias with a known sign and an unknown magnitude. Thus, its value should be determined for "worst case" conditions.

The above discussion applies for the typical case where the RTD sensing loop is ungrounded. If, however, the loop is grounded, the IR degradation may cause either an increase or a decrease in the apparent signal for the loop, depending upon the specific circuit configuration.

9.5.3 Conduit Seal Effects (CSE)

In certain applications of high ambient temperatures, conduit seals may provide a current leakage path similar to that discussed above for insulation resistance. Depending on how the IR error is determined, the conduit seal error may be combined with the IR error or determined separately. Like the IR error, it will act as a bias and have the same effect on the loops as the IR error - acting as a positive bias for current loops and a negative bias for RTD loops. Loops susceptible to IR error should also be evaluated for conduit seal effect error.

9.5.4 RTD Lead Wire Effects (LW)

Resistance temperature detectors (RTD) can experience an additional error effect due to changes in the resistance of the signal wiring conductors. The effect, generally known as the lead wire effect (LW), is usually only significant on RTDs which use two (2) wires to sense RTD variation. To a lesser extent, the lead wire effect is apparent on three (3) wire RTDs, but the third lead eliminates most of the error.

In a two (2) wire RTD installation, the resistance temperature coefficient in the signal wiring can cause significant changes in total circuit resistance. This change in resistance appears as a change in sensed temperature. As the temperature of the signal wiring goes up, the wire resistance rises in the same manner as the RTD itself. The wire resistance is directly proportional to the length of the cable as well. Therefore, two (2) wire RTDs should only be used where required accuracy is not critical, or cable lengths are limited to a few feet.

As a general rule, three or four wire RTD's are used in applications requiring accurate temperature measurement. The four wire RTD does not experience any significant lead wire effect since it measures the voltage variation caused by the RTD.

The relevant points to remember regarding lead wire effects are:

- The lead wire error is a positive bias for the 2 wire RTD and may be either a positive or a negative bias for a 3 wire RTD.

- The magnitude of lead wire error increases with increasing cable length. For example, for a three wire RTD whose wires are all routed and terminated the same, the effect would be determined from the RTD cable length multiplied by three.

- The higher the RTD ice point resistance, the lower the lead wire error, for the same length/size of lead wire.

9.5.5 RTD Self Heating Effect (SH)

The measurement of the resistance of an RTD demands that a current be passed through the resistance element. This current produces heat that raises the temperature of the element and, therefore, its resistance. The self-heating error is the amount of resistance change, converted to degrees, and is typically stated by the manufacturer.

The magnitude of the self-heating error depends on the efficiency of heat transfer from the sensing element to the protective sheath and from the sheath to the medium being measured. The self-heating error is, therefore, much larger when the detector is measuring moving air than when it is measuring moving liquid.

The standard method of determining the self-heating error is to immerse the thermometer in a stirred constant temperature bath, usually an ice bath. The resistance of the bulb is measured at two levels of current and the wattage dissipated at each level of current is calculated. The self-heating error, SH, is then:

$$SH = \frac{1}{S} * \frac{(R_2 - R_1)}{(W_2 - W_1)} \qquad \text{(Eq. 32)}$$

Where,

S = Average slope of the calibration curve, in ohms/°C at the temperature at which the test is carried out.

R_1 = Resistance at the first level of current, in ohms

R_2 = Resistance at the second level of current, in ohms

W_1 = Wattage dissipated at the first level of current

W_2 = Wattage dissipated at the second level of current

The error is calculated in terms of °C/watt and must be converted to units of percent span.

The above discussion characterizes what the self-heating effect is and how it is determined. However, it should be noted that the effect is typically insignificant, relative to the other uncertainties.

9.6 Error Analysis

The analysis of instrument, and loop, uncertainty requires the application of probabilities and statistics to known instrument and loop errors. By defining each of the errors as either random or bias, as discussed in Section 9.2.5, one is able to apply the science of statistics to establish the cumulative effects of the errors. By using statistical analysis, truer relationships between probable errors and their resultant effects can be established. The statistical analysis of errors allows the determination of a total error effect based on both the magnitude of individual errors and the probability of their occurrence over time.

There are numerous methodologies within the science of statistics for analyzing data (errors). These methods include in depth analysis techniques (regression, partial derivatives, etc.) which are designed to predict the most probable value for a given set of numerical data. While the subject of probabilities is not the primary focus of this document, an understanding of the subject is necessary for instrument error analysis. The following sections discuss the primary methodology used in instrument error analysis. This methodology is based on accepted data analysis techniques, and has been endorsed by both the Nuclear Regulatory Commission, and the Instrumentation, Systems and Automation Society (formerly Instrument Society of America) (References 2.1 and 2.2, respectively).

9.6.1 Summary of Errors

Before discussing the methodology for combining the individual error terms, it is helpful to reiterate the individual error terms, and how they are applied. Described below is a summary of the types of errors that should typically be considered for the determination of instrument loop uncertainty. Other errors may also be applicable to individual loops, however, the errors described below represent the most common error types. This summary is derived from the discussions previously presented in Sections 9.3, 9.4, and 9.5.

Process Measurement Effects - Consider for each loop, including any primary elements such as flow orifices, venturies, etc.

Reference Accuracy - Consider for each device within a loop.

Drift - Consider for each device within a loop.

Temperature Effect - Consider for each device within a loop. Does not have to be included whenever an ATE value is used.

Static Pressure Effect - Consider for Differential Pressure transmitters that operate at high (i.e. > 200 psig) pressures.

Overpressure Effect - Consider only for pressure transmitters (including d/p).

9.6.1 Summary of Errors (cont'd)

Power Supply Effect - Consider for each device within a loop.

Accident Temperature Effect - Consider for each device within a harsh environment.

Accident Pressure Effect - Consider for each device within a harsh environment.

Accident Radiation Effect - Consider for each device within a harsh or radiation harsh environment.

Seismic Effect - Consider for each device within a loop that is designated Seismic Class 1.

Readability - Consider for each indication or recording device, including local gauges and digital displays.

Calibration Tolerance - Consider for each device within the loop or loop as a whole, as appropriate..

M&TE Uncertainty - Consider for each device within a loop that is calibrated. Include all M&TE used within the calibration.

Insulation Resistance Error - Consider for the portion of a loop within a harsh environment.

Conduit Seal Effect - Consider for the portion of a loop within a harsh environment.

RTD Lead Wire Effect - Consider for two or three wire RTDs.

RTD Self Heating Effect - Consider for RTDs.

9.6.2 Error Combination Methodologies

There are two primary methods of combining instrument and/or loop uncertainties: linear addition, and a simple statistical analysis called the Square-Root-Sum-of-the-Squares method. By combining these two methods, a third method can be defined such that random error terms are combined in the statistical manner and then algebraically summed with the bias error terms. This third method, or "combined" method, is the primary method used in industry for instrument loop error analysis. A fourth, but rarely used, method is one where individual device errors are determined from SRSS, and then the error allowance for each device is added together to yield the loop error. The three predominant methods are described below.

9.6.2 Error Combination Methodologies (cont'd)

1. Linear Addition

Combination of all component errors by linear addition is by far the most conservative approach to loop uncertainty analysis. By algebraically summing all of the error effects of each component for the most severe abnormal situations anticipated, a bounding total loop uncertainty can be generated. This large uncertainty, though, when combined with plant limits can reduce operating bands to such an extent that it will impact process limits and restrict the operational flexibility of a plant.

It is true that an instrument loop will always function within the boundaries established using the linear addition method. However, it is generally not cost effective to take the operational penalties associated with such a conservative analysis. The linear addition method essentially treats all errors as correlated (bias) terms, and does not take advantage of the statistical nature of random error components.

2. Square Root Sum of the Squares

Square-Root-Sum-of-the-Squares (SRSS) is a statistical method of combining multiple random errors for a device, or loop, in order to establish the total error attributable to all of the individual errors. The SRSS method accounts for the individual probabilities of random errors. The method is based on the knowledge that the probability of a group of random errors, each being at their maximum value, and in the same direction (i.e., + or -), simultaneously, as is assumed in the linear addition method, is extremely small.

The SRSS method of combining random error terms is a methodology accepted by the NRC as discussed in Reference 2.1. The methodology produces a resultant error value which has the same level of probability as the individual terms being combined. A pure SRSS equation considers that all uncertainty effects are independent and random.

Since all component errors are generally considered independent, personnel doing this type of analysis need only square each uncertainty term and take the square root of the sum.

The basic SRSS combination of error terms takes the form:

$$Z = \pm[A^2 + B^2 + C^2 + . . + n^2]^{0.5} \qquad \text{(Eq. 33)}$$

Where,

A, B, C, n - are random and independent error terms

Z - is the resultant uncertainty

9.6.2 Error Combination Methodologies (cont'd)

3. Combined Analysis Method

The combined method uses portions of both the linear addition, and SRSS methods for combining uncertainties. For the combined method, the individual random error terms are combined by SRSS to establish a single, resultant random error component. Linear addition is then used to combine all non-random (bias) terms to establish single positive, and negative, bias error components. The total error or uncertainty, is obtained by combining the random and bias components of error, as discussed in Section 9.2.5.

The basic formula for an uncertainty calculation takes the form of:

$$Z = \pm [A^2 + B^2 + C^2 + \ldots n^2]^{0.5} + L + M \qquad \text{(Eq. 34)}$$

Where,

A,B,C, & n - are random and independent uncertainty terms.

L & M - are, respectively, the positive and negative bias error terms (terms which are not random and independent, but which are dependent uncertainties, non-random, correlated, etc).

Z - is resultant uncertainty. The resultant uncertainty combines the random uncertainty with the positive and negative components of the correlated terms separately to give a final total uncertainty.

The random and bias components for each device in an error calculation must remain separate and distinct throughout each intermediate calculation step, except when determining a final total error. In addition, the bias errors of opposite signs (+ or -) must remain separate, since biases can contain uncertainties which vary in magnitude over time. In other words, a bias may not exist at all moments in time, or always be at its maximum value with respect to other bias terms. Therefore, the positive and negative bias terms must be kept separate in order to establish a worst case possible error. Bias terms of opposite sign cannot be assumed to offset each other, and thereby reduce total error. However, certain bias terms such as head effects, will always be present and are of known sign and magnitude. For these cases, the bias term could be used in the determination of both the positive and negative uncertainty terms.

In calculating the total error, the total bias error for a given direction is combined with the random error in that direction. This establishes a final set of upper and lower bounds of error for a group of individual error terms. The bounds represent the limits within which the total error for a group of individual errors will remain 95% of the time. (Assuming all random error terms were of 95% probability as discussed in Section 9.2.5.1).

9.6.2 Error Combination Methodologies (cont'd)

Consider the following example,

If we have a loop which contains the following error terms,

Process measurement error	= +0.5 (bias)
Transmitter accuracy	= ±0.25 (random)
IR error	= -1.2 (bias)
Indicator accuracy	= ±0.5 (random)

The total loop uncertainty, TLU, is calculated as:

$$TLU = \pm [0.25^2 + 0.5^2]^{0.5} + 0.5 - 1.2$$

$$= \pm 0.56 + 0.5 - 1.2$$

$$= +1.06 / -1.76$$

The total error is between +1.06 and -1.76 of the true value.

In determining the random portion of an uncertainty, situations may arise where two or more random terms are not totally independent of each other, but they are independent of the other random terms. This dependent relationship can be accommodated within the SRSS method by algebraically summing the dependent random terms prior to performing the SRSS determination.

An example is the dependent relationship between MTE error and CAL error, as discussed in Section 9.5.1.2. The formula would take the following form:

$$Z = \pm [A^2 + B^2 + C^2 + (D+E)^2]^{0.5} + L+M \qquad \text{(Eq. 35)}$$

Where,

D, E - are random, dependent uncertainty terms that are independent of terms A, B & C.

The combined analysis method can be used in the calculation of either a device uncertainty or a total loop uncertainty. The results are independent of the order of combination as long as the dependent terms, and non-random terms are accounted for properly. For example, the uncertainty of a device can be determined from its individual terms, and then combined with other device uncertainties to provide a loop uncertainty. Or, all of the specific device terms for each device in the loop can be combined in one loop uncertainty formula. Either way, the result will be the same. The specific groupings of an uncertainty formula can be varied for convenience of understanding

.

9.6.3 Instrument/Device Uncertainty Equations

Using the basic analysis methods discussed above, the uncertainties introduced into a loop measurement signal, by the individual instruments/devices within a loop, can be determined. The effect that a device has on a measurement signal is dependent on both the mathematical relationship between the input and output signals, and the amount of additional error the device imparts on the signal due to its own inherent error effects.

Loop devices such as amplifiers, multipliers, and square root extractors each impart a predictable level of error into a measurement. Non-linear devices, such as a square root extractor, not only increase potential error but can cause extreme variations in total error, due to mathematical manipulation of input error as part of the signal.

To aid in the development of actual loop error analysis, instrument/device uncertainty equations have been developed for the common devices. The equations define the output error, or uncertainty of a device based on its function, input error, input signal, and accuracy. These equations are intended to be used in the development of specific loop error analyses for the plants, as needed.

In the uncertainty equations contained in this section, the following codes are used:

A, B	=	Input signal(s) to the device
a, b	=	Uncertainty in the input signal(s)
C	=	Output signal from the device
c	=	Uncertainty in the output signal
e	=	Inherent uncertainty of the device
k1, k2	=	Gain of the device inputs

1. Signal Converter

The term, "signal converter" alludes to any loop transducer having an overall gain equal to unity (1.000), and an error free transfer function of:

Output = (k)[Input]

$C = k \bullet A$

The output uncertainty (c) for signal converters is expressed as:

$$c = \pm (a^2 + e^2)^{0.5} \qquad \text{(Eq. 36)}$$

The output uncertainty equation is applicable to any component having a gain (k) equal to 1.0. All errors are expressed in terms of percent span.

Typical applications are transmitter, indicator, and isolation/buffer amplifier output uncertainties.

2. Linear Signal Devices

These are single input, fixed gain devices such as a common amplifier or ratio station. Linear signal devices have an error free transfer function of:

Output = (k)(Input)

$C = k \bullet A$ (From Section 9.6.3.1)

The output uncertainty (c) for linear devices is expressed as:

$c = \pm [(ka)^2 + e^2]^{0.5}$ (Eq. 37)

This statistical uncertainty equation is applicable to any component having a fixed gain, where gain, k, is expressed as a multiple or fraction of 1.0, or unity gain. All errors are expressed as percent span. Any errors associated with the function of the device are included as part of the inherent device uncertainty (e).

3. Multiplier

This type of device not only changes the amplitude of the input by a factor of the gain, but also by a factor proportional to the amplitude of a second input. The module has individual gains for each input. The module has an error free transfer function of:

Output = (k1)(Input 1)(k2)(Input 2)

$C = (k1A)(k2B)$ (Eq.38)

The output uncertainty (c) for multipliers is expressed as:

$c = \pm [(k1k2Ab)^2 + (k1k2aB)^2 + (k1k2ab)^2 + e^2]^{0.5}$ (Eq.39)

4. Divider

A divider is used for applications such as a differential pressure signal which needs to be corrected for density changes in the flowing fluid, or liquid level. The error free transfer function of a divider is:

Output = (k1)(Input 1)/(k2) (Input 2)

$C = (k1A)/(k2B)$

The output uncertainty (c) for dividers is expressed as:

$c = \pm\ k1/k2B(B^2\text{-}b^2)\ [(aB^2)^2 + (abB)^2 + (ABb)^2 + (Ab)^2 + e^2]^{0.5}$ (Eq. 40)

5. Square Root Extractor

A square root extractor module has a fixed gain of unity, and its output is the square root of its input. The error free transfer function of this module is:

$$\text{Output} = (\text{Input})^{0.5}$$

$$C = (A)^{0.5}$$

The output uncertainty (c) for square root extractors is expressed as:

$$c = \pm\ [(a/2C)^2 + e^2]^{0.5} \qquad \text{(Eq. 41)}$$

The user of this equation should be aware that better error models are available and may be applicable for use.

6. Summing Amplifier

A summing amplifier is a very high gain operational amplifier with a summing junction (resistor network) connected in front of its input. The gain factor (k1, k2, etc.) for an individual input is controlled by selecting an input resistor such that the feedback resistor value divided by the input resistor value provides the desired gain. The error free transfer function of a two input summing amplifier is:

$$\text{Output} = (k1)(\text{Input 1}) + (k2)(\text{Input 2})$$

$$C = k1A + k2B$$

The output uncertainty (c) for summing amplifiers is expressed as:

$$c = \pm\ [(k1a)^2 + (k2b)^2 + e^2]^{0.5} \qquad \text{(Eq. 42)}$$

The output uncertainty equation is applicable to any device required to add, subtract or compare two or more input signals. As a summer, the output signal will be equal to the algebraic sum of the input. In the case of a comparator (bistable), one signal (A) is a constant or variable (setpoint) with polarity opposite that of the process variable signal (B). The switching device is energized or de-energized when the two opposing signals approach the same amplitude.

9.6.3 Instrument/Device Uncertainty Equations (cont'd)

7. Characterizer (Function Generator)

A characterizer module approximates a nonlinear mathematical function using multiple straight line segments. To operate on each segment of the nonlinear input, an adjustable gain (k1, k2, . . . kn) control is provided for each segment, and a separate gain (k0) is provided for the output amplifier. Therefore, the error free transfer function is:

Output	=	k0[k1(Input to segment 1) + k2(Input to segment 2) +. . . + kn(Input to segment n)]
C	=	k0[k1A1 + k2A2 + . . . + knAn]

where, segment input (A1, A2, . . . An) is defined as the total input value minus the low breakpoint value of that segment.

It is important to note that when a specific function segment is in operation, only the gain for that segment of the function curve is to be used for error quantification. All other segments are not in operation, and thus the gains are zero.

The output uncertainty (c) for characterizers is expressed as:

$$c = \pm\, [(k0\ k1\ a1)^2 + (k0\ k2\ a2)^2 + ... + (k0\ Kn\ an)^2 + e^2]^{0.5} \qquad \text{(Eq. 43)}$$

For a characterizer, the errors associated with the segmented curve fit are included as part of the device error term (e).

8. Controllers

Controllers by nature of their function, continuously correct a process to eliminate what they see as errors between a measurement and a setpoint. The basic purpose of a controller is to force the measured variable to match the setpoint value, such that the setpoint minus measured value is equal to zero. Controllers will normally not impart additional significant error uncertainty into a loop unless improperly calibrated or tuned. The controller uses both internal and process measurement feedback to continually adjust its output signal, and related control elements to force the detected error to zero.

9.6.3 Instrument/Device Uncertainty Equations (cont'd)

Error in the measured variable used by the controller can cause significant errors in a controller's final control point. However, the error present in the measured variable signal cannot be detected by the controller. Therefore, it becomes a proportional error in the final control point. If a measured variable contains a +1% error, the controller will decrease the variable by an amount equal to the error (-1%), and vice versa, due to negative feedback. Once corrected, the final control point will be -1% below the actual desired point of control. The error could not be reduced unless a separate measurement loop, with no error, were available to check the actual control point.

9.7 Establishment of Uncertainty Allowances

All of the potential error effects for a loop must be evaluated, and applicable ones incorporated into a loop error analysis. The analysis may cover the total loop from process to final output device, or only that portion of a loop needed to perform a specific function. The loop error analysis will establish the total uncertainty in a loop's measurement under the conditions of concern. From the total uncertainty, allowances can be established and used to delineate the required control limits. These allowances define the boundaries of uncertainty a loop can possess under various operating conditions. Allowances are used to define the acceptable levels of performance an instrument/loop must meet to satisfy its functional criteria.

9.7.1 Graded Approach

Apply a graded approach for the reconstruction of setpoints at the Nuclear Plants. The concept behind "Graded Approaches to Setpoint Determination" is that all of the rigor and conservatism established in Ref. 2.3 is not warranted for all safety related setpoints in a Nuclear Plant. This graded approach consists of defining a classification scheme and then establishing a corresponding level of rigor for each of the different classification schemes.

All setpoints that have to be reconstructed will be reviewed on a case by case basis. While all uncertainties that effect the performance of a component shall be accounted for, a broader application of assumptions may be utilized to reduce unnecessary engineering effort for some categories of setpoints.

This determination of what a setpoint uncertainty calculation will consider should include, but not limited to the following: Safety Classification; Operational aspects; and Consequences of exceeding limits. The design engineer in conjunction with his/her supervisor will make these basis decisions before the calculations are started. Setpoints which should be eligible for less rigorous treatment are those not explicitly credited for in statistical/analytic plant design (accident) analyses, but are instead based on utility, industry and/or vendor experience, consistent with engineering judgment.

Documentation for the calculation can take the form of a formalized calculation, an EC response, or a data sheet that shows the basis for the setpoints.

9.7.2 Conditions for Which Uncertainty is Determined

For the NGG plants, three design bases conditions of operation have been established for which instrument accuracy should be determined. The three conditions, calibration (reference), normal, and accident, define the bases and limits of the plant process, and environmental conditions, under which instrumentation must function. The three conditions are shown pictorially in Figure 9-12.

1. Calibration Conditions

The calibration conditions are, essentially, the conditions under which an instrument/loop provides its highest degree of accuracy. Typically, no operational influences are imposed on the loop under these reference conditions. For calibrations, all ambient environmental parameters are considered to be within an instrument's/loop's relatively narrow range of reference operating limits. This accuracy is that of a loop immediately after calibration.

2. Normal Conditions

The normal conditions define the environmental conditions under which an instrument/loop must function during normal plant operation. This condition includes anticipated operational occurrences, but does not include design bases accident conditions. The normal conditions are defined as the normal condition maximum values.

3. Accident Conditions

The accident conditions define the maximum or worst case process and environmental conditions under which an instrument/loop must function. This condition includes those uncertainties expected to exist at the time of a trip or indicator based action. The accident conditions are defined in each plant's FSAR.

9.7.3 Loop Error Determination

The calculation of instrument loop error must utilize a clear, and straightforward process. The calculation should coincide with a loop's layout from process measurement to the final output device(s) of concern. The terms for each device in a loop must be clearly identified and classified for proper inclusion in the error formula. For the NGG error calculations, a set of standard abbreviations has been developed to identify the various error components of a loop. This nomenclature is provided in Section 3.0 of this document. All calculations should use these abbreviations for consistency and ease of identification of terms contained within this procedure.

9.7.3 Loop Error Determination (cont'd)

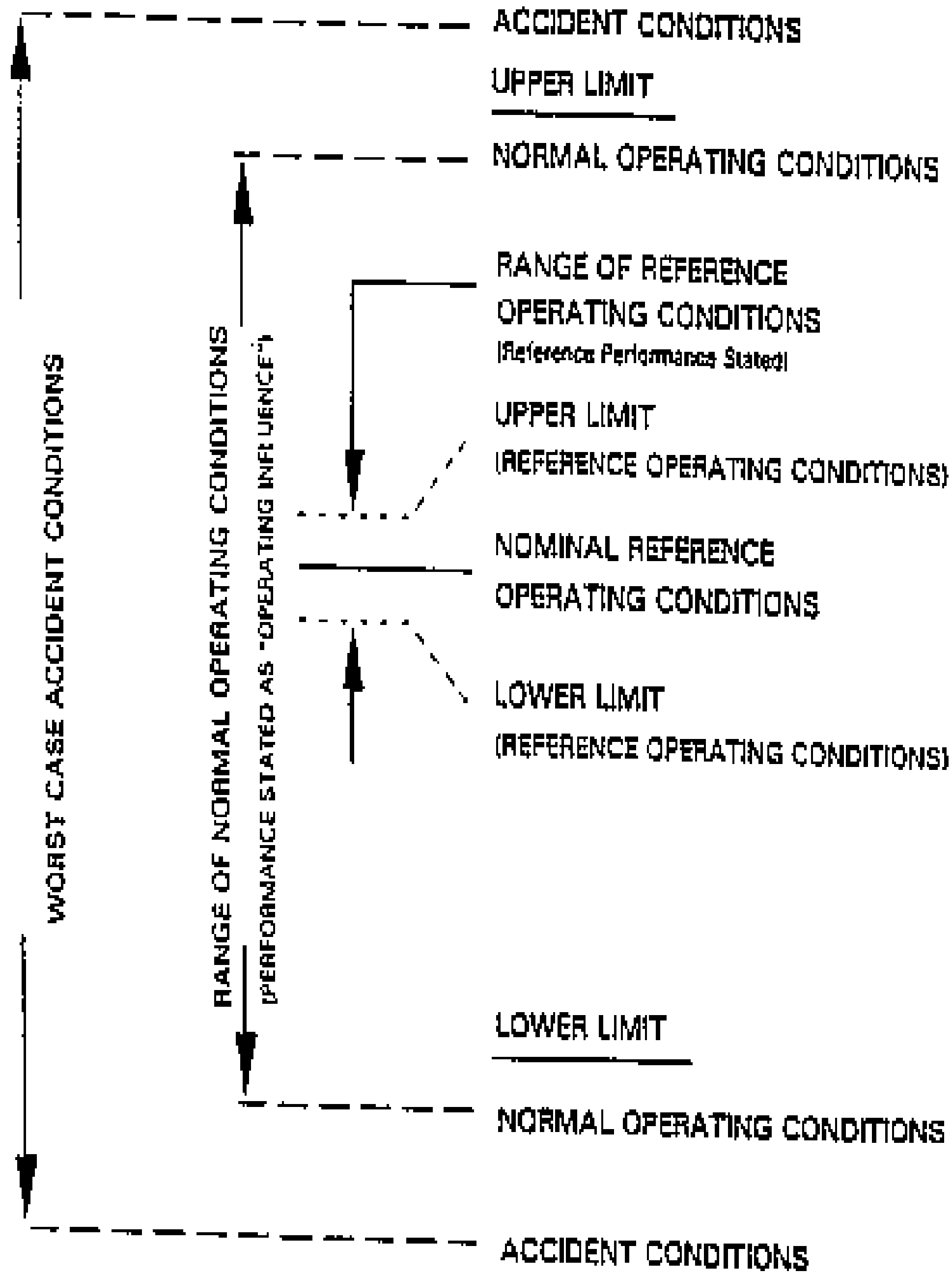


FIGURE 9-12
DIAGRAM OF INSTRUMENTATION OPERATING CONDITIONS

9.7.3 **Loop Error Determination** (cont'd)

The basic process for calculating loop errors will involve the separate calculation of individual device uncertainties, and the calculation of partial loop error values at the output of each loop device. This process is shown graphically in Figure 9-13.

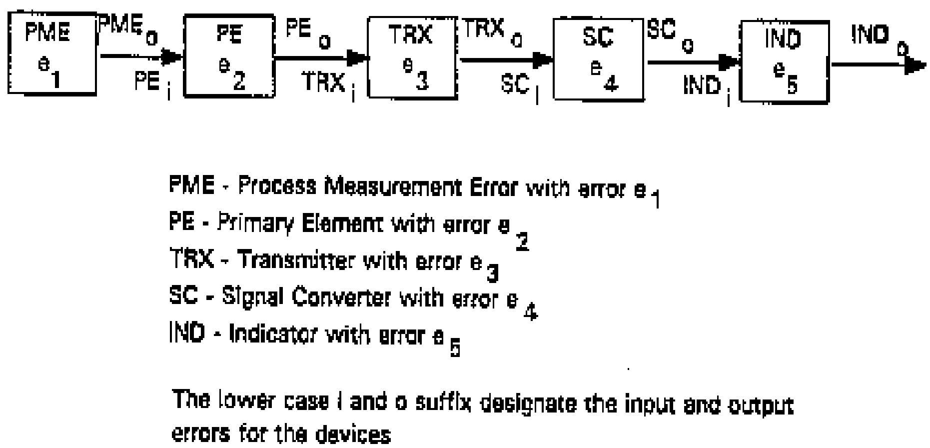


FIGURE 9-13
TYPICAL LOOP ERROR DIAGRAM

A loop error analysis should always start with an evaluation for process measurement errors as discussed in Section 9.3. Even if no process measurement error exists, a statement to that affect should be noted in the calculation. The process measurement error (PME), e_1, would take the form of,

$$e_1 = \pm PME + PMEb^{+} - PMEb^{-} \qquad \text{(Eq. 44)}$$

Where,

± PME	-	are the random components of PME, if any
PMEb	-	are the bias error portions of the process measurement, if any

Bias error term abbreviations will use a lower case "b" as a suffix to designate bias. Random error term abbreviations will not have a random suffix designator.

9.7.3 Loop Error Determination (cont'd)

Since PME is the starting point of the loop analysis,

$$PMEo = e_1$$

In general, no additional error will exist between PME and the primary element (PE). Therefore,

$$PEi = PMEo$$

The PE error, e_2, would then be calculated,

$$e_2 = \pm[RA^2 + (\text{other error effects})^2]^{0.5} + PEb^+ - PEb^- \qquad \text{(Eq. 45)}$$

Where,

RA - is the primary element's reference accuracy
PEb - are the bias error portions of the primary element, if any.

The PE error, e_2, would then be combined with the PEi error to establish the primary element output error, PEo.

$$PEo = \pm [PEi^2 + e_2^2]^{0.5} + PMEb^+ + PEb^+ - PMEb^- - PEb^-$$

If no additional error is identified between the PE and the transmitter (TRX), then

$$TRXi = PEo$$

The TRX error, e_3, would then be calculated from an equation such as,

$$e_3 = \pm[(MTE + CAL)^2 + DR^2 + TE^2 + RA^2]^{0.5} + TRXb^+ - TRXb^- \qquad \text{(Eq. 46)}$$

The actual error components which make up the total transmitter error will vary based on functional requirements, and reference operating conditions. The individual error components are discussed in Section 9.4. For this discussion, we will assume that no bias error exists for the transmitter, thus allowing the bias terms to be dropped from Equation 46.

9.7.3 Loop Error Determination (cont'd)

The TRX error, e_3, would then be combined with the TRXi error to establish transmitter output error, TRXo. The transmitter device equation from Section 9.6.2.3 is used to combine the errors.

$$TRXo = \pm[TRXi^2 + e_3^2]^{0.5} + PMEb^+ + PEb^+ - PMEb^- - PEb^- \qquad \text{(Eq. 47)}$$

The output error of one device will generally equal the input error of the next device in a string. The exception occurs when an additional error term such as IR comes into play between two devices. In this situation, the signal conditioning equipment input (SCi) is,

$$SCi = TRXo + IRb^+ \text{ (or } - IRb^-\text{)}$$

In an actual loop analysis, only one IRb component would exist (+ or -) since IR does not exhibit both a positive and negative component for the same loop.

The process of calculating individual device error terms and combining them with the partial loop error term would continue through to the device of concern.

Assuming no bias errors existed for SC and IND,

$$INDo = \pm[INDi^2+e_5^2]^{0.5} +IRb^+ +PMEb^+ + PEb^+ - PMEb^- - PEb^- \text{ (Eq. 48)}$$

All loop and device error terms shall be expressed in the same basis (i.e. units) prior to combining the error terms. Typically, the simplest basis to express the errors in is percent of span. Careful evaluation of the individual error terms is required to ensure that consistent units are maintained throughout the calculations. Examples of various expressions of error terms and conversion values for percent of span are shown in Sections 9.3 through 9.5. Attachment 3 shows techniques for converting from other bases to percent span.

If it is questionable whether a particular module or uncertainty is applicable because it may not have an appreciable amount of error associated with it, the calculation does not need to consider the term as long as acceptable justification is documented within the calculation for the term's exclusion. Due to the statistical nature of combining the errors, if a random independent uncertainty is one-fifth or less than the largest random independent uncertainty, it may be disregarded. However it is important to document within the calculation why it can be disregarded.

When a loop contains a non-linear device, the loop errors must be calculated for specific values of span downstream of the non-linear device. For a non-linear device, such as a square root extractor, the output error is proportional to the magnitude of the true signal. This non-linearity can be seen in the example below.

9.7.3 Loop Error Determination

EXAMPLE:	Assume we have a flow measurement loop containing a square root extraction module. The loop is calibrated such that an output signal of 0-4000 GPM is generated for an input of 0-100 in WC.

The basic flow to differential pressure relationship is:

$F = k(DP)^{0.5}$

where, k is a constant for a particular loop.

For this example k is:

$k = F/(DP)^{0.5} = 4000/(100)^{0.5} = 400$

Now if we have an error in the measurement upstream of the square root extractor, this error is seen as a change in the DP input.

Using the basic flow/DP relationship, a table can be made showing the effect of a +2% DP span error on the flow measurement.

Factual (GPM)	F (% flow)	D (inWC)	DP (% DP span)	DP+2% error (inWC)	F reading (GPM)	F error (% flow span)	F error (% reading)
0	0	0	0	2	565.7	14.1	8
800	20	4	4	6	979.8	4.5	22.5
2000	50	25	25	27	2078.5	2.0	3.9
3200	80	64	64	66	3249.6	1.2	1.6
4000	100	100	100	102	4039.8	1.0	1.0

Note that as the true flow signal increases, the effect of the constant +2% DP span error decreases due to the basic non-linear function of square root extraction. Therefore, the error in the output of a non-linear device should be calculated for specific values of output span unless the largest error of the span is used.

9.7.4 Uncertainty Allowances

The uncertainties determined to exist in a loop are used to establish allowances for that loop. The allowances define the bounds within which a loop and/or its components can operate and still satisfy their design functions. Multiple allowances exist for each instrument loop. These allowances, also known as tolerances, or performance limits, are provided to aid in the calibration, and maintenance of the instrument loop.

1. Tolerances

Tolerances, as discussed in Section 9.5.1.1, are allowances established on specific loop components, groups of components, or the total loop, and which are used to aid in the maintenance and calibration of the loop. Tolerances define the limits to which an instrument loop must be calibrated to assure proper loop function. Tolerances allow for the basic inaccuracy of a device, or group of devices, and establish the acceptable level of performance of the components being calibrated. Tolerances are defined under the reference conditions only, since calibration is performed under these conditions. For an instrument loop, the various tolerances are,

- Device Tolerance - the calibration tolerance of a specific component or device within a loop. The device tolerance is equal to the reference accuracy of the device, plus any device setting tolerance.

- Loop Tolerance - the total loop calibration tolerance which defines the basic accuracy of a loop. The loop tolerance is established based on the calibration tolerances of the devices which make up the loop.

- As-Found Tolerance - the generic term given to the bounding tolerance allowed between calibrations of a defined device, loop segment, or loop. The As-Found tolerance establishes the limit of error the defined device(s) can be found to have during surveillance testing, and still be considered to be in calibration. The As-Found tolerance accounts for the calibration tolerances, drifts, and M&TE uncertainties of the device(s) under test. Note that if only the rack instruments through the final device is being tested, the sensor uncertainties should not be included.

- As-Left Tolerance - the generic term given to the calibration tolerance allowed for a defined device, group of devices or loop. For a single device, the As-Left tolerance is the same as the device tolerance discussed above. For a total loop, the As-Left tolerance is the same as the loop tolerance discussed above. The term is also commonly used to define the calibration tolerance allowed in a loop segment which is periodically tested. The As-Left tolerance accounts for the calibration tolerance of the loop segment. The As-Left tolerance establishes the required accuracy band within which the loop segment must be calibrated.

2. Loop Allowances

An understanding of the concepts of allowances, and tolerances, in instrument loops is essential to understanding loop performance, and capabilities. The allowances, and their associated limits, establish the performance characteristics of an instrument/loop, which in turn establishes the design relationships between the loops and plant control.

a. Basic Relationships

Figure 9-14 shows the basic relationship of allowances for a typical instrument or loop. In Figure 9-14, the horizontal center line marked "desired value" represents a measurement value without error. This desired value could be the output of any device, group of devices, or loop. The true output will vary about the desired value based on the accuracy of the device(s). This variance is encompassed by the As-Left tolerance for the device(s). For a general measurement process, the As-Left tolerance is typically applied both above, and below, the desired value, since the true output varies randomly about the actual value.

The As-Left tolerance is normally equal to the reference accuracy, or the combination of reference accuracies for the device(s). A device setting tolerance, which is a value used to increase a device tolerance above the reference accuracy, may also be applied as desired. However, for the remaining discussions, no device setting tolerances will be assumed to exist.

9.7.4 **Uncertainty Allowances** (cont'd)

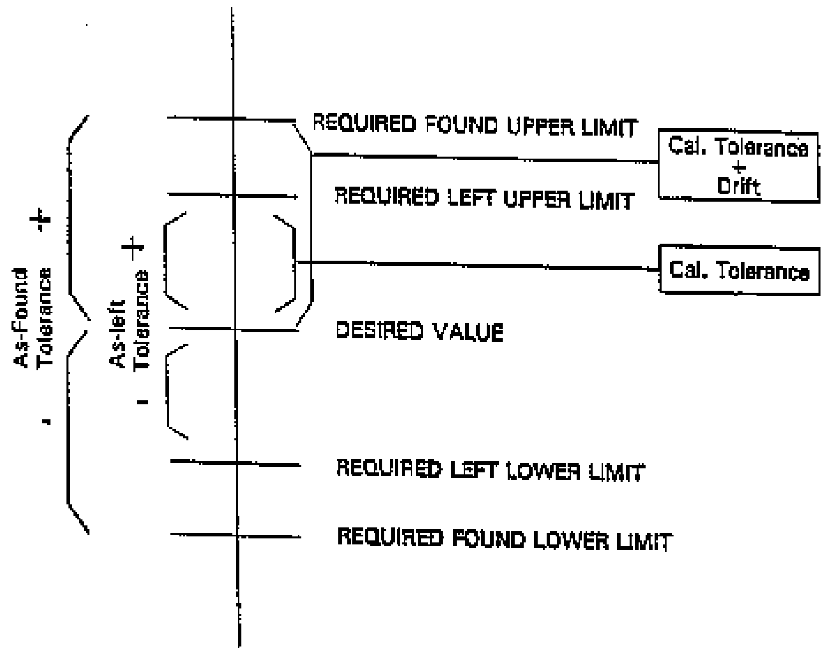


FIGURE 9-14
TOLERANCE RELATIONSHIPS

The As-Left tolerance provides calibration personnel with a measurable calibration band, within which the device(s) must be adjusted. In addition, the As-Left tolerance allows a set of acceptable performance limits to be set, against which actual performance can be monitored. The acceptable performance limits are actually beyond the As-Left tolerance by an amount equal to the MTE error effect.

As discussed in Section 9.5.1.2, the MTE error effect is an error due to calibration equipment inaccuracies, which is not discernable to a calibration technician. As such, it cannot be eliminated. Therefore, actual performance limits for the device(s) being calibrated are equal to the As-Left tolerance plus MTE effect. The acceptable performance limits define the true uncertainty in an output for plant reference conditions (i.e. the highest accuracy obtainable). However, the device(s) must be left within the As-Left tolerance band, as indicated by the technician's MTE. If the performance of the device(s) remains within these limits, no further calibration adjustment would be required. Device(s) found outside of the As-Left tolerance would require recalibration to bring the errors back within the tolerance.

Because all devices experience drift, as discussed in Section 9.4.2, the additional tolerance value of As-Found has been created. The amount of drift applies only to that which can occur between successive periodic calibrations. The As-Found tolerance establishes what can be called "required limits of performance" on the device(s). These required limits define the maximum amount of error allowed during normal plant operation. Any device whose error exceeds the As-Found tolerance should be evaluated for possible corrective action. The As-Found tolerance can provide a means to verify the operability of the device(s), at any time after calibration.

The As-Found tolerance, as indicated, includes the As-Left tolerances (usually equal to the Reference Accuracy), the MTE error, and the drift (DR) of the device(s), and are combined as discussed in Section 9.5.1.1. If the equipment is tested on a frequency greater than the normally scheduled calibration intervals, the drift can only account for the time between successive surveillance tests. For many safety-related loops, the surveillance test for accessible components, such as those located in the rack, are required to be performed on a monthly basis.

It is important to note that As-Left and As-Found tolerances can be established for a single instrument, or device, a select group of devices, or a total loop. The tolerances only encompass inherent instrument inaccuracies, and do not account for inaccuracies caused by varying external influences (i.e., ambient environment effects, PME, IR, etc.).

[BNP - Only one tolerance is typically provided within the calibration procedures (MSTs, PICs, LPs), and it represents the As-Left tolerance. A separate As-Found tolerance for each device being calibrated is usually not delineated within the procedures. Instead, the procedures specify that any device found to be outside the (As-Left) tolerance by more than twice the tolerance, shall have a Calibration Nonconformance Action Form (CNAF) prepared. The "twice the tolerance" criteria acts as an As-Found tolerance to account for drift of the devices, and if devices are found outside of this tolerance, they must be evaluated for operability via the CNAF.

9.7.4 Uncertainty Allowances (cont'd)

The manner in which BNP utilizes the "twice the tolerance" criteria to act as an As-Found tolerance is a generic method of providing two tolerances. However, the method must also be used with caution. When establishing the setpoints and allowable values discussed in Section 9.8, the As-Found tolerance may be larger than just the As-Left tolerance plus the drift. If so, this must be accounted for within the individual setpoint and allowable value determinations. Otherwise, a device could drift within the "twice the tolerance" band yet potentially be beyond its allowable value.

Consider the following example,

A pressure switch at BNP has a reference accuracy (and calibration tolerance) of ±0.50% span. The drift value for the pressure switch, as provided by the vendor is ±0.50% span per 6 months. The MTE error for calibrating the pressure switch is ±0.25% span. The existing allowable value is equivalent to 1.0% span, and the pressure switch is required to be calibrated every 18 months ± 25%.

In performing a calibration of the pressure switch, the As-Found condition would have to be greater than twice the tolerance, or greater than 1.0% span (i.e., 2 * 0.50%) before a CNAF would be initiated. However, at greater than 1.0% span, the existing allowable value would be exceeded. Thus, using the "twice the tolerance" criteria for As-Found values provides the potential for exceeding the allowable value. If the allowable value had been established considering the reference accuracy, the drift, and the MTE, it would have been determined as follows,

$$AV = [(CAL)^2 + (DR)^2 + (MTE)^2]^{½}$$

First, the drift would be determined for the 18 months ± 25%. Using the SRSS method, the 18 months ± 25% is approximately equal to 4 six month periods. Thus, drift would be determined as,

$$DR = [(0.5)^2 + (0.5)^2 + (0.5)^2 + (0.5)^2]^{½}$$

$$DR = 1.0\%$$

The allowable value would then be calculated as,

$$AV = [(0.5)^2 + (1.0)^2 + (0.25)^2]^{½}$$

$$AV = 1.15\%$$

Even though the existing allowable value was 1.0% span, it should probably be increased, via the proper procedures, to at least 1.15% span. Otherwise, the switch may be found to exceed the allowable value more often than would normally be expected.

In order to prevent the As-Found value from being less than twice the tolerance but greater than the allowable value at BNP, the actual allowable values are shown on the calibration sheets and the technician is instructed to verify the As-Found are less than the allowable values. However, it is important that the preparer of any uncertainty calculation understand the way that BNP treats the "twice the tolerance" criteria and ensure that if a value is found up to twice its tolerance, it would still be considered operable in the field.]

[CR3 - Generally both an As-Found and an As-Left tolerance are specified within the calibration procedures. For those loops with allowable values, if the As-Found tolerance is met, then the loop is operating within its allowable value. If the As-Found tolerance is exceeded, then a condition report must be initiated to evaluate whether or not the allowable value was also exceeded. This is because, in some cases, there may be sufficient margin between the trip setpoint and the allowable value such that the As-Found tolerance can be exceeded without exceeding the allowable value. A condition report must also be initiated if the loop cannot be calibrated to within the As-Left tolerance.]

[HNP - Generally only one tolerance is specified within the calibration procedures, and it acts as the As-Left tolerance. The devices with allowable values have the allowable values denoted on the individual calibration sheets. All As-Found and As-Left values must be within the allowable values to meet the calibration requirements of the procedure. If the As-Found values are found to be within the allowable range, then no adjustment is necessary. For Q-Class A transmitters an Allowable Drift tolerance is given in addition to the allowable range. The

transmitter allowable drift tolerance (which may be single sided) is defined by the (S) term in Technical Specification Equations 2.2-1 and 3.3-1. When the transmitter allowable drift tolerance is exceeded, then a Condition Report (CR) must be initiated to evaluate Technical Specification drift. This report provides a documented mechanism for evaluating the out of tolerance condition. For all other devices found to be out of tolerance, the device is calibrated back to within tolerance and the Unit SCO notified.

For all other devices without any criteria for assessing out of tolerance values, the device may have drifted beyond what was expected but it does not create a plant operability concern. It may create a device operability concern, and this determination is left up to the Unit SCO to make an evaluation. If calculations quantify the value a device is expected to drift, then this value should be provided to the plant. This will yield a quantifiable assessment of out of tolerance conditions to more easily identify potential problem devices and those whose out of tolerance condition is within the expected range of drift.]

[RNP - Only one tolerance is specified within most calibration procedures, and it acts as the As-Left tolerance. If the As-Found value is found to be outside the tolerance, it is calibrated back to within tolerance. The calibration records are then reviewed by responsible personnel. It is the responsibility of these reviewers to evaluate any device that had exceeded its tolerance.

Using this method, evaluating out of tolerance conditions is rather subjective. If calculations quantify the expected drift for a device, then this value should be provided to the Maintenance group. This will afford the reviewers of calibration data with an "As-Found" value that will allow a quantifiable assessment of which out of calibration values present a problem and which out of tolerance values are justified.]

b. Loop Relationships

Normally, the calibration of instrument loops (or channels) is divided into three major parts due to the general inaccessibility of loop field sensors for calibration during plant operation. In order to be able to verify loop performance, the loop is divided into a section which is required to be tested and a non-testable section. The section which is

required to be tested generally includes the portion of the loop downstream of the sensor, to a specific loop output. The non-testable section generally contains only the field sensor. Actual division of the loop is as defined in the applicable loop calibration procedures.

The section of the loop required to be tested, the individual loop devices, and the loop as a whole make-up the three parts for calibration. Each part has an associated set of tolerances.

Individual device tolerances define the performance requirements for each of the devices within a loop. As discussed in Section 9.7.4.2.a, each device has an As-Left tolerance and may have an actual or implied As-Found tolerance. The As-Left tolerances are assigned for a device as discussed in Section 9.5.1.1. If an As-Found tolerance was to be assigned to a device or simply used in assessing an out of tolerance condition, it would be determined as shown below:

Device Tolerance

$$\text{As-Found} = \pm\left[(\text{As-Left})^2 + (DR)^2 + (MTE)^2\right]^{0.5} \qquad \text{(Eq. 49)}$$

The tolerances for the section of the loop required to be tested define the requirements for a group of devices. This group can consist of a number of loop devices and is usually defined by the group of devices tested periodically to verify acceptable loop operation. The tolerances for a group of devices is defined as:

Group Tolerance

$$\text{As-Left} = \pm\left[\text{As-Left}_1^{\,2} + \text{As-Left}_2^{\,2} + \ldots + \text{As-Left}_n^{\,2}\right]^{0.5} \qquad \text{(Eq. 50)}$$

Where, As-Left_1 through As-Left_n represents the As-Left tolerances of the individual devices which make-up the defined group 1 through n.

$$\text{As-Found} = \pm\left[\text{As-Left}_1^{\,2} + DR_1^{\,2} + MTE_1^{\,2} + \text{As-Left}_2^{\,2} + DR_2^{\,2} + MTE_2^{\,2} \ldots + \text{As-Left}_n^{\,2} + DR_n^{\,2} + MTE_n^{\,2}\right]^{0.5} \qquad \text{(Eq. 51)}$$

Where, As-Left_i, DR_i, and MTE_i are the As-Left, drift, and MTE error, respectively, for each device 1 through n.

Figure 9-15 shows the relationship of the group tolerances to the final set of tolerances, the loop tolerances. The loop tolerances, as discussed in Section 9.7.4.1, define the performance requirements for the loop as a whole. The loop tolerances are calculated in the same manner as defined above, for a group of devices, but include all devices from sensor to final loop output device.

The As-Found tolerance for a loop, establishes an important performance limit for safety-related instrument loops. This limit, which we will call the "Channel Operability Limit", is the limit for verifying operability of a safety-related loop. A safety-related loop found outside of its channel operability limit would normally be declared inoperable, and may cause the initiation of a Licensee Event Report (LER) to the NRC.

9.7.4 Uncertainty Allowances (cont'd)

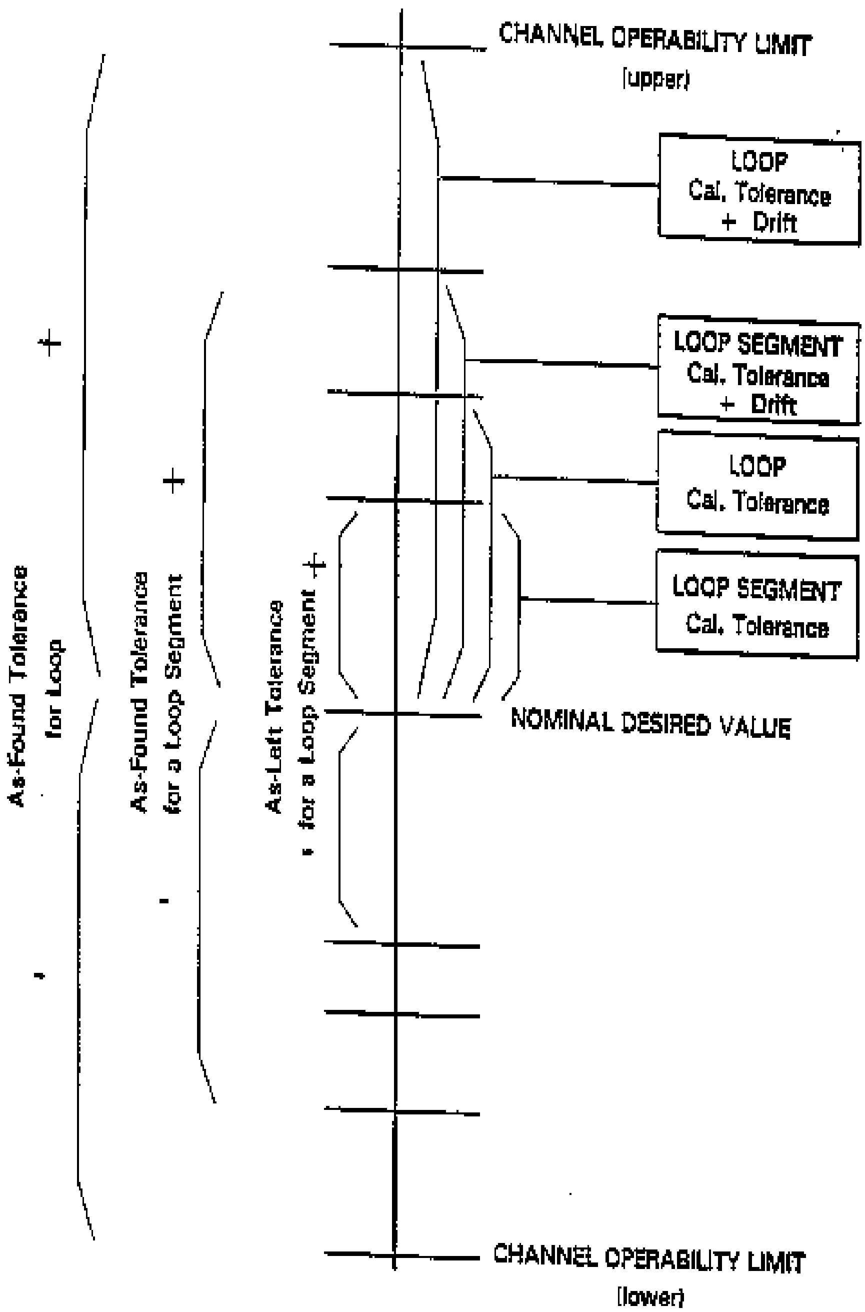


FIGURE 9-15
LOOP TOLERANCE RELATIONSHIPS

c. Setpoint Relationship

The application of tolerances, or allowances, in loops containing setpoints, is of particular importance for a nuclear power plant. This is particularly true of the numerous setpoint functions in quality-related applications. For loops containing setpoints, the output of the setpoint device defines the end of a complete loop or channel. This division allows each setpoint/setpoint device to be treated as a separate loop or channel.

The loop is normally divided in the same manner as discussed in Section 9.7.4.2.b, with the setpoint device included in the testable section of the loop. This division allows for the periodic testing of the loop's setpoint actuation value.

The primary function of setpoint loops is to actuate within an acceptable process variable range. This function leads to a slightly different treatment of tolerances for setpoint loops. Instead of being concerned with the accuracy of the loop measurement (i.e., the variance band around the true value), the concern focuses around when the loop will actuate with respect to a true process value limit of concern. Because of these differences, tolerances for setpoint loops will be discussed in detail in Section 9.8.

9.8 Setpoint Determination

Development and maintenance of setpoints is an essential prerequisite to the safe and efficient operation of plant systems and equipment. Properly selected setpoints provide early warning of pending problems, correct abnormal situations, and protect the public, plant personnel, and equipment, without unduly compromising the operability, or efficiency, of the plant.

Keeping this in mind, the purpose of each setpoint must be satisfied by the final value established. Setpoints for alarms, for example, should have sufficient margin from a system trip point, or safety limit, to allow an operator time to take corrective action. An alarm, coincident with an equipment trip setpoint, may serve no useful function. However, when attempting to achieve this margin, alarm and plant trip points should not be set so close to normal plant operation limits that they cause nuisance alarms and spurious trips.

9.8 Setpoint Determination (cont'd)

An instrument loop using many components and functional modules can possess large uncertainties, even though the accuracy rating of the individual components may be reasonable. Therefore, for all instrument loops, and particularly for multi-component instrument loops, setpoints should be located in that portion of the instrument range which has the required accuracy. It is accepted practice that setpoints should generally not be located in the extreme upper or lower portions of the instrument range.

Figure 9-16 shows the relationships between the various parameters that make up, or define, safety-related setpoints and related allowances. Each of these parameters will be discussed in more detail in the following paragraphs.

9.8.1 Limits

The Technical Specifications for each of the NGG plants are governed by 10CFR50.36, which defines two terms, safety limit (SL) and limiting safety system setting (LSSS), and their relation to instrumentation and control design bases. These terms, as well as two other associated terms, are described below.

1. **Safety Limit**

   Plant safety limits (SL) are design limits placed on important process variables to maintain the integrity of plant barriers designed to prevent the release of radioactivity. The limits are established by various regulatory requirements, industry design standards, such as ASME, and initial plant design assumptions bases. The actual plant systems and equipment must be designed such that the plant safety limits are not exceeded during the worst case accident conditions.

   Safety limits are the absolute limits. To exceed them, risks incurring uncontrolled releases of radioactivity. In order to ensure they are never reached or exceeded, each plant has conducted in-depth analyses of the accidents and transients postulated to occur for that facility. Such analyses are described in Chapter 15 of each plant's FSAR, as well as in supplemental analyses such as reload reports.

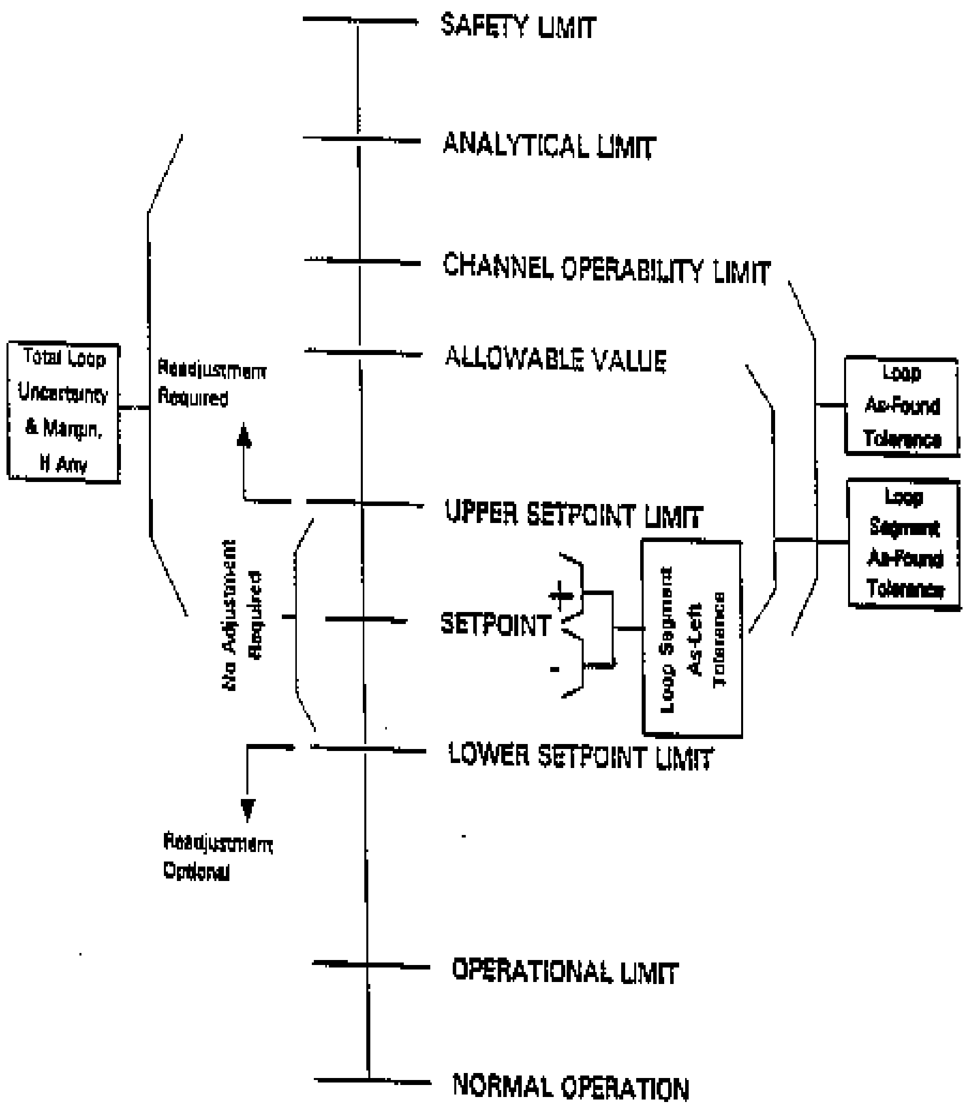


FIGURE 9-16
LOOP / SETPOINT RELATIONSHIPS

The safety limits are specific values of plant process variables, such as pressure or temperature. They may also be defined by directly calculated process conditions, such as the departure from nuclear boiling ratio (DNBR).

2. Analytical Limit

The accident analyses conducted for each plant (fuel reload analyses and fuel vendor accident analyses), assume protective trips are initiated at certain conservative values prior to a variable reaching the safety limit. Both the assumed values that form the model for such an analyses, and the maximum value that process variables attain in such an analysis, are referred to as analytical limits (AL).

As shown in Figure 9-16, the safety limit is the uppermost limit that cannot be exceeded without risking potential radioactive releases to the public. To prevent safety limits from being reached, analytical limits are established prior to the safety limits, and are obtained from the results of the fuel vendors fuel reload analyses or accident analyses or from fuel vendor assumed values. The region between the safety limit and the analytical limit is to provide an additional margin of safety and/or to accommodate any rapid "spikes" or transient overshoots beyond the postulated conditions.

It is important to note that there are relatively few safety limits. Typically, there are numerous analytical limits established, for several types of process conditions, to prevent exceeding a single safety limit. Thus, there may be analytical limits established for RCS temperature, pressurizer level, core power, etc. to prevent exceeding the safety limit associated with RCS pressure.

The determination of Analytical Limits (AL) is the responsibility of the Engineering Discipline which is responsible for the plant system associated with the instrument loop. Each analytical limit and its basis, shall be justified through an engineering calculation or other appropriate means. The value for the analytical limit and the bases for its determination shall be documented in the uncertainty/setpoint calculation.

An evaluation shall be made by the appropriate Engineering Discipline to determine the analytical limit. This evaluation shall take all viable actions necessary to establish the analytical limit and its bases. Such actions may include, but not be limited to - reviewing fuel vendor fuel reload analyses, fuel vendor accident analyses, plant safety analyses, reviewing existing calculations pertaining to the system/instrument loop of concern, reviewing correspondence files with the appropriate vendor, contacting the vendor and/or performing an audit of their files, obtaining and reviewing the original design specifications and/or associated data sheets, contacting other utilities to ascertain what relevant information they may have, and reviewing start-up test reports.

The Technical Specification value may be the only limiting value available. As a last resort, the Technical Specification value could be taken as the analytical limit. However, this would be a very conservative assumption and could result in new setpoints and allowable values closer to the normal operational limits. As discussed later in Section 9.8.2.2, moving a setpoint too close to the normal operational limits is a legitimate safety concern. Thus, using the Technical Specification value as the analytical limit should be avoided, and only implemented after it has been properly evaluated as to its effects on normal operation and plant safety.

3. Limiting Safety System Setting

The second term discussed in 10CFR50.36 for use within the Technical Specifications is the Limiting Safety System Setting (LSSS). The LSSS, as defined in Section 3.0 is,

> "Settings for automatic protective devices in nuclear reactors that are related to those variables having significant safety functions. A LSSS is chosen to begin protective action before the analytical limit is reached to ensure that the consequences of a design basis accident are not more severe than the safety analysis predicted."

The LSSS is comprised of two components - the trip setpoint and the allowable value. The trip setpoint is the predetermined value at which a device changes state to indicate that the quantity under surveillance has reached the selected value. The allowable value is the limiting value that the trip setpoint can have when tested periodically, beyond which the instrument channel must be evaluated for operability. Thus, the trip setpoint corresponds to the nominal value at which a device is set and expected to change state. The allowable value is the maximum region associated about a setpoint that is still considered to be acceptable for the instrument to fulfill its safety function without risking exceeding the analytical limit. The safety limits and LSSSs are typically defined in the Technical Specifications and the analytical limits are typically defined in the fuel vendor fuel reload analyses, fuel vendor accident analyses, or the FSAR.

To further illustrate the relationships between the terms discussed above, the RCS Pressure for Harris will be used as an example (Note - any associated head effects have been ignored in the following example for simplicity of illustration). Technical Specifications 2.1.2 define the RCS Pressure safety limit as 2735 psig.

9.8.1 Limits (cont'd)

Within Table 15.0.6-1 of the Harris FSAR, the high pressurizer pressure trip setpoint is assumed to be 2445 psig for the safety analyses. This is the analytical limit. To ensure that the analytical limit is not exceeded, Technical Specifications 2.2 lists the limiting safety system setting. The limiting safety system setting is composed of the trip setpoint and the allowable value. The trip setpoint is identified as 2385 psig and the allowable value is identified as 2399 psig within Table 2.2-1 of the Harris Technical Specifications. Thus, as long as the trip setpoint for RCS Pressure, and other process variables, are maintained below their allowable values, the safety analyses have ensured that the maximum RCS Pressure achievable under accident conditions will be significantly below the safety limit.

The limits discussed above apply to instrument loops with a protective function. The limits associated with control and indication design bases are treated similarly. Since the control and indication functions are typically not included in the accident analyses, no safety limits, analytical limits, or limiting safety system settings pertain to their settings. However, there is usually a limit associated with control and indication functions and it is frequently referred to as the design limit.

The design limit for control and indication functions is comparable to the analytical limit for protection functions. It is a limit for a measured or calculated variable to prevent undesired conditions such as equipment damage, spurious trips, or challenges to plant safety signals. The design limit may be a calculated value for a particular system or application or it may be a limit specified by the vendor.

The indicated value is like a setpoint except a setpoint results in an automatic action and an indicated value results in a manual action in response to an indication. Depending on the importance of the setpoint or indicated value, corresponding allowable values may also be established similar to the Technical Specification allowable values for the protection functions.

When identifying a limit associated with a particular instrument, it is thus important to understand what that limit represents. It must be clearly understood whether the function is for protection, control, or indication purposes. Once that is confirmed, it must be further clarified as to the type of limit represented by the value and how it relates to the instrument loop's design basis. Otherwise, the design basis may be misinterpreted and/or misapplied.

9.8.1 Limits (cont'd)

4. Channel Operability Limit

Although not addressed in the Technical Specifications, another limit exists for determining operability of an instrument channel. This limit, called the Channel Operability Limit (COL), is the loop As-Found tolerance (plus any associated margin) as discussed in Section 9.7.4.2.b. It would be added or subtracted from the setpoint in a manner similar to the allowable value.

Per the Technical Specifications, an instrument loop whose As-Found setpoint exceeds the allowable value in a non-conservative direction must be declared inoperable, and corrective actions taken. However, this determination does not always conclusively demonstrate that the actuation would have occurred at a non-conservative value. This is true because the allowable value only accounts for drift in the tested instruments in the loop, which typically does not include the sensor.

The channel operability limit includes the whole loop, from sensor to final actuation device. This limit includes a larger total allowance for drift, which gives rise to the possibility that unused drift in the sensor may offset the drift incurred in the testable portion of the loop. Therefore, if it is feasible to test the entire loop when an allowable value is exceeded, a reportable condition may not exist, as long as, the As-Found allowance for the loop is not exceeded. However, corrective actions must be in accordance with the Technical Specifications when the allowable value is exceeded, regardless of whether or not the channel operability limit was exceeded.

If it is not feasible to test the entire loop, it may be possible to analytically determine whether the channel operability limit would have been exceeded.

5. Operational Limits

These operational limits (OL) are the minimum/maximum values within which a process should be maintained during normal operation. A margin should be maintained between the operational limit(s), and the setpoint limit(s) to allow flexibility for plant maneuvering.

9.8.2 Setpoints

As discussed above in Section 9.8.1.3, trip setpoints or setpoints (SP) typically refer to an automatic action in response to a process variable achieving or exceeding some predetermined value. An indicated value is similar except that the action taken is manual in response to an indication. The discussions below will refer to the term "setpoint", however, it is intended that such discussions apply to any type of setpoint or indicated value.

1. Types of Setpoints

Setpoints are generally characterized as one of three types: rising, falling, and variable. The setpoint is categorized based on (1) the direction from which a process variable approaches the setpoint, and (2) whether the setpoint has a fixed value or varies as a function of another variable (i.e., time, power, level, temperature, etc.)

Rising setpoints are associated with a process that has a high limit. Action is initiated when the process variable increases to a point equal to, or greater than, the setpoint.

Falling setpoints are associated with a process that has a low limit. Action is initiated when the process variable decreases to a point equal to, or less than, the setpoint.

Variable setpoints can be of either a rising or falling type. The distinction is that in lieu of a fixed value, the setpoint will vary as a function of another parameter or a preset program. A variable setpoint will always be either a rising or a falling setpoint over its entire range. It cannot change from a rising to a falling, or vise versa. Identification of the setpoint type is an important factor when assessing the impact of setpoint inaccuracies.

Figure 9-17 graphically illustrates both a rising and falling setpoint, and the treatment of loop uncertainties. For a rising setpoint, a conservative setting would be less than the actual limit. Therefore, the loop uncertainties must be subtracted from the analytical limit. For a falling setpoint, a conservative setting would be higher than the actual limit. Therefore, the loop uncertainties must be added to the analytical limit.

9.8.2 Setpoints (cont'd)

2. Calculating Setpoints

Sections 9.3, 9.4, and 9.5 discussed the various components of a loop's uncertainty, and Section 9.6 described how to combine those uncertainties to determine a total loop uncertainty (TLU). The TLU is the maximum potential deviation in the positive and negative direction about the true value of a variable which the loop could consider as the true value of the variable. This can be expressed mathematically as:

$$LV = TV \pm TLU \quad \text{(Eq. 52)}$$

Where,

LV = Loop Value
TV = True Value
TLU = Total Loop Uncertainty

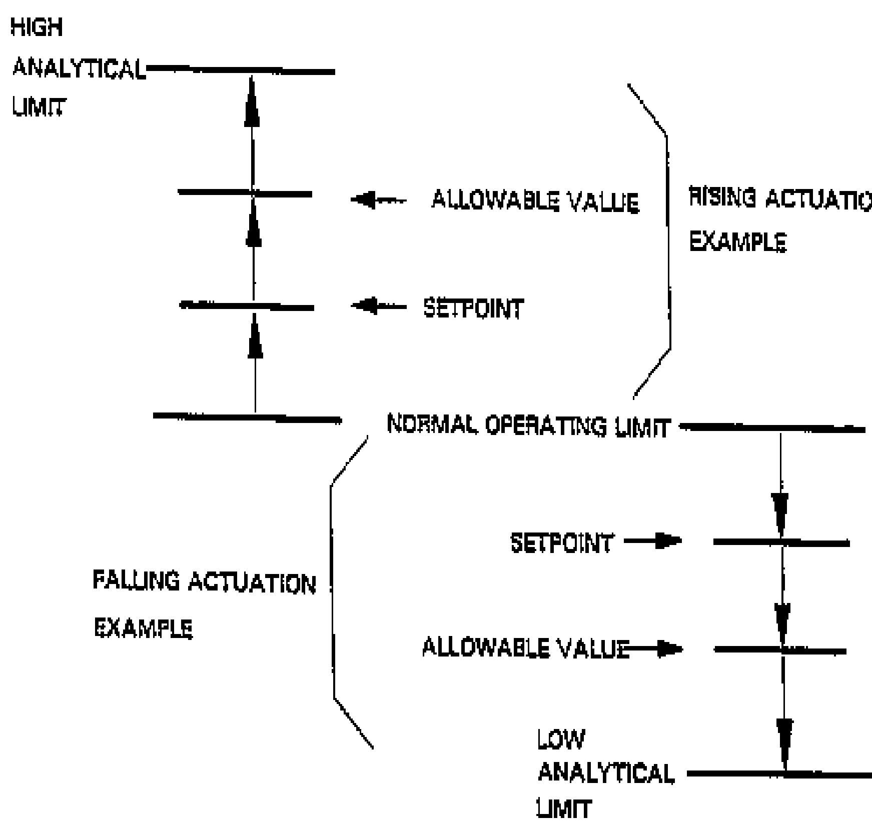


FIGURE 9-17
SETPOINT TYPES

9.8.2 Setpoints (cont'd)

For calculating setpoints, we have determined the total loop uncertainty but we do not know the true value of the process. What we do know, however, is that the loop value has been analyzed not to exceed a certain value, i.e., the analytical limit (or design limit as applicable). Therefore, we can let the loop value equal the analytical limit, AL:

$$AL = LV \qquad \text{(Eq. 53)}$$

Substituting into Equation 52,

$$AL = TV \pm TLU \qquad \text{(Eq. 54)}$$

For an analytical limit that is higher than the true value of a variable, the equation becomes,

$$AL = TV + TLU \qquad \text{(Eq. 55)}$$

Similarly, for an analytical limit that is lower than the true value of a variable, the equation becomes,

$$AL = TV - TLU \qquad \text{(Eq. 56)}$$

The true value in both these equations represents the maximum true value that the actual process variable may have, which when combined with the maximum expected deviation, will still not exceed the analytical limit. It also represents the maximum value which a setpoint can be assigned and the process be ensured to respond as it was analyzed. As described later in Section 9.8.3.1, additional margin may also be used to position the setpoint further away from the analytical limit.

Assuming that no additional margin is used and substituting the setpoint (SP) in for the true value, Equations 55 and 56 can be written as,

$$AL = SP + TLU \qquad \text{(Eq. 57)}$$

and

$$AL = SP - TLU \qquad \text{(Eq. 58)}$$

Rearranging the terms, the setpoint can be determined from the following,

$$SP = AL - TLU \qquad \text{(Eq. 59)}$$

and

$$SP = AL + TLU \qquad \text{(Eq. 60)}$$

Equation 59 represents an analytical limit that is higher than the setpoint and Equation 60 represents an analytical limit that is lower than the setpoint. Another way of viewing it is that Equation 59 applies to a process that must be prevented from rising above a certain analytical limit, and Equation 60 applies to a process that must be prevented from falling below a certain analytical limit. Thus, as discussed in Section 9.8.2.1, Equation 59 applies to a rising setpoint and Equation 60 applies to a falling setpoint. They may also be combined into one equation,

$$SP = AL \pm TLU \qquad \text{(Eq. 61)}$$

It is important to understand how the positive and negative terms are used when writing the equation this way. For a rising setpoint, the maximum absolute negative TLU is subtracted (i.e, add the negative value) from the analytical limit. Similarly, for a falling setpoint, the maximum positive TLU is added to the analytical limit.

Figure 9-17 illustrates both a rising and falling setpoint and the treatment of loop uncertainties. For a rising setpoint, a conservative setting would be less than the limiting value, therefore, the loop uncertainties must be subtracted from the analysis limit. For a falling setpoint, a conservative setting would be higher than the limiting value, therefore, the loop uncertainties must be added to the analytical limit.

Another factor frequently overlooked when establishing a setpoint is the setpoint's proximity to the normal operational limits. If a setpoint is placed too close to the operational limits, it can result in spurious alarms or trips.

Consider the example of the RCS Pressure for Harris discussed in Section 9.8.1.3. As stated in Section 9.8.1.3, the trip setpoint for RCS Pressure is 2385 psig, however, in actuality the Technical Specifications state the trip setpoint must be = 2385 psig. Selecting the trip setpoint as 2250 psig versus 2385 psig would provide additional conservatism that the analytical limit would not be exceeded. Additionally, it would also increase the probability of spurious plant trips. Besides the economic consequences, such trips unnecessarily cycle plant equipment which is only designed for a given number of such trips. Thus, overall plant safety may actually be degraded by moving the setpoint too far away from the analytical limit.

Another illustration of the potential safety significance of placing setpoints too close to their operational limits involves equipment availability and the potential for common mode failures. Consider two trains of an Emergency Core Cooling System (i.e., HPCI, SI, etc,) with their associated pumps. The pumps would typically have trip functions on low suction pressure. If the setpoint for the low suction pressure was established conservatively away from the limiting suction pressure for the pump, it may be set too close to the expected range of the suction pressure. This could cause an inadvertent trip of the pump. Normally, the setpoints for both trains would be set at approximately the same value. Thus, both pumps could potentially trip due to a common mode failure of establishing the setpoints too close to the normal operational values.

When calculating a setpoint, Equations 59 and 60 describe how to ensure a setpoint is far enough away from the analytical limit. A similar approach can be used to ensure that it is far enough away from the operational limits. For a rising setpoint, Equation 59 states that the maximum absolute negative TLU should be subtracted from the analytical limit. To ensure the setpoint is sufficiently away from the operational limit (OL), the maximum positive component of the TLU is added to the OL, as follows:

$$SP = OL + TLU \qquad \text{(Eq. 62)}$$

The value for OL in this equation would be the maximum value the process would be expected to achieve under its normal operational conditions. Similarly, to ensure that the setpoint is sufficiently away from the operational limit for a falling setpoint, the maximum absolute negative component of the TLU would be subtracted from the OL, as follows:

$$SP = OL - TLU \qquad \text{(Eq. 63)}$$

For this equation, the OL represents the minimum value the process would be expected to achieve under its normal operational conditions.

3. Setpoint Tolerances

An upper and lower setpoint limit or tolerance should be established for setpoints. The limits should provide a band around the setpoint which, as a minimum, accounts for the reference accuracy of the periodically tested segment of a loop. This would usually be from the output of a transmitter or detector (i.e., where the test input is injected) up to, and including, the device where calibration measurements are periodically taken during surveillance tests. This is the same as the group As-Left tolerance as discussed in Section 9.7.4.2.b.

Section 9.7.4 describes how the device, group and loop tolerances are established. For a device, the calibration tolerance is normally at least as large as the device's reference accuracy. In some applications, such as when more accurate test equipment is not available, the calibration tolerance may need to be increased beyond the device's reference accuracy.

As a calibration tolerance is widened, it increases its value. This higher value contributes to a higher value for the total loop uncertainty. The higher value for the total loop uncertainty moves the setpoint away from the analytical limit or design limit, as applicable.

Similarly, narrowing the calibration tolerance will move the setpoint closer to the analytical or design limit. Therefore, increasing a tolerance band makes calibrations easier via fewer devices found outside the band and less tuning required to stay within the band. However, increasing the tolerance band also moves a setpoint closer to its operational limits and increases the potential for spurious trips, alarms, etc. Thus, an optimum value should be determined for a device's tolerance and the associated group (i.e. setpoint) and loop tolerances, to allow the most flexibility for both the I&C group to perform their calibrations, and the operations group to operate their equipment.

One method of potentially providing some flexibility for a device tolerance may be to include a calibration tolerance that is not symmetrical. That is, in the direction of interest (falling or rising) the calibration tolerance may be relatively narrow yet broader in the other direction. For example for a rising setpoint, the negative portion of the TLU will be used to establish the setpoint with respect to the analytical limit. Therefore, the tolerance may be tighter in the negative direction and broader in the positive direction (e.g. +10/-5 psig). In such a case, different values would need to be calculated for the positive and negative TLU terms using the respective calibration tolerances. Although acceptable, this practice is discouraged because instrument drift and reference accuracies do not typically manifest themselves asymmetrically. In addition, any device that can be reliably maintained within tolerance on the "tight" side of an asymmetrical tolerance should be expected to meet that tolerance symmetrically; and if a larger tolerance is needed, the setpoint should be revised to allow for it instead of revising the tolerance so calibration can be satisfied by "playing the tolerance."

The tolerance band provides calibration personnel with a measurable calibration band within which the device(s) must be adjusted. In addition, the tolerance band establishes a set of acceptable performance limits against which actual performance can be monitored. As long as the performance of the device(s) remains within these limits, no calibration adjustment would be required. Device(s) found outside of the calibration tolerance would require recalibration to bring the errors back within the tolerance and a review would potentially need to be made to determine if the instrument was, and had been prior to its recalibration, operable.

4. Allowable Values

Technical Specifications typically list, along with an instrument's setpoints, another term called the allowable value which provides an allowance to account for the expected drift in the testable portion of the loop. Usually, the Technical Specifications will state that if a setpoint is found to be less conservative than its allowable value, the loop is to be declared inoperable until the setpoint is restored to within the allowable value. An evaluation is usually made to determine how long such a loop may have been inoperable and any plant operations that may have been affected.

The allowable value defines a limit which the setpoint should be maintained within to show that the uncertainties which are present within the loop when it is periodically tested/calibrated, are consistent with the values used within its uncertainty/setpoint calculation. In other words, it provides an acceptance criteria for the setpoint during the required periodic surveillance test, and from which operability determinations can be made.

9.8.2 Setpoints (cont'd)

The allowable value (error allowance) can be determined from the As-Found tolerance for that group or loop of instruments periodically tested as discussed in Section 9.7.4. If the allowable value is applied to surveillance testing that excludes the sensor, then the group As-Found tolerance is used. If the allowable value is applied to surveillance testing that includes the sensor, then the loop As-Found tolerance is used. In this case, the Channel Operability Limit (COL) as discussed in Section 9.8.1.4 should be used as the allowable value. The allowable value can be determined by adding or subtracting the group As-Found tolerance or loop As-Found tolerance, as appropriate, to the setpoint such that the allowable value moves closer to the analytical limit. Note that the drift term in Equation 51 would only account for the interval between successive tests (as few as 30 days for rack components and up to 30 months for sensors).

Thus for a rising setpoint, the allowable value would be determined by,

$$AV = SP + GAFT \qquad \text{(Eq. 64)}$$

and for a falling setpoint the allowable value would be determined by,

$$AV = SP - GAFT \qquad \text{(Eq. 65)}$$

Where,
- AV = Allowable Value
- SP = Setpoint
- GAFT = Group As-Found Tolerance

As discussed in Section 9.8.1.4, the channel operability limit is a value established to encompass the drift from the entire loop, inclusive of the sensor. Whenever the drift from the testable portion of the loop exceeds its allowable value, the drift for the entire loop may still be acceptable if the allowable value is not the same as the channel operability limit and the sensor drift is less than predicted. Although the Technical Specifications must still be followed in assessing loop operability, showing that a loop is still within its channel operability limit is one potential method of evaluating safety significance.

9.8.2 Setpoints (cont'd)

The channel operability limit is calculated similar to the allowable value, except the Loop As-Found Tolerance is used in place of the Group As-Found Tolerance. For a rising setpoint it is determined by,

$$COL = SP + LAFT \quad \text{(Eq. 66)}$$

and for a falling setpoint the channel operability limit is determined by,

$$COL = SP - LAFT \quad \text{(Eq. 67)}$$

Where, COL = Channel Operability Limit
SP = Setpoint
LAFT = Loop As-Found Tolerance

9.8.3 Application of Margin

Margin (M) is a term used to describe a general allowance made for determining setpoints. Adding margin has the affect of moving a setpoint further away from the analytical limit (AL) or also known as the design limit (DL). Similarly, removing margin moves a setpoint closer to the analytical limit. Both applications are described in more detail below.

1. Additional Margin

For some loops, the setpoint may be determined to be too close to the analytical limit (or design limit). Such an evaluation may be based on "engineering judgement" or it may be more quantitative. For example, the As-Found values for a given loop may be repeatedly exceeding the allowable value and the loop is continually being evaluated for operability. Regardless of the reason, whenever a setpoint is moved further away from the analytical limit (or design limit), it is referred to as "adding margin". Equation 61 shows that a setpoint is calculated by the expression:

$$SP = AL \pm TLU$$

By adding margin (M), the equation becomes,

$$SP = AL \pm TLU \pm M \quad \text{(Eq. 68)}$$

When margin is added it has the effect of increasing the conservatism of the setpoint. That is the action initiated by the setpoint will occur prior to where it would have occurred without the margin. Caution must be exercised, however, in that too much margin may also lead to spurious trips, nuisance alarms, etc. As discussed in Section 9.8.2.2, overall plant performance and plant safety can be degraded because of inadvertent challenges to plant equipment.

Whenever margin is added to a setpoint or determined to be present in an existing setpoint, it should be identified as such within the setpoint calculation. This will assist in any future evaluations of the loop or process system, should modifications be required of the equipment or the safety analyses.

9.8.4 Reducing Overconservatisms

As discussed in Section 9.6.2, there are several ways of combining uncertainties (linear, SRSS, combinational) that employ varying levels of conservatism. Similarly, there are ways and assumptions used in determining the actual uncertainties that inject varying levels of conservatism. This document has reflected a general approach that may be used efficiently for most setpoints. It is not necessary to finetune each setpoint to very precise values. Thus, the methods described up to now may introduce certain conservatisms for the sake of convenience in performing the calculations. Some applications have a very narrow region between the normal operating range and the analytical limit (or design limit). For these cases, the conservatism must be reduced as much as practical to prevent inadvertent trips. Presented below are some suggestions which may be used on a case-by-case basis to reduce an individual conservatism.

a. Review the timing of the setpoint's actuation (or the time needed for an indication) versus the plant specific accident profiles to determine if the loop's design basis trip function occurs prior to a harsh environment forming. Also, the accident temperature effect usually occurs immediately after an accident and then dissipates. The accident radiation effect is frequently not a concern until a significant period following an accident. Thus, only one or the other of the effects may need to be included in the total loop uncertainty instead of both.

b. Determine if the specific location of the loop (or components results in a milder environment than that assigned to the general room or building. For example, a sensor may be shielded by equipment reducing its radiation dose or a sensor may be on the floor of a large open area such that its temperature is less than the average room temperature.

c. Determine if a loop calibration can be performed versus a component-by-component calibration. If not, evaluate whether a loop check can be done following the component-by-component calibration. Either of these minimizes the number of times the M&TE uncertainty must be applied.

d. Ascertain whether more accurate M&TE is available for performing the calibrations. It may be possible to use more accurate equipment if the device is calibrated in the shop versus in the field.

e. Reduce the calibration tolerance for all devices to their minimum acceptable values (typically their reference accuracies).

f. Revise the method of calibration to verify all attributes of each device such that only the calibration tolerance must be included in the total loop uncertainty calculation.

g. Perform a loop specific insulation resistance (IR) calculation instead of relying on a worst case or assumed IR value.

h. Utilize calibration tolerances that are not symmetrical, but are smaller in the direction of interest.

i. Determine if the calibration frequency can be increased to approach the interval used by the vendor for his drift value or, to be even more frequent than that assumed by the vendor.

j. Investigate whether updated information from the vendor can reduce drift or other uncertainties. Also, evaluate whether or not plant As-Found/As-Left calibration data may be analyzed to determine drift, rather that using the vendor specifications.

k. Modify equipment whereby its span is closer to its range, and the turndown factor can be decreased or deleted.

9.8.4 Reducing Overconservatisms (cont'd)

l. For indicators and recorders, assess whether another indication (i.e, via the plant computer) may provide a more accurate indication. If possible, scale faces, chart paper, etc. may be changed to reduce the readability error. The substitution of digital displays for analog displays will usually result in a smaller indicator error.

m. Evaluate if sensors can be moved to a more moderate environment.

n. For differential pressure loops, determine if calibrating the sensor at pressure could reduce the static pressure effect.

o. Treat calibration tolerances and M&TE errors as statistically independent terms when combining the uncertainties.

p. Reduce the uncertainty values using the "single side of interest" statistical methodology factor described in section 9.4.12, if applicable.

9.8.5 Dead Band and Reset

Dead band and reset are two interrelated control phenomenon which can affect an instrument loop's performance. Dead Band is the term given to the phenomenon that occurs in all instruments upon the reversal of an input signal (i.e., from rising to falling, or falling to rising). A band of non-response, or dead band, exists for a change in input, where no change in output is seen. This is demonstrated graphically in Figure 3-1. Whenever an input signal changes direction, a discrete amount of reverse signal change has to take place before the output begins to change. This characteristic is inherent in most devices.

Dead band is found in both analog and digital (setpoint) devices. In analog devices, the dead band is part of the basic accuracy of the device, and affects the device's ability to respond to a change in input signal. For digital or setpoint devices, the dead band affects the point at which a device resets after actuation. Generally dead band is an undesirable trait of a control system because of its effect on stability. Many digital applications, though, rely on dead band as an integral part of the control scheme.

9.8.5 Dead Band and Reset (cont'd)

To prevent cycling, chatter and subsequent system instability, it is usually necessary to allow a sufficiently large difference (or dead band) between the actuation and reset point of a setpoint device. Some setpoint devices have only a fixed differential between the actuation and reset point. When selecting such a device, an assessment should be made to ensure that the fixed differential is adequate for the application. For devices which have an adjustable differential, the setting for the reset point should be based on system capabilities and required system performance. A sufficient band must be allowed between a device's setpoint and reset point to prevent cycling, and equipment wear due to normal process system variations.

In general, dead band and reset do not have to be considered in loop error analysis. The dead band and reset do, however, have to be evaluated during a final setpoint determination.

9.8.6 Time Response

The speed, or time response, of both a process, and the I&C system that is monitoring a process, can be an important factor in the selection of setpoints. Allowances in setpoint values may be necessary to compensate for specific system, or equipment, time responses which affect the operation of a setpoint. A slow time response can cause a setpoint to be actuated too late to prevent damage of equipment.

The lead time needed to correct an abnormal process condition prior to reaching unacceptable levels may need to be determined, and factored into a setpoint.

However, most "time response" type setpoint concerns are addressed by either establishing circuitry and system response time requirements that are verified by testing, or by installing "lead circuit" devices in the instrument loop. "Lead circuits" cause output signal increases based on the rate of change of the input signal thus ensuring trip points are reached sooner for fast changes to the input signal. When "time response" is of concern and these methods are used, no time considerations need to be included in the setpoint selection.

Consider the following example where a simple pressure switch is used without a "lead circuit" capability,

A setpoint is needed for a pressure switch which serves to maintain a minimum pressure in a system. The pressure switch starts a pump, which requires 5 seconds before it is capable of supplying pressure. If the normal pressure is 100 psi, the system pressure can decrease by 5 psi per second and the absolute minimum pressure to be maintained is 50 psi, the switch would require a setpoint of at least 75 psi. This would ensure that the actual system pressure does not fall below the required minimum before the pump corrects the decrease.

9.8.6 Time Response (cont'd)

In a similar manner, the time response of an instrument or instrument loop may have to be determined and factored into a setpoint. This happens primarily with processes which have very fast time constraints. Every instrument or loop has a time response, or elapsed time period between the time a process reaches a given setpoint and action is taken. For many instrument loops, this is a matter of a second or less. But for a process condition which could also significantly change within this period of time, a setpoint may have to be lowered or raised to allow for the instrument time response or a "lead circuit" may need to be present in the design.

9.9 Calculation Format

9.9.1 Overview

In order to assist in the development, review and approval processes required for instrument loop error/setpoint calculations, a standard format should be used in the preparation of these calculations. The following format should be used in conjunction with the EGR-NGGC-0017 procedure to generate or revise all future instrument loop error and setpoint calculations. A general discussion of the format is provided below.

Each loop uncertainty/setpoint calculation should contain, as a minimum, the following sections:

- Calculation Cover Sheet
- List of Effective Pages
- Table of Contents
- Objective
- Functional Description
- Loop Diagram
- References
- Inputs and Assumptions
- Calculation of Uncertainties/Setpoints
- Discussion of Results
- Setpoint Relationship Form (optional)
- Attachments (as necessary)

Other sections may be added as needed, depending upon the specific application and complexity of the instrument loop. Each of the above sections is briefly described below.

9.9.2 Format Details

1. **Calculation Cover Sheet**

   The Calculation Cover Sheet should comply with the EGR-NGGC-0017 calculation procedure and would typically include the calculation number, revision, title, safety classification, seismic classification, and applicable signatures and dates. The title should directly indicate whether the calculation is just an uncertainty calculation a setpoint calculation a scaling calculation, or some combination of these; and the system, process, and function (protection, control, indication) being monitored.

2. **List of Effective Pages**

   The List of Effective Pages should comply with the EGR-NGGC-0017 procedure and would typically show all pages in the calculation, including any attachments or appendices. Page numbering should start with the List of Effective Pages, which should be page i. Any subsequent pages up to the start of the calculation (i.e., with the Objective) should use lower case Roman numerals as the page numbers (e.g. ii, v, ix, etc.). Starting with the first page of the calculation, the remaining pages should be numbered with Arabic numbers (e.g. 2, 5, 9, etc.). Any Attachments, Appendices, Figures should also be included on the List of Effective Pages. In addition to their consecutive numbers as part of the calculation, Attachments, Appendices, and Figures should also be numbered as "page __ of __" to indicate how many pages make up the complete Attachment/ Appendix/Figure. Only their consecutive page numbers as part of the calculation need be included in the List of Effective Pages.

3. **Table of Contents**

   The Table of Contents should include a listing of each section and subsection of the calculation, along with any Attachments, Appendices, and/or Figures. Each section and subsection should be numbered with Arabic numbers (e.g. 2.1, 4.4, 6.0, etc.). The Table of Contents should denote Attachments, Appendices, and Figures by their consecutive page number within the calculation and by their total number of pages. Their title/subject should also be identified within the Table of Contents.

9.9.2 **Format Details** (cont'd)

4. Objective

The Objective should describe what the calculation is intended to achieve. It should discuss what is being calculated (i.e. uncertainties, setpoints, indicated values, etc.), the reason it is being calculated, and the applicable system and instrument loop numbers.

5. Functional Description

The Functional Description should briefly describe the functions of the loop(s) (i.e., protection, control, and indication), their safety significance, the plant conditions for which the calculation is valid, and the general design basis of the instrument's function.

6. Loop Diagram

A Loop Diagram shall be generated to identify each component in the loop by component type, manufacturer/model number, location, and tag number. The diagram should begin with the loop's relative location to the process, show the primary element or sensor, and progress to each applicable bistable and/or end device. Both the process units being monitored, as well as any electrical units, should be shown together with their associated range. The diagram is intended to be a simplified "block" diagram, and does not need to include individual termination points.

7. References

The References should list all documents, and their revision number, that govern, and/or supply, data used in the calculation. References should be grouped into major subsections (i.e. drawings, vendor data, calibration procedures, other procedures, etc.) and assigned a unique number within that subsection. As a minimum, the following references should be included within the calculation: P&ID, loop diagram, vendor literature (preferably from the vendor technical manual), this procedure and any applicable Tech Spec or FSAR sections.

9.9.2 Format Details (cont'd)

8. Inputs and Assumptions

The Inputs and Assumptions section should list any known conditions or values from codes/standards, measured data, functional requirements, performance requirements, design conditions, or other specific requirements. Such conditions may include the normal and accident ranges of the process condition, the normal and accident environmental conditions for each applicable location, the span of each component, the calibration frequency of each component, etc. The source of each input shall be referenced.

Also included within this section shall be any assumptions necessary to complete the calculation. Assumptions shall be kept to a minimum and specifically identified as an assumption, and not a design input. Information that can be specifically referenced to a source document should be treated as input. Each assumption must state the basis for the assumption, and use of "engineering judgment" as a basis should be minimized.

9. Calculation of Uncertainties/Setpoints

The Calculation of Uncertainties/Setpoints section should define each individual uncertainty, calculate the total loop uncertainty, and as applicable, calculate the setpoint, allowable value, channel operability limit, and indicated value. Using the loop diagram as a guide, the process measurement uncertainties should be determined first and progress through all loop components to each appropriate bistable/end device. Error propagation through the loop should be calculated as discussed in Section 9.6.2.

As each device in a loop is encountered, the specific error effects for the device should be listed. Following the device information, the resultant device errors shall be calculated. Each facet of the loop that exists should be addressed, even if it is only to explain why an uncertainty value is not applicable. The Setpoint Relationship Form shown in Attachment 1 should be completed for each instrument loop (or group of loops if all information for a loop is common to other channels).

9.9.2 Format Details (cont'd)

10. Discussion of Results

The Discussion of Results shall provide the specific results of the calculation, by instrument loop and/or function. The status of the plant to which these results apply should be described, along with any other clarifying assumptions/conditions. The relationship of the results to any existing values should be described along with any available margin. If the results necessitate, or potentially necessitate, the change of any existing documents, drawings, procedures, etc., these shall be specifically identified and discussed.

11. Setpoint Relationship Form (optional)

The Setpoint Relationship Form shown in Attachment 1 may be completed for each loop. The form is designed to quickly summarize the individual error terms and how they are combined. The form itself is not important, but rather the information it provides. If, for particular applications, other means are more appropriate to present this information, they may be used instead of this form (e.g. a separate printout of the information, a diagram, etc.).

12. Attachments

Attachments should be used to document instrument scaling calculations when it is necessary to provide scaling and no separate scaling calculation exists, or to provide clarification of the information used within the calculation. Frequently, the information used within the calculation may be from a source that is not easily reproducible/recoverable. In such cases, copies of the information should be included with the calculation as an attachment. Such information may include - vendor literature, letters, memos, telecons, specifications, etc.

9.9.3 General Guidelines

Some other general information should be considered in developing the calculations. These general guidelines are described below:

1. Calculations may be performed by "hand" or preferably, by applying the techniques of a computer based word processor. An alternate method would employ a computer based software program.

2. Calculated values should be rounded to the least significant digit. For values that end in five or higher, they should be rounded up to the next higher significant digit. For values ending in one through four, they should be rounded down to the lower significant number. When determining setpoints, calculated values may be rounded in a direction that is conservative with respect to the analytical limit.

9.10 TSTF-493 Implementation

NOTE 1: **Background Information**: RIS 2006-17 identifies NRC concerns regarding industry compliance with 10 CFR 50.36(c)(1)(ii)(A), which states:

> "Limiting safety system settings for nuclear reactors are settings for automatic protective devices related to those variables having significant safety functions. Where a limiting safety system setting is specified for a variable on which a safety limit has been placed, the setting must be so chosen that automatic protective action will correct the abnormal situation before a safety limit is exceeded. If, during operation, it is determined that the automatic safety system does not function as required, the licensee shall take appropriate action, which may include shutting down the reactor."

TSTF-493, Rev. 4 with Errata, April 23, 2010 defines the collaborative NRC/ industry response to RIS 2006-17. The intent of TSTF-493 is to maximize assurance that instruments supporting selected Technical Specification functions perform both "as required" and "as expected".

All Technical Specification instrument functions, whether or not subject to TSTF-493, must perform "as required." That criterion is satisfied by Surveillance Test as-found results being within Technical Specification Allowable Values and it is unchanged by application of TSTF-493. When Surveillance Test as-found results are within Technical Specification Allowable Values, the tested function is demonstrated to be Operable.

The impact of TSTF-493 applicability is imposition of an additional operability criterion to demonstrate that a function is also performing "as-expected," relative to the applicable manufacturer-identified tolerances and the manner in which those tolerances have been applied within setpoint calculations. This is accomplished by requiring that Surveillance Test As-Found results be within a specifically limited tolerance band established around the actual device field setting. When Surveillance Test As-Found results are within the Allowable Value, but not within the specified limited as-found tolerance band, the TSTF provides that the function to be considered Operable, but Degraded.

(cont'd)

(cont'd)

In response to that condition, TSTF-493 requires 1) performance of certain immediate actions to enable determination that the function can be considered Operable and 2) follow-up processing within the Corrective Action Program for further evaluation.

Compliance with TSTF-493 is accomplished by imposition of unique design and testing requirements as follows:

- Restricting the types of uncertainty factors that may be considered in determination of Surveillance Test As-Found and As-Left Tolerances,
- Inclusion of those "restricted" As-Found and As-Left Tolerances as part of the acceptance criteria within applicable Surveillance Test procedures,
- Requiring satisfactory evaluation of any Surveillance Test Out-of-Tolerance As-Found Results prior to returning the equipment to Operable status.
- Performance of follow-up reviews by Engineering for further evaluation, documented within the Corrective Action Program.

Section 9.10 establishes the detailed guidance necessary to implement the TSTF-493 requirements.

9.10.1 TSTF-493 Applicability

1. Applicability of the requirements in 9.10 is currently limited to:
   - Those specific Technical Specification functions for which compliance with TSTF-493 has been committed within a facility's Operating License, and
   - Those design activities performed in support of pending Licensing Amendment Requests for which TSTF-493 compliance is required.

9.10.2 Determination of Tech Spec Trip Setpoints and Allowable Values

1. Technical Specification Trip Setpoints and Technical Specification Allowable Values are determined using the same generic methodology established in 9.8.2.2 and 9.8.2.4, respectively. No unique or additional requirements are imposed by TSTF-493 applicability.

9.10.3 Determination of Surveillance Test As-Found Acceptance Criteria

1. Specific tolerances to be applied as As-Found Surveillance Test acceptance criteria shall be established as directed in 9.5.1, 9.7.4 and 9.8.2.3, subject to the following clarifications and restrictions:
   a. The As-Found Tolerance should be based on As-Left Tolerance, Drift, and M&TE uncertainties. No additional margin should be applied, except as permitted per the following step.
   b. In cases where unique circumstances suggest inclusion of specific uncertainty factors (not discretionary margin) in the As-Found Tolerance beyond those permitted in the preceding step, the basis for that inclusion shall be explicitly documented within the calculation.

9.10.4 Determination of Surveillance Test As-Left Acceptance Criteria

1. Specific tolerances to be applied as As-Left Surveillance Test acceptance criteria shall be established as directed in 9.5.1, 9.7.4 and 9.8.2.3, subject to the following clarifications and restrictions:
   a. The As-Left tolerance should be based on Reference Accuracy. No additional margin should be applied, except as permitted per the following step.
   b. In cases where unique circumstances suggest inclusion of specific uncertainty factors (not discretionary margin) in the As-Left Tolerance beyond Reference Accuracy, the basis for that inclusion shall be explicitly documented within the calculation.

9.10.5 Use of As-Found and As-Left Acceptance Criteria in Surveillance Tests

1. All Surveillance Test Procedures include acceptance criteria requiring test results to be within Technical Specification Allowable Values. These criteria are unchanged by TSTF-493 applicability.
2. For Surveillance Test Procedures subject to TSTF-493, the following additional acceptance criterion shall be applied:
   a. As-Found trip settings shall be within the As-Found Tolerance band (as specifically established in 9.10.3) around the desired trip setting.
   b. As-Left trip settings shall be within the As-Left Tolerance band (as specifically established in 9.10.4) around the desired trip setting.
   c. In the case where a Surveillance Test Procedure does not provide separate As-Found and As-Left tolerances, the single tolerance specified must be used for both purposes and its magnitude must be less than or equal to the magnitude of the As-Left Tolerance (as established in 9.10.4). This approach effectively excludes any allowance for potential instrument drift and should only be utilized in applications that are known to be exceptionally stable. Otherwise, test results might unnecessarily cause entry into the Out-of-Tolerance evaluation and operability determination steps defined in 9.10.6.

9.10.6 Response to Surveillance Test Out-of-Tolerance As-Found Results

1. Surveillance Test Procedures shall include specific requirements for the maintenance technicians to perform the following actions when As-Found results are found to be outside the As-Found Tolerance band:
   a. Prompt notification to Operations of the initial Out-of-Tolerance test result.
   b. Attempt to adjust the trip setting to within the As-Left Tolerance.
   c. If resetting to within the As-Left Tolerance is successful, then consider whether the adjustment activity revealed any unusual device response or whether any adverse physical or functional conditions are apparent. Determine whether the function can be reasonably expected to perform satisfactorily throughout the next surveillance interval.
   d. Report the results of steps b and c above to Operations. This action constitutes a recommendation by Maintenance for use in a determination by Operations regarding whether the function can be declared operable.
   e. Initiate a Condition Report within the Corrective Action Program describing the Out-of-Tolerance Surveillance Test result for further evaluation by Engineering.

10.0 RECORDS

10.1 No records are generated specifically from the performance of this procedure. This procedure describes a methodology to perform certain types of engineering calculations. Other corporate/site specific procedures exist to provide direction regarding the records required to be generated, record format, and approval requirements.

10.2 Use of the three forms provided in Attachment 1 is optional. The completed forms are not, by themselves, records. When used, however, they may be included as part of the calculation for which they were prepared.

ATTACHMENT 1
Sheet 1 of 4
Forms

These forms are provided to assist in the calculation of total loop uncertainty, setpoints, allowable values, etc. The use of these forms are optional and intended to be an aid to the preparer of such calculations and provide the relevant information in a summary format. It is believed that by viewing the pertinent information in a format such as that provided, the overall relationships of the different error and limit terms can be more readily understood. If the user of this document determines that another format is more suitable for their application, then another format can be used as long as the necessary information is documented.

[HNP, RNP - The GAFT is typically used to determine the allowable value.] [BNP - The LAFT is typically used and the channel operability limit is the allowable value. Therefore, the GAFT need not be shown in the setpoint analysis results.]

Three forms are provided. Form 1-1 is for listing device uncertainties, Form 1-2 is for increasing setpoints, and Form 1-3 is for decreasing setpoints.

Form 1-1 lists potential uncertainties that may apply to a given device. Appropriate values should be inserted for each applicable device error/effect. Under "TYPE", the user should identify what type of error the value represents: random, bias, dependent, independent. If the error is dependent, the dependency should be explained in the "COMMENTS" field. Any other clarifying information may also be included within the "COMMENTS" field. Using Section 9.6.2.3 of the procedure, the errors/effects should be combined to determine an overall device uncertainty.

Once all of the uncertainties for the devices have been determined, they should be summarized at the top of Form 1-2 or 1-3, as appropriate. The process measurement errors, primary element errors, and any other applicable errors should be combined with the device uncertainties to determine the total loop uncertainty. The values for the other parameters should be documented on the applicable form, in the spaces provided. Some values must be obtained from the design bases of the instrument loop, and others must be calculated, as shown.

Listing Device Uncertainties (Form 1-1)

Device Type ________________ Device Name(s) ________________

ERROR/EFFECT	VALUE	TYPE	COMMENTS
Ref. Accuracy			
Cal. Tolerance (ALT)			
M&TE Error			
Drift			
Temp. Effect			
Pwr. Supply Effect			
Readability			
Seismic Effect			
Acc. Temp. Effect			
Acc. Press. Effect			
Acc. Rad. Effect			
Insul. Resist. Effect			
Other			
Total Device Uncertainty (TDU)	TDU = +__/-__		

(EGR-NGGC-0153-1-1-9)

Note: All errors/effects must be converted to the same basis (i.e. units) prior to entering their values onto the form.

Increasing Setpoint (Form 1-2)

PE	________	$Bias_1$	________
PME	________	$Bias_2$	________
TDU_{sensor}	________	$Bias_3$	________
TDU_1	________	Total Bias	________
TDU_2	________		
TDU_3	________		

$TLU = (PE^2 + PME^2 + TDU_{sensor}^2 + TDU_1^2 + TDU_2^2 + TDU_3^2)^{½} + \text{Total Bias}$

TLU ________

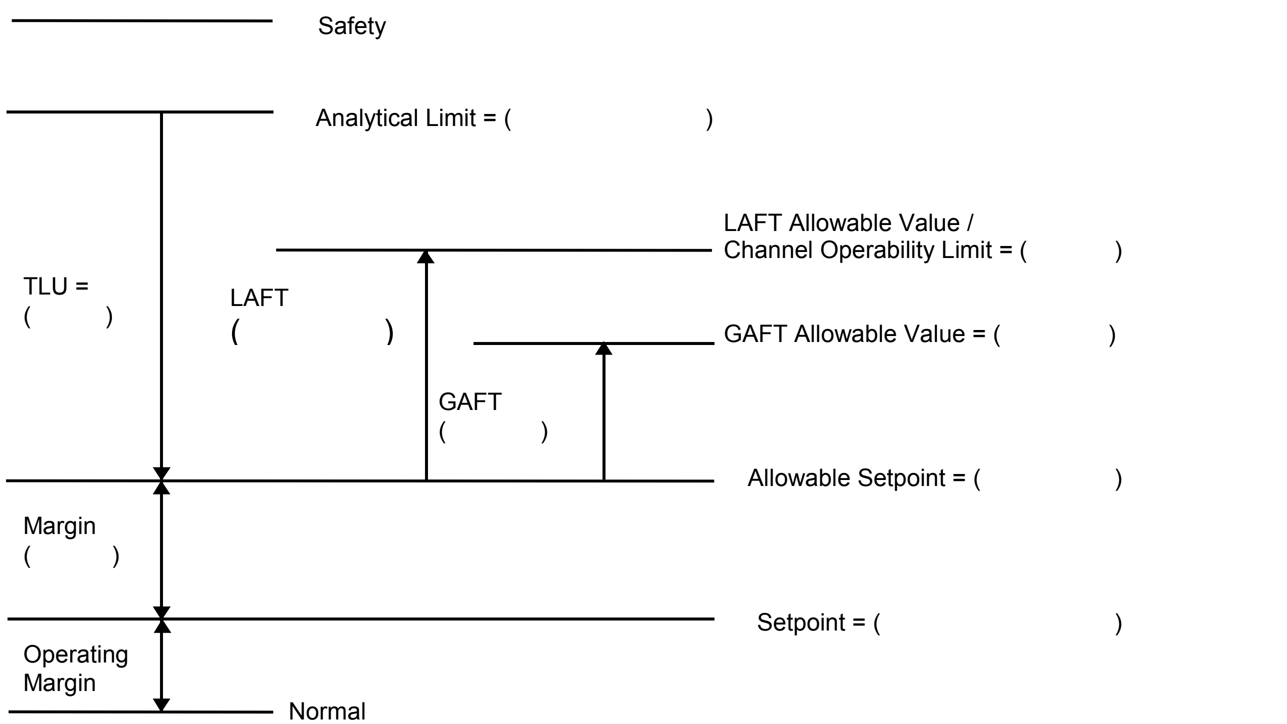
Margin ________

$GAFT = (ALT_1^2 + DR_1^2 + MTE_1^2 + \bullet\ \bullet\ \bullet + ALT_n^2 + DR_n^2 + MTE_n^2)^{½}$

GAFT ________

$LAFT = (GAFT^2 + ALT_{sensor}^2 + DR_{sensor}^2 + MTE_{sensor}^2)½$

LAFT ________



(EGR-NGGC-0153-1-2-9)

ATTACHMENT 1
Sheet 4 of 4
Decreasing Setpoints (Form 1-3)

PE	______________	$Bias_1$	______________
PME	______________	$Bias_2$	______________
TDU_{sensor}	______________	$Bias_3$	______________
TDU_1	______________	Total Bias	______________
TDU_2	______________		
TDU_3	______________		

$$TLU = (PE^2 + PME^2 + TDU_{sensor}^2 + TDU_1^2 + TDU_2^2 + TDU_3^2)^{½} + \text{Total Bias}$$

TLU ______________

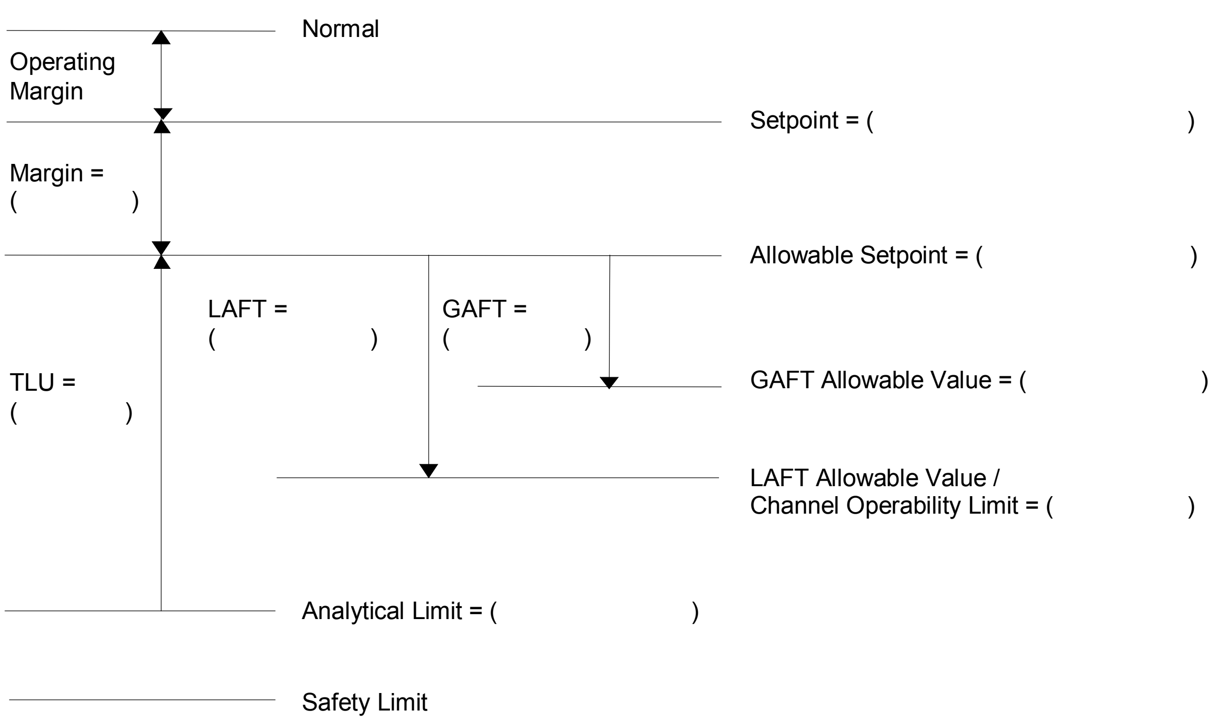
Margin ______________

$$GAFT = (ALT_1^2 + DR_1^2 + MTE_1^2 + \bullet\ \bullet\ \bullet + ALT_n^2 + DR_n^2 + MTE_n^2)^{½}$$

GAFT ______________

$$LAFT = (GAFT^2 + ALT_{sensor}^2 + DR_{sensor}^2 + MTE_{sensor}^2)½$$

LAFT ______________



(EGR-NGGC-0153-1-3-9)

Specific Gravity Determination for Boric Acid Solutions

The most common chemical composition affecting the density of water in Light Water Reactors is boric acid. Boric acid is typically provided in either units of "parts per million (ppm)" or "weight percent". The Method 1 discussion below provides one convenient means of correlating such values to an equivalent specific gravity, that can then be used in making the appropriate corrections for density in the process measurement determination. Alternate methods are acceptable if a documented basis is provided. For example, Method 2 below (based on CR3 calculation I-95-0006) develops the following equations for boric acid density in terms of ppm boron and percent weight of boric acid.

Method 1 (Simplified technique):

A solution of boric acid (B.A.) will have a certain percent by weight (%wt) of boric acid according to the relationship,

$$1 \text{ \%wt B.A.} = \frac{1 \text{ pound B.A.}}{100 \text{ pounds of solution}}$$

By definition,

$$1 \text{ ppm B.A.} = \frac{1 \text{ pound B.A.}}{1{,}000{,}000 \text{ pounds of solution}}$$

Combining these two equations produces,

$$\frac{1 \text{ \%wt B.A.}}{1 \text{ ppm B.A.}} = \frac{1 \text{ pound B.A.}}{100 \text{ pounds of solution}} * \frac{1{,}000{,}000 \text{ pounds of solution}}{1 \text{ pound B.A.}}$$

Simplifying the relationship produces,

$$1 \text{ \%wt B.A.} = 10{,}000 \text{ ppm B.A.}$$

Since concentration is normally stated in ppm boron (B), not ppm B.A., the equation must be modified. Boric acid is H_3BO_3 with a molecular weight of 61.83. Boron's atomic weight is 10.81. Thus, the correction factor becomes,

$$\frac{10.81 \text{ ppm B}}{61.83 \text{ ppm B.A.}}$$

Using this correction factor, the above relationship for boric acid is revised to,

$$1 \text{ \%wt B.A.} = 10{,}000 \text{ ppm B.A.} * \frac{10.81 \text{ ppm B}}{61.83 \text{ ppm B.A.}}$$

$$1 \text{ \%wt B.A.} = 1748 \text{ ppm B}$$

Another way to state this is,

$$1 \text{ ppm B} = 0.000572 \text{ \%wt B.A.}$$

This is the derived conversion factor that will be used in concentration conversions. Next, the conversion factor will be used to determine the Specific Gravity (S.G.) of a solution. The S.G. of a solution of B.A. can be defined by the equation,

$$\text{S.G. of solution} = \frac{[(\text{\%wt } H_2O)(\text{S.G. of } H_2O)] + [(\text{\%wt B.A.})(\text{S.G. of B.A.})]}{100}$$

To find the S.G. of a particular boric acid solution with a known concentration (in ppm Boron) at a certain temperature, follow these steps,

1. Convert the ppm B to %wt B.A. using the derived conversion factor determined above.
2. Determine the water's S.G. (from appropriate tables) for the given temperature.
3. Substitute the values into the equation for the S.G. for a solution.

Consider the following example,

EXAMPLE

Find the S.G. of a 2300 ppm B solution at 100°F.

From steam tables, the S.G. of water at 100°F is determined as 0.99544. From the CRC handbook of Chemistry and Physics, the S.G. of B.A. is determined as 1.435. Using the conversion factor, the ppm B is converted to %wt B.A. as follows,

$$2300 \text{ ppm B} * \frac{0.000572 \text{ \%wt B.A.}}{\text{ppm B}} = 1.3156 \text{ \%wt B.A.}$$

Specific Gravity Determination for Boric Acid Solutions

The %wt of water (H_2O) is determined by subtracting the %wt of B.A. from 100%, or

$$\%wt\ H_2O = 100 - 1.3156 = 98.6844$$

Substituting the values into the equation for the S.G. for a solution produces,

$$\text{S.G. of solution} = \frac{[(98.6844)(0.99544)] + [(1.3156)(1.435)]}{100}$$

$$\text{S.G. of solution} = 1.0012$$

It should be noted that the S.G.of boric acid is 1.435 at 15°C (about 60°F). Due to the small amount of boric acid in the solution, the density change of the boric acid due to temperature is negligible. The density change of the water due to temperature is included.

Method 2 (based on CR3 calculation I-95-0006)

For boric acid density in terms of ppm boron:

$$\rho_{C2} = [(1.973 \times 10^{-6} \times \text{ppm B}) + 1] \times \rho_1$$

and

$$\rho_{C4} = [(2.2305 \times 10^{-6} \times \text{ppm B}) + 0.9991] \times \rho_1$$

where,

ρ_1 = density of water in lbm/ft^3

ppm B = parts per million of boron

ρ_{C2} = density of boric acid solution for <3497 ppm B (2% weight) solutions in lbm/ft^3

ρ_{C4} = density of boric acid solution between 3497 and 6994 ppm B (2 and 4% weight) solutions in lbm/ft^3

Specific Gravity Determination for Boric Acid Solutions

For boric acid density in terms of percent weight of boric acid:

ρ_{C2} = [(0.00345 x %Wt) + 1] x ρ_1

and

ρ_{C4} = [(0.0039 x %Wt) + 0.9991] x ρ_1

where,

ρ_1 = density of water in lbm/ft^3

%Wt = % weight of boric acid

ρ_{C2} = density of boric acid solution for <2% weight (3497 ppm B) solutions in lbm/ft^3

ρ_{C4} = density of boric acid solution between 2 and 4% weight (3497 and 6994 ppm B) solutions in lbm/ft^3

The results from the above CR3 calculation may be used by all NGG sites in lieu of the simplified Method 1 described below.

Conversion of Error Basis

The error basis which provides the most flexible and useful information is "percent of span". However, different devices may have their error expressed in different bases. The following methods are provided for the user to convert from typical bases to "percent span". Many of these methods have been described in examples throughout the design guide. However, they are summarized here for the user's convenience.

1. Upper Range Limit

The upper range limit is associated with an instrument which has an adjustable range, and the upper range limit represents the maximum possible range of the instrument. To convert from upper range limit (URL) to percent span, use the following relationship,

$$\text{Error in \% cal. span} = \frac{(\text{Error in \% URL})(\text{URL})}{(\text{Span})}$$

For example, if the drift accuracy of a transmitter is ±0.5% URL, the span is 0-100 psig, and the URL is 0-400 psig, determine the error in % span.

$$\text{Error in \% cal. span} = \pm \frac{(0.5\%)\ (400\ \text{psig})}{(100\ \text{psig})}$$

$$\text{Error in \% cal. span} = \pm\ 2.0\%$$

2. MTE Ranges

Measurement and test equipment (MTE) frequently has a range which is different from an instrument's range. Thus, the error for the MTE is given in terms of % of its range and must be converted to % of the instrument's span. This is done using the following relationship,

$$\text{Error in \% cal. span} = \frac{(\text{MTE Error in \% of range})(\text{MTE Range})}{(\text{Equivalent Instrument Span})}$$

For example, a pressure transmitter has a span of 0-100 psig. It produces an equivalent signal of 4-20 madc. This is dropped across a 250 ohm resistor at the test point to produce a 1-5 vdc signal. A digital multimeter has a voltage range of 0-25 vdc and an MTE error of ±0.2% of its range. Determine the multimeter's error in % span of the transmitter.

The transmitter has a range of 0-100 psig which also corresponds to 4-20 madc. Instead of measuring the current, however, the multimeter measures the equivalent voltage across a 250 ohm resistor, or 1-5 vdc. The transmitter's equivalent range is then 1-5 vdc, or 4 vdc (i.e., 5 - 1 = 4 vdc). Substituting this into the above equation produces,

$$\text{Error in \% cal. span} = \pm \frac{(0.2\%)(25 \text{ volts})}{(4 \text{ volts})}$$

$$\text{Error in \% cal. span} = \pm 1.25\%$$

[Note: This is just the error of the multimeter and does not include the error of the resistor, which would also need to be determined for the MTE error.]

3. MTE Error as a Percentage of Reading

For some MTE, its error may be expressed as a percentage of its reading. This is especially common for digital meters. To convert to an error expressed in terms of % span of the instrument, the following relationship is used,

$$\text{Error in \% cal. span} = \frac{(\text{Error in \% reading})(\text{Reading})}{(\text{Equivalent Instrument Span})}$$

For example, a piece of test equipment has an accuracy of ±0.3% of reading for all scales. The transmitter's span is 0-100 psig, producing an equivalent signal of 4-20 madc. The test equipment measures this signal as a 1-5 vdc signal across a 250 ohm resistor. The transmitter's setpoint is 50 psig. Determine the test equipment's error in % span.

At the setpoint of the transmitter, the test equipment should read 3 vdc. This is because the 50 psig setpoint is equal to one half of the transmitter's span of 0-100 psig. At 50 psig, the transmitter will output a signal of 12 madc (halfway across the 4-20 madc span) which will be monitored by the test equipment as 3 vdc (halfway across the 1-5 vdc span). Since the test equipment begins with a reading of 1 vdc, this must be subtracted from the 3 vdc to obtain the effective reading of the test equipment, which is 2 vdc. The equivalent instrument span is 1-5 vdc, or 4 vdc (5 - 1 vdc). Substituting these values into the above equation produces,

$$\text{Error in \% cal. span} = \pm \frac{(0.3\%)(2\text{ vdc})}{(4\text{ vdc})}$$

$$\text{Error in \% cal. span} = \pm\ 0.15\%$$

[Note: This is just the error of the test equipment identified and does not include the error of the resistor, which would also need to be determined for the MTE error.]

4. Bias of a Known Maximum Magnitude

Many times a bias of a known maximum magnitude, must be converted to % span of the instrument loop. The bias will typically be expressed in terms of units of the process. This is converted to terms of error in % span by the relationship,

$$\text{Error in \% cal. span} = \frac{(\text{Bias})}{(\text{Span})}$$

For example, the temperature bias in the reference leg of a level transmitter can cause a maximum error of 2 in WC. The transmitter has a span of 250 in WC. Determine the bias error in % span.

$$\text{Error in \% cal. span} = \frac{(2\text{ in WC})}{(250\text{ in WC})}$$

$$\text{Error in \% cal. span} = 0.8\%$$

5. MTE Error with Rounding of Least Significant Digits

Digital meters have an error associated with rounding off to the least significant digit displayed. If the meter displays four or more digits, then the error caused by rounding off to the fourth digit will not add an appreciable amount of error. For meters that display three or fewer digits, the error is equal to half the value of the least significant digit displayed by the digital meter.

For example, a digital multimeter has an error of ± 0.2% of its range plus the error associated with rounding off to the least significant digit. If the meter is used to read 0-20 vdc to ±0.1 vdc, the error for the round-off would be,

$$\text{Error (in vdc)} = \tfrac{1}{2}(\pm 0.1\ \text{vdc}) = \pm 0.05\ \text{vdc}$$

$$\text{Error (in \% of meter's range)} = 100\% * \frac{(0.05\text{vdc})}{(20\text{vdc})} = \pm 0.25\%$$

Thus, the total error for the multimeter would be ±0.2% + 0.25% or ±0.45%. This would then be converted to error in % span of the instrument as described in Section 2 of this Attachment.

Site-Specific Commitments

1.0 Site-Specific Commitments

1.1 [BNP – No specific licensing commitments have been made.]

R2.1, R2.30, R2.32 1.2 [HNP – Committed to Regulatory Guide 1.105, "Instrument Setpoints", Revision 1, as identified in HNP FSAR, page 1.8-135 and to the format described in the Technical Specifications Bases (i.e., either 5 column or 2 column, as appropriate).]

R2.40 1.3 [RNP – In the response to LER 95-009-01, RNP established the following corrective action: "Engineering procedures for performing calculations will be revised and implemented by June 30, 1996, to address the effects of gas under pressure in a closed vessel measurement, and will include the SI accumulator as an example." This corrective action was accomplished by insertion of Example 2 into Section 9.3.1.3 of Revision 0 of this procedure.

SUMMARY OF CHANGES
PRR 615032

SECTION/STEP	CHANGES
Throughout	The justification for the changes to this procedure is 'Due to CR3 being decommissioned CR3 is no longer part of NGG (cessation of power operations letter 3F0213-07.) All references to CR3 are being removed from this procedure. A site specific procedure has been developed for CR3.'
All	Changed revision number to 12.
Cover Page	Updated to reflect procedure no longer applies to CR3. Site-specific procedure EGR-0153 created due to decommissioning efforts.
2.35	Deleted "[CR3 - I&C Design Criteria for Instrument Loop Uncertainty Calculations].'
2.36	Deleted '[CR3 - Environmental Qualification Plant Profile Document (EQPPD)] '
Pg 83, 2nd para.	Deleted '[CR3 - the applicable calibration procedure]'
Pg 86, 5th para.	Deleted '[CR3 - CR3 Environmental Qualification Plant Profile Document (EQPPD)]'
Pg 87, 7th para.	Deleted 'CR3'
Pg 91, 1st para.	Deleted '[CR3 - Vendor information for the applicable loop power supply and the applicable electrical system Enhanced DBD.]'
Pg 94, 1st para.	Deleted '[CR3 - CR3 Environmental Qualification Plant Profile Document (EQPPD)]'
Pg. 94 3rd para.	Deleted '[CR3 - Vendor Qualification Package (VQP)]'
Pg. 102 1st para.	Deleted '[CR3 - I&C Design Criteria for Instrument Loop Uncertainty Calculations, Attachment 1, describes how As-Left and As-Found tolerances should be established.]'
Pg 107, 1st para.	Deleted '[CR3 - I-95-0005, Measurement and Test Equipment Accuracy Calculation]'
Pg. 112, 4th para.	Deleted '[CR3 - The applicable VQP and IR calculation should be used to determine the IR error '
Pg 171, 2nd para.	Deleted 'CR3'
Pg 183 2nd para.	Deleted '1.2 [CR3 – No specific licensing commitments have been made.]'

DUKE ENERGY CORPORATION

TOPICAL REPORT

Quality Assurance Program Description

Operating Fleet

DUKE-QAPD-001 -A-

QUALITY ASSURANCE PROGRAM

POLICY STATEMENT

Duke Energy Corporation (DEC) designs, procures, constructs and operates its nuclear plants in a manner that ensures the health and safety of the public and workers. These activities are performed in compliance with the requirements of the Code of Federal Regulations (CFR), the applicable Nuclear Regulatory Commission (NRC) Facility Operating Licenses, and applicable laws and regulations of the state and local governments.

The applicable Quality Assurance Program (QAP) is the Quality Assurance Program Description (QAPD) contained or referenced in each nuclear plant's Updated Final Safety Analysis Report and the associated implementing documents. Together they provide for control of DEC activities that affect the quality of safety-related nuclear plant structures, systems, and components (SSCs) and include all planned and systematic activities necessary to provide adequate confidence that such SSCs will perform satisfactorily in service. The QA Program may also be applied to certain equipment and activities that are not safety-related, but support safe plant operations, or where other NRC guidance establishes program requirements.

The QAPD is the top-level policy document that establishes DEC's overall philosophy regarding achievement and assurance of quality. Implementing documents assign detailed responsibilities and requirements and define the organizational interfaces involved in conducting activities within the scope of the QAP. Compliance with the QAP is mandatory for individuals involved directly or indirectly with its implementation.

DEC personnel have authority commensurate with their responsibility, including the authority to stop work that does not conform to established requirements. This stop work authority may be exercised in accordance with established nuclear system procedures.

Figure 17-1, Duke Energy Corporation Quality Assurance Policy Statement

Summary of Changes

Changes since last NRC update at Amendment 41

DRR #	Description of Change
02062915	Revised Section 17.3.3.2 to reflect the implementation of independent review consistent with the safety evaluation dated January 13, 2005 to Nuclear Management Company (ML050210276). Site Specific content is deleted for Sections A17.3.3.2, A17.3.4.6, B17.3.3.2, B17.3.4.2, C17.3.3.2, C17.3.4.6, D17.3.3.2, and D17.3.4.5 with the On-Site review Committee responsibilities being consolidated in Section 17.3.3.2. Site specific exceptions for Regulatory Guide 1.33 and ANSI N18.7 in Tables A17-1, B17-1, C17-1, and D17-1 were revised reflecting the revised implementation of the Independent Review requirements. Transition from the Independent Review function described in Amendment 41 to the method in Amendment 42 must be completed by December 31, 2017.
01992862	Revised Table D17-1 for Regulatory Guide 1.88 to clarify the fire protection engineer requirements aligning with SFPE qualifications. Also made similar clarifications for the fire protection engineer required to support audits of the fire protection program in Section 17.3.3.3.3.2.
01994566	Revised Section 17.3.3.3.3.2 Independent Audit of Fire Protection Program to separate audit requirements for sites that have transitioned to NFPA 805 from those for sites that have not. Under NFPA a single triennial audit is required. Change is based on the SE dated June 28, 2010 (ADAMS ML101750602) to Harris. Removed site specific content from A17.3.3.3.3.2, B17.3.3.3.3.2, C17.3.3.3.3.2, and D17.3.3.3.3.2.
02016998	Clarified exception 2 for ANSI N45.2.6 in Tables A17-1, B17-1, and C17-1 to include " or in interface agreements for Duke Energy non-nuclear organizations providing services identified in Section 17.3.1.2.3"
02041305	Revised standard exception in Table 17-1 for Regulatory Guide 1.123, Section 17.3.2.4, and Section 17.3.2.5 to identify that for the procurement of commercial grade calibration and/or testing services, Duke Energy Corporation uses NEI 14-05A. The conditions for the use of this process, consistent with NRC Safety Evaluation dated April 1, 2016 to Union Electric Company, Callaway Plant (ADAMS ML16089A167), are identified in Sections 17.3.2.4 and 17.3.2.5. Revised the discussion of Generic Letter 89-02 in Table 17-1 to address newly issued Regulatory Guide 1.231, Acceptance of Commercial-Grade Design and Analysis Computer Programs Used in Safety-Related Applications for Nuclear Power Plants, Revision 0 January 2017.
02041313	Revised Attachment B, Table B17-1 conformance with Regulatory Guide 1.38 exception 22. to ANSI N45.2.2 Section 6.4.2 item (7) to reflect "The degree of turn shall be established so that the parts receive a coating of lubrication where applicable, and so that the shaft does not come to rest in the position prior to rotation. (90 deg. and 450 deg. rotations are examples.)"

DRR #	Description of Change
02069093	Organization Changes in Section 17.3.1.2. These changes include a change eliminating the NOS site performance assessment teams. The NOS Audit and Quality Control teams remain, therefore these changes do not affect the performance of the QA Functions.
02073170	Revised the final paragraph of Section 17.3.3.3.3.1 by deleting "as identified in site specific information." 10 CFR 20.1101c does not require the reviews to be performed by an independent organization. Corresponding site specific content was removed from Sections A17.3.3.3.3.1, B17.3.3.3.3.1, C17.3.3.3.3.1, and D17.3.3.3.3.1. Revised audit scheduling requirements in Section 17.3.3.3.7 to standardize the scheduling by the month of the audit initiation rather than by the audit exit date as previously stated for Brunswick, Harris, and Robinson. Details in the Tables A17-1, B17-1, C17-1, and D17-1 for audit frequency extensions were revised to refer to extensions as identified in Section 17.3.3.3.7, Audit Frequency Extensions.
02073172	Revised Section 17.3.4 to identify standard content eliminating duplication between the sites and to clarify the difference between the licensing reviews (50.59) and the technical reviews required by the QA Program. Site specific content was reduced or eliminated for the following Sections: A17.3.4.1, Procedures, Tests, and Experiments; A17.3.4.2, Modifications; A17.3.4.4, 10CFR 50.59 Evaluations and Independent Review Control; A17.3.4.5, Nuclear Reviewers; A17.3.4.6, Plant Nuclear Safety Committee; B17.3.4.1 10CFR50.59 and technical reviews; B17.3.4.2, Plant Nuclear Safety Committee (PNSC); B17.3.4.3, HNP Nuclear Oversight Section Independent Review Program; B17.3.4.6, Procedure Review Requirements; C17.3.4.1, Procedures, Tests, and Experiments; C17.3.4.2, Modifications; C17.3.4.4, Review of RNP Technical Specifications Violations; C17.3.4.5, 10CFR 50.59 Review Qualification; C17.3.4.6, Plant Nuclear Safety Committee (PNSC); C17.3.4.7, Nuclear Oversight Section Independent Review Program; C17.3.4.10., Reportable Event Action; C17.3.4.11., Safety Limit Violation; D17.3.4.1, Technical Reviews; D17.3.4.2, 10 CFR 50.59 Reviews; D17.3.4.5, On-Site Review Committee; and D17.3.4.6, Reportable Event Action.

CONTENTS

LIST OF FIGURES:

LIST OF TABLES

17 QUALITY ASSURANCE

17.1 QA DURING DESIGN AND CONSTRUCTION

NOTE: Not included, this description of the Quality Assurance Program follows Standard Review Plan Section 17.3 for format and content.

17.2 OPERATIONAL QA

NOTE: Not included, this description of the Quality Assurance Program follows Standard Review Plan Section 17.3 for format and content.

17.3 QUALITY ASSURANCE PROGRAM DESCRIPTION

INTRODUCTION

The Duke Energy Corporation Quality Assurance Program (QAP) Policy Statement in Figure 17-1 describes the corporate policy and assigns responsibility for implementation of the QAP.

Duke Energy Corporation maintains full responsibility for assuring its nuclear power plants are designed, constructed, tested and operated in conformance with good engineering practices, applicable regulatory requirements and specified design bases and in a manner to protect the public health and safety. To this end Duke Energy Corporation has established and implemented a Quality Assurance Program which conforms to the criteria established in Appendix B to Title 10 Code of Federal Regulations (10 CFR), Part 50, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants" published June 27, 1970 (35 F. R. 10499), amended September 17, 1971 (36 F. R. 18301), amended January 20, 1975 (40 F. R. 3210D), and amended August 28, 2007 (72 F. R. 49505).

This document follows the format and content guidance of NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants", Section 17.3, "Quality Assurance Program Description," except that the Duke Energy Corporation QAP is based on ANSI N18.7 and the ANSI N45.2 series standards in lieu of ANSI/ASME NQA-1 and NQA-2. This document is applicable to Duke Energy Corporation operating nuclear power stations as referenced by Chapter 17 of each station's UFSAR for those systems, components, items, and services that have been determined to be nuclear safety related.

This document is organized with a generic description of the organization and overview of the QAP in the main body of the document. Site specific details for the Quality Assurance Program Description along with conformance to the regulatory positions of the NRC QA Regulatory Guides are addressed in separate attachments as follows:

- Attachment A, Brunswick Specific QAPD
- Attachment B, Harris Specific QAPD
- Attachment C, Robinson Specific QAPD
- Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Each Attachment follows the section numbering in the main body of the document. The Brunswick, Harris, and Robinson attachments contain the conformance to the QA related Regulatory Guides, identified in Table 17-1, transferred from Chapter 1 of each respective UFSAR. Each attachment also contains supplemental descriptions, with approved changes, transferred from each respective UFSAR Chapter 17, Section 17.3 when detail was included

beyond the generic text in the main body. Attachment D contains the conformance to the QA related Regulatory Guides, identified in Table 17-1, transferred from Amendment 40 of the Duke Energy Carolinas Topical Report Quality Assurance Program. Attachment D also contains supplemental descriptions, with approved changes, from Amendment 40 of Duke Energy Carolinas Topical Report Quality Assurance Program when detail was included beyond the generic text in the main body.

As discussed herein, the Quality Assurance Program (QAP) includes the description contained in this document and the controlled documents providing implementation of the requirements of this document, including the requirements of industry standards to the degree identified in Table 17-1, Conformance with QA Regulatory Guides and Industry Standards, and Table 17-2, Site Specific Response to Regulatory Guides and Industry Standards. The QAP provides a method of applying graded controls to certain non-safety related systems, components, items, and services (such as fire protection and radioactive waste structures, systems, and components).

Subsequent changes to the Duke Energy Corporation QAP are incorporated in this document as identified in Section 17.3.1.7. The QAP controlled implementing documents are used and updated as necessary to assure the nuclear generating units are managed such that they will be operated and maintained in a safe manner.

DEFINITIONS

The following definitions are applicable to terms used in this report. Refer to ANSI N45.2.10, "Quality Assurance Terms and Definitions" for definition of terms not included below.

Audit – The following modifications are applied to the definition in ANSI N45.2.10:

> Internal Audit - An activity to determine through investigation the adequacy of, and adherence to, established procedures, instructions, specifications, codes, and licensing requirements, and the effectiveness of implementation of the Duke Energy Corporation QAP.
>
> Supplier Audit - A documented activity performed in accordance with written procedures or checklists to verify, by examination and evaluation of objective evidence, that applicable elements of the supplier's QA program has been developed, documented and implemented in accordance with specified requirements.

Basic Component – See 10 CFR Part 21.

Commercial Grade Items - See 10 CFR Part 21.

Deficiency - Any condition considered to be adverse to quality including inadequacies of personnel, procedures, systems, methods, or items.

Engineering Change (Modification) - A planned change in plant design accomplished in accordance with the requirements and limitations of applicable codes, standards, specifications, licenses and predetermined safety restrictions.

Hold Point - That point in the manufacturing, preparation, development, installation and construction, inspection, or testing process that requires witness or review by qualified personnel.

Inspector - Any individual certified to the requirements identified in Table 17-1 for Regulatory Guide 1.58 who performs required inspections, tests or examinations.

Pre-award Survey - A documented activity performed in accordance with written procedures or checklists to verify, by examination and evaluation of objective evidence, that the supplier's QA

program has been developed, documented, and implemented in accordance with specified requirements.

Quality Assurance (QA) - The planned and systematic actions necessary to provide adequate confidence that a structure, system, or component will perform satisfactorily in service.

QA Records - Those records which furnish documentary evidence of the quality of items and of activities affecting quality.

QA Requirements - Those inspection, test, examination, certification and documentation requirements which are imposed to provide objective evidence of the conformance of an item or activity to established design, engineering, standards, and code requirements.

Services - The performance by a supplier of activities such as calibration, design, investigation, inspection, nondestructive examination, software applications, and installation.

EXPLANATION OF “QUALITY ASSURANCE”

Quality Assurance (QA) as used in this document includes:

1) Performance of planned and systematic actions necessary to provide assurance of the safety and integrity of the facility.

   The QAP is founded on the principle that the line organization has the primary responsibility for quality and safety. Self-assessment practices are used to ensure the desired levels of quality and safety are achieved and maintained. Each individual is responsible to ensure the plant is operated in a safe, reliable, and efficient manner.

2) Quality verifications performed by those independent of the performers.

   When required, verification of conformance to established program requirements is accomplished by qualified individuals who do not have responsibility for performing or directly supervising the work. Nuclear Oversight (NOS) evaluates the performance, compliance, and effectiveness of plant programs, processes, and personnel. The activities of NOS are intended to detect deficiencies in the desired levels of performance and quality, communicating these conditions to those responsible for the activities, appropriate management and the Chief Nuclear Officer, and ensuring adequate action is taken to correct these conditions.

QA STANDARDS AND GUIDES

The Duke Energy Corporation QAP conforms to Appendix B of 10 CFR 50. This description of the QA Program is formatted per NUREG-0800 Section 17.3, "Quality Assurance Program Description;" however, the Duke Energy Corporation QAP continues to use the ANSI N45.2 series standards in lieu of ANSI/ASME NQA-1 and NQA-2.

Table 17-1 identifies the QA program Regulatory Guides and other NRC program guidance for which conformance is addressed in this description of the QA Program. Changes to conformance for the Regulatory Guides in Table 17-1 are controlled in accordance with 10 CFR 50.54(a) and are incorporated in this document as identified in Section 17.3.1.7.

Table 17-2 identifies additional Regulatory Guides that relate to QA program implementation but where the subject matter closely relates to UFSAR technical content. Conformance for those Regulatory Guides is site specific and addressed with each site's UFSAR.

Together, Tables 17-1 and 17-2 indicate where conformance is identified for the regulatory guidance documents referenced in NUREG-0800 Section 17.3.

Table 17-1. Conformance with QA Regulatory Guides and Industry Standards

Generic Exception:

Table 17-1 addresses Duke Energy Corporation's Conformance of the Quality Assurance Program to certain NRC Regulatory Guides. In so doing, specific editions of industry standards are identified for compliance with exceptions and alternatives. Those identified standards include references to other industry standards for activities. Those referenced industry standards are considered to be guidance documents for details of how activities may be accomplished. The actual standard to be used in such cases is controlled by each station's current licensing and design bases (e.g. ANSI N18.7-1976 Section 3.4.2 identifies American National Standard for Selection and Training of Nuclear Power Plant Personnel, N18.1-1971. The actual standard used is site specific as identified in Table 17-2 for Regulatory Guide 1.8.).

Regulatory Guide 1.28, Quality Assurance Program Requirements (Design and Construction)
The Duke Energy Corporation QAP conforms to Regulatory Guide 1.28 as identified in: • Attachment A, Brunswick Specific QAPD • Attachment B, Harris Specific QAPD • Attachment C, Robinson Specific QAPD • Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Regulatory Guide 1.30, Quality Assurance Requirements for the Installation, Inspection and Testing of Instrumentation and Electric Equipment
The Duke Energy Corporation QAP conforms to Regulatory Guide 1.30 as identified in: • Attachment A, Brunswick Specific QAPD • Attachment B, Harris Specific QAPD • Attachment C, Robinson Specific QAPD • Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Regulatory Guide 1.33, Quality Assurance Program Requirements (Operation)
The Duke Energy Corporation QAP conforms to Regulatory Guide 1.33 as identified in: • Attachment A, Brunswick Specific QAPD • Attachment B, Harris Specific QAPD • Attachment C, Robinson Specific QAPD • Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Table 17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.37, Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants
The Duke Energy Corporation QAP conforms to Regulatory Guide 1.37 as identified in: • Attachment A, Brunswick Specific QAPD • Attachment B, Harris Specific QAPD • Attachment C, Robinson Specific QAPD • Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Regulatory Guide 1.38, Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage and Handling of Items for Water-Cooled Nuclear Power Plants
The Duke Energy Corporation QAP conforms to Regulatory Guide 1.38 as identified in: • Attachment A, Brunswick Specific QAPD • Attachment B, Harris Specific QAPD • Attachment C, Robinson Specific QAPD • Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Regulatory Guide 1.39, Housekeeping Requirements for Water-Cooled Nuclear Power Plants
The Duke Energy Corporation QAP conforms to Regulatory Guide 1.39 as identified in: • Attachment A, Brunswick Specific QAPD • Attachment B, Harris Specific QAPD • Attachment C, Robinson Specific QAPD • Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Regulatory Guide 1.58, Qualification of Nuclear Power Plant Inspection, Examination and Testing Personnel
The Duke Energy Corporation QAP conforms to Regulatory Guide 1.58 as identified in: • Attachment A, Brunswick Specific QAPD • Attachment B, Harris Specific QAPD • Attachment C, Robinson Specific QAPD • Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Table 17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.64, Quality Assurance Requirements for the Design of Nuclear Power Plants
The Duke Energy Corporation QAP conforms to Regulatory Guide 1.64 as identified in: • Attachment A, Brunswick Specific QAPD • Attachment B, Harris Specific QAPD • Attachment C, Robinson Specific QAPD • Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Regulatory Guide 1.74, Quality Assurance Terms and Definitions
The Duke Energy Corporation QAP conforms to Regulatory Guide 1.74 as identified in: • Attachment A, Brunswick Specific QAPD • Attachment B, Harris Specific QAPD • Attachment C, Robinson Specific QAPD • Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Regulatory Guide 1.88, Collection, Storage, and Maintenance of Nuclear Power Plant Quality Assurance Records
The Duke Energy program for storage of records on microfilm, dual storage or in electronic format meets the preservation requirement for the retention of QA Records. For management of electronic records, the appropriate controls on quality are summarized as follows: a) The Electronic Records Management (eRM) system does not allow deletion or modification of records. (NOTE: Authorized deletion of records per the Record Retention Rules is controlled.) b) The eRM system provides redundancy (i.e., system backup, dual storage, etc.). c) The legibility of each record is verified prior to acceptance into the eRM system. d) The media used by the eRM system is maintained to ensure the records are acceptably copied onto a new media before the manufacturer's certified useful life of the media is exceeded. This includes verification of the records so copied. e) Periodic random inspections of records are performed to verify that there has been no degradation of record quality. f) If the eRM system in use is to be replaced by new system, the records stored on the old system are acceptably converted into the new system before the old system is taken out of service. This includes verification of the records so copied. To implement those controls, Duke Energy Corporation uses the following Nuclear Information and Records Management Association (NIRMA) standards: • NIRMA TG 11-2011 “Authentication of Records and Media” • NIRMA TG 15-2011, “Management of Electronic Records,” • NIRMA TG 16-2011, “Software Quality Assurance Documentation and Records” • NIRMA TG 21-2011, “Required Records Protection, Disaster Recovery and Business Continuation”

Table 17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.88, Collection, Storage, and Maintenance of Nuclear Power Plant Quality Assurance Records
The Duke Energy Corporation QAP conforms to Regulatory Guide 1.88 as identified in: • Attachment A, Brunswick Specific QAPD • Attachment B, Harris Specific QAPD • Attachment C, Robinson Specific QAPD • Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Regulatory Guide 1.94, Quality Assurance Requirements for Installation, Inspection, and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants
The Duke Energy Corporation QAP conforms to Regulatory Guide 1.94 as identified in: • Attachment A, Brunswick Specific QAPD • Attachment B, Harris Specific QAPD • Attachment C, Robinson Specific QAPD • Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Regulatory Guide 1.116, Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems
The Duke Energy Corporation QAP conforms to Regulatory Guide 1.116 as identified in: • Attachment A, Brunswick Specific QAPD • Attachment B, Harris Specific QAPD • Attachment C, Robinson Specific QAPD • Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Regulatory Guide 1.123, Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants
Duke Energy Corporation follows Generic Letter 89-02 and EPRI NP-5652 for procurement of Commercial Grade Items and services. For the procurement of commercial grade calibration and/or testing services, Duke Energy Corporation uses NEI 14-05A, Revision 0, "Guidelines for the Use of Accreditation In Lieu of Commercial Grade Surveys for Procurement of Laboratory Calibration and Test Services." The conditions for the use of this process, consistent with NRC Safety Evaluation dated April 1, 2016 to Union Electric Company, Callaway Plant (ADAMS Accession # ML16089A167), are identified in Sections 17.3.2.4 and 17.3.2.5.

Table 17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.123, Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants
Note: Well defined and documented measurement assurance techniques or uncertainty analysis may be used to verify the adequacy of the measurement process. If such techniques are not used, the collective uncertainty of the measurement standards shall not exceed 25% of the acceptable tolerance for each characteristic being calibrated. (This is typically referred to as the four-to-one ratio.) The Duke Energy Corporation QAP conforms to Regulatory Guide 1.123 as identified in: • Attachment A, Brunswick Specific QAPD • Attachment B, Harris Specific QAPD • Attachment C, Robinson Specific QAPD • Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Regulatory Guide 1.144, Auditing of Quality Assurance Programs for Nuclear Power Plants
The Duke Energy Corporation QAP conforms to Regulatory Guide 1.144 as identified in: • Attachment A, Brunswick Specific QAPD • Attachment B, Harris Specific QAPD • Attachment C, Robinson Specific QAPD • Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Regulatory Guide 1.146, Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants
The Duke Energy Corporation QAP conforms to Regulatory Guide 1.146 as identified in: • Attachment A, Brunswick Specific QAPD • Attachment B, Harris Specific QAPD • Attachment C, Robinson Specific QAPD • Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Regulatory Guide 1.152 Criteria for Programmable Digital Computer System Software in Safety-Related Systems of Nuclear Power Plants
Conformance to Regulatory Guide 1.152 was not addressed during the licensing of the operating Duke Energy Corporation Nuclear plants.

Table 17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 7.10, Establishing Quality Assurance Programs for Packaging Used in the Transport of Radioactive Material
Duke Energy Corporation does not conform to Regulatory Guide 7.10. This QAPD is used to satisfy applicable Quality Assurance requirements for packaging and transportation of radioactive material.

Generic Letter 89-02, Actions to Improve the Detection of Counterfeit and Fraudulently Marketed Products
Generic Letter (GL) 89-02 endorses EPRI NP-5652, *"Guideline for the Utilization of Commercial-Grade Items in Nuclear Safety-Related Applications (NCIG-07)"*, which is used by Duke Energy Corporation. When NRC publishes additional guidance for the dedication of Commercial Grade Items, Duke Energy may utilize that guidance in the completion documentation provided any clarifications identified by the NRC are followed. Regulatory Guide 1.231 Acceptance of Commercial-Grade Design and Analysis Computer Programs Used in Safety-Related Applications for Nuclear Power Plants, Revision 0 January 2017 Duke Energy complies with the provisions of Regulatory Guide 1.231 which approves for use, with clarifications, EPRI Technical Report 1025243, "Plant Engineering: Guideline for the Acceptance of Commercial-Grade Design and Analysis Computer Programs Used in Nuclear Safety-Related Applications," Revision 1.

Quality assurance for Fire Protection from Positions 2 & 4 of Branch Technical Position CMEB 9.5-1 (Attachment to NUREG 0800 Section 9.5.1 Revision 3)
Quality assurance controls for non-Nuclear Safety Related components Important to Fire Protection are in accordance with the intent of Positions 2 & 4 of Branch Technical Position CMEB 9.5-1. Identification of items Important to Fire Protection is site specific consistent with each site's Fire Protection Program.

Table 17-2. Site Specific Response to Regulatory Guides and Industry Standards

Table 17-2 identifies additional Regulatory Guides addressing subjects related to implementation of the QAP but the implementation is site specific and addressed with each site's UFSAR.

Regulatory Guide 1.8, Personnel Selection and Training
Personnel selection and training is site specific addressing requirements beyond nuclear safety related applications.

Regulatory Guide 1.26, Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants
Quality group classifications and standards trace to the original design and construction of the nuclear power plant and therefore are site specific.

Regulatory Guide 1.29, Seismic Design Classification
Seismic design classification trace to the original design and construction of the nuclear power plant and therefore is site specific.

Regulatory Guide 1.36, Nonmetallic Thermal Insulation for Austenitic Stainless Steel
Nonmetallic thermal insulation for austenitic stainless steel trace to the original design and construction of the nuclear power plant and therefore is site specific.

Regulatory Guide 1.54, Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants
Requirements for protective coatings applied to water-cooled nuclear power plants trace to the original design and construction of the nuclear power plant and therefore is site specific.

Regulatory Guide 1.143, Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light-Water-Cooled Nuclear Power Plants
Design of radioactive waste management systems, structures, and components installed in light-water-cooled nuclear power plants trace to the original design and construction of the nuclear power plant and therefore is site specific.

Regulatory Guide 1.155, Station Blackout
Addressing Station Blackout is site specific.

Table 17-2. Site Specific Response to Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 4.15, Quality Assurance for Radiological Monitoring Programs (Normal Operations) – Effluent Streams and the Environment
Requirements for radiological monitoring program (normal operations) – effluent streams and the environment is site specific.

17.3.1 MANAGEMENT

17.3.1.1 Methodology

The Chief Nuclear Officer is the corporate executive responsible for quality assurance (QA) and is the highest level of management responsible for establishing Duke Energy Corporation's QA policies, goals, and objectives.

The QAP Policy Statement, shown in Figure 17-1, requires compliance with the QAP implementing documents in nuclear safety related matters. Organizations performing quality affecting activities are bound by this Policy Statement. The QAP has been developed in accordance with this Policy Statement. The QAP applies to individuals and organizations responsible for operating and supporting the nuclear plants in the performance of activities affecting quality (e.g., operation, maintenance, modification, and refueling). The implementing documents define responsibilities and authorities, prescribe measures for the control and accomplishment of activities for the operation of nuclear safety related structures, systems, and components and requires appropriate verification of conformance to established requirements to an extent consistent with their importance to safety. The individuals who constitute Nuclear Generation have full personal and corporate responsibility to assure that nuclear power plants are designed, constructed, tested and operated in a manner to protect the public health and safety. The comprehensive program to assure this began with initial design and continues throughout the life of the station. The Duke Energy Corporation QAP assures that the necessary quality requirements for nuclear safety related structures, systems, components and materials are achieved. All special equipment, environmental conditions, skills and processes that are determined to be nuclear safety related will be provided within the scope of the QAP.

Nuclear safety related structures, systems, and components (SSCs) are specified by approved design documents. Each nuclear plant has a controlled system for identifying items and activities to which the QAP applies. Controls and responsibilities for maintaining the system are prescribed in procedures.

The QAP applies to the nuclear safety related portions of the plant. The program is applied, in whole or in part, to other selected items based on the item's or activity's importance to safety. This application includes but is not limited to control and accomplishment of activities for radioactive waste, fire protection, seismically designed/restrained SSCs whose continued functions are not required during and after a seismic event, and License Renewal non-safety-related SSCs that are subject to an aging management review. Procedures provide a graded application of this QAP to non-safety related systems, components, items, and services by prescribing measures for the control and accomplishment of activities for their operation. For example, aging effects of non-safety related SSCs that were determined to be within the scope of License Renewal Aging Management Program as identified in Chapter 18 of the applicable site UFSAR, are included in the QAP for the administrative controls, corrective actions and confirmation processes described in Sections 17.3.1.6 and 17.3.2.13, Corrective Action, and 17.3.2.14, Document Control.

The QAP is founded on the principle that the line organization has the primary responsibility for quality and safety. Self-assessment practices are used to ensure the desired levels of quality and safety are achieved and maintained. This consists of each individual being involved with plant performance to ensure the plant is operated in a safe, reliable, and efficient manner. The Nuclear Oversight (NOS) Department evaluates the compliance, and effectiveness of plant programs, processes, personnel, and the line organization's self-assessment.

17.3.1.2 Organization

This section provides a generic functional description of the organization. The actual organization in-place is defined in a controlled implementing document containing the fleet operating model.

Plant specific details for the organization responsible for the safe plant operation are described in Chapter 13 of the UFSAR for each plant and in implementing documents. The term "line organization" refers to the production organization reporting to the Chief Nuclear Officer and the interfacing department staff supporting the Nuclear Generation as identified in Section 17.3.1.2.3, Department Interfaces. "Line organization" does not include the independent verification functions of the Nuclear Oversight organization.

17.3.1.2.1 Corporate Organization

The Chairman, President and Chief Executive Officer has overall responsibility for Design, Construction, Operation, and Decommissioning of generation facilities. Reporting to the Chairman, President and Chief Executive Officer is the Executive Vice President and Chief Operating Officer, who is responsible for generation and transmission including nuclear operations, nuclear development and nuclear decommissioning. Reporting to the Executive Vice President and Chief Operating Officer are the Senior Vice President and Chief Nuclear Officer (CNO), who has the overall authority and responsibility for Nuclear Generation, and the executive for Operations Support, whose responsibilities include Nuclear Decommissioning. Nuclear Decommissioning is controlled under a separate description of the quality assurance program as identified in the UFSAR for that facility.

As described in Section 17.3.1.2.3, Nuclear Generation receives support services from other organizations, reporting to the Chief Operating Officer, having responsibilities for supply chain, environmental, health and safety and non-nuclear generation activities including: fossil and hydro generation; coal combustion product strategic management; and fuels and system optimization. Services also are provided to Nuclear Generation by Group Executives, reporting to the President and Chief Executive Officer, responsible for the following: electrical distribution; support for the emergency response communications; and Information Technology Services. The interfaces with organizations providing those activities are described in Section 17.3.1.2.3. As such, the attainment of quality rests with those assigned the responsibility of performing the activity. The verification of quality is assigned to qualified personnel independent of the responsibility for performance or direct supervision of the activity. The degree of independence varies commensurate with the activity's importance to safety.

The policies described in this document are implemented through departmental program manuals and procedures, and are, thereby, available to all levels of management.

17.3.1.2.2 Nuclear Generation

Nuclear Generation has direct line responsibility for Duke Energy Corporation nuclear station operations. Nuclear Generation is responsible for achieving quality results during engineering, preoperational testing, operation, testing, maintenance and modification of the Corporation's nuclear stations and with complying with applicable codes, standards and NRC regulations. The functions of Nuclear Generation are directed by the CNO.

The CNO formulates, recommends, and carries out plans, policies, and programs related to the nuclear generation of electric power. The CNO is informed of significant problems or

occurrences relating to safety and QA through established administrative procedures and participates directly in their resolution, where necessary.

Nuclear Generation is organized into three divisions. The activities of each division are directed by an executive who reports to the CNO. The divisions are Nuclear Corporate, Nuclear Oversight, and Nuclear Operations.

The CNO has the organizational flexibility to reassign responsibilities, within the limits specified in the following section, between the standard divisions to provide added focus on areas determined to need increased management attention. This flexibility includes both the ability to consolidate divisions or to identify new divisions. The actual organization in-place is defined in a controlled document containing the fleet operating model.

a) NUCLEAR CORPORATE

The senior executive(s) reports to the CNO and is responsible for Corporate Governance and support functions to the Nuclear Sites in the following areas: Nuclear Engineering; Nuclear Regulatory Affairs; Nuclear Support Services; Nuclear Protective Services; Nuclear Operations; Nuclear Corporate Organizational Effectiveness; Nuclear Training; and Emergency Preparedness.

The organizational structure for these functions may vary based on near-term activities and the strategic importance of our fleet initiatives, in our continuing efforts to set and achieve industry-leading operational and outage performance. These functions are primarily off-site located in the Nuclear General Office (NGO).

NUCLEAR ENGINEERING

Nuclear Engineering provides broad engineering leadership and technical support to the nuclear sites with emphasis on generic issues and consistent practices, providing expertise in safety assessment with technical support in the areas of risk assessment, radiological engineering, and safety analysis; fuel management with leadership and technical support in the areas of fuel supply, spent fuel management, reactor core mechanical and thermal hydraulic analysis; the fleet electrical and procurement engineering with technical support in the areas of procurement engineering, nuclear process systems, and electrical systems and analysis; and programs and components support in the areas of steam generator inspections and maintenance, engineering programs, component engineering, material failure analysis and materials science, equipment reliability, and ASME Code inspections and testing. Nuclear Engineering provides support to Site engineering for contracts and engineering related to fleet and nuclear site major project modifications.

Nuclear Engineering provides record storage and document management services, technology planning, project control and technical support for information technology applications and systems such as equipment databases, applications, infrastructure, and plant process information systems.

Nuclear Engineering is also responsible for Nuclear Development, which includes the licensing actions needed in support of new nuclear site development under 10 CFR Part 52. Responsibilities also include engineering oversight of contractors, site layout, staffing and program development, and operational readiness. Nuclear Development activities are controlled under a separate description of the quality assurance program as identified in the UFSAR for those facilities.

NUCLEAR MAJOR PROJECTS

Nuclear major projects provides project management for select projects critical to the success of the Nuclear Generation Department. This responsibility includes scope development,

estimating, planning and scheduling, project controls, timely and accurate financial reporting, contract management, and execution of assigned projects.

NUCLEAR REGULATORY AFFAIRS

Nuclear regulatory affairs provides fleet support to and governance of the site regulatory affairs and licensing activities to help improve overall fleet performance.

NUCLEAR SUPPORT SERVICES

Nuclear support services provides fleet support to the nuclear sites for laboratory, calibration, and select maintenance and refueling activities.

NUCLEAR PROTECTIVE SERVICES

Nuclear protective services provides access authorization support to the nuclear sites security organization. Nuclear protective services is responsible for governance of the site security functions, providing assistance to help improve overall fleet performance.

NUCLEAR OPERATIONS

Nuclear operations is responsible for governance of the nuclear site operating organizations, providing assistance to promote improvements to overall fleet performance.

NUCLEAR CORPORATE ORGANIZATIONAL EFFECTIVENESS

Nuclear corporate organizational effectiveness is responsible for governance of the nuclear site performance improvement organizations, providing assistance to promote improvements to overall fleet performance through the corrective action and self-assessment programs. This group also supports implementation of the corrective action and self-assessment programs by the Nuclear Corporate Organization.

NUCLEAR TRAINING

Nuclear training is responsible for governance of the nuclear site training organizations, providing assistance to promote improvements to overall fleet performance. This group also supports implementation of the training programs by the Nuclear Corporate Organization.

EMERGENCY PREPAREDNESS

Emergency preparedness is responsible for governance of the nuclear site emergency response organizations, providing assistance to promote improvements to overall fleet performance.

b) NUCLEAR OVERSIGHT

The executive for Nuclear Oversight (NOS) reports to the CNO and is located in the NGO. NOS consists of both site assigned and NGO located personnel. NOS provides oversight of the NGO, Departmental Interfaces, and the nuclear sites with QA program audits, vendor quality, and quality control. In addition, NOS coordinates the off-site review board, which provides an advisory function to senior management. NOS also provides oversight of Nuclear Development and Nuclear Decommissioning through QA program audits. The NOS executive has the authority and organizational freedom to: identify quality problems, initiate, recommend or provide solutions to quality problems through designated channels, verify the implementation of solutions to quality problems, and ensure cost and schedule do not influence decision making involving quality. This includes full access to Nuclear Development and Nuclear Decommissioning and all levels of management up to and including the Chief Executive Officer.

The NOS executive has primary ownership of the department QA program description (this document) and is responsible for interpretation and resolution of QA issues.

If significant quality problems are identified, NOS personnel have the authority to stop work as discussed in Section 17.3.1.4 pending satisfactory resolution of the identified problem.

Also reporting to the executive for NOS is Employee Concerns, which investigates concerns identified through the Employee Concerns Program to determine their validity and initiate corrective actions as appropriate. Employee Concerns also promotes the Safety Conscious Work Environment (SCWE) Program and is sensitive to SCWE concerns during investigations.

c) NUCLEAR OPERATIONS

The executive for Nuclear Operations reports to the CNO and is located in the NGO. This executive is responsible for the safe operation of the nuclear stations. Reporting to this executive are the executives for the operation of the nuclear stations.

The organization structure for each site is controlled by the site's UFSAR, which may vary from the following generic description. Reporting to the site executive for each nuclear station is a Nuclear Plant Manager who is assigned the direct responsibility for the safe operation of the facility including operations, maintenance, work management, radiation protection, chemistry, and environmental services. Also reporting to the site executive is a site Engineering manager; a site Training manager; and an Organization Effectiveness manager, typically having responsibility for regulatory affairs, emergency preparedness, performance improvement, and procedures. Each site executive also has a Security manager assigned to provide services to the site. The qualification requirements for the Nuclear Plant personnel are in accordance with the provisions of ANSI N18.1 or ANS 3.1 as identified in each site's UFSAR and Technical Specifications.

17.3.1.2.3 Department Interfaces

Quality related activities performed by departments other than Nuclear Generation are identified by and conducted in accordance with controls identified in approved departmental interface agreements. The following are generic descriptions of those other corporate departments and the services they provide. These generic organizations are referred to, as appropriate, within this document; however, approved departmental interface agreements establish and define the applicability of the QAP to the services they provide.

CORPORATE COMMUNICATIONS

Corporate Communications provides support for the nuclear site emergency response organization.

ENVIRONMENTAL HEALTH AND SAFETY

Environmental, Health and Safety provides occupational safety and environmental and laboratory support services.

NUCLEAR FINANCE

Nuclear Finance provides support for the nuclear sites in the areas of financial planning.

INFORMATION TECHNOLOGY

Information Technology provides a variety of services and technical support to Nuclear Generation for information technology applications and systems such as equipment databases, applications, and infrastructure including the electronic document management system and telecommunication systems.

CUSTOMER OPERATIONS

Customer Operations provides electrical distribution and switchyard engineering, as well as providing electrical maintenance and testing support.

NUCLEAR SUPPLY CHAIN

Nuclear Supply Chain provides procurement services including receipt inspection/testing, storage, and inventory control of materials, parts, and components.

17.3.1.3 Responsibility

The primary responsibility for quality performance, including the identification and effective correction of problems potentially affecting the safe and reliable operation of the Company's nuclear facilities, resides with the line organization. The individuals who constitute Nuclear Generation have full personal and corporate responsibility to assure nuclear power plants are designed, constructed, maintained, tested and operated in a manner to protect the public health and safety; and to assure the effectiveness of the QAP.

Appropriate procedures are developed, approved by the responsible implementing manager, issued for use, and used at the location where the prescribed activity is performed, where appropriate. Managers assure that their personnel are adequately trained for their jobs and they have the experience and education required to carry out their assigned responsibilities. These managers ensure that adequate resources and procedures are available for correctly implementing the work activities. Sufficient personnel, including necessary resources, are available and trained prior to performing activities that affect quality.

Independent inspections are conducted to verify specific critical quality attributes. Individuals performing these inspections have access to necessary information to ensure that activities and equipment meet established acceptance criteria.

NOS is responsible for monitoring and auditing activities that are performed by the line organization for, or in support of, Duke Energy Corporation's Nuclear Plants and Nuclear Generation. These activities include those performed at the individual plant sites, corporate offices, and other Nuclear Generation locations. NOS performs audits to verify that applicable elements of the quality assurance and other regulatory required programs have been developed, documented and effectively implemented in accordance with specified requirements. NOS monitors supplier performance to assure implementation of the applicable quality assurance program requirements. A periodic briefing of NOS activities, along with any potential findings and recommendations, is presented to the Chief Nuclear Officer.

The Chief Nuclear Officer is responsible for ensuring that the results and effectiveness of the nuclear oversight program are regularly evaluated as discussed in Section 17.3.3.3.6, Independent Audit of QA Functions.

17.3.1.4 Authority

Personnel involved in quality activities have the authority and responsibility to stop work if they discover deficiencies in quality.

Personnel performing the QA functions have the authority and responsibility to stop unsatisfactory work and to assure the item/activity is controlled to prevent further processing, delivery, installation, or use until authorized by appropriate management.

Procedures outline the methodology for resolution of disputes involving quality and nuclear safety issues arising from a difference of opinion between identifying personnel and other groups.

17.3.1.5 Personnel Training and Qualification

Both on-site and off-site personnel who perform activities affecting quality (implement requirements of the QAP) are indoctrinated and trained such that they are knowledgeable and capable of performing their assigned tasks.

Training programs and reviews ensure that proficiency of personnel performing activities affecting quality is achieved and maintained by training, examining, and/or certifying, as appropriate.

Training programs are modified to reflect station engineering changes and changes in procedures.

Personnel training and qualification records are to be maintained in accordance with procedures.

Personnel within the Operating organization performing duties of a licensed operator are indoctrinated, trained, and qualified as required by 10 CFR 55 Operators' Licenses.

17.3.1.6 Corrective Action

It is the policy of Duke Energy Corporation to seek improvement in each nuclear plant's performance as well as in the performance of supporting Departments. Duke Energy Corporation has established a corrective action process whereby all personnel are expected to assure conditions adverse to quality are promptly identified, controlled, and corrected. Individuals are encouraged to voluntarily report events, near misses, and potential problems. In the case of significant conditions adverse to quality, the process assures that the cause of the condition is determined and action be taken to preclude repetition. This process also provides for trending of problems to detect adverse trends in quality performance, including reporting of results to appropriate levels of management.

Management will emphasize to all levels in the organization the importance of identifying and effectively correcting situations that can adversely affect human and equipment performance. An important aspect of this program is the assignment of qualified personnel to accurately evaluate equipment/human performance problems, implement appropriate corrective actions, and verify corrective action adequacy.

Management is responsible for fostering a positive environment that encourages the self-identification of adverse conditions and trends. This includes assuring the process is administered to correct the problem rather than to establish blame or fault.

License Renewal non-safety-related SSCs that are subject to an aging management review are included in the scope of the corrective action program.

Section 17.3.2.13, Corrective Action provides additional detail.

17.3.1.7 Regulatory Commitments

The operation of nuclear plants is accomplished in accordance with the U.S. Nuclear Regulatory Commission (NRC) regulations specified in Title 10 of the U.S. Code of Federal Regulations.

The operation of the Company's nuclear power plants is in accordance with the terms and conditions of the facility operating license issued by the NRC.

The QAP provides for compliance with QA regulatory guides and the related codes and standards as identified in Table 17-1, Conformance with QA Regulatory Guides and Industry Standards.

The requirements of this section (17.3) may provide additional details for implementation of exceptions to these Regulatory Guides and codes and standards.

Changes to the description of the QAP contained in this document are controlled in accordance with 10 CFR 50.54(a).

Table 17-2, Site Specific Response to Regulatory Guides and Industry Standards, identifies additional Regulatory Guides that relate to implementation of the QAP but the implementation is site specific and controlled with each site's UFSAR in accordance with 10 CFR 50.59.

17.3.2 PERFORMANCE/VERIFICATION

17.3.2.1 Methodology

Personnel performing work activities are responsible for achieving the acceptable level of quality.

Personnel performing verification activities are responsible for verifying the achievement of acceptable quality.

Work is accomplished and verified using instructions, procedures, or appropriate means that are of a detail commensurate with the activity's complexity and importance to safety. The implementing manager is responsible to ensure instructions and procedures provide adequate detail for achieving an acceptable level of quality.

Criteria that define acceptable quality are specified in procedures and/or other documents, and verification, when required is performed against these criteria.

17.3.2.2 Design Control

In order to provide for the continued safe and reliable operation of a nuclear station's nuclear safety related structures, systems and components, design control measures commensurate with those applied to the original design are implemented during the operational phase to assure that the quality of such structures, systems and components is not compromised by engineering changes.

Nuclear Engineering is responsible for design activities during the operational phase of nuclear stations to Nuclear Generation. Nuclear Engineering will assure that the organization performing design has access to pertinent background information, including an adequate understanding of the requirements and intent of the original design, and that the organization has demonstrated competence in applicable design areas.

Procedures and instructions for design control during the operational phases for nuclear safety related items provide controls to assure the design is performed in accordance with approved criteria, and that deviations and nonconformances are controlled.

Procedures identify the responsibilities of the various individuals/organizations involved in nuclear safety related engineering changes. The assignment of responsibility for the evaluation and design of a particular engineering change to a specific individual/organization is documented. Procedures addressing the control, including the review, approval, release, and distribution of engineering changes, address the communication of information between internal and external individuals/organizations and, where appropriate, require documentation of such communications.

The procedures include measures to assure that the design selected to accomplish a necessary or desirable change does not create "new" problems in off-normal modes of operation or in adjacent inter-tied systems. For each proposed nuclear safety related engineering change, the individual/organization assigned responsibility for evaluation and design of the engineering change considers the following in the design of the engineering change:

a. Necessary design analyses, e.g., physics, stress, thermal, hydraulic, accident, etc.
b. Compatibility of materials.
c. Accessibility for operation, testing, maintenance, inservice inspection, etc.

d. Necessary installation and periodic inspections and tests, and acceptance criteria therefore.
e. The suitability of application of materials, parts, components, and processes that are essential to the function of the structure(s), system(s) and/or component(s) to be modified.
f. Materials, parts, and equipment which are commercial grade items or which have been previously approved for a different application are evaluated for suitability prior to selection.

Engineering changes are then executed in accordance with approved checklists, instructions, procedures, drawings, etc., appropriate to the nature of the work to be performed. These checklists, instructions, procedures, drawings, etc., include criteria for determining the acceptability of the engineering change.

Any errors or deficiencies found in the design process or the nuclear safety related design itself are documented and corrected using the corrective action program.

Prior to a structure, system, or component that has been modified by engineering change being declared operable and returned to service, the procedures governing the operation are reviewed and revised as necessary. If the engineering change significantly alters the function, operating procedure, or operating equipment, then additional training is administered as necessary.

Adequate identification and retrievable documentation of station engineering changes is retained for the life of the station.

Engineering changes are reviewed to determine whether or not the modification is a change in the facility as described in the UFSAR, involves a change to the Technical Specifications, or requires a license amendment in accordance with 10 CFR 50.59(c)(2). Engineering changes which are determined to require a license amendment are reviewed by the On-Site Review Committee and must be authorized by the NRC prior to implementation.

17.3.2.3 Design Verification

Procedures require that the adequacy of nuclear safety related designs and design changes be verified by the performance of design reviews, alternate calculations, or qualification testing. The control measures specified in the plan for control of design verification activities are as follows:

a. Personnel responsible for design verification do not include the original designer or the designer's immediate supervisor unless the immediate supervisor is the only one capable of verifying the design, in which case additional requirements apply as identified below.
b. Procedures identify the positions or organizations responsible for design verification and define their authority and responsibility. Procedures also provide guidelines as to the method of design verification to be used. Unless otherwise specified, design verification is performed by the method of independent design reviews and includes verification that UFSAR commitments have been addressed.
c. Qualification tests to verify the adequacy of the design are performed using the most adverse specified design conditions.
d. Design changes are reviewed to assure that design parameters are defined and that inspection and test criteria are identified.
e. Design verification is completed prior to relying upon the component, system or structure to perform its function or before its installation becomes irreversible.

The use of the originator's immediate supervisor for verification is:

1) restricted and justified to special situations where the immediate supervisor is the only individual capable of performing the verification
2) the need is individually documented and approved in advance by the supervisor's management and
3) the frequency and effectiveness of the supervisor's use as design verifier are independently verified to guard against abuse.

The individuals assigned to perform the design verification of a nuclear safety related document have full authority to withhold approval of the document until every question concerning the work has been resolved. If required, the matter can be carried up to the Chief Nuclear Officer for resolution.

17.3.2.4 Procurement Control

Duke Energy Corporation maintains a program for supplier evaluation, results of supplier evaluation, surveillance of suppliers, supplier furnished records, certificates of conformance, effectiveness of supplier quality control, and the purchase of spare or replacement parts. The Duke Energy Corporation QAP requires the control of nuclear safety related items or services purchased from a supplier, subsupplier, or consultant through appropriate processes and specific procurement documents.

Procedures identify the responsibilities and requirements for the control of procurement documents and ensure that purchased material and services are of acceptable quality. Procurement of QA items is to the quality program requirements in effect at the time of purchase.

Nuclear safety related material, equipment and services procured as basic components may only be procured from qualified suppliers. Supplier qualification is accomplished by NOS evaluation of the supplier QA program. An audit or pre-award survey is performed by NOS when required. The audit or pre-award survey is carried out in accordance with a comprehensive audit checklist to determine the ability of the supplier QA program and manual(s) to meet applicable criteria of 10 CFR 50, Appendix B; 10 CFR 21; the ASME Code, when required, and any other codes and standards determined to be appropriate for the prospective scope of supply.

The above requirements apply to procurement of services and items as basic components, including obtaining a Commercial Grade Item dedicated as basic component from an approved third party dedicator. The remainder of this section addresses alternate requirements for purchase of Commercial Grade Items or services.

17.3.2.4.1 Commercial Grade Dedication

When nuclear safety related items/services are not supplied as a basic component and meet the definition of Commercial Grade Item, the item may be procured without the performance of a supplier qualification audit or the existence of a documented supplier QA program. These Commercial Grade Items used in nuclear safety related applications require evaluation, dedication (consistent with GL 89-02 and industry standard EPRI NP-5652 for dedication of Commercial Grade Items) and approval by Nuclear Generation personnel. Supplier selection for Commercial Grade Items is the responsibility of the responsible engineering personnel or designated supply chain personnel as identified in procedures. These items are subject to the same verification and checking process for suitability of application as other nuclear safety related items.

17.3.2.4.2 Commercial Grade Dedication of Laboratory and Testing Services

As identified in NEI 14-05A, commercial grade calibration or testing services may be procured from commercial laboratories based on the laboratory's accreditation to ISO/IEC-17025 by an Accreditation Body (AB) which is a signatory to the International Laboratory Accreditation Cooperation (ILAC) Mutual Recognition Arrangement (MRA) without performing commercial grade surveys as part of commercial grade dedication provided all of the following are met:

1. A documented review of the supplier's accreditation is performed and includes a verification of the following:
    a. The calibration or test laboratory holds accreditation by an accrediting body recognized by the ILAC MRA. The accreditation encompasses ISO/IEC-17025:2005, "General Requirements for the Competence of Testing and Calibration Laboratories."
    b. For procurement of calibration services, the published scope of accreditation for the calibration laboratory covers the needed measurement parameters, ranges, and uncertainties.
    c. For procurement of testing services, the published scope of accreditation for the test laboratory covers the needed testing services including test methodology and tolerances/uncertainty.
2. The purchase documents require that:
    a. The service must be provided in accordance with their accredited ISO/IEC-17025:2005 program and scope of accreditation.
    b. As found calibration data must be reported in the certificate of calibration when calibrated items are found to be out-of-tolerance. (for calibration services only)
    c. The equipment/standards used to perform the calibration must be identified in the certificate of calibration. (for calibration services only)
    d. The customer must be notified of any condition that adversely impacts the laboratory's ability to maintain the scope of accreditation.
    e. Additional technical and quality requirements, as necessary, are specified for verification at receipt based upon a review of the procured scope of services, which may include, but are not necessarily limited to, tolerances, accuracies, ranges, and industry standards.
3. It is validated, at receipt inspection as part of the commercial grade dedication process, that the laboratory's documentation certifies that:
    a. The contracted calibration or test service has been performed in accordance with their ISO/IEC-17025:2005 program, and has been performed within their scope of accreditation, and
    b. The purchase order's requirements are met.

17.3.2.5 Procurement Verification

Duke Energy Corporation procurement documents are prepared, reviewed, approved, and controlled in accordance with procedures to assure that requirements are correctly stated, inspectable, verifiable, and controllable, and there are adequate acceptance/rejection criteria. Procurement documents are reviewed by personnel knowledgeable in applicable technical and quality requirements, and documentary evidence of that review and approval is retained and available for verification.

As required by procurement criteria, in order to assure that material and equipment are fabricated in accordance with applicable requirements, supplier reviews are performed by

Vendor Quality. Those reviews may include witnessing of tests, observation of fabrication checkpoints, and documentation review.

Receipt inspections are performed by qualified inspectors in accordance with procedures to assure that:

1. Materials, equipment, or components are properly identified and correspond with associated documentation.
2. Inspection records or certificates of conformance attesting to the acceptance of materials, equipment, and components are completed and are available prior to installation or use.
3. Materials, equipment, and components are inspected and judged acceptable in accordance with predetermined inspection instructions prior to installation or use.
4. Items not meeting applicable requirements are identified and controlled until proper disposition is made.

The process ensures that required documentation of compliance is received and available on site and procurement, inspection, and testing requirements are satisfied before the item is placed in service.

As identified in Section 17.3.2.4.2, specific to the commercial grade dedication of Calibration Testing and Laboratory Services, receipt inspection verifies that:

- The laboratory's documentation certifies that:
    - contracted calibration or test service has been performed in accordance with their ISO/IEC-17025:2005 program,
    - has been performed within their scope of accreditation, and
    - the purchase order's requirements are met.
- Additional technical and quality requirements are met.

17.3.2.6 Identification and Control of Items

Procedures require spare or replacement parts to be subject to QAP controls, codes and standards, and technical requirements which ensure they are suitable for their intended service. Items accepted or released are identified as to their inspection status prior to forwarding them to a controlled storage area or releasing them for installation or further work. Bulk items will not require individual accept tags; however, status of unacceptable bulk items will be so indicated.

Identification requirements for materials, parts and components important to nuclear safety are stated in specifications, drawings and purchase documents.

Control of material, parts and components is governed by approved procedures.

Following QA receipt inspection, materials, parts and components which are determined to be acceptable are assigned an identifying designation such as a unique tracking number in order to provide traceability of each item. This traceability is maintained for nuclear safety related items. In the event that the identification of an item becomes lost or illegible, the item is considered nonconforming and not utilized until proper resolution of the nonconformance.

Consumables utilized in nuclear safety related structures, systems and components are subject to appropriate controls as described in procedures.

17.3.2.7 Handling, Storage, and Shipping

Procedures utilized by suitably trained individuals define requirements for the control of the handling, storage, and shipping of safety-related items. These procedures require measures to be taken to ensure special handling, storage, cleaning, packaging, shipping, and preservation requirements are established to control these activities in accordance with design and specification requirements to preclude damage, loss or deterioration by environmental conditions such as temperature or humidity. Nuclear safety related materials, parts and components are handled, stored, issued and shipped in such a manner that the serviceability and QA traceability of an item is not impaired.

Nonconforming items are identified, segregated, or otherwise controlled in such a manner as to preclude their inadvertent substitution for and use as conforming materials parts and components.

17.3.2.8 Test Control

The QAP addresses both preoperational and periodic (surveillance) testing. The program requires that such testing associated with nuclear safety related structures, systems and components demonstrate that the items will perform satisfactorily in service. Testing activities are accomplished in accordance with approved, written procedures. Testing schedules are provided and maintained in order to assure that all necessary testing is performed and properly evaluated on a timely basis. Test controls include requirements on the review and approval of test procedures, and on the review and approval of changes to such procedures, as discussed in Section 17.3.2.14, Document Control.

Modifications, repairs, and replacements are accomplished in accordance with the original design and testing requirements or acceptable alternatives.

17.3.2.9 Measuring and Test Equipment Control

The organizations performing nuclear safety related work activities have the responsibility to assure the required accuracy of tools, gauges, instruments, radiation measuring equipment, non-destructive testing equipment and other measuring and test devices affecting the proper functioning of nuclear safety related structures, systems and components and that a program of control and calibration for such devices is provided.

Procedures define requirements for the control of measuring and test equipment (M&TE) used. These procedures include requirements to establish procedures for the calibration technique and frequency, maintenance, and control of measuring and test equipment. The requirements include the following:

a. M&TE is assigned permanent, identifying designations. M&TE is identified and traceable to the calibration test data.
b. M&TE is calibrated at prescribed intervals against certified equipment having known, valid relationships to nationally recognized standards or where national standards do not exist, provisions are established to document the basis for the calibration. The calibration interval is based on the applicable manufacturer's recommendations. If experience shows that the manufacturer's recommendations are not appropriate, the calibration interval is changed as necessary. One or more of the following may be used to adjust intervals: 1. Technical Specifications; 2. Required accuracy; 3. Intended use; 4. Frequency of usage; 5. Stability characteristics; 6. Other conditions affecting

measurement. In lieu of specified intervals, infrequently used M&TE may be calibrated immediately before and after use.

c. Status of calibration for M&TE is provided through the use of tags, stickers, labels, routing cards, computer programs, or other suitable means. The status indicators indicate the date recalibration is due or the frequency of recalibration.
d. M&TE failing to meet calibration specifications is identified through the use of tags, stickers, labels, routing cards, computer programs, or other suitable means, showing the date of rejection, the reason for rejection and the identification of the individual rejecting the device. "Accepted" and "Rejected" calibration identification is sufficiently different to preclude confusion between them.
e. Items and processes determined to be acceptable based on measurements made with M&TE that subsequently cannot be demonstrated to meet calibration specifications are re-evaluated to determine the validity of previous inspections and test results and the results of the evaluation documented.
f. M&TE is stored under conditions which are in accordance with, or more conservative than, the applicable manufacturer's recommendations.
g. M&TE is issued under the control of responsible personnel so as to preclude unauthorized use.
h. M&TE is shipped in a manner that is in accordance with, or more conservative than, the applicable manufacturer's recommendations.
i. Records are maintained for each item of M&TE identifying the device designation, the calibration frequency and specifications. Records are maintained reflecting current calibration status, the date of calibration, the date the next calibration is due, and the identification of the individual who was responsible for performing the calibration.
j. As a rule, the calibration program achieves a minimum ratio of 4-to-1 calibration standard accuracy to measuring and test equipment accuracy is used. However, well defined and documented measurement assurance techniques or uncertainty analysis may be used to verify the adequacy of the measurement process. See site specific requirements for other exceptions to the 4:1 rule.

M&TE is selected to assure accurate measurement (i.e., to overcome inherent inaccuracies associated with environment, human error, equipment, etc.).

17.3.2.10 Inspection, Test, and Operating Status

Procedures define requirements for the identification and control of the inspection, test, and operating status of safety-related structures, systems, and components, to assure that equipment operating status is clearly evident, and to prevent inadvertent operation of nuclear safety related structures, systems and components which, if operated, could cause damage to other equipment/systems or to personnel

These measures include the use of checklists, computer programs, logs, stickers, tags, labels, record cards, and test records to indicate the acceptable operating status of installed equipment. Where appropriate, an independent verification of the correct implementation of such identification measures is performed.

When tags, labels or stamps are utilized for the identification of equipment status, the issuance and removal thereof is documented in order to assure proper control of such identification measures. Also, procedures require that the operability of an item removed from operation for maintenance or testing be verified prior to returning the item to normal service.

Selected plant procedures and subsequent revisions receive separate technical review to ensure required inspections, tests, and other critical operations are included.

17.3.2.11 Special Process Control

Procedures define requirements for the control of special processes, such as welding, heat treating, nondestructive examination (NDE), coatings, and chemical cleaning when the performance of such processes affects the proper functioning of nuclear safety related structures, systems, and components.

Procedures require that special processes be performed by qualified personnel using proper equipment and in accordance with written qualified procedures. These personnel and procedures are to be qualified in accordance with applicable codes, standards, and specifications as described in procedures.

Qualification records of special process procedures and personnel performing special processes are maintained and available for verification.

17.3.2.12 Inspection

Procedures define requirements for an inspection program to verify conformance to performance and quality requirements specified for nuclear safety related structures, systems, and components.

Inspections are performed by personnel who are not directly responsible for performing or supervising the activity being inspected. Inspection personnel are qualified in accordance with applicable codes and standards, and their qualifications and certifications are maintained current.

Inspections are performed in accordance with procedures or other documents, which provide for the following:

1. Identification of individuals or groups responsible for performing the inspections
2. Identification of characteristics and activities to be inspected
3. Acceptance criteria
4. Inspection techniques
5. Recording the results of the inspection, review of the results, and identification of the inspector
6. Indirect control by monitoring of processing methods, equipment, and personnel when direct inspection is not possible

Mandatory inspection hold points are included in the documents addressing the activities being performed, as necessary and work does not proceed until satisfactory completion of the required inspection.

When acceptance criteria are not met, the condition will be documented in accordance with the corrective action program procedures and work does not proceed until satisfactory disposition of any item not meeting the acceptance criteria and satisfactory completion of any required re-inspection.

Modification, repairs, and replacements are inspected in accordance with the original design and inspection requirements or acceptable alternatives.

17.3.2.13 Corrective Action

Station personnel are responsible for the implementation of the QAP as it pertains to the performance of their activities. Specific to this responsibility is the requirement for informing the

responsible supervisory personnel and/or for taking appropriate corrective action whenever any deficiency in the implementation of the requirements of the program is determined.

Procedures define requirements for a corrective action program that charges personnel working at or supporting the nuclear plants with the responsibility to identify adverse conditions (including conditions adverse to quality). Conditions adverse to quality are identified through inspections, assessments, tests, checks, and review of documents. Procedures require that conditions adverse to quality be corrected. In the case of significant conditions adverse to quality, the procedures assure that the cause of the condition is determined and action be taken to preclude repetition.

Significant conditions adverse to quality are reported to appropriate management for review and evaluation. Violations of Technical Specifications, safety limit violations, and other reportable events are investigated to evaluate the occurrence and provide recommendations to prevent recurrence. Such reports and other special reviews and investigations are reviewed by a knowledgeable individual/organization other than the individual/organization which prepared the report.

Periodic reviews and evaluations of adverse conditions are performed to identify and correct adverse trends.

17.3.2.14 Document Control

Procedures define requirements for the development, review, approval, issue, use, revision, and control of documents. These procedures define the scope of which documents are to be controlled. These activities include measures to control the issuance of documents such as, instructions, procedures, and drawings, and changes thereto, which prescribe activities affecting quality.

A document control system has been established to identify the current revision number of instructions, procedures, specifications, and drawings. This system includes provisions to ensure that superseded documents are controlled to prevent inadvertent use.

Controlled documents are to be distributed to and used by the person performing the activity in accordance with procedures. These controlled documents are distributed electronically. Hardcopy distribution, if required, is by distribution indices.

Procedures require the identification of those individuals or organizations responsible for reviewing, approving, and issuing documents and revisions thereto. The required reviews include reviews verifying that changes to the procedures, tests or experiments do not involve a change in the Technical Specifications or otherwise require prior NRC approval.

In addition to procedures and engineering documents (e.g. specifications and drawings), the following are considered to be controlled documents:

- The station Facility Operating License and Technical Specifications
- Updated Final Safety Analysis Reports
- Process Control Program
- Offsite Dose Calculation Manual
- Radiological Effluent Controls of the UFSAR, and radwaste treatment systems

Procedures established for operational phase activities include:

1. Operating Procedures
2. Alarm Responses
3. Radiation Protection Procedures

4. Maintenance Procedures
5. Instrument Procedures
6. Chemistry Procedures
7. Process Control Program Implementing Procedures
8. Periodic Test Procedures
9. Abnormal Procedures
10. Emergency Procedures
11. Emergency Response Procedures
12. License Renewal Aging Management Program

17.3.2.15 Records

Each nuclear station is required to maintain adequate identifiable and retrievable QA records. The QAP requires that sufficient records be maintained to provide documentary evidence of the quality of items and the accomplishment of activities affecting quality.

Procedures define requirements for the identification, collection, and storage of quality assurance records.

The program for storage of records on microfilm, dual storage or in electronic format meets the preservation requirement for the retention of QA Records.

Media used for retention of records include (but are not limited to): microfilm, compact disk recordable (CD-R), and magnetic media including videotape, computer tape, optical disks, and hard disk storage. Electronic records retention is an integral component of the Record Retention Program, approved by the management position responsible for Nuclear Generation Department records. The format used must be capable of producing legible, accurate, and complete documents supporting the required retention period. Electronic approval and authorization procedures are established to assure that only those persons authorized grant the required approvals.

For creation and maintenance of on-line electronic records, Duke Energy Corporation follows the Nuclear Information and Records Management Association (NIRMA) Technical Guides as identified in Table 17-1, Conformance with QA Regulatory Guides and Industry Standards.

There is no requirement to convert records stored on media including hardcopy, microfilm, compact disk recordable (CD-R), and magnetic media including videotape, computer tape, and optical disks to on-line electronic records. Those records may be maintained in their current form as long as retrieval technology and media life support the continued use of the media. If records stored on one media are to be converted to a new media, the records stored on the old system's media are acceptably converted into the new system before the old system is taken out of service. This includes verification of the records so copied are complete and accurate in the new system.

Records are identifiable and retrievable through the use of indexes and filing systems, which are required by the program.

Procedures are required to be developed to indicate responsibilities and retention periods.

The actual retention times for the various QA records are in accordance with corporate retention policies. The development of these retention policies includes consideration of applicable requirements, including those of the Code of Federal Regulations, a station's Technical Specifications, established national codes and standards, and regulatory guidance as listed in Table 17 1, Conformance with QA Regulatory Guides and Industry Standards.

The following is a list of typical QA Records retained for the operational phase:

1. Records and drawing changes reflecting facility design modifications made to systems and equipment described in the Final Safety Analysis Report. These include: drawings, design specifications, calculations, design analyses, and vendor documents for nuclear safety related structures, systems and components.
2. Records of new and irradiated fuel inventory, fuel transfers and assembly burn-up histories.
3. Radiation monitoring records, including records of radiation and contamination surveys.
4. Personnel radiation exposure records.
5. Records of radioactive releases and waste disposal, records of gaseous and liquid radioactive material released to the environs.
6. Records of component cyclic or transient limits established for the reactor coolant system, reactor vessel, and secondary coolant system.
7. Records of the qualifications, experience and training of appropriate station personnel
8. Records of quality control inspections.
9. Records of reviews performed for changes made to procedures or safety related SSCs or reviews of tests and experiments pursuant to 10 CFR 50.59.
10. Changes to station procedures; including review and approval documentation.
11. Records of meetings of the off-site review committee.
12. Records of Independent Review. These records include on-site review committee meeting minutes.
13. Records of reactor tests and experiments.
14. Records of inservice inspections performed pursuant to Technical Specifications and 10 CFR 50.55a(g).
15. Records of the service lives of all safety-related snubbers (required by Technical Specification) including the data at which the seal service life commences and associated installation and maintenance records.
16. Records of analyses required by the Radiological Environmental Monitoring Program that would permit evaluation of the accuracy of the analysis at a later date.
17. Records of secondary water sampling and water quality.
18. Records of reviews performed for changes made to the Off-Site Dose Calculation Manual, the Process Control Program, and Radwaste Treatment Systems.
19. Isotopic and physical inventory records of special nuclear materials.
20. Nuclear safety related preoperational testing records.
21. Records such as vendor documentation packages and inspection reports, piping isometric drawings, welding records, etc. compiled during the design and construction of a nuclear station.
22. Approved purchasing documents for items requiring QA certification.
23. Purchase specifications.
24. Records of special processes affecting nuclear safety related structures, systems and components.
25. Records of off-site environmental surveys.
26. Records of environmental qualification.
27. By-product material inventory records.
28. Radioactive liquid effluent, gaseous effluent, and gaseous process monitoring instrumentation alarm/trip setpoints.
29. Records of reviews performed for changes made to Radiological Effluent Controls.
30. Records of reviews performed on the Fire Protection Program and implementing procedures.
31. Audit reports and required written responses.

32. Records and logs of facility operation covering time interval at each power level, including: switchboard record, reactor operator logbook, and shift supervisor logbook.
33. Records and logs of principal maintenance activities, inspections, repair and replacement of principal items of equipment related to nuclear safety.
34. Reports of all reportable and other significant events.
35. Records of surveillance activities, inspections, and calibrations required by Technical Specifications.
36. Records of radioactive shipments.
37. Records of sealed source and fission detector leak tests and results.
38. Records of annual physical inventory of all sealed source material of record.
39. Calibration standard records and Measuring and Test Equipment (M&TE) calibration records.

Dry cask storage records pertaining to the design, fabrication, erection, testing, maintenance, and use of structures, systems, and components important to safety must be maintained for the life of the storage mode.

17.3.3 SELF-ASSESSMENT

17.3.3.1 Methodology

Each site executive and the Chief Nuclear Officer are responsible for ensuring that an environment exists for a strong assessment program at each nuclear site and within Nuclear Generation, respectively.

The overall objective at Duke Energy Corporation is to encourage ownership, involvement, and dedication by each individual supporting Nuclear Generation. This involves continually looking for ways to improve the overall performance and safety at each plant. This approach of identifying and correcting conditions early, requires active support by management and employees.

The Duke Energy Corporation self-assessment process includes the line organization self-assessment activities, independent review activities, and an independent assessment process implemented by NOS that encompasses internal and supplier audits. NOS may perform in-plant reviews and other independent assessments requested by the CNO.

The managers of line organizations are responsible for ensuring that self-assessment activities and processes are implemented within their functions to promote continuous improvements. A process of self-assessment is an attitude by personnel that the Duke Energy Corporation Nuclear Generation is improving on a continual basis. This process, along with an effective corrective action program, ensures that conditions are identified early, corrected promptly and effectively before becoming significant quality or safety problems.

The independent review activities are discussed in Section 17.3.3.2.

As directed by the CNO, an off-site review board periodically performs independent reviews of matters involving the safe operation of its fleet of nuclear power plants. The review addresses matters that plant and corporate management determine warrant special attention, such as plant programs, performance trends, employee concerns, or other matters related to safe plant operations. The review is performed by a team consisting of personnel with experience and competence in the activities being reviewed, but independent (from cost and schedule considerations) from the organizations responsible for those activities. The review is supplemented by outside consultants or organizations as necessary to ensure the team has the requisite expertise and competence. Results are documented and reported to responsible management.

The independent assessment process is to confirm to management that activities affecting quality comply with the QAP and that the QAP has been implemented effectively. The assessment activities are performed in accordance with instructions and procedures by organizations independent of the areas being assessed. This process is discussed in detail in Section 17.3.3.3.

17.3.3.2 Independent Review

The independent review function is provided through a combination of the On-Site Review Committee, Nuclear Oversight, and the line organization executing quality assurance program required reviews as follows:

- Reviews of the independent review subjects are performed by the On-Site Review Committee as described in Section 17.3.3.2.1, On-Site Review Committee.

- Reviews of audit reports, identified in ANSI N18.7-1976 Section 4.5, are performed by management of the audited area and Nuclear Oversight instead of the independent review function.
- Reviews of the corrective actions for significant conditions adverse to quality are performed by appropriate management. Collectively, the On-Site Review Committee and the NOS audit function perform the independent review, identified in ANSI N18.7-1976 Section 5.2.11, for significant conditions adverse to quality.

17.3.3.2.1 On-Site Review Committee

The On-Site Review Committee is responsible to the Nuclear Plant Manager for advice on all plant-related matters concerning nuclear safety. The requirements for personnel, committee composition, meeting frequency, quorum and meeting records are identified in procedures. A general description of these areas is included below. (Note: Each plant may name this function differently. Regardless of the name, these requirements are met.)

In discharging its independent review responsibilities, the On-Site Review Committee keeps safety considerations paramount when opposed to cost or schedule considerations. Should a voting member at a particular meeting have direct responsibility for item under review where a conflict of such considerations is likely, that member is replaced (to fill the quorum) by another voting member not having such potential conflict.

17.3.3.2.1.1 Composition

The On-Site Review Committee is comprised of a minimum number of members as designated by the Plant Manager and detailed in procedures. All members are qualified in accordance with procedure requirements that meet site Technical Specifications. Membership includes representation from at least the following disciplines: Operations, Maintenance, Engineering, Radiation Protection and Chemistry. The On-Site Review Committee collectively has, or has access to, the experience and competence necessary to review the areas of (1) nuclear power plant operations, (2) nuclear engineering, (3) chemistry and radiochemistry, (4) metallurgy, (5) nondestructive testing, (6) instrumentation and control, (7) radiological safety, (8) mechanical and electrical engineering, (9) administrative controls and quality assurance practices, and (10) other fields associated with the unique characteristics of the plant. Consultants may be utilized to provide expert advice as needed.

Alternate chairmen and members may be appointed by the Nuclear Plant Manager to serve on a permanent or temporary basis.

17.3.3.2.1.2 Meetings

The On-Site Review Committee meets commensurate with the scope of activities, but minimal frequency requirements are specified in procedures.

Rules for a quorum are established and adhered to. However, no more than a minority of alternates may participate as voting members at any one time.

17.3.3.2.1.3 Review Topics

In performing its independent review responsibilities, the On-Site Review Committee reviews:

(1) Proposed changes to the facility as described in the UFSAR. This review is to confirm that the change does not adversely affect safety and if a Technical Specification change or NRC review is required.

(2) Proposed changes to procedures as described in the UFSAR and tests or experiments not described in the UFSAR. This review is to confirm that the change does not adversely affect safety and if a Technical Specification change or NRC review is required.

(3) Proposed Technical Specifications changes and license amendments, except in those cases where the change is identical to a previously reviewed proposed change.

(4) Licensee Event Reports that are required to be made to the NRC. This review includes results of any investigations made and recommendations resulting from such investigations to prevent or reduce the probability of recurrence of the event.

(5) Any other matter related to nuclear safety requested by the Site executive, Plant Manager, selected by On-Site Review Committee members, or referred for review by other organizations.

The On-Site Review Committee also reviews changes to Site documents including but not limited to the Offsite Dose Calculation Manual (ODCM), the Process Control Program (PCP), the Emergency Plan, and the Security Plan.

The On-Site Review Committee conducts special reviews and investigations as requested by the Site executive or Nuclear Plant Manager.

17.3.3.2.1.4 Authority

The On-Site Review Committee may establish subcommittees or use designated organizational units to carry out the review. The subcommittees or organizational units regularly report results of reviews for full committee consideration and may recommend items for full committee review as warranted. Additionally the reviews by the On-Site Review Committee recognize that the QA Program requires independent technical reviews to be completed including but not limited to design verification and reviews of procedures. Those independent technical reviews are conducted commensurate with the item or activities importance to nuclear safety. In conducting its review, the On-Site Review Committee is not required to independently reperform such reviews.

The On-Site Review Committee:

- Recommends to the Nuclear Plant Manager approval or disapproval of items reviewed.
- Renders determinations with regards to whether items (1) through (3) adversely affect safety and if a Technical Specification change or NRC review is required.
- Provides written notification to the Site executive of any disagreements between the On-Site Review Committee and the Nuclear Plant Manager.

The On-Site Review Committee advises the Nuclear Plant Manager on matters related to safe operation and overall performance. The Committee has authority to obtain access to records and personnel as needed to conduct reviews.

17.3.3.2.1.5 Records

The On-Site Review Committee maintains written minutes of each Committee meeting, to include identification of items reviewed, and decisions and recommendations of the Committee. Copies of the minutes are provided to the Site executive, and to other onsite and offsite management responsible for the areas reviewed as necessary. On-Site Review Committee records are retained according to Section 17.3.2.15.

17.3.3.3 Independent Assessment

NOS is responsible for conducting independent assessments of functions and activities affecting the nuclear programs at Duke Energy Corporation locations. NOS monitors and assesses the Company's nuclear programs on a continuing basis. As part of this continuing assessment process, NOS performs audits to verify that applicable elements of the quality assurance and other regulatory required programs have been developed, documented and effectively implemented in accordance with specified requirements. In this section, the words assess, assessment, and their various word forms are used generically to indicate the act of monitoring the performance of the line organization for indications of decline.

NOS, along with the line organization management, monitors functional areas to determine if the required levels of performance are being achieved.

The functions of NOS are to assess line organization performance including the self-assessment and corrective action process. NOS performs these monitoring activities for nuclear safety related functions in operations, engineering, and maintenance.

NOS evaluations, including the results and recommended corrective actions, are reported to senior management.

17.3.3.3.1 Organization

On an exception basis, personnel in NOS may provide assistance to the line organization by participating in emergency preparedness activities, ad hoc committees or analyzing technical issues, if such assistance is deemed to be in the overall best interest of safety and is approved in advance by NOS management.

NOS teams may include peers from other Duke Energy Corporation plants and from the nuclear utility industry, as appropriate, to lend expertise to the assessment process. When subject matter experts from the line organizations are utilized to add specific technical expertise to a specific audit team, the subject matter experts will work under the direction of the audit team leader and not evaluate any documentation for which they had direct responsibility.

Selection of personnel is based on experience and training that establishes that their qualifications are commensurate with the complexity or special nature of the area being audited. The process for qualification of personnel to perform audits is established in procedures.

17.3.3.3.2 Internal Assessment Process

The internal assessment process includes gathering data, analyzing data, focusing on selected issues and identifying deficiencies to desired performance. Data is gathered using performance based techniques during:

a) Observations of work activities
b) Interviews

c) Reviews of documents to gather information (including the use of NRC, INPO, and other agency evaluations)
d) Audits, and
e) Analysis of data and reports (including adverse condition reports, etc.)

NOS personnel have access to records, procedures, and line organization personnel to gather data.

NOS conducts observations of specific activities, and processes on the basis of their impact and importance relative to safety. The schedule is flexible and dynamic to allow the overall assessment process to be changed depending on plant conditions, events, or issues raised by senior management. Assessment activities can be focused on areas most in need of improvement.

Audits are a specific independent assessment activity performed to verify that applicable elements of the quality assurance and other regulatory required programs have been developed, documented and effectively implemented in accordance with specified requirements. Independent Audit activities are selected with flexibility based on various factors. These factors include but are not limited to: importance to safety and reliability, monitoring of performance indicators, time since last audit, plant management perspective, outside agency audits, and problem areas identified from industry and Duke Energy Corporation experience.

Preparation activities may include a review of performance data, relevant documentation, previous assessment data, industry experience, team member experience, and management input. These activities enable the team to focus on issues which may impact safety and reliability when analyzing data.

Audits are scheduled per the following section.

17.3.3.3.3 Internal Audit Program

The Duke Energy Corporation QAP requires a comprehensive system of planned and periodic internal audits for all phases of station operations and supporting activities.

Periodic audits of activities or records of processes (e.g., welding, maintenance, development of design, record management, or system testing), to verify compliance and effectiveness of the implementation of the QAP are performed. NOS audits are performance based and scheduled based on plant performance and importance to safety but at a frequency not to exceed twenty-four months with extensions as allowed in Section 17.3.3.3.7, Audit Frequency Extensions.

The audit system is reviewed periodically and revised as necessary to assure coverage commensurate with current and planned activities. These audits encompass:

- The conformance of facility operation to provisions contained within the Technical Specifications and applicable license conditions.
- The performance, training and qualifications of the Nuclear Generation Department.
- The results of actions taken to correct deficiencies occurring in facility equipment, structures, or systems that affect nuclear safety; or method of operation that affect nuclear safety.
- The performance of activities required by the QAP to meet the criteria of Appendix B to 10 CFR 50 for activities performed by the Nuclear Generation Department and the interfacing organizations.
- Any other area of nuclear generation considered appropriate by responsible management.
- The Radiological Environmental Monitoring Program and the results thereof.

- The Offsite Dose Calculation Manual and implementing procedures.
- The Process Control Program and implementing procedures for processing and packaging of radioactive wastes.
- The acceptability of a representative sample of station procedures, including the effectiveness of the procedure review and revision program.
- Independent Spent Fuel Storage Installation Activities (reference 10 CFR Part 72).
- Packaging of Radioactive Materials for Off-Site Shipment (reference 10 CFR Part 71).

The scope of each audit is determined by the responsible Lead Auditor, under the direction of NOS management. The lead auditor is responsible for completion of audit checklists and directing the audit team in the performance of the audit. The audit is conducted in accordance with checklists; the scope may be expanded upon by the audit team during the audit, if needed. One or more persons comprise an audit team, one of whom is a qualified lead auditor.

17.3.3.3.3.1 Other Reviews Prescribed by the Code of Federal Regulations

Other reviews prescribed by the Code of Federal Regulations are scheduled and performed per the CFR. The audit frequency extension provisions of Section 17.3.3.3.7 do not apply.

NOS performs the following reviews under the internal audit program:

a. Emergency Preparedness (per 10 CFR 50.54(t))
b. Security (per 10 CFR 50.54(p) and 10 CFR Part 73)
c. Fitness for Duty and Fatigue Rule (per 10 CFR Part 26)

The periodic review of the radiation protection program content and implementation required by 10 CFR 20.1101c may be performed by either the line organization or NOS.

17.3.3.3.3.2 Independent Audit of Fire Protection Program

For sites implementing the fire protection program under provisions of 10 CFR 50.48(c) National Fire Protection Association Standard NFPA 805:

- An independent fire protection audit is performed at least once per 36 months using an outside (external to Duke Energy Corporation) qualified fire protection engineer meeting education and experience requirements for a Professional Member of the Society of Fire Protection Engineers (SFPE).

For the remaining sites, audits of the following functions are completed within a period of 24 months:

- The Facility Fire Protection programmatic controls including the implementing documents.
- The fire protection equipment and program implementation utilizing either a qualified offsite fire protection engineer or an outside independent fire protection consultant. An an outside (external to Duke Energy Corporation) qualified fire protection engineer meeting education and experience requirements for a Professional Member of the SFPE shall be used at least every 36 months.
- The audit scope may be combined into a single audit performed on a 24 month frequency with the inclusion of an outside independent qualified fire protection engineer.

17.3.3.3.4 Results

Adverse conditions are reported in accordance with the applicable corrective action program procedure.

Independent audit results are communicated to line management to allow for timely action to address potential problems or recognize strengths and superior performance.

Follow-up is accomplished to assure that corrective action is taken as a result of the audit and that deficient areas are re-audited, when necessary, to verify implementation of adequate corrective actions.

17.3.3.3.5 Supplier Oversight

Supplier QA programs are evaluated and monitored by NOS-Vendor Quality, to assure that QA requirements are met. Supplier QA programs require a system of periodic and planned supplier and sub-supplier audits conducted by persons not directly involved in the activity being audited. Supplier audits are performed on a three year frequency with extensions as allowed in Section 17.3.3.3.7, Audit Frequency Extensions.

17.3.3.3.6 Independent Audit of QA Functions

As directed by the Chief Nuclear Officer, the executive for NOS initiates a program audit of the QA Functions performed by NOS. These functions include the internal audit program, the NOS portions of the supplier oversight program, and maintenance of this document (Quality Assurance Program Description). This program audit is performed within a period of two years with extensions as allowed in Section 17.3.3.3.7 Audit Frequency Extensions.

This audit team consists of qualified individuals, none of which is from the area audited.

The audit is performed with pre-approved checklists, instructions, or plans.

The audit team conducts a post-audit conference with the responsible management of the areas audited to discuss the audit results, including deficiencies. The audit team prepares checklists and the audit report. The report is sent to the executive for NOS.

The executive for NOS and/or responsible management of the area being audited determines the need for corrective action and re-evaluation. Necessary corrective action and re-evaluation are performed as required.

Pertinent correspondence and reports related to the audit are filed.

17.3.3.3.7 Audit Frequency Extensions

Except when the frequency is specified by regulation, the following criteria for extending audit intervals apply:

1) Schedules are based on the anniversary established for each audit.
2) A maximum extension not to exceed 25 percent of the audit interval may be allowed (e.g., audits on a two year frequency may not be extended beyond 30 months, audits on an annual frequency may not be extended beyond 15 months).
3) When an audit interval extension is used, the next audit for that particular audit area is scheduled from the original anniversary.

4) Provision 2) also applies to supplier audits and evaluations except that a total combined time interval for any three consecutive inspection or audit intervals should not exceed 3.25 times the specified inspection or audit interval.

17.3.4 ADMINISTRATIVE CONTROLS RELOCATED FROM TECHNICAL SPECIFICATIONS

Consistent with NRC Administrative Letter 95-06, certain administrative controls from the original station Technical Specifications have been relocated to the Quality Assurance Program. These relocated administrative controls included technical review, independent review, 10 CFR 50.59 review, record retention, and audit requirements. This section provides references to the sections of this document where the administrative controls have been integrated with QAP controls.

17.3.4.1 Technical Reviews

This content provided requirements for technical reviews of station modifications, procedures, tests, and experiments to assure adequacy of nuclear safety related SSCs and associated activities. Those reviews are embedded in the QAP and its committed Standards. See Sections 17.3.2.2, Design Control; 17.3.2.3, Design Verification; 17.3.2.8, Test Control; and 17.3.2.14, Document Control.

As identified by procedures, technical evaluations are performed by personnel qualified in the subject matter to determine the technical adequacy and accuracy of the proposed activity. If interdisciplinary evaluations are required to cover the technical scope of an activity, they will be performed. Technical review personnel are identified by the responsible manager or his designee for a specific activity when the review process begins.

17.3.4.2 10 CFR 50.59 Reviews

The review of station modifications, procedures, tests, and experiments against the requirements of 10 CFR 50.59 is to ensure that changes requiring prior NRC approval are submitted to and approved by the NRC prior to implementation. Provisions are included in Sections 17.3.2.3 Design Verification and 17.3.2.14 Document Control to amplify the need to complete these reviews.

The program for 10 CFR 50.59 reviews is in accordance with NEI 96-07, Revision 1, “Guidelines for 10 CFR 50.59 Evaluations” as endorsed by Regulatory Guide 1.187, November 2000.

This program includes provisions to ensure that individuals have appropriate qualifications prior to completing these reviews. A list of individuals qualified to perform 50.59 evaluations is maintained for each site.

17.3.4.3 Record Retention

The list of typical operational phase records is in Section 17.3.2.15, Records.

17.3.4.4 Audit Types and Frequencies

These are addressed in Section 17.3.3.3.3 Internal Audit Program.

17.3.4.5 On-Site Review Committee

This is addressed in Section 17.3.3.2, Independent Review.

17.3.4.6 Reportable Event Action

Procedures are established to assure events are reviewed and notifications and reports are made as required by Regulations including, but not limited to, 10 CFR Part 21, 10 CFR 50.72, and 10 CFR 50.73.

These procedures require for significant incidents occurring during operation where a safety limit is exceeded, or which could otherwise be related to the nuclear safety of the station, the Site executive is notified, the event is investigated, and a report prepared. These reports:

a) Contain a summary description of the circumstances and information relating to the subject incident.
b) Contain an evaluation of the effects of the incident.
c) Describe corrective action taken or recommended as a result of the incident.
d) Describe, analyze and evaluate any significant nuclear safety related implications of the incident.

17.3.4.7 Independent Safety Engineering Group Functions

Independent Safety Engineering Group (ISEG) was addressed on a Site Specific basis for certain plants. See Site specific Attachments for additional requirements as follows:

- Attachment A, Brunswick Specific QAPD, Not Addressed.
- Attachment B, Harris Specific QAPD, Section B17.3.4.4, Independent Safety Engineering Group.
- Attachment C, Robinson Specific QAPD, Not Addressed
- Attachment D, Catawba, McGuire, and Oconee Specific QAPD, Section D17.3.4.7, Independent Safety Engineering Group

Attachment A, Brunswick Specific QAPD

Information presented in this attachment is specific to Brunswick and was contained in the UFSAR prior to Amendment 41.

Where a section contains no descriptive information beyond that in the generic text in the body of the document, a statement is made to that effect and no content is included. See A17.3.1.2, Organization for example.

A17. BNP SPECIFIC QUALITY ASSURANCE

A17.1 BNP QA DURING DESIGN AND CONSTRUCTION

See Brunswick UFSAR Chapter 17 for historic information from the description of the QA Program for design and construction.

A17.2 OPERATIONAL QA

Deleted

(NOTE: In April 1995, NRC approved the reformatting of the description of the Brunswick QA Program to follow Standard Revision Plan Section 17.3, replacing the content of 17.2.)

A17.3 BNP QUALITY ASSURANCE PROGRAM (QAP) DESCRIPTION

INTRODUCTION

This content is not addressed in SRP Section 17.3; therefore, the Brunswick description of the QA Program did not include this section.

DEFINITIONS

There are no Brunswick specific definitions.

EXPLANATION OF "QUALITY ASSURANCE"

There is no Brunswick specific content.

QA STANDARDS AND GUIDES

The QAP Brunswick conforms to Appendix B of 10CFR 50, as discussed in Section 17, "Quality Assurance." The QAP also conforms to applicable NRC Regulatory Guides and approved ANSI Standards, or applicable alternatives. Table A17-1 and A17-2 address QAP conformance to the referenced regulatory and program guidance contained in NUREG-0800 Section 17.3.

The content of Table A17-1 was transferred from Table 1-6 of the Brunswick UFSAR. Changes to the content of Table A17-1 are controlled in accordance with 10 CFR 50.54(a). Subsequent changes to the QAP are incorporated in this document as identified in Section 17.3.1.7.

Table A17-2 addresses additional Regulatory Guides that relate to implementation of the QAP but the implementation is site specific and controlled with the Brunswick UFSAR in accordance with 10 CFR 50.59.

Table A17-1. Conformance with QA Regulatory Guides and Industry Standards

Generic Exception:

Table A17-1 addresses Brunswick's Conformance of the Quality Assurance Program to certain NRC Regulatory Guides. In so doing, specific editions of industry standards are identified for compliance with exceptions and alternatives. Those identified standards include references to other industry standards for activities including, but not limited to; design, fabrication, inspection, and testing. Those included reference industry standards are considered to be guidance documents for details of how activities may be accomplished. The actual standard to be used in such cases is controlled by each station's current licensing and design bases.

Regulatory Guide 1.28, Quality Assurance Program Requirements (Design and Construction) (Safety Guide 28 June 1972) (Rev. 0)
ANSI Standard N45.2-1971, Quality Assurance Requirements for Nuclear Power Plants
This guide, and the standard it endorses, have been superseded for operations activities by Regulatory Guide 1.33 and ANSI N18.7-1976, which it endorses. The Operational Quality Assurance Program complies with Regulatory Guide 1.33 and ANSI N18.7-1976 as stipulated in Appendix A to that Program; therefore, Regulatory Guide 1.28 (Safety Guide 28) and ANSI N45.2-1971, which it endorses, are not considered necessary and are not included as part of the program.

Regulatory Guide 1.30, Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electrical Equipment (Safety Guide 30, Revision 0, August 1972)
ANSI Standard N45.2.4-1972 (IEEE-336-1971), Installation, Inspection, and Testing Requirements for Instrumentation and Electrical Equipment During the Construction of Nuclear Power Generating Stations
BNP 1 and 2 complies with the provisions of Regulatory Guide 1.30, August 1972, as indicated below:

The installation, inspection, and testing of nuclear power plant instrumentation and electrical equipment at BNP will be in accordance with the applicable requirements of ANSI N45.2.4-1972 with the following exceptions:

1. Section 1.4 titled Definitions: Definitions in this standard which are not included in ANSI N45.2.10 will be used; definitions which are included in ANSI N45.2.10 will be used as clarified in Brunswick commitment to Regulatory Guide 1.74.
2. Section 1.5 titled Reference Documents: Brunswick's commitment to other documents referenced in this standard shall be as stated in our commitment to that document.
3. Section 2.5 titled Measuring and Test Equipment: Brunswick will implement the applicable portions of this Section as follows:

    The status of portable items of measuring and test equipment and reference standards shall be identified by use of status cards, computer schedules, or tags for the date recalibration is due. These items are in a calibration program which requires recalibration on a specified frequency or, in certain cases, prior to use.

Table A17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.30, Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electrical Equipment (Safety Guide 30, Revision 0, August 1972)

ANSI Standard N45.2.4-1972 (IEEE-336-1971), Installation, Inspection, and Testing Requirements for Instrumentation and Electrical Equipment During the Construction of Nuclear Power Generating Stations

Instrumentation and electrical equipment in the categories listed below shall be in a calibration program. This program provides, by the use of status cards, computer schedules, or tags, for the date that recalibration is due and indicates the status of calibration. The identity of person(s) performing the calibration is provided on the calibration documents.

a. Instruments installed as listed in the BNP Technical Specifications
b. Installed instrumentation used to verify BNP Technical Specification parameters
c. Installed safety-related instruments and electrical equipment that provide an active function during operation or during shutdown; i.e., not a device being designated safety-related solely because the instrument is an integral part of a pressure retaining boundary.

4. Section 7 titled Data Analysis and Evaluation states in part, "Procedures shall be established for processing inspection and test data and their analysis and evaluation." At BNP 1 and 2, (data processing procedures per se have not been developed; instead, test data are recorded, processed, and analyzed in accordance with procedures and instructions in appropriate functional areas; e.g., maintenance, startup.

Regulatory Guide 1.33, Quality Assurance Program Requirements (Operation) (Safety Guide 33 November 1972)

ANSI Standard N18.7-1976, Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants

BNP 1 and 2 complies with the provisions of Regulatory Guide 1.33, November 1972, and the requirements and recommendations for administrative controls described in ANSI N18.7-1976 except as stated below:

1. The requirements of Paragraph 4.3 Independent Review Program are replaced by Section 17.3.3.2, Independent Review. This exception uses NRC Safety Evaluation dated January 13, 2005 to Nuclear Management Company (ADAMS ML050210276).
2. Deleted - see exception 1.
3. Paragraph 4.5 - Written audit reports are not formally reviewed as part of the Independent Review function.
4. Paragraph 4.5 - The Chief Nuclear Officer will assure that an independent assessment of the overall Nuclear Oversight Program is conducted at least once every 24 months. Results of the independent assessment will be reported directly to the Chief Nuclear Officer and entered into the Corrective Action Program for resolution. For scheduling consistency, the exceptions included in paragraph 5 of this section will be used as clarification for scheduling this independent assessment.
5. Paragraph 4.5, Audit Program - ANSI N18.7-1976/ANS-3.2, Section 4.5 is implemented with the following clarification: The audits of selected aspects of operational phase activities as identified in Section 17.3.3.3.3, Internal Audit Program, are scheduled based on plant performance and importance to safety but at a frequency not to exceed twenty-four months with extensions as allowed in Section 17.3.3.3.7, Audit Frequency Extensions.

Table A17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.33, Quality Assurance Program Requirements (Operation) (Safety Guide 33 November 1972)

ANSI Standard N18.7-1976, Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants

6. Section 5.2.2 titled Procedure Adherence: Temporary changes to approved procedures and proposed tests or experiments may be made provided; a) the intent of the original procedure, proposed test or experiment is not altered; b) the change is approved by two members of the plant management staff, at least one of whom holds a Senior Reactor Operator License on the unit affected; and c) the change is documented and, if appropriate, reviewed and approved for incorporation in the next revision of the procedure within 14 days of implementation of the temporary change.
7. The applicable procedures recommended in Appendix "A" of Regulatory Guide 1.33, November 1972, shall be established, implemented, and maintained as specified in the BNP 1 and 2 BNP Technical Specifications.
8. Paragraph 5.2.7 - BNP will comply with requirements of the first sentence of the second paragraph and provides the following clarification:
   a. "Documented Instructions" is defined as any credible information (e.g., vendor manuals, vendor recommendations, engineering direction, etc.) Used for work planning/execution which is reviewed and approved prior to use in accordance with approved procedures.
9. Paragraph 5.2.13, titled Procurement Document Control: When purchasing commercial grade calibration services from certain accredited calibration laboratories, the procurement documents are not required to impose a quality assurance program consistent with ANSI N45.2-1971. Alternate requirements described in Section 1.8 for Regulatory Guide 1.123 may be implemented in lieu of imposing a quality assurance program consistent with ANSI N45.2-1971.
10. 5.2.15 states, in part: “Plant procedures shall be reviewed by an individual knowledgeable in the area affected by the procedure no less frequently than every two years to determine if changes are necessary or desirable.”
    BNP implements administrative and programmatic controls that ensure procedures are maintained current in accordance with 10CFR 50, Appendix B, thus meeting the intent of the biennial review.
    BNP implements administrative controls to perform biennial reviews of non-routine procedures such as Emergency Operating Procedures, Abnormal Operating Procedures, Emergency Plan, Security, and other procedures that may be dictated by an event.
    Programmatic controls specify conditions when mandatory review of plant procedures apply, and include a requirement to review applicable procedures following and accident or transient and following any modification to a system.
    BNP utilizes a pre-job briefing practice to ensure that personnel are aware of what is to be accomplished and what procedures will be used prior to beginning a job. In addition, the Procedure Adherence Policy requires that the job be stopped and the procedure be revised or the situation resolved prior to work continuing if procedures cannot be implemented as written.
    Additionally, the Nuclear Oversight audit program requires the review of a representative sample of plant procedures, as part of routine audits, to ensure that existing administrative controls for procedure verification, review, and revision are effective in maintaining the quality of plant procedures. Significant QA Program deficiencies are identified in the audit reports. These deficiencies are investigated in accordance with the Corrective Action Program. The plant Self-Assessment Program also periodically reviews selected procedures and identified deficiencies and improvements through the Corrective Action Program.

Table A17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.33, Quality Assurance Program Requirements (Operation) (Safety Guide 33 November 1972)

ANSI Standard N18.7-1976, Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants

11. Section 5.2.17, second to the last sentence in the last paragraph, "Deviations, their cause, and any…," to be consistent with Paragraph 5.2.11 and 10CFR 50, Appendix B, the cause of the deviation will be determined for only significant conditions adverse to safety.
12. Paragraph 5.3.5(4) last sentence - BNP interprets the review requirements for "Supporting Maintenance Documents" which have not been incorporated in a procedure, be performed in an equivalent manner as described in approved procedures.
13. Section 5.3.9.1, titled Emergency Procedure Format and Content: Emergency procedures shall be in the format as committed to in NUREG-0737, TMI Action Plan.
14. ANSI N18.7-1976, Section 5.2.16. See Section A17.3.2.9 for clarification.
15. Section 5.3.10, first paragraph - The requirement "Test and inspection results shall be documented...," will be implemented as follows:
    As an alternative to the records required for inspections outlined in paragraph 5.3.10, BNP shall provide the following as the method to document results of inspections.
    The results of inspections will be documented in appropriate records and those records shall, as a minimum, identify a) through f) below:
    a) Item inspected
    b) Date of inspection
    c) Inspector
    d) Type of observation
    e) Results or acceptability
    f) Reference to information on action taken in connection with non-conformances.

Regulatory Guide 1.37, Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants (March 1973)

ANSI Standard N45.2.1-1973, Cleaning of Fluid Systems and Associated Components During Construction Phase of Nuclear Power Plants

Those areas of the QA Program applicable to onsite cleaning of materials and components, cleanliness control, and pre-operation cleaning and layup of BNP 1 and 2 fluid systems, will be in accordance with ANSI N45.2.1-1973, with the following exceptions:

1. At BNP 1 and 2, a classification system similar to ANSI N45.2.1-1973 has been developed and is fully implemented for cleaning of fluid systems.
2. Section 1.4 titled Definitions: Definitions in this standard which are not included in ANSI N45.2.10 will be used; definitions which are included in ANSI N45.2.10 will be used as clarified in BNP's commitment to Regulatory Guide 1.74.
3. Section 1.5 titled Referenced Documents: BNP's commitment to other documents referenced in this standard shall be as stated in our commitment to that document.

Table A17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.38, Quality Assurance Requirements for Packaging Shipping Receiving Storage and Handling of Items for Water-Cooled Nuclear Power Plants (March 1973)

ANSI Standard N45.2.2-1972, Packing, Shipping, Receiving, Storage, and Handling of Items for Nuclear Power Plants

Packaging, shipping, receiving, storage, and handling of BNP items are in accordance with applicable requirements of ANSI N45.2.2-1972 with the following specific exceptions:

1. Section 1.4 titled Definitions: Definitions in this standard which are not included in ANSI N45.2.10 will be used; definitions which are included in ANSI N45.2.10 will be used as clarified in BNP's commitment to Regulatory Guide 1.74.
2. Section 1.5 titled Referenced Documents: BNP's commitment to other documents referenced in this standard shall be as stated in our commitment to that document.
3. Section 2.7 titled Classification of Items and Section 6.1.2 titled Levels of Storage:
   a. Special electronic equipment and instrumentation received as assembled panels will be stored as recommended by the manufacturer and/or based on engineering evaluation to prevent damage, deterioration, or contamination, but not necessarily in a Level A storage area.
   b. Chemicals used at BNP 1 and 2 are stored at the point of use and/or in warehouse areas that satisfy the requirement of Level B storage. These storage areas have been evaluated and determined to be adequate for the limitations established by the manufacturer.
   c. Special nuclear materials are stored in areas specifically designed for such storage.
4. Paragraph 6.4.2, Care of Items: The following alternates are provided for indicated subparts:
   a. Space heaters in electrical equipment shall be energized unless a documented engineering evaluation determines that such space heaters are not required.
   b. Rotating electrical equipment, commensurate to safety or reliability, shall be given insulation resistance tests on a schedule basis, unless a documented evaluation determines that such tests are not required.
   c. Rotating equipment, commensurate to safety or reliability, shall be evaluated for shaft rotation requirements. The degree of turn shall be established so that the parts receive a coating of lubrication where applicable, and so that the shaft does not come to rest in a previous position. (90 deg. and 450 deg. rotations are examples.)
   d. Other maintenance requirements specified by the manufacturer's instructions shall be evaluated to determine applicability during storage of the item.
5. Section 7.3.4 - BNP intends to comply with the requirements of this Section with the following clarification: Test loads equal to or greater than the original crane rating shall not pass over locations where special nuclear material is stored or where reactor system components or high cost equipment are located.

Table A17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.39, Housekeeping Requirements for Water-Cooled Nuclear Power Plants (March 1973)

ANSI Standard N45.2.3-1973, Housekeeping, During the Construction Phase of Nuclear Power Plants

The applicable operational phase requirements of N45.2.3-1973 are followed at BNP within the context of the established QA Program with the following specific exception -- the zone designations of Section 2.1 of N45.2.3 and the requirements associated with each zone are considered impractical for implementation, as stated, at BNP during the operations phase. Instead, procedures or instruction for housekeeping activities, which include the applicable requirements outlined in Section 2.1 of N45.2.3, and which take into account radiation control considerations, security considerations, and cleanliness requirements, are developed on a case by case basis for work to be performed.

Regulatory Guide 1.58, Qualification of Nuclear Power Plant Inspection, Examination, and Testing Personnel (September 1980)

ANSI Standard N45.2.6-1978, Qualification of Inspection, Examination, and Testing Personnel for Nuclear Power Plants”

BNP 1 and 2 complies with NRC Regulatory Guide 1.58, September 1980, which endorses ANSI N45.2.6-1978, with the following exceptions:

1. Section 1.2 titled Applicability: BNP elects not to apply the requirements of this guide to those personnel who are involved in the daily operations of surveillance, maintenance, and certain technical and support services whose qualifications are controlled by the BNP Technical Specifications or are controlled by other QA Program commitment requirements. Only personnel in the following listed categories will be required to meet ANSI N45.2.6-1978 requirements:
   a. Nondestructive examination (NDE) personnel
   b. QC inspection personnel
   c. Receipt Inspection personnel
2. The fourth paragraph of Section 1.2 requires that the Standard be imposed on personnel other than BNP employees. The applicability of the Standard to suppliers and contractors will be documented and applied, as appropriate, in the procurement documents for such suppliers and contractors or in interface agreements for Duke Energy non-nuclear organizations providing services identified in Section 17.3.1.2.3.
3. Section 1.4 titled Definitions: Definitions in this Standard which are not included in ANSI N45.2.10 will be used; definitions which are included in ANSI N45.2.10 will be used as clarified in BNP's commitment to Regulatory Guide 1.74.
4. Section 2.5 titled Physical: BNP will implement the requirements of this Section with the stipulation that, where no special physical characteristics are required, none will be specified. The converse is also true: if no special physical requirements are stipulated by BNP, none are considered necessary. BNP employees receive an initial physical examination to assure satisfactory physical condition; however, only the following listed personnel will receive an annual examination:
   a. NDE personnel
   b. QC inspection personnel
   c. Receipt inspection personnel

   This annual examination shall consist of the near visual acuity using the standard Jaeger's type chart or equivalent test.

Table A17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.58, Qualification of Nuclear Power Plant Inspection, Examination, and Testing Personnel (September 1980)

ANSI Standard N45.2.6-1978, Qualification of Inspection, Examination, and Testing Personnel for Nuclear Power Plants"

5. Section 3 titled Qualifications: Only personnel performing NDE (such as LP, MT, UT, and RT) will be grouped in levels of capability and certified as such. QC inspection personnel will be certified for inspection, review, and evaluation of inspection data, and reporting of inspection and test results.
6. Section 3.5 titled Education & Experience Recommendations: BNP will certify individual inspectors through training and experience to requirements appropriate to the specific assignment; however, except for NDE, personnel will not be classified by levels of capability. The training and experience requirements will be directed toward qualifying personnel for specific inspection and testing operations.

Regulatory Guide 1.64, Quality Assurance Requirements for the Design of Nuclear Power Plants (October 1973)

ANSI Standard N45.2.1.1-1974, Quality Assurance Requirements for the Design of Nuclear Power Plants

Those areas of the QA Program for BNP 1 and 2 applicable to design or modification of the plant are in accordance with the applicable guidance of ANSI N45.2.11-1974, with the following exception:

1. Section 1.4 titled Definitions: Definitions in this standard which are not included in ANSI N45.2.10 will be used; definitions which are included in ANSI N45.2.10 will be used as clarified in the BNP commitment to Regulatory Guide 1.74.

Regulatory Guide 1.74, Quality Assurance Terms and Definitions (February 1974)

ANSI Standard N45.2.1.0-1973, Quality Assurance Terms and Definitions

Comply with the provisions of Regulatory Guide 1.74, February, 1974.

Regulatory Guide 1.88, Collection, Storage, and Maintenance of Nuclear Power Plant Quality Assurance Records (August 1974)

ANSI Standard N45.2.9-1974, Collection, Storage, and Maintenance of QA Records

The requirements for collection, storage, and maintenance of QA records at BNP will be in accordance with ANSI N45.2.9-1974 and 17.3.2.15, with the following specific exceptions:

See standard exception in Table 17-1 Regulatory Guide 1.88 for the appropriate controls on quality in the management of electronic records.

1. The document control facility at the BNP shall comply with the requirement of Regulatory Guide 1.88, October, 1976, Regulatory Position C.2 in that the facility has been specifically designed to protect the contents from fire in accordance with NFPA 232-1975, with the following exceptions/alternatives/comments:
   a. Records are classified as Class 1 - Vital Records in accordance with NFPA 232-1975, Chapter 5, Section 5222; however, the records that meet this classification include those determined to be QA records as defined in ANSI N45.2.9-1974, paragraph 1.4.

Regulatory Guide 1.88, Collection, Storage, and Maintenance of Nuclear Power Plant Quality Assurance Records (August 1974)

ANSI Standard N45.2.9-1974, Collection, Storage, and Maintenance of QA Records

b. The facility is constructed in accordance with NFPA 232-1975 requirements for a fire-resistive file room as defined in NFPA 232-1975, Chapter 3. The walls were designed and constructed equivalent to a four-hour barrier. The doors are four-hour rated vault doors. Penetrations for electrical service and ventilation are sealed to a rating of 3 hours to protect the vault from a fire originating outside the vault.
c. Due to the construction of the facility and other safety measures described herein, the statement in NFPA 232-1975, Chapter 3, Section 3022(d), "Class 1 . . . records should not be subjected to these possibilities of destruction by fire" is deemed to be inappropriate.
d. The facility is protected by a Halon fire extinguishing system, automatic door closures, and fire detection system.
e. The floor of the file room is six inches higher than the floor areas outside the file room.
f. The walls are reinforced concrete, ten inches thick.
g. The exterior walls are totally enclosed and insulated from the outside environment and elements.
h. The facility is constructed independently from the building.
i. NFPA 232-1975, Chapter 3, Sections 332 and 333 describe methods for heating and ventilation.
   The facility will have penetrations in the wall for the purposes of heating and ventilation. The facility is equipped with a Heating, Ventilating and Air Conditioning system external to the file room with automatic closing dampers. "The temperature and humidity should be controlled between 65 and 75 degrees and 20 and 40 percent, respectively. Temporary operation outside this range is acceptable during extreme low outside relative humidity conditions which have shown to drop the vault humidity below 20 percent. Humidity above the upper 40 percent range is acceptable during maintenance. The above times are short in duration and the humidity change is gradual. Evaluation for out of tolerance conditions will be performed. Corrective actions or compensatory measures will be taken if required, to ensure there is no adverse impact on storage of records and to restore the vault to prescribed conditions."
j. 120 VAC wall outlets are provided in the file room for emergency lighting and janitorial needs. These outlets may be de-energized from a disconnect box installed on the outer wall of the records storage facility. The lighting may be disconnected outside the room and is equipped with a red pilot light.
k. BNP QA records not stored in the facility described above may be retained at off-site locations which meet the requirements (with approved exceptions as necessary) of Section 5.6, ANSI 45.2.9-1974.

2. Paragraph 1.4, Definitions: The phrase "when the document has been completed" is clarified to mean when the document has received the final review performed by the organizational element responsible for generating or collecting the records. In the case of a record package made up of several individual documents, the package will be considered to be the document for the purpose of determining when the record is complete.
3. Paragraph 3.2.1, Generation of Quality Assurance Records: The phrase "completely filled out" is clarified to mean that sufficient information is recorded to fulfill the intended purpose of the record.
4. Paragraph 4.2, Timeliness: BNP's contractual agreement with its contractors and suppliers will constitute fulfillment of the requirements of this paragraph.

Table A17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.88, Collection, Storage, and Maintenance of Nuclear Power Plant Quality Assurance Records (August 1974)
ANSI Standard N45.2.9-1974, Collection, Storage, and Maintenance of QA Records

5. Paragraph 5.4, Preservation: The following clarification is substituted for the current subparagraph 5.4.2: "Records shall not be stored loosely. They shall be secured for storage in file cabinets or on shelving in containers." The following clarification is substituted for the current subparagraph 5.4.3: "Appropriate provisions shall be made for special processed records (such as radiographs, photographs, negatives, microfilm and magnetic media) to prevent or minimize damage for excessive light, stacking, electromagnetic fields, temperature and humidity, etc. Manufacturer's recommendations will be considered as appropriate."
6. Paragraph 5.6, Facility: This paragraph provides no distinction between temporary and permanent facilities. To cover temporary storage, the following clarification is added: "Complete records may be stored in one-hour fire rated file cabinets until transmitted for permanent storage. In general, records shall not be maintained in temporary storage by the generating organization for more than 90 days after completion. Any exceptions to this requirement must be justified, evaluated and approved by the Document Management Supervisor and documented. A list of exceptions shall be maintained and available for NRC review. Exceptions may include records needed on a continuing basis for an extended period of time at the location of the work group responsible for generating the records and records which are cumulative in nature and could best be turned over for storage for a designated period of time.
   In addition, Document Management & Information Services will store records in one- hour rated file cabinets while the records are being processed for permanent storage.
7. See standard exception in Table 17-1 Regulatory Guide 1.88 for the appropriate controls on quality in the management of electronic records.

Regulatory Guide 1.94, Quality Assurance Requirements for Installation, Inspection, and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants (Rev. 1, April 1976)
ANSI Standard N45.2.5-1974, Supplementary Quality Assurance Requirements for Installation Inspections and Testing of Structural Steel During the Contract Phase of Nuclear Power Plants
Regulatory Guide 1.94, Revision 1, April 1976 endorses ANSI N45.2.5-1974. BNP 1 and 2 do not commit to Regulatory Guide 1.94 but do endorse parts of ANSI N45.2.5-1974 as described below.
The original specification requirements, applicable guidance contained in ANSI N45.2.5-1974, or acceptable alternatives based on an engineering evaluation will be utilized in the event future structural work is to be performed which falls under the established requirements of the BNP QA Program.

Table A17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.116, QA Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems (June 1976)

ANSI Standard N45.2.8-1975, Supplementary Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems for the Construction Phase of Nuclear Power Plants

Regulatory Guide 1.116, June 1976, endorses ANSI N45.2.8-1975. BNP 1 and 2 does not commit to Regulatory Guide 1.116 but does endorse parts of ANSI N45.2.8-1975 as described below.

Within the context of the established QA Program, the applicable guidance contained in ANSI N45.2.8-1975 will be utilized in relation to mechanical maintenance or modification with the following exceptions:

1. Section 1.4 titled Definitions: Definitions in this standard which are not included in ANSI N45.2.10 will be used; definitions which are included in ANSI N45.2.10 will be used as clarified in BNP's commitment to Regulatory Guide 1.74.
2. Section 1.5 titled Referenced Documents: BNP's commitment to other documents referenced in this standard shall be as stated in our commitment to that document.
3. Section 2.8 titled Measuring and Test Equipment: BNP will implement the applicable portions of this Section as follows:
    a. The status of portable items of measuring and test equipment and reference standards shall be identified by use of status cards, computer schedules, or tags for the date recalibration is due. These items are in a calibration program which requires recalibration on a specified frequency or, in certain cases, prior to use.
    b. Instrumentation and electrical equipment in the categories listed below shall be in a calibration program. This program provides, by the use of status cards, computer schedules, or tags, for the date that recalibration is due and indicates the status of calibration. The identity of person(s) performing the calibration is provided on the calibration documents.
        1) Instruments installed as listed in the BNP Technical Specifications
        2) Installed instrumentation used to verify BNP Technical Specification parameters
        3) Installed safety-related instruments and electrical equipment that provide an active function during operation or during shutdown; i.e., instead of being designated safety-related solely because the instrument is an integral part of a pressure retaining boundary,
4. Section 6 titled Data Analysis and Evaluation states in part, "Procedures shall be established for processing inspection and test data and their analysis and evaluation."

    At BNP 1 and 2, data processing procedures per se have not been developed; instead, test data are recorded, processed, and analyzed in accordance with procedures and instructions in appropriate functional areas; e.g., maintenance, startup.

Table A17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.123, “Quality Assurance Requirement for Control or Procurement of Items and Services for Nuclear Power Plants”

ANSI Standard N45.2.13, “Quality Assurance Requirements for Control or Procurement of Items and Services for Nuclear Power Plants” (Draft 2, Rev. 4, April 1974)

BNP does not commit to Regulatory Guide 1.123; however, the applicable guidance contained in ANSI N45.2.13 (Draft 2, Revision 4, April 1974) and ANSI N18.7-1976, will be utilized in relation to procurement of items and services performed under the established requirements of the QA Program.

See standard exceptions in Table 17-1 for Regulatory Guide 1.123 for the procurement of Commercial Grade Items and Services including, purchasing commercial-grade calibration services from calibration laboratories.

Regulatory Guide 1.144, Auditing of Quality Assurance Programs for Nuclear Power Plants (January 1979)

ANSI Standard N45.2.12-1977, Requirements for Auditing of Quality Assurance Programs for Nuclear Power Plants

BNP will follow the requirements and recommendations of Regulatory Guide 1.144 and ANSI Standard N45,2.12, with the following clarifications:

1. BNP will follow the requirements and recommendations of Regulatory Guide 1.144, paragraphs C.1, C.2, C.3.a.2, C.3.b, and C.4. BNP's position on paragraph C.3.a.1 is as follows:

   Audits of operational phase activities, as outlined in Section 17.3.3.3 shall be performed at the frequencies stated in exception 5 for RG 1.33 in Table A17-1.

   See standard exceptions in Table 17-1 for Regulatory Guide 1.123 for the procurement of Commercial Grade Items and services including, purchasing commercial-grade calibration services from calibration laboratories.

2. (Deleted)
3. BNP will comply with the last paragraph of Section 4.4 of ANSI N45.2.12 concerning issuing audit reports, with the following clarification: "Audit reports shall be issued within thirty working days after the last day of the audit. The last day of the audit shall be considered to be the day of the post-audit conference. If a post-audit conference is not held because it was deemed unnecessary, the last day of the audit shall be considered to be the date the post-audit conference was deemed unnecessary as documented in the audit report."
4. ANSI N45.2.12 Paragraph 4.3.1, Preaudit Conference: BNP will comply with the requirement of this paragraph by inserting the word "Normally" at the beginning of the first sentence. This clarification is required because, in the case of certain unannounced audits or audits of a particular operation or work activity, a preaudit conference might interfere with the spontaneity of the operation or activity being audited. In other cases, persons who should be present at a preaudit conference may not always be available. Such lack of availability should not be an impediment to beginning an audit. Even in the above examples, which are not intended to be all inclusive, the material set forth in paragraph 4.3.1 will normally be covered during the course of the audit.

Table A17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.144, Auditing of Quality Assurance Programs for Nuclear Power Plants (January 1979)

ANSI Standard N45.2.12-1977, Requirements for Auditing of Quality Assurance Programs for Nuclear Power Plants

5. ANSI N45.2.12 Paragraph 4.3.3, Post Audit Conference: BNP will substitute and comply with the following paragraphs:
   For all external audits, a post audit conference shall be held with management of the audited organization to present audit findings and clarify misunderstandings. Where no adverse findings exist, this conference may be waived by management of the audited organization. Such waiver shall be documented in the audit report. For all internal audits, unless unusual operating or maintenance conditions preclude attendance by appropriate managers/supervisors, an audit exit shall be held with managers/supervisors. If there are no adverse findings, management of the audited organization may waive the audit exit. Such waiver shall be documented in the audit report.
6. ANSI N45.2.12 Paragraph 4.4, Reporting:
   a. This paragraph requires that the audit report be signed by the audit team leader which is not always the most expeditious route for the audit report to be issued as soon as possible. BNP will comply with Paragraph 4.4 as clarified to read:
      An audit report shall be signed by the audit team leader or the leader's supervisor in the absence of the audit team leader. In cases where the audit report is not signed by the audit team leader due to the leader's absence, the record copy of the report must be signed by the audit team leader upon return. The report shall not require the audit team leader's review/concurrence/signature if the audit team leader is no longer employed by BNP at the time audit report is issued. The audit report shall provide:
   b. BNP will comply with subparagraph 4.4.3 clarified to read: "Supervisory level personnel with whom significant discussions were held during the course of preaudit (where conducted), audit, and post audit (where conducted) activities.
   c. Subparagraph 4.4.6 requires audit reports to include recommendations for corrective actions. BNP may choose not to comply with this requirement. Instead, BNP audit reports are required to document findings.

Regulatory Guide 1.146, Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants (Rev. 0 August 1980)

ANSI Standard N45.2.23-1978, Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants

BNP 1 and 2 complies with NRC Regulatory Guide 1.146, Revision 0, which endorses ANSI N45.2.23-1978, with the following exceptions:

1. Section 1.4 titled Definitions: Definitions in this Standard which are not included in ANSI N45.2.10 will be used; "Audit" which is included in ANSI N45.2.10 will be used as clarified in BNP's commitment to Regulatory Guide 1.74.
2. Section 2.2 titled Qualification of Auditors: Subsection 2.2.1 references an ANSI B45.2 which will be assumed to be N45.2. BNP will comply with an alternate subsection 2.2.1 which reads:
   Orientation to provide a working knowledge and understanding of the BNP Quality Assurance Program, including the Regulatory Guides and ANSI standards included in the Program, and BNP procedures for performing audits and reporting results.
3. (Deleted)

Table A17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.146, Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants (Rev. 0 August 1980)

ANSI Standard N45.2.23-1978, Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants

4. Section 4.1 titled Organizational Responsibility: BNP will comply with this Section with the substitution of the following sentence in place of the last sentence in the Section:

   Management or the Audit/NOS Team Leader shall, prior to commencing the audit, assign personnel who collectively have experience or training commensurate with the scope, complexity, or special nature of the activities to be audited.

5. Section 5.3 titled Updating of Lead Auditors' Records: BNP will substitute the following sentence for this Section:

   Records for each Lead Auditor shall be maintained and updated during the annual management assessment as defined in Section 3.2 (as clarified).

6. Section 5.4 titled Record Retention: BNP will substitute the following sentence for this Section:
   Qualification records shall be retained as required by the BNP Quality Assurance Program.

7. ANSI N45.2.23-1978, Section 2.3.4 titled Audit Participation: BNP will substitute the following for this Section:

   Prospective Lead Auditors shall demonstrate the ability to effectively implement the audit process and effectively lead an audit team. This process is described in written procedures which provide for evaluation and documentation of the results of this demonstration. In addition, the prospective Lead Auditor shall have participated in at least two Nuclear Oversight audits within the year preceding the individual's effective date of qualification. Upon successful demonstration of the ability to effectively implement the audit process and effectively lead audits, and having met the other provisions of Section 2.3 of ANSI/ASME N45.2.23-1978, the individual may be certified as being qualified to lead audits.

Table A17-2. Site Specific Response to Regulatory Guides and Industry Standards

Table A17-2 identifies additional Regulatory Guides addressing subjects related to implementation of the QAP but the implementation is site specific and controlled with the UFSAR in accordance with 10 CFR 50.59.

Regulatory Guide 1.8, Personnel Selection and Training

Personnel selection and training is site specific.

> Brunswick addresses conformance with Regulatory Guide 1.8 (SAFETY GUIDE 8, MARCH 1971) in UFSAR Chapter 1 Table 1-6.

Regulatory Guide 1.26, Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants

---

Quality group classifications and standards trace to the original design and construction of the nuclear power plant and therefore are site specific.

> Brunswick does not address Regulatory Guide 1.26 in UFSAR Chapter 1 Table 1-6. Quality group classifications are addressed in UFSAR Chapter 3.

Regulatory Guide 1.29, Seismic Design Classification

Seismic design classification trace to the original design and construction of the nuclear power plant and therefore is site specific.

> Brunswick addresses conformance with Regulatory Guide 1.29 in UFSAR Chapter 1 Table 1-6.

Regulatory Guide 1.36, Nonmetallic Thermal Insulation for Austenitic Stainless Steel

---

Nonmetallic thermal insulation for austenitic stainless steel trace to the original design and construction of the nuclear power plant and therefore is site specific.

> Brunswick does not address conformance with Regulatory Guide 1.36 in UFSAR Chapter 1 Table 1-6. Thermal insulation for austenitic stainless steel is addressed in UFSAR Section 5.2.

Regulatory Guide 1.54, Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants

---

Quality assurance requirements for protective coatings applied to water-cooled nuclear power plants trace to the original design and construction of the nuclear power plant and therefore is site specific.

> Brunswick addresses conformance with Regulatory Guide 1.54 in UFSAR Chapter 1 Table 1-6.

Table A17-2. Site Specific Response to Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.143, Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light-Water-Cooled Nuclear Power Plants

Design guidance for radioactive waste management systems, structures, and components installed in light-water-cooled nuclear power plants trace to the original design and construction of the nuclear power plant and therefore is site specific.

Brunswick does not address conformance with Regulatory Guide 1.143 in UFSAR Chapter 1 Table 1-6. Design guidance for radioactive waste management systems, structures, and components is addressed in UFSAR Chapter 11.

Regulatory Guide 1.155, Station Blackout

Addressing Station Blackout is site specific.

Brunswick addresses conformance with Regulatory Guide 1.155 in UFSAR Chapter 1 Table 1-6.

Regulatory Guide 4.15, Quality Assurance for Radiological Monitoring Programs (Normal Operations) – Effluent Streams and the Environment

Quality assurance for radiological monitoring program (normal operations) – effluent streams and the environment is site specific.

Brunswick does not address conformance to Regulatory Guide 4.15 in UFSAR Chapter 1 Table 1-6. The radiological monitoring program is addressed in UFSAR Chapter 11.

A17.3.1 MANAGEMENT

A17.3.1.1 Methodology

There are no Brunswick specific amplifications for this section.

A17.3.1.2 Organization

There are no Brunswick specific amplifications for this section.

A17.3.1.3 Responsibility

There are no Brunswick specific amplifications for this section.

A17.3.1.4 Authority

The program and procedures require that the authority and duties of persons and organizations performing activities affecting quality functions be clearly established and delineated in writing and that these individuals and organizations have sufficient authority and organizational freedom to:

1. Identify quality, nuclear safety, and performance problems.
2. Order unsatisfactory work to be stopped and control further processing, delivery, or installation of nonconforming material.
3. Initiate, recommend, or provide solutions for conditions adverse to quality.
4. Verify implementation of solutions.

A17.3.1.5 Personnel Training and Qualification

There are no Brunswick specific amplifications for this section.

A17.3.1.6 Corrective Action

The program requires that an evaluation of adverse conditions such as conditions adverse to quality, nonconformances, failures, malfunctions, deficiencies, deviations, and defective material and equipment is conducted to determine need for corrective action.

Conditions adverse to quality are identified through inspections, assessments, tests, checks, and review of documents.

The program requires corrective action to be initiated to preclude recurrence of significant conditions adverse to quality.

Procedures require follow-up reviews, verifications, inspections, etc., to be conducted to verify proper implementation of corrective action and to close out the corrective action documentation.

The program outlines the methodology for resolution of disputes involving quality and nuclear safety issues arising from a difference of opinion between identifying personnel and other groups.

Significant conditions adverse to quality are reported to appropriate management for review and evaluation.

Periodic review and evaluation of adverse trends are performed by management.

A17.3.1.7 Regulatory Commitments

Written procedures shall be established, implemented, and maintained to ensure implementation of the Process Control Program.

A17.3.2 PERFORMANCE/VERIFICATION

A17.3.2.1 Methodology

There are no Brunswick specific amplifications for this section.

A17.3.2.2 Design Control

There are no Brunswick specific amplifications for this section.

A17.3.2.3 Design Verification

There are no Brunswick specific amplifications for this section.

A17.3.2.4 Procurement Control

Potential contractors and suppliers are evaluated prior to award of a procurement contract when needed to assure the contractor's or supplier's capability to comply with applicable technical and quality requirements.

Procurement documents, such as purchase specifications, contain or reference the following:

1. Technical, administrative, regulatory, and reporting requirements, including material and component identification requirements, drawings, specifications, codes and industrial standards, test and inspection requirements, and special process instructions.
2. Identification of the documentation to be prepared, maintained, or submitted (as applicable) to BNP for review and approval. These documents may include, as necessary, inspection and test records, qualification records, or code required documentation.
3. Identification of those records to be retained, controlled, and maintained by the supplier, and those delivered to the purchaser prior to use or installation of the hardware.

Procurement documents require suppliers to operate in accordance with QA programs which are compatible with the applicable requirements of BNP's QA Program and procedures where their services are utilized in support of plant activities.

A17.3.2.5 Procurement Verification

There are no Brunswick specific amplifications for this section.

A17.3.2.6 Identification and Control of Items

Procedures require that materials, parts, and components be identified and controlled to prevent the use of incorrect or defective items. These procedures also require that identification of items be maintained either on the item in a manner that does not affect the function or quality of the item, or on records traceable to the item.

Procedures implementing these requirements provide for the following:

1. Verification that items received at the plant are properly identified and can be traced to the appropriate documentation, such as drawings, specifications, purchase orders, manufacturing and inspection documents, nonconformance reports, or material test reports.
2. Verification of item identification consistent with the BNP inventory control system and traceable to documentation which identifies the proper uses or applications of the item.

A17.3.2.7 Handling, Storage, and Shipping

Provisions are established to control the shelf life and storage of chemicals, reagents, lubricants, and other consumable materials.

A17.3.2.8 Test Control

Test procedures incorporate or reference the following, as required:

1. Instructions and prerequisites for performing the test,
2. Use of proper test equipment,
3. Mandatory inspection hold points,
4. Acceptance criteria

Test results are documented, evaluated, and their acceptability determined by a qualified, responsible individual or group.

When the acceptance criteria are not met, affected areas are to be retested or evaluated, as appropriate.

A17.3.2.9 Measuring and Test Equipment Control

Portable measuring and test equipment are calibrated by standards at least four times as accurate as the portable measuring and test equipment, unless limited by the state of the art.

Special tools such as torque wrenches, calipers, and micrometers are calibrated to be at least as accurate as the application(s) for which it is used, using standards which are at least as accurate as the special tool being calibrated.

Installed measuring and test instruments are calibrated by instruments at least as accurate as the installed, unless limited by the state of the art.

Reference and transfer standards are traceable to nationally recognized standards; or where national standards do not exist, provisions are established to document the basis for the calibration.

A17.3.2.10 Inspection Test and Operating Status

These procedures include the application, removal, and verification of inspection and welding stamps, or other status indicators as appropriate.

Altering the sequence of required tests, inspections, and safety-related operations can only be accomplished by methods outlined in procedures.

A17.3.2.11 Special Process Control

There are no Brunswick specific amplifications for this section.

A17.3.2.12 Inspection

There are no Brunswick specific amplifications for this section.

A17.3.2.13 Corrective Action

The primary goal of the BNP corrective action program is to improve overall plant operations and performance by identifying and correcting root causes of equipment and human performance problems.

Procedures define requirements for a corrective action program that charges personnel working at or supporting the nuclear plants with the responsibility to identify adverse conditions (including conditions adverse to quality).

Procedures include requirements for verification of the acceptability of the rework/repair of items by re-inspection and/or testing in accordance with the original inspection or test requirements or by an accepted alternative inspection and testing method.

Conditions that require rework/repairs are identified through the use of maintenance work request forms.

A17.3.2.14 Control of Documents

Changes to documents are reviewed and approved by the same organization that performed the original review and approval or by other designated qualified responsible organizations.

A17.3.2.15 Records

The structure in which single copy records are maintained is designed to prevent destruction, deterioration or theft. This structure ensures protection against destruction by fire, flooding, theft and deterioration by the environmental conditions of temperature and humidity.

A17.3.2.16 Record Retention

A list of typical operational phase QA Records is included in 17.3.2.15.

A17.3.3 ASSESSMENT

A17.3.3.1 Methodology

There are no Brunswick specific amplifications for this section.

A17.3.3.2 Independent Review

There are no Brunswick specific amplifications for this section.

A17.3.3.3 Independent Assessment

There are no Brunswick specific amplifications for this section.

A17.3.3.3.1 Organization

There are no Brunswick specific amplifications for this section.

A17.3.3.3.2 Internal Assessment Process

There are no Brunswick specific amplifications for this section.

A17.3.3.3.3 Internal Audit Program

A17.3.3.3.3.1 Other Reviews Prescribed by the Code of Federal Regulations

There are no Brunswick specific amplifications for this section.

A17.3.3.3.3.2 Independent Audit of Fire Protection Program

There are no Brunswick specific amplifications for this section.

A17.3.3.3.4 Results

There are no Brunswick specific amplifications for this section.

A17.3.3.3.5 Supplier Oversight

There are no Brunswick specific amplifications for this section.

A17.3.3.3.6 Independent Audit of QA Functions

There are no Brunswick specific amplifications for this section.

A17.3.3.3.7 Audit Frequency Extensions

There are no Brunswick specific amplifications for this section.

A17.3.4 REVIEW AND AUDIT

A17.3.4.1 Procedures, Tests, and Experiments

1. The procedures established, implemented, and maintained for the Quality Assurance Program for effluent and environmental monitoring use the guidance in Regulatory Guide 1.21, Revision 1, June 1974 and Regulatory Guide 4.1, Revision 1, April 1975.
2. See Section 17.3.2.14 for required reviews for changes to procedures, tests, and experiments.

A17.3.4.2 Modifications

There are no Brunswick specific amplifications for this section. See Section 17.3.2.2 for reviews required for modifications.

A17.3.4.3 Operating License/BNP Technical Specifications

1. Operating License/BNP Technical Specification changes shall be processed in accordance with 10CFR 50.90.
2. Operating License/BNP Technical Specification change requests shall be reviewed by the On-Site Review Committee in accordance with Section 17.3.3.2.
3. Changes to the 61BTH Independent Spent Fuel Storage Installation (ISFSI) BNP Technical Specifications and License are processed by Transnuclear, Inc., and will only be reviewed by the PNSC if a plant-specific safety issue is identified.

A17.3.4.4 10CFR 50.59 Evaluations and Independent Review Control

There are no Brunswick specific amplifications for this section. See Section 17.3.4.2, 10 CFR 50.59 Reviews.

A17.3.4.5 Nuclear Reviewers

There are no Brunswick specific amplifications for this section. Technical reviewer quailfications are addressed in Section 17.3.4.1, Technical Reviews and 10 CFR 50.59 evaluator qualifications are addressed in Section 17.3.4.2, 10 CFR 50.59 Reviews.

A17.3.4.6 Plant Nuclear Safety Committee

This content is addressed in Section 17.3.3.2, Independent Review.

Attachment B, Harris Specific QAPD

Information presented in this attachment is specific to Harris and was contained in the UFSAR prior to Amendment 41.

Where a section contains no descriptive information beyond that in the generic text in the body of the document, a statement is made to that effect and no content is included. See B17.3.1.2, Organization for example.

B17. QUALITY ASSURANCE

B17.1 QA DURING DESIGN AND CONSTRUCTION

See Harris UFSAR Chapter 17 for historic information from the description of the QA Program for design and construction.

B17.2 OPERATIONAL QA

Deleted

(NOTE: In April 1995, NRC approved the reformatting of the description of the Harris QA Program to follow Standard Revision Plan Section 17.3, replacing the content of 17.2.)

B17.3 HNP QUALITY ASSURANCE PROGRAM (QAP) DESCRIPTION

INTRODUCTION

This content is not addressed in SRP Section 17.3; therefore, the Harris description of the QA Program did not include this section.

DEFINITIONS

Harris specific definitions are found in Table B17.1 addressing conformance with Regulatory Guide 1.74, Quality Assurance Terms and Definitions.

EXPLANATION OF “QUALITY ASSURANCE”

There is no Harris specific content.

QA STANDARDS AND GUIDES

The Harris QAP conforms to Appendix B of 10CFR 50, as discussed in Section 17, “Quality Assurance.” The QAP also conforms to applicable NRC Regulatory Guides and approved ANSI Standards, or applicable alternatives. Table B17-1 and B17-2 address QAP conformance to the referenced regulatory and program guidance contained in NUREG-0800 Section 17.3.

The content of Table B17-1 was transferred from Section 1.8 of the Harris UFSAR. Changes to the content of Table B17-1 are controlled in accordance with 10 CFR 50.54(a). Subsequent changes to the Harris QAP are incorporated in this document as identified in Section 17.3.1.7.

Table B17-2 addresses additional Regulatory Guides that relate to implementation of the QAP but the implementation is site specific and controlled with the Harris UFSAR in accordance with 10 CFR 50.59.

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards

Generic Exception:

Table B17-1 addresses Harris's Conformance of the Quality Assurance Program to certain NRC Regulatory Guides. In so doing, specific editions of industry standards are identified for compliance with exceptions and alternatives. Those identified standards include references to other industry standards for activities including, but not limited to; design, fabrication, inspection, and testing. Those included reference industry standards are considered to be guidance documents for details of how activities may be accomplished. The actual standard to be used in such cases is controlled by each station's current licensing and design bases.

Regulatory Guide 1.28, Quality Assurance Program Requirements (Design and Construction) (Rev 0)

ANSI N45.2-1971, Quality Assurance Program Requirements for Nuclear Power Plants

---

For those activities performed under operating license, HNP shall comply with the requirements of Regulatory Guide 1.33 as specified in Harris Nuclear Plant's (HNP)'s position on Regulatory Guide 1.33. Regulatory Guide 1.28 is not considered necessary and is not included as part of the operational QA program.

Regulatory Guide 1.30, Quality Assurance Requirements for the Installation and Testing of Instrumentation and Electric Equipment (Rev. 0)

HNP complies with the requirements of ANSI N45.2.4-1972), Installation, Inspection, and Testing Requirements for Instrumentation and Electrical Equipment During the Construction of Nuclear Power Generating Stations, as it is endorsed by Regulatory Guide 1.30 with the following clarifications:

---

1. Paragraph 2.1, planning: requirements, as determined by responsible plant management, will be incorporated into procedures.
2. Paragraphs 2.2 and 2.3; prerequisites, procedures, and instructions: these controls will be implemented as determined by responsible plant management in approved procedures.
3. Paragraph 2.4, results, will be implemented as set forth in 17.3.2.12 and by compliance with Regulatory Guide 1.33.
4. Paragraph 2.5, measuring and test equipment, will be implemented as set forth in 17.3.2.9 in lieu of the requirements set forth in this paragraph.
5. Paragraph 3, preconstruction verification: "approved instructions" are interpreted to include vendor manuals.
6. Paragraph 4, installation, will be implemented by inclusion of requirements in modification or maintenance procedures, where such procedures are used. Standard HNP practices require that appropriate care be exercised whether a procedure is required or not.
7. Paragraph 5.1, inspections, including subparagraphs 5.1.1, 5.1.2, and the first sentence in 5.1.3, will be implemented as set forth in 17.3.2.12. The remaining sentence in 5.1.3 is covered in equivalent detail by HNP's commitment to Regulatory Guide 1.33, paragraph 5.2.6; the requirements as set forth in that commitment will be implemented in lieu of the requirements stated here.
8. Paragraph 5.2, tests, including subparagraphs 5.2.1 through 5.2.3, will be implemented as set forth in 17.3.2.8. The test program will consider the elements outlined in this paragraph when developing test requirements for inclusion in maintenance and modification procedures. In some cases, testing requirements may be met by post-installation surveillance testing in lieu of a special post-installation test.

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.30, Quality Assurance Requirements for the Installation and Testing of Instrumentation and Electric Equipment (Rev. 0)

HNP complies with the requirements of ANSI N45.2.4-1972), Installation, Inspection, and Testing Requirements for Instrumentation and Electrical Equipment During the Construction of Nuclear Power Generating Stations, as it is endorsed by Regulatory Guide 1.30 with the following clarifications:

9. Paragraph 6, post-construction verification, is not generally considered applicable at operating facilities because of the scope of the work and the relatively short interval between installation and operation.
10. Paragraph 6.2.1 titled equipment tests: the last paragraph of this section deals with tagging and labeling. HNP will comply with an alternate last paragraph which reads: "Each safety-related component of process instrumentation is identified with a unique number. This number is utilized in instrument maintenance records so that current calibration status, including data such as the date of the calibration and identity of person that performed the calibration, can be readily determined. Such information may also be contained on tags or labels which may be attached to installed instrumentation."
11. Paragraph 7, data analysis and evaluation, will be implemented as stated with adding the clarifying phrase "when used" at the beginning of that paragraph. The plant shall have procedures, to the extent determined by responsible plant management, for the performance of analyzing test data, but these procedures are not referred to as data processing procedures.

Regulatory Guide 1.33, Quality Assurance Program Requirements (Rev. 2) (Operation)

HNP complies with this guide, which endorses ANSI N18.7-1976, Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants, with the following clarifications:

1. Paragraph 1,"Scope", recommends that this standard applies to activities other than those associated with safety related equipment, activities, and procedures. ANSI N18.7-1976 has not fully taken into account the requirements of regulations other than 10CFR 50. Conflicts may exist between ANSI N18.7-1976 and those other regulations, such as OSHA, 10CFR 19, 20, 21, 30, 40, 70, 71, 73, and ASME. Therefore, HNP shall apply ANSI N18.7-1976 only to those plant features addressed in Section 3.2 of the HNP UFSAR that are classified as safety-related and under the control of the QA program.
2. Written audit reports are not formally reviewed as part of the independent review function.
3. The Chief Nuclear Officer will assure that an independent assessment of the overall nuclear oversight program is conducted at least once every 24 months. Results of the independent assessment will be reported directly to the Chief Nuclear Officer and entered into the corrective action program for resolution. (for scheduling consistency, the exceptions included in paragraph 18 of this section will be used as clarification for scheduling this independent assessment).
4. Paragraph 5.2.6, Equipment Control: HNP will comply with the "independent verification" requirements based on the definition of this phrase as given under the commitment to Regulatory Guide 1.74.

   Since HNP sometimes uses descriptive names to designate equipment, the sixth paragraph, second sentence is replaced with: "Suitable means include identification numbers or other descriptions which are traceable to records of the status of inspections and tests.

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.33, Quality Assurance Program Requirements (Rev. 2) (Operation)

HNP complies with this guide, which endorses ANSI N18.7-1976, Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants, with the following clarifications:

The first sentence in the seventh paragraph will be complied with after clarifying "operating personnel" to mean trained employees assigned to, or under the control of, Duke Energy management at an operating nuclear facility.

5. Paragraph 5.2.7, Maintenance and Modification: since some emergency situations could arise which preclude preplanning of all activities, HNP will comply with an alternate to the first sentence in the second paragraph which reads:
   "Except in emergency or abnormal operating conditions where immediate actions are required to protect the health and safety of the public, to protect equipment or personnel, or to prevent the deterioration of plant conditions to a possible unsafe or unstable level, maintenance or modification of equipment shall be preplanned and performed in accordance with written procedures. Where written procedures would be required and are not used, the activities that were accomplished shall be documented after the fact and receive the same degree of review as if they had been preplanned." where procedures are not available, documented instructions may be used to perform maintenance and modification activities. "Documented instructions" are defined as any credible information (e.g., vendor manuals, vendor recommendations, engineering direction etc.) used during work planning/execution which is reviewed and approved prior to use in accordance with approved procedures.
   Paragraph 5.2.7.1, Maintenance Programs: HNP will comply with the requirements of the first sentence of the fifth paragraph. This clarification is needed since it is not always possible to promptly determine the cause of the malfunction. HNP will initiate proceedings to determine the cause, and will make such determination promptly where practical. Determination of the term "promptly" and the term "practical" will be the responsibility of plant management and shall be based on the effect of the condition on the immediate health and safety of the public.
6. Paragraph 5.2.8, Surveillance Testing and Inspection Schedule: In lieu of a "master surveillance schedule," the following requirement shall be complied with: "surveillance testing schedule(s) shall be established reflecting the status of all planned in-plant surveillance tests and inspections."
7. Paragraph 5.2.9, Plant Security and Visitor Control, requires certain procedures and controls. In order to ensure that a conflict between 10CFR 73 and Regulatory Guide 1.17 and ANSI N18.17 does not exist, HNP shall not follow paragraph 5.2.9. An NRC approved security plan shall be implemented prior to fuel loading.
8. Paragraph 5.2.11, Corrective Action, requires certain activities to be performed. In order to avoid conflict between requirements, HNP shall follow the requirements in Sections 17.3.1.6 and 17.3.2.13, in lieu of paragraph 5.2.11.
9. Paragraph 5.2.13.1, Procurement Document Control: When purchasing commercial-grade calibration services from certain accredited calibration laboratories, the procurement documents are not required to impose a quality assurance program consistent with ANSI N45.2-1971. Alternate requirements described in this table for Regulatory Guide 1.123 may be implemented in lieu of imposing a quality assurance program consistent with ANSI N45.2-1971.
10. Paragraph 5.2.15, Review, Approval and Control of Procedures: The third sentence in paragraph three is interpreted to mean: "Applicable procedures shall be reviewed following an accident, an unexpected transient or a significant operator error. Applicable procedures shall also be reviewed following an equipment malfunction which results in a reportable event."

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.33, Quality Assurance Program Requirements (Rev. 2) (Operation)
HNP complies with this guide, which endorses ANSI N18.7-1976, Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants, with the following clarifications:

Paragraph 5.2.15 states that, "Plant procedures shall be reviewed by an individual knowledgeable in the area affected by the procedure no less frequently than every two years to determine if changes are necessary or desirable. A revision to a procedure constitutes a procedure review." in lieu of these requirements, the Shearon Harris Nuclear Power Plant has programmatic controls in place to continually identify procedure revisions to routine procedures which may be needed to ensure that procedures are appropriate for the circumstance and are maintained current.

11. Paragraph 5.2.16, Measuring and Test Equipment - In order to properly address this paragraph, HNP submits the following discussion of M&TE:

    IEEE Standard 498-1975 defines measuring and test equipment (M&TE) as follows:

    Devices or systems used to calibrate, measure, gauge, test, inspect, or control in order to acquire research, development, test, or operational data to determine compliance with design, specifications, or other technical requirements. M&TE does not include permanently installed operating equipment or test equipment used for preliminary checks where accuracy is not required; for example, circuit checking multimeters.

    Note: M&TE does not include rules, tape measures, levels, and other devices if normal commercial practices provide adequate accuracy.

    There is a key distinction between installed process instruments and measuring and test equipment. A piece of measuring and test equipment may be used to calibrate a number of plant instruments. Thus, a calibration error could affect a wide variety of plant equipment. Process instruments, on the other hand, perform a single function and may be used to operate equipment, verify operability of equipment, or perform a single monitoring or trip function. In the case of measuring and test equipment, the key concern when a device is out of calibration is to identify other instruments to which this accuracy has been transferred and, secondly, to prevent recurrence. In the case of process instruments, the key emphasis is to prevent recurrence of the out-of-calibration condition.

    In ANSI N18.7-1976 (and other documents), the distinction between measuring and test equipment and process instruments is not well defined.

    The requirements in the second and third paragraphs in Section 5.2.16 will be applied to measuring and test equipment and those in the first and third paragraphs applied to process instruments with the exception that process instrumentation shall be "suitably marked <u>or tracked</u> to indicate calibration status" versus "suitably marked to indicate calibration status." in addition, a review of out-of-calibration process instruments will be made to determine if action is required to prevent recurrence. Such action may include modification, procedural revision, or corrective maintenance. Section 17.3.2.9 provides additional requirements for control of M&TE.
12. Paragraph 5.2.17, Inspections: As a general clarification, when inspections are not contained in a separate inspection report, inspection requirements will be integrated into appropriate procedures or other documents with the procedure or document serving as the record. Records of inspections will be identifiable and retrievable.
13. Paragraph 5.2.17, second to the last sentence in the last paragraph, "Deviations, their cause, and any . . .", to be consistent with paragraph 5.2.11, the cause of the condition will be determined for only significant conditions adverse to safety.
14. Paragraph 5.3.5(4), HNP interprets the review requirements for "supporting maintenance documents" which have not been incorporated in a procedure, be performed in an equivalent manner as described in approved procedures.

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.33, Quality Assurance Program Requirements (Rev. 2) (Operation)

HNP complies with this guide, which endorses ANSI N18.7-1976, Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants, with the following clarifications:

15. Paragraph 5.3.6, Radiation Control Procedures, Discusses certain control programs. As previously stated, paragraph 1, scope, of ANSI N18.7-1976 references those activities involved with being safety-related.
    The radiation protection program is not considered to be in this category but rather a program required to comply with 10CFR 19, 20, 30, 70, 71, and 100. Therefore, HNP shall develop its radiation protection program as stated in Section 12.5 of the HNP UFSAR.
16. Paragraph 5.3.9.3, Emergency Procedures: As directed by the NRC, HNP will follow a format for emergency procedures in accordance with 10CFR 50, Appendix E.
17. Exception to Paragraph C.3 of Regulatory Guide 1.33 and ANSI N18.7-1976 Paragraph 4.3: Independent Review Program requirements are replaced by Section 17.3.3.2, Independent Review. This exception uses NRC Safety Evaluation dated January 13, 2005 to Nuclear Management Company (ADAMS ML050210276).
18. Regulatory position C.4 modifies the audit frequencies in Section 4.5 of ANSI N18.7. Duke Energy Carolinas takes exception to this regulatory position. The audits of selected aspects of operational phase activities as identified in Section 17.3.3.3.3, Internal Audit Program, are performance based scheduled based on plant performance and importance to safety but at a frequency not to exceed twenty-four months with extensions as allowed in Section 17.3.3.3.7, Audit Frequency Extensions.
19. Paragraph C.5.d of the Regulatory Guide 1.33 will be implemented by adding the clarifying phrase "Where practicable" in front of the fourth sentence of the fifth paragraph. The Regulatory Guide's changing of the two uses of the word "should" in this sentence to "shall" unnecessarily restricts HNP's options on repair or replacement parts. It is not always practicable to test parts prior to use. Modification review in accordance with the provisions of 10CFR 50.59 will be conducted and documented.
    The words "where practical" will be determined by responsible plant management and the results documented.
20. Paragraph C.5.e of Regulatory Guide 1.33 will be implemented subject to the same clarifications made for ANSI N45.2.2.
21. Paragraph C.5.f of Regulatory Guide 1.33 will be implemented with the substitution of the word "practical" for the word "possible" in the last sentence.
22. Paragraph C.5.g of Regulatory Guide 1.33 will be implemented with the addition of the modifier "normally" after each of the verbs (should) which the regulatory guide converts to "shall". It is HNP's intent to fully comply with the requirements of this paragraph, and any conditions which do not fully comply will be documented and approved by the plant staff. In these cases, the reason for the exception shall be retained for the same period of time as the affected preoperational tests.
23. Paragraph 5.2.2, Procedure Adherence describes that for temporary changes to procedures that one of the approvers shall be the supervisor in charge of the shift and hold a senior reactor operator license. To avoid overloading the supervisor in charge of the shift with administrative tasks, any member of operation's management with a senior reactor operator license will be allowed to approve temporary changes to procedures. The change is documented and, if appropriate, reviewed and approved for incorporation in the next revision of the procedure within 14 days of implementation of the temporary change.

Regulatory Guide 1.33, Quality Assurance Program Requirements (Rev. 2) (Operation)
HNP complies with this guide, which endorses ANSI N18.7-1976, Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants, with the following clarifications:
24. Paragraph 5.3.10 of ANSI N18.7-1976/ANS-3.2, the last sentence in the first paragraph requires "test and inspection results, shall be documented and evaluated..." also, the last sentence in the second paragraph requires "the test and inspection procedures shall require recording the date, identification of those performing the test or inspection, as-found condition, corrective actions performed, if any, and as-left condition." as an alternative to the records required for inspections outlined in paragraph 5.3.10, hnp shall provide the following as the method to document results of inspections: the results of inspections will be documented in appropriate records and those records shall, as a minimum, identify (A) through (H) below: (A) authorized individual approving results. (B) date of inspection. (C) inspector/data recorder. (D) item inspected. (E) M&TE used. (F) reference to information on action taken in connection with non-conformances. (G) results or acceptability. (H) type of observation.

Regulatory Guide 1.37, Quality Assurance Requirements for Cleaning Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants (Rev. 0)
HNP shall comply with the requirements of ANSI N45.2.1-1973, Cleaning of Fluid Systems and Associated Components During Construction Phase of Nuclear Power Plants, as it is endorsed by Regulatory Guide 1.37-March 1973, with the following clarifications:
1. Paragraph 2.5, Test Equipment, outlines control of inspection and test equipment. HNP has addressed its position relative to measuring & test equipment (M&TE) in 17.3.2.9. 2. Paragraph 5, Installation Cleaning: The recommendation that local rusting on corrosion resistant alloys be removed by mechanical methods is interpreted to mean that local rusting may be removed mechanically, but the use of other removal means is not precluded provided other cleaning methods are not considered detrimental as determined by responsible plant management. 3. The guide and standard are applicable to those areas of the quality assurance program addressing on-site cleaning of materials and components, cleanness control, preoperation cleaning and layup of fluid systems. 4. With regard to paragraph C.3 of Regulatory Guide 1.37: Chromates or other additives, normally in the system water, will not necessarily be added to the flush water. 5. With regard to paragraph C.4 of Regulatory Guide 1.37: Expendable materials, such as inks and related products; temperature indicating sticks; tapes; gummed labels; wrapping materials; water soluble dam materials; lubricants, NDT penetrant materials and couplants, dessicants, which contact stainless steel or nickel alloy surfaces shall be of commercial quality. Levels for halogens, sulfur, chlorides, low melting point metal, etc., for use on stainless steel and nickel alloy surfaces will be as determined by responsible technical group to limit or preclude intergranular cracking and stress corrosion cracking.

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.38, Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants (Rev. 2)

HNP shall comply with the requirements of ANSI N45.2.2-1972, Packing, Shipping, Receiving, Storage, and Handling of Items for Nuclear Power Plants, as it is endorsed by Regulatory Guide 1.38 with the following clarifications:

1. Paragraph 2.1, Planning: (first sentence) the specific items to be governed by the standard shall be identified. However, the standard is part of the HNP QA program and it will, therefore, be applied to those structures, systems, and components which are included in that program.
2. Paragraph 2.3 - Results - The full requirements of this paragraph shall apply to the inspections and tests that are performed to determine the acceptability of product quality.
3. Paragraph 2.4 - those personnel that perform inspection, examination, and testing activities for verification and acceptance/rejection purposes shall be qualified in accordance with Regulatory Guide 1.58.
4. Paragraph 2.5 - Measuring and Test Equipment (2.5.2) - That equipment which measures quality of the permanent plant items shall be under the calibration and control program; whereas the equipment used to measure secondary conditions, such as warehouse temperature, humidity, etc., will be maintained in good working order and checked for proper functioning when accuracy is in doubt, but not maintained under the calibration and control program. Traceability to calibration records will be provided when it is impractical (because of size, configuration, or application) to physically mark calibration information on the item. Note: M&TE does not include rulers, tape measures, levels, and other devices if normal commercial practices provide adequate accuracy.
5. Paragraph 2.7, Classification of Items: HNP may choose not to explicitly use the four level classification system. However, the specific requirements of the standard that are appropriate to each class will be applied unless justified and documented.
6. Paragraph 2.7.1(3) requires special nuclear material (fuel) and sources to be classified as Level A. HNP shall store new/used nuclear fuel and radioactive sources in storage locations as described in the Chapters 9 and 12 of the UFSAR. Radioactive sources used by HP personnel shall be stored and controlled in accordance with HP practices and procedures.
7. Paragraph 3.2 - Levels of Packaging - Packaging for shipment off-site will be equal to or exceed the original packaging by the vendor, as required to assure the quality of the item is not degraded as a result of shipping or handling.
8. Paragraph 3.4, Methods of Preservation: (first sentence) HNP will comply with these requirements subject to the clarification that the term "deleterious corrosion" means corrosion which cannot be subsequently removed and which adversely affects form, fit, or function.
9. Paragraph 3.6 - Barrier and Wrap Materials and Desiccants - The use of clear plastic in warehouses will be minimized. The guide rule is that the clear plastic shall be used only where periodic visual inspection is necessary.
   Plastic wrap on items supplied in accordance with a vendor's approved QA/QC program will be accepted and stored without rewrapping.
10. Paragraph 3.7, Containers, Crating and Skids: In lieu of the requirements of this paragraph, HNP will use means as determined by responsible plant technical personnel needed to provide adequate protection of the items in storage.
11. Paragraph 4 - Shipping - Requirements of paragraph 4, Shipping, primarily applies to the vendor. Plant functions with regard to return shipments will meet or exceed the methods of the vendor for the item or approved alternatives.

Regulatory Guide 1.38, Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants (Rev. 2)

HNP shall comply with the requirements of ANSI N45.2.2-1972, Packing, Shipping, Receiving, Storage, and Handling of Items for Nuclear Power Plants, as it is endorsed by Regulatory Guide 1.38 with the following clarifications:

12. Paragraph 5.2.1, Shipping Damage Inspection: Warehouse personnel will normally visually scrutinize incoming shipments for damage of the types listed in this paragraph; this activity is not necessarily performed prior to unloading. Since required items receive the item inspection of paragraph 5.2.2, separate documentation of the shipping damage inspection is not necessary. Release of the transport agent after unloading and the signing for the receipt of the shipment may be all of the action taken to document completion of the shipping damage inspection. Any nonconformances noted will be documented and dispositioned as required by 17.3.2.13. The person performing the visual scrutiny during unloading is not considered to be performing an inspection function as defined under Regulatory Guide 1.74; therefore, while he will be trained and qualified to perform this function, he may not necessarily be certified (N45.2.6) as an inspector.
13. Paragraph 5.2.2, Item Inspection: The need and extent for inspection of items will be determined by responsible plant technical personnel. Receiving inspections shall be performed in an area designated for receipt of material and shall normally be performed in the receiving building. The receiving building and the areas designated will provide adequate protection for the material, but may not comply with all of the specific requirements contained in Section 6 of this standard. Material that is suspected of being compromised during the receiving process shall be evaluated by responsible technical personnel, as determined by plant management.
14. Paragraph 5.2.2(1) - Identification and Marking - Item inspection will include inspection for identification and marking required by the purchase order documents. Marking that is not quality related or which provides no traceability will not be inspected.
15. Paragraph 5.3.1 - Acceptable - Item acceptance status will be indicated by application of tags, stickers, ribbons, or signs. Storage areas are not designated as accept areas except for bulk items.
16. Paragraph 6.1.1 - Scope - The levels and methods of storage for items between the time of removal from the prescribed storage until placement in the installed location may be relaxed as determined by responsible plant management for short periods of time, according to the sensitivity of the item being handled and the elements of contact anticipated during this interval. Where relaxation of storage requirements of this standard are deemed appropriate, the item, conditions, precautions and follow-up inspection for assurance that quality of the item has been maintained will be documented.
17. Paragraph 6.1.2, Levels of Storage: Subpart (2) is replaced with the following:
    (2) Level B items shall be stored within a fire-resistant, weather-tight, and well ventilated building or equivalent enclosure. This building shall be situated and constructed so that it will not normally be subject to flooding; the floor shall be paved or equal, and well drained. If any water comes in contact with stored equipment, such equipment will be labeled or tagged nonconforming, and then the nonconformance document will be processed and evaluated. Items shall be placed on pallets, shoring, or shelves to permit air circulation. The building shall be provided with heating and temperature control or its equivalent to reduce condensation and corrosion. Minimum temperature shall be 40°F and maximum temperature shall be 140°F or less if so stipulated by a manufacturer.
18. Paragraph 6.2.1, Access to Storage Areas: Items which fall within the level d classification of the standard will be stored in areas which may be posted to limit access, but other positive controls such as fencing or guards will not normally be provided.

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.38, Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants (Rev. 2)

HNP shall comply with the requirements of ANSI N45.2.2-1972, Packing, Shipping, Receiving, Storage, and Handling of Items for Nuclear Power Plants, as it is endorsed by Regulatory Guide 1.38 with the following clarifications:

19. Paragraph 6.2.4, Storage of Food and Associated Items: The sentence is replaced with the following: "The use or storage of food, drinks, and salt tablet dispensers in any storage area shall be controlled and shall be limited to designated areas where such use or storage is not deleterious to stored items."
20. Paragraph 6.2.5, Measures to Prevent Entrance of Animals: The sentence is replaced with the following: "Warehouse personnel shall be alert to detect evidence of rodents or small animals in indoor storage areas.
    Consideration will be given when setting up the system to provide reasonable assurance that rodents or other small animals will not be present. If any such evidence is detected, a survey or inspection will be utilized to determine the extent of the damage; exterminators or other appropriate measures shall be used to control these animals to minimize possible contamination and mechanical damage to stored material."
21. Paragraph 6.3.3, Storage of Hazardous Material: The sentence is replaced with the following: "Hazardous chemicals, paints, solvents, and other materials of a like nature shall be stored in approved cabinets or containers which are not in close proximity to installed safety systems required for safe shutdown."
22. Paragraph 6.4.2, Care of Items: The following alternates are provided for indicated subparts:
    (5) "Space heaters in electrical equipment shall be energized unless a documented engineering evaluation determines that such space heaters are not required."
    (6) "Large (greater than or equal to 50 hp) rotating electrical equipment shall be given insulation resistance tests on a scheduled basis unless a documented engineering evaluation determines that such tests are not required."
    (7) "Prior to being placed in storage, rotating equipment weighing over approximately 50 pounds shall be evaluated by engineering personnel to determine if shaft rotation in storage is required; the results of the evaluation shall be documented. If rotation is required, it shall be performed at specified intervals, and documented.
    The degree of turn shall be established so that the parts receive a coating of lubrication where applicable, and so that the shaft does not come to rest in the position prior to rotation. (90 deg. and 450 deg. rotations are examples.) For long shafts or heavy equipment subject to undesirable bowing, shaft orientation after rotation shall be specified and obtained."
    (8) Other maintenance requirements specified by the manufacturer's instructions shall be evaluated by responsible plant personnel to determine applicability during storage of the item.
23. Paragraph 6.5, Removal of Items from Storage: HNP does not consider the last sentence of this paragraph to be applicable to the operations phase due to the relatively short period of time between installation and use. The first sentence of the paragraph is replaced with: "HNP will develop, issue, and implement a procedure(s) which cover(s) the removal of items from storage. The procedure(s) will assure that the inspection status of all material issued is known, controlled, and appropriately dispositioned."
    When items are released and waiting at a location prior to installation, responsible plant management in accordance with plant procedures will determine and document the extent of inspection and storage requirements.

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.38, Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants (Rev. 2)

HNP shall comply with the requirements of ANSI N45.2.2-1972, Packing, Shipping, Receiving, Storage, and Handling of Items for Nuclear Power Plants, as it is endorsed by Regulatory Guide 1.38 with the following clarifications:

24. Paragraph 6.6, Storage Records: HNP will comply with the requirements of this section with the clarification that, for record purposes, personnel access to storage areas will not be recorded. Unloading or pick-up of material shall not be considered "access," nor shall inspection by NRC or other regulatory agents, nor shall tours by non-HNP employees who are accompanied by HNP employees.
25. Paragraph 7.3 - Hoisting Equipment - The load chart for each crane includes the model number for that crane. This load chart is considered to be "certification" by the manufacturer for that crane as required by paragraph 7.3.1. Likewise, forklifts are considered certified by the manufacturer's literature giving maximum capacity as required by Paragraph 7.3.2.
    Paragraph 7.3, Hoisting Equipment: Rerating of hoisting equipment will be considered only when absolutely necessary. Prior to performing any lift above the load rating, the equipment manufacturer will be contacted for his approval and direction. The manufacturer will be requested to supply a document granting approval for a limited number of lifts at the new rating and any restrictions involved, such as modifications to be made to the equipment, the number of lifts to be made at the new rating, and the test lift load. At all times, the codes governing rerating of hoisting the equipment will be complied with.
    If rerating of hoisting equipment is necessary and HNP cannot or does not contact the equipment manufacturer as described above, the test weight used in temporarily rerating hoisting equipment for special lifts will be at least equal to 110 percent of the lift weight. A dynamic load test over the full range of the lift using a weight at least equal to the lift weight will be performed.
26. Paragraph 7.4 - Inspection of Equipment and Rigging - Nondestructive examinations will be performed by QC personnel qualified in accordance with Regulatory Guide 1.58 (except as amended by safety analysis report position). Operators will be trained in the operation and maintenance inspections of their assigned equipment.
27. Appendix A.3.5.1 - Caps and Plugs; A.3.5.2, Tapes and Adhesives; and A.3.6.3, Desiccants - Plugs, caps, tapes, adhesives, desiccants, markers and other temporary items will be of commercial quality. Levels for halogens, sulfur, chlorides, low melting point metal, etc., for use on stainless steel and nickel alloy surfaces will be as determined by the responsible technical group to limit or preclude intergranular cracking and stress corrosion cracking.

Regulatory Guide 1.39, Housekeeping Requirements for Water Cooled Nuclear Power Plants (Rev. 2)

HNP complies with the requirements of ANSI N45.2.3-1973, Housekeeping, During the Construction Phase of Nuclear Power Plants, as endorsed by Regulatory Guide 1.39, September 1977, with the following clarifications for:

1. Paragraph 2.1, Planning: The zone designations provided in the standard will be used as a guide in developing plant procedures; however, plant areas will not necessarily be divided into zones I through V. Equivalent controls will be maintained as prescribed in approved procedures.
2. Paragraph 3.5, Surveillance, Inspection, and Examinations: Subparagraph (1) is not applicable during normal operations but will be implemented if large items are to be moved or handled.

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.58, Qualification of Nuclear Power Plant Inspection, Examination and Testing Personnel (Rev. 1)

HNP shall comply with NRC Regulatory Guide 1.58, Revision 1, which endorses ANSI N45.2.6-1978, Qualification of Inspection, Examination, and Testing Personnel for Nuclear Power Plants, with the following clarifications:

1. With regard to paragraph 1.2 of ANSI N45.2.6-1978 titled Applicability: HNP elects not to apply the requirements of this guide to those personnel who are involved in the daily operations of surveillance, maintenance, and certain technical and support services whose qualifications are controlled by 17.3 or are controlled by other QA program commitment requirements. Only personnel in the following listed categories will be required to meet ANSI N45.2.6-1978 requirements: (1) nondestructive examination (NDE) personnel (2) QC inspection personnel, and (3) receipt inspection personnel.
2. The fourth paragraph of Paragraph 1.2 requires that the standard be imposed on personnel other than HNP employees. The applicability of the standard to suppliers and contractors will be documented and applied as specified in the procurement documents for each supplier and contractor or in interface agreements for Duke Energy non-nuclear organizations providing services identified in Section 17.3.1.2.3.
3. With regard to Paragraph 2.5 of ANSI N45.2.6-1978 titled Physical: HNP will implement the requirements of this section with the stipulation that, where no special physical characteristics are required, none will be specified. The converse is also true: if no special physical requirements are stipulated by HNP, none are considered necessary. HNP employees receive an initial physical examination to assure satisfactory physical condition; however, only the following listed personnel will receive an annual examination: (1) NDE personnel (2) QC inspection personnel, and (3) receipt inspection personnel. This annual examination shall consist of the near visual acuity using the standard Jaeger's type chart or equivalent test.
4. With regard to Paragraph 3 of ANSI N45.2.6-1978 titled Qualifications: Only personnel performing NDE (such as LP, MT, UT, and RT) will be grouped in levels of capability and certified for inspection, review, and evaluation of inspection data, and reporting of inspection and test results. Inspection personnel are qualified based on preestablished experience, education, on-the-job training, written examinations and proficiency tests associated with the specific activity. Proficiency tests are given to personnel performing independent QC inspections and documented acceptance criteria are developed to determine if individuals are properly trained and qualified. Certificates of qualification delineate the functions personnel are qualified to perform. Qualification records are maintained and performance evaluations conducted at least on an every three year basis.
5. With regard to Paragraph 3.5 of ANSI N45.2.6-1978 titled Education & Experience Recommendations: HNP will certify individual inspectors through training and experience to requirements appropriate to the specific assignment; however, except for NDE, personnel will not be classified by levels of capability. The training experience requirements will be directed toward qualifying personnel for specific inspection and testing operations.

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.64, Quality Assurance Requirements for the Design of Nuclear Power Plants (Rev. 2)
HNP shall comply with NRC Regulatory Guide 1.64, Rev. 2, which endorses ANSI standard N45.2.11-1974, Quality Assurance Requirements for the Design of Nuclear Power Plants, with the following clarification:
Paragraph C.2(1): For the exceptional circumstance in which the designer's immediate supervisor is the only technically qualified individual available, this review can be conducted by the supervisor, provided that: i) the other provisions of the regulatory guide are satisfied, ii) the justification is individually documented and approved in advance by the supervisor's management, and iii) quality assurance audits cover frequency and effectiveness of the use of supervisors as design verifiers to guard against abuse.

Regulatory Guide 1.74, Quality Assurance Terms and Definitions (Rev. 0)
Regulatory Guide 1.74 endorses ANSI N45.2.10-1973, Quality Assurance Terms and Definitions. The HNP project complies with this guide as described below:
HNP complies with the requirements of this guide with the following clarifications:

1. HNP reserves the right to define additional words or phrases which are not included in this standard. Such additional definitions will be documented in appropriate procedures, manuals, etc.
2. In addition to the standard's definition of "inspection," HNP will use the following: "Inspection (when used to refer to activities that are not performed by quality organization personnel) - examining, viewing closely, scrutinizing, looking over or otherwise checking activities. Personnel performing these functions are not necessarily certified to ANSI N45.2.6."

   When HNP intends for inspection to be performed in accordance with the QA program by personnel certified as required by that program and for activities defined by "Inspection" in ANSI N45.2.10, appropriate references to the plant quality organization which will perform the activity and/or to quality procedures to be used for performing the activity will be made. If such references are not made, inspections are considered under the additional definition given above.
3. In addition to the standard's definition of "procurement documents," HNP will utilize the definitions given in ANSI N45.2.13 and in Regulatory Guide1.74. The compound definition, procurement documents-contractually binding documents that identify and define the requirements which items or services must meet in order to be considered acceptable by the purchaser. They include documents which authorize the seller to perform services or supply equipment, material or facilities on behalf of the purchaser (e.g. contracts, letters of intent, work orders, purchase orders, or proposals and their acceptance, drawings, specifications, or instructions which define requirements for purchase).
4. "Quality assurance program requirements" (not defined in ANSI N45.2.10, but used and defined differently in ANSI N45.2.13) - those individual requirements of the QA program which, when invoked in total or in part, establish the requirements to the quality assurance program for the activity being controlled. Although not specifically used in the operational QA program, ANSIN45.2 may be imposed upon HNP's suppliers.

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.74, Quality Assurance Terms and Definitions (Rev. 0)

Regulatory Guide 1.74 endorses ANSI N45.2.10-1973, Quality Assurance Terms and Definitions. The HNP project complies with this guide as described below:

5. "Independent Verification" - Verification that required actions have been completed by an individual other than the person who performed the operation or activity being verified. Such verification will not require confirmation of the identical action when other indications provide assurance or indication that the prescribed activity is in fact complete. Examples include, but are not limited to: verification of a breaker opening by observing remote breaker indication lights; verification of a set point (made with a voltmeter or ammeter for example) by observing the actuation of status or indicating lights are the required panel-meter indicated value; verification that a valve has been positioned by observing the starting or stopping of flow on meter indications or by remote valve position indicating lights.
6. "Audit" (will be a modification of the word - to allow the use of subjective evidence if available - as defined in paragraph 1.4 of ANSI N45.2.12-1977 and paragraph 1.4.3 of ANSI N45.2.23-1978 as opposed to the definition given in ANSI N45.2.10-1973) - A documented activity performed in accordance with written procedures or checklists to verify, by examination and evaluation of objective evidence where available, that applicable elements of the quality assurance program have been developed, documented, and effectively implemented in accordance with specified requirements. An audit should not be confused with surveillance or inspection for the sole purpose of control or product acceptance.

Regulatory Guide 1.88, Collection, Storage and Maintenance of Nuclear Power Plant Quality Assurance Records (Rev. 2)

HNP shall comply with NRC Regulatory Guide 1.88, Rev. 2, which endorses ANSI N45.2.9-1974, Collection, Storage, and Maintenance of QA Records, with the following clarifications:

See standard exception in Table 17-1 Regulatory Guide 1.88 for the appropriate controls on quality in the management of electronic records.

1. Appendix A of ANSI N45.2.9 is not considered to be a mandatory list. This list will be used as a guideline for classifying those documents that need to be maintained as QA records. Whether a particular type of document needs to be classified as a QA record and its appropriate retention period is determined in accordance with records management procedures.
2. Paragraph 1.4, Definitions: The phrase "When the document has been completed" is clarified to mean when the document has received the final review performed by the organizational element responsible for generating or collecting the records. In the case of a record package (plant change request, equipment qualification, etc.) made up of several individual documents, the package will be considered to be the document for the purpose of determining when the document is complete.
3. Paragraph 3.2.1, Generation of Quality Assurance Records: The phrase "Completely filled out" is clarified to mean that sufficient information is recorded to fulfill the intended purpose of the record.
4. Paragraph 3.2.2, Index: The storage location will be delineated in procedures in lieu of in the index. The specific location of a record "within a storage area" is delineated by a computerized indexing system plus a storage area labeling system which provides information by record type and storage medium.
5. Paragraph 4.2, Timeliness: HNP 's contractual agreement with its contractors and suppliers will constitute fulfillment of the requirements of this paragraph.

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.88, Collection, Storage and Maintenance of Nuclear Power Plant Quality Assurance Records (Rev. 2)

HNP shall comply with NRC Regulatory Guide 1.88, Rev. 2, which endorses ANSI N45.2.9-1974, Collection, Storage, and Maintenance of QA Records, with the following clarifications:

6. Paragraph 5.4, Preservation: The following clarification is substituted for the current subparagraph 5.4.2: "Records shall not be stored loosely. They shall be secured for storage in file cabinets or on shelving in containers." the following clarification is substituted for the current subparagraph 5.4.3: "appropriate provisions shall be made for special processed records (such as radiographs, photographs, negatives, microfilm, and magnetic media) to prevent or minimize damage from excessive light, stacking, electromagnetic fields, temperature and humidity, etc. Manufacturer's recommendations will be considered as appropriate."
7. Paragraph 5.5, Safekeeping: Routine general office and nuclear site security systems and access controls are provided. No special security systems are required to be established for record storage areas.
8. Paragraph 5.6, Facility: This paragraph provides no distinction between temporary and permanent facilities. To cover temporary storage, the following clarification is added: "complete records may be stored in one-hour fire rated file cabinets until transmitted for permanent storage. In general, records shall not be maintained in temporary storage for more than ninety days after completion.

   Any exceptions to this requirement must be justified, evaluated and approved by the supervisor document services or designee and documented. A list of exceptions shall be maintained and available for nrc review. Exceptions may include records needed on a continuing basis for an extended period of time at the location of the work group responsible for generating the records and records which are cumulative in nature and could best be turned over for storage for a designated period of time.
9. Paragraph 5.6, subparagraph 3, is clarified to require a two-hour minimum fire rating to be consistent with the 1979 version of the standard and <u>NRC Criteria for Record Storage Facilities</u> (Guidance - ANSI N45.2.9, Section 5.6) issued 7/1/80.
10. Paragraph 5.6, subparagraph 9, is clarified to read: "No pipes or penetrations except those providing fire protection, lighting, temperature/humidity control or communications are to be located within the facility. All such penetrations shall be sealed or dampened to comply with a minimum two-hour fire protection rating."
11. Additional clarification for QA records is provided in Section 17.3.2.15.
12. See standard exception in Table 17-1 Regulatory Guide 1.88 for the appropriate controls on quality in the management of electronic records.
13. See standard exception in Table 17-1 Regulatory Guide 1.88 for the appropriate controls on quality in the management of electronic records.

Regulatory Guide 1.94, Quality Assurance Requirements for Installation, Inspection and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants (Rev. 1)

HNP complies with the requirements and guidance of ANSI N45.2.5-1974, Supplementary Quality Assurance Requirements for Installation Inspections and Testing of Structural Steel During the Contract Phase of Nuclear Power Plants, as it is referenced in Regulatory Guide 1.94, Rev. 1, with the following clarifications:

A) Paragraph 2.1, Planning: Requirements, as determined by responsible plant management, will be incorporated into procedures.

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.94, Quality Assurance Requirements for Installation, Inspection and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants (Rev. 1)
HNP complies with the requirements and guidance of ANSI N45.2.5-1974, Supplementary Quality Assurance Requirements for Installation Inspections and Testing of Structural Steel During the Contract Phase of Nuclear Power Plants, as it is referenced in Regulatory Guide 1.94, Rev. 1, with the following clarifications:
B) Paragraph 2.3, Results, Will be implemented as set forth in Sections 17.3.2.12, 17.3.2.8, and 17.3.2.15 and Regulatory Guide 1.33. C) Paragraph 2.5 of ANSI N45.2.5, Measuring & Test Equipment, Requires certain controls over this type of equipment. The equipment listed shall be included in the calibration control program; however, the basis and control of measuring and test equipment is that stated in Section 17.3.2.9. D) The cement test frequency for standard physical and chemical properties is in accordance with ASTM C 183, on the basis of one test per daily production at the cement plant, reference ANSI N45.2.5, Table B. Table B also lists a test frequency for ASTM C 235 which has been discontinued by ASTM. HNP plans to discontinue testing in accordance with ASTM C 235. Acceptance of aggregates for durability/hardness will be in accordance with ASTM C 131 OR C 535, Los Angeles Abrasion Test. E) Gradation - In addition to the gradations listed in ASTM C-33, an aggregate designated 78-M (State of North Carolina designation) is used in special areas such as around major penetrations or in reinforcing steel congested areas, with the approval of the engineers. This aggregate meets all other qualifications of ASTM C-33, with the exception of gradation analyses. The results during preliminary concrete mix design have been satisfactory and in accordance with the requirements of ASME Section III, Division 2/ACI-359 code. F) Paragraph 5.4, High Strength Bolting: Bolting connection points will be visually inspected in accordance with ANSI N45.2.5-1974 except that bolt length will be checked to ensure bolts are long enough as indicated by the point of the bolts being flush with or outside the face of the nuts in accordance with ANSI N45.2.5-1978.

Regulatory Guide 1.116, Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems, (Rev. 0-R)
HNP complies with the requirements of ANSI N45.2.8-1975, Supplementary Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems for the Construction Phase of Nuclear Power Plants, as it is endorsed by Regulatory Guide 1.116, Revision O-R, June 1976, with the following clarifications:
1. Paragraph 2.1, Planning: Requirements, as determined by responsible plant management, will be incorporated into procedures. 2. Paragraph 2.3, results, will be implemented as set forth in Section 17.3.2.12 and by compliance with RG 1.33. 3. Paragraph 2.8, Measuring and Test Equipment - HNP has addressed this requirement for the operational phase of the plant in Section 17.3.2.9. 4. Paragraph 2.9, Prerequisites, References requirements of other standards. HNP has addressed applicable standards in the appropriate sections of the HNP UFSAR in lieu of the requirements of this paragraph. The extent to which this paragraph applies will be determined by responsible plant management based on end use and complexity of the item. 5. Paragraph 3.3, Processes and Procedures: "Approved instructions" are interpreted to include vendor manuals.

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.116, Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems, (Rev. 0-R)

HNP complies with the requirements of ANSI N45.2.8-1975, Supplementary Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems for the Construction Phase of Nuclear Power Plants, as it is endorsed by Regulatory Guide 1.116, Revision O-R, June 1976, with the following clarifications:

6. Paragraph 4.6, Care of Items: This will be done as outlined in the position on Regulatory Guide 1.38.
7. Paragraph 5, including subparagraphs 5.1 through 5.4, Installed Systems, Inspections and Tests: Responsible plant management will determine the extent to which the elements in this paragraph are applied when developing test requirements for inclusion in modification procedures. In some cases, testing requirements may be met by post-installation surveillance testing in lieu of a special post-installation test.

Regulatory Guide 1.123, Quality Assurance Requirements for Control or Procurement of Items and Services for Nuclear Power Plants, (Rev. 1)

HNP shall comply with the requirements of ANSI N45.2.13-1976, Quality Assurance Requirements for Control or Procurement of Items and Services for Nuclear Power Plants, as it is endorsed by Regulatory Guide 1.123 with the following clarifications:

1. Paragraph 1.2.2, Purchaser's Responsibilities: Item C is one of the options which may be used by HNP to assure quality; however, any of the options given in 10CFR50, Appendix B, Criterion VII as implemented by 17.3 may also be used. Evaluation of supplier's QA program will be conducted as determined depending on complexity and end use of item.
2. Paragraph 3.1, Procurement Document Preparation, Review and Control Change: The changed document may not always be as reviewed by the originator; however, at least an equivalent level shall review and approve any changes.
3. Paragraphs 3.2.3, 3.2.4, and 3.2.6 - HNP does not consider that these paragraphs or vendor qualifications apply for the procurement of off-the-shelf items. Off-the-shelf items (which include original as well as spare and replacements) are Commercial Grade Items which are defined in 10CFR 21.
   Special quality verification requirements shall be determined, as necessary, by responsible technical group to assure acceptability of the item. The responsible technical organization will review purchase requisitions of items classified as "commercial grade" to assure proper application of the 10CFR 21 criteria.
   See standard exceptions in Table 17-1 for Regulatory Guide 1.123 for the procurement of Commercial Grade Items and services including, purchasing commercial-grade calibration services from calibration laboratories.
4. Paragraph 3.3 requires procurement documents to be reviewed prior to bid or award of contract. The documented review of procurement documents is provided through review of the procurement specification and purchase requisition by the responsible technical organization prior to bid or award of contract.
5. Paragraph 3.4, Procurement Document Control: HNP will meet the requirements of 17.3 in lieu of the requirements specified in this paragraph.
6. Paragraph 4.2, Selection Measures, Outlines certain methods acceptable for the selection of suppliers. HNP's history of using similar methods has proven adequate in the procurement of items; therefore, HNP wishes to replace paragraph 4.2(a), (b), and (c) with the following selection methods:

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.123, Quality Assurance Requirements for Control or Procurement of Items and Services for Nuclear Power Plants, (Rev. 1)

HNP shall comply with the requirements of ANSI N45.2.13-1976, Quality Assurance Requirements for Control or Procurement of Items and Services for Nuclear Power Plants, as it is endorsed by Regulatory Guide 1.123 with the following clarifications:

1) The supplier's quality assurance capabilities as determined by a direct survey of his facilities and personnel, and the implementation of his quality assurance program.
2) Evaluating the supplier's history of providing a product which performs satisfactorily in actual use. One or more of the following information shall be evaluated:
   - (i) Experience of users of identical or similar products of the same prospective supplier.
   - (ii) HNP's records that have been accumulated in connection with previous procurement actions and product operating experience. Historical data should be representative of the supplier's current capability. If there has been no recent experience with the supplier, or if he is a new supplier, the prospective supplier shall be requested to submit information on a similar item or service for evidence of his current capabilities.
   - (iii) Evaluating the supplier's current quality records supported by documented qualitative and quantitative information which can be objectively evaluated.
     This would include review and evaluation of the supplier's quality assurance program manual and procedures, as appropriate, to ensure that the applicable requirements of 10CFR 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants" are met.
   - (iv) Verification that the supplier holds an active certificate of authorization from the ASME to supply or manufacture materials or the item(s) described in the purchase requisition. A supplier may be considered acceptable, without a survey, to supply off-the-shelf items. An inspection shall be performed to assure that the correct item was received and no damage exists.
     Verification that the supplier is listed in the current NUPIC (Nuclear Procurement Issues Committee) database. However, the audit report which formed the basis for listing the supplier in the NUPIC database must be obtained and reviewed for applicability to the procurement. All deficiencies which could degrade the procured item must be resolved prior to the procurement. This review shall be documented and, together with the audit report, be retained.
3) See standard exceptions in Table 17-1 for Regulatory Guide 1.123 for the procurement of Commercial Grade Items and services including, purchasing commercial-grade calibration services from calibration laboratories.

7. Paragraphs 5.2 and 5.3 shall be applied to the extent determined by responsible plant management based on complexity of the item and its end use. It is not intended that these paragraphs be applied to spares or replacement parts that do not change original design intent.
8. Paragraph 6.1, General, Outlines methods for monitoring and evaluating supplier performance. HNP wishes to replace paragraph 6.1(a), (b), (c), (d), and (e) with the following methods for monitoring and evaluating supplier performance:
   - A. Reviewing documents generated or processed during activities fulfilling procurement requirements.
   - B. Reviewing LER'S.
   - C. Periodic audits.
   - D. Annual evaluations.
   - E. Those controls specified 17.3.

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.123, Quality Assurance Requirements for Control or Procurement of Items and Services for Nuclear Power Plants, (Rev. 1)

HNP shall comply with the requirements of ANSI N45.2.13-1976, Quality Assurance Requirements for Control or Procurement of Items and Services for Nuclear Power Plants, as it is endorsed by Regulatory Guide 1.123 with the following clarifications:

9. Paragraph 6.4, Control of Changes in Items or Services: Since ANSI N45.2 does not apply to the operational phase, equivalent controls outlined in ANSI N18.7-1976 will be used in lieu of the requirements of ANSI N45.2, Section 7.
10. Paragraph 7.4, Measuring and Test Equipment, outlines certain measures to be taken. HNP for the operating phase has addressed the topic of measuring and test equipment in 17.3.2.9 in lieu of the requirements in this paragraph.
11. Paragraph 8 provides guidance for purchaser review and disposition of vendor nonconformances. HNP, as purchaser, requires as a minimum deviations to procurement documents and previously approved supplier documents that cannot be brought into conformance prior to shipment of the material to be submitted to dep for approval. Such deviations, when approved by purchaser, are required to be submitted along with shipment of the material. Additionally, paragraph 8.2, disposition: the third sentence of item b is revised to read:

    Nonconformances to the contractual procurement requirements or purchaser approved documents which consist of one or more of the following shall be submitted to the purchaser for approval of the recommended disposition prior to shipment, when the nonconformance could adversely affect the end use of a *module or shippable component relative to safety, interchangeability, operability, reliability, integrity, or maintainability:

    A. Technical or material requirement is violated;
    B. Requirement in supplier documents, which have been approved by the purchaser, is violated;
    C. Nonconformance cannot be corrected by continuation of the original manufacturing process or by rework; and/or
    D. The item does not conform to the original requirement, even though the item can be restored to a condition such that the capability of the item to function is unimpaired.

       A module is any assembly of interconnected components which constitute 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 which permit it to be tested as a unit. A module could be a card or other subassembly of a larger device, provided it meets the requirements of this definition.
12. Regulatory Position C.3 indicates that purchaser should verify the implementation of the supplier's corrective action systems when such a system is required, but this verification need not be included as part of the purchaser's corrective action measures.

    HNP interprets this statement to mean that once corrective action has been verified by purchaser on nonconforming vendor items, the items can be released for use in its intended application.

    The cause and action to preclude recurrence of deficiencies is the responsibility of the vendor, and independent verification of such vendor action by purchaser or vendor notification of such action to purchaser, is not required on the basis that the vendor's QA program has been accepted by the purchaser. The QA program provides for determining cause and action to preclude recurrence on significant deficiencies, and purchaser audits are conducted to ensure vendor's compliance with his accepted QA program commitments. In addition, HNP will provide overview of those causes and corrective action activities associated with items of high volume and which are considered significant to safety in cases where vendor's recent performance has appeared marginal.

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.123, Quality Assurance Requirements for Control or Procurement of Items and Services for Nuclear Power Plants, (Rev. 1)

HNP shall comply with the requirements of ANSI N45.2.13-1976, Quality Assurance Requirements for Control or Procurement of Items and Services for Nuclear Power Plants, as it is endorsed by Regulatory Guide 1.123 with the following clarifications:

13. Paragraph 10.2a: HNP will comply with this paragraph to the extent that for non-code items, certificates of compliance will be traceable only to the purchase order and not to the specific item.

Regulatory Guide 1.144, Auditing of Quality Assurance Programs for Nuclear Power Plants (Rev. 0)

HNP shall comply with requirements of Regulatory Guide 1.144, January 1979, which endorses ANSI N45.2.12-1977, Requirements for Auditing of Quality Assurance Programs for Nuclear Power Plants, with the following clarifications.

1. C.3.(B)(2): The concepts of when audits are required, i.e., annually, triennially, will be complied with; however, such audits would only be required of the vendor if the vendor is involved with an active contract/procurement document. This concept is as discussed in paragraphs 3.5.3.1 and 3.5.3.2 of ANSI N45.2.12-1977.
   See standard exceptions in Table 17-1 for Regulatory Guide 1.123 for the procurement of Commercial Grade Items and services including, purchasing commercial-grade calibration services from calibration laboratories.
2. Paragraph 2.3, Training: The training of HNP audit personnel will be accomplished as described in HNP's position on Regulatory Guide 1.146.
3. Paragraph 2.4, Maintenance of Proficiency: The maintenance of proficiency of HNP audit personnel will be accomplished as described in HNP's position on Regulatory Guide 1.146.
4. Paragraph 3.2.2 indicates that objective evidence is to be examined and evaluated. HNP believes that the use of subjective evidence is also an important element of the audit program. See paragraph 4.3.2 clarifications below.
5. Paragraph 3.3, Essential Elements of the Audit System; HNP will comply with subparagraph 3.3.5 as it was originally written (subparagraph 3.2.5) in ANSI N45.2.12, Draft 3, Revision 4: "Provisions for reporting on the effectiveness of the quality assurance program to the responsible management." For the audited organization, effectiveness is reported as required in Section 17.3.3.3 and by audit procedures. Other than audit reports, HNP may not directly report on the effectiveness of the quality assurance programs to the audited organization, when such organizations are outside of Duke Energy.
   Subparagraph 3.3.7 requires verification of effective corrective action on a "timely basis". Timely basis is interpreted to mean within the period of time that is accepted by the organization. Each finding requires a response and a corrective action completion date. These dates are subject to revision and must be escalated to higher authority when there is a disagreement between the audited and the auditing organization on what constitutes "timely corrective action."

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.144, Auditing of Quality Assurance Programs for Nuclear Power Plants (Rev. 0)

HNP shall comply with requirements of Regulatory Guide 1.144, January 1979, which endorses ANSI N45.2.12-1977, Requirements for Auditing of Quality Assurance Programs for Nuclear Power Plants, with the following clarifications.

6. Paragraph 4.3.1, Preaudit Conference: HNP will comply with the requirement of this paragraph by inserting the word "normally" at the beginning of the first sentence. This clarification is required because, in the case of certain unannounced audits or audits of a particular operation or work activity, a preaudit conference might interfere with the spontaneity of the operation or activity being audited. In other cases, persons who should be present at a preaudit conference may not always be available. Such lack of availability should not be an impediment to beginning an audit. Even in the above examples, which are not intended to be all inclusive, the material set forth in paragraph 4.3.1 will normally be covered during the course of the audit.
7. Paragraph 4.3.2, Audit/Assessment Process:
   A. Subparagraph 4.3.2.2 could be interpreted to limit auditors to the review of only objective evidence. Sometimes objective evidence may not be available; therefore, HNP will comply with an alternate sentence which reads: "When available, objective evidence shall be examined for compliance with quality assurance program requirements. If subjective evidence is used (e.g., personnel interviews, direct observations by the auditor), then the audit report or checklist must indicate how the evidence is obtained."
   B. Subparagraph 4.3.2.4 is modified as follows to take into account the fact that some nonconformances are virtually "obvious" with regards to the needed corrective action. As a result of this, HNP proposes the following alternate words: "When a nonconformance or quality assurance program deficiency is identified as a result of an audit, unless the apparent cause, extent, and corrective action is readily evident, further investigations shall be conducted by the audited organization in an effort to identify the cause and effect and to determine the extent of the corrective action required."
   C. Subparagraph 4.3.2.5 contains a statement "acknowledged by a member of the audited organization". This is clarified to mean that "A member of the audited organization has been informed to the findings. Agreement or disagreement with a finding may be expressed in the response from the audited organization."
   D. Subparagraph 4.3.2.6 is modified as follows to account for the fact that immediate notification is not always possible: "Conditions requiring immediate corrective action (i.e., those which are so severe that any delay would be undesirable) shall be reported as immediately as practical to management of the audited organization."
8. Paragraph 4.3.3, Post Audit Conference: HNP will substitute and comply with the following paragraphs: "For all external audits, a postaudit conference shall be held with management of the audited organization to present audit findings and clarify misunderstandings. Where no adverse findings exist, this conference may be waived by management of the audited organization. Such waiver shall be documented in the audit report. For all internal audits unless unusual operating or maintenance conditions preclude attendance by appropriate managers/supervisors, an audit debrief shall be held with managers/supervisors. If there are no adverse findings, management of the internal assessed organization may waive the audit debrief. Such waiver shall be documented in the audit report."
9. Paragraph 4.4, Reporting:

Regulatory Guide 1.144, Auditing of Quality Assurance Programs for Nuclear Power Plants (Rev. 0)

HNP shall comply with requirements of Regulatory Guide 1.144, January 1979, which endorses ANSI N45.2.12-1977, Requirements for Auditing of Quality Assurance Programs for Nuclear Power Plants, with the following clarifications.

A. This paragraph requires that the audit report shall be signed by the audit team leader which is not always the most expeditious route for the audit report to be issued as soon as practical. HNP will comply with Paragraph 4.4 as clarified by the following words: "An audit report, which shall be signed by the unit team leader, or his supervisor in the absence of the audit team leader shall provide:" in cases where the audit report is not signed by the lead auditor due to his absence, the record copy of the report must be signed by the lead auditor upon his return. The report shall not require the lead auditor's review/concurrence/signature if the lead auditor is no longer employed by HNP at the time audit report is issued.
B. HNP will comply with subparagraph 4.4.3 clarified to read: "Supervisory level personnel with whom significant discussions were held during the course of preaudit (where conducted), audit, and postaudit (where conducted) activities.
C. Audit reports may not necessarily contain an evaluation statement regarding the effectiveness of the quality assurance program elements which were audited, as required by subparagraph 4.4.4, but they will provide an effectiveness summary of the audited areas."
D. Subparagraph 4.4.6 - Nuclear Oversight section management will determine the need for audit reports to include recommendations for corrective actions.
E. HNP will comply with the last paragraph of Section 4.4 of ANSI N45.2.12 concerning issuing audit reports with the following clarification: "Audit reports shall be issued within thirty working days after the last day of the audit. The last day of an audit shall be considered to be the day of the post-audit conference. If a post-audit conference is not held because it was deemed unnecessary, the last day of the audit shall be considered to be the date the post-audit conference was deemed unnecessary as documented in the audit report."

10. Paragraph 4.5.1, By Audited Organization: HNP will comply with the following clarification of this paragraph:
"Management of the audited organization or activity shall review and investigate all adverse audit findings, as necessary, (cause, etc.) to determine and schedule appropriate corrective action including action to prevent recurrence. They shall respond, in writing, within thirty days after the date of receipt of the audit report. The response shall clearly state the corrective action taken or planned to prevent recurrence and the results of the investigation if conducted. In the event that corrective action is not completed by the time the response is submitted, the audited organization's response shall include a scheduled date for completion of planned corrective action. A follow-up response shall be provided stating the corrective action was completed.
If corrective actions are verified as satisfactorily completed by the quality organization prior to the scheduled completion date or when completion of corrective action can be verified during a follow-up audit, no follow-up response is required. The audited organization shall take appropriate action to assure that corrective action is accomplished as scheduled."
11. Paragraph 5 - audit checklists are not considered QA records. HNP believes that actual audit reports provide sufficient detail to substantiate the results of the audit, and the checklist is maintained as an audit "tool" versus a QA record. Additionally, the audit checklist need only document objective evidence examined to support the audit findings.

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.146, Qualification of QA Program Audit Personnel for Nuclear Power Plants (Rev. 0, 8/80)

HNP shall comply with requirements of Regulatory Guide 1.146, August 1980, which endorses ANSI N45.2.23-1978, Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants with the following clarifications.

1. Paragraph 2.2, Qualification of Auditors: subparagraph 2.2.1 references an "ANSI B45.2" (presumed to be N45.2); therefore, HNP will comply with an alternate subparagraph 2.2.1 which reads:
   "Orientation to provide working knowledge and understanding of the HNP QA program, including the ANSI standards and Regulatory Guides included in the program, and Duke Energy's procedures for implementing audits and reporting results."
2. Paragraph 4.1, Organization Responsibility: HNP will comply with this paragraph with the substitution of the following sentence in place of the last sentence in the paragraph.
   "The NOS manager or the audit team leader shall, prior to commencing the audit, assign personnel who collectively have experience or training commensurate with the scope, complexity, or special nature of the activities to be audited."
3. Paragraph 5.3, Updating of Lead Auditor's Records: HNP will substitute the following sentence for this paragraph:
   "Records for each lead auditor shall be maintained and updated during the period of the annual management assessment. This annual management assessment shall be as defined in the clarification for Paragraph 3.2 noted above."
4. ANSI N45.2.23, Paragraph 2.3.4 states, "The prospective lead auditor shall have participated in a minimum of five (5) quality assurance audits within a period of time not to exceed three (3) years prior to the date of qualification, one audit of which shall be a nuclear quality assurance audit within the year prior to qualification."
   HNP substitutes the following instead of the cited sentence of ANSI N45.2.23, Paragraph 2.3.4:
   "Prospective lead auditors shall demonstrate the ability to effectively implement the audit process and effectively lead an audit team. This process is described in written procedures that provide for evaluation and documentation of the results of this demonstration. In addition, the prospective lead auditor shall have participated in at least two nuclear quality assurance audits within the year preceding the individual's effective date of qualification. Upon successful demonstration of the ability to effectively implement the audit process and effectively lead audits, and having met the other provisions of Section 2.3 of ANSI N45.2.23-1978, the individual may be certified as being qualified to lead audits."

Table B17-2. Site Specific Response to Regulatory Guides and Industry Standards

Table B17-2 identifies additional Regulatory Guides addressing subjects related to implementation of the QAP but the implementation is site specific and controlled with the UFSAR in accordance with 10 CFR 50.59.

Regulatory Guide 1.8, Personnel Selection and Training
Personnel selection and training is site specific. Harris addresses conformance with Regulatory Guide 1.8 in UFSAR Chapter 1 Section 8.

Regulatory Guide 1.26, Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants
Quality group classifications and standards trace to the original design and construction of the nuclear power plant and therefore are site specific. Harris addresses conformance with Regulatory Guide 1.26 in UFSAR Chapter 1 Section 8.

Regulatory Guide 1.29, Seismic Design Classification
Seismic design classification trace to the original design and construction of the nuclear power plant and therefore is site specific. Harris addresses conformance with Regulatory Guide 1.29 in UFSAR Chapter 1 Section 8.

Regulatory Guide 1.36, Nonmetallic Thermal Insulation for Austenitic Stainless Steel
Nonmetallic thermal insulation for austenitic stainless steel trace to the original design and construction of the nuclear power plant and therefore is site specific. Harris addresses conformance with Regulatory Guide 1.36 in UFSAR Chapter 1 Section 8.

Regulatory Guide 1.54, Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants
Quality assurance requirements for protective coatings applied to water-cooled nuclear power plants trace to the original design and construction of the nuclear power plant and therefore is site specific. Harris addresses conformance with Regulatory Guide 1.54 in UFSAR Chapter 1 Section 8.

Table B17-2. Site Specific Response to Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.143, Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light-Water-Cooled Nuclear Power Plants

Design guidance for radioactive waste management systems, structures, and components installed in light-water-cooled nuclear power plants trace to the original design and construction of the nuclear power plant and therefore is site specific.

Harris addresses conformance with Regulatory Guide 1.143 in UFSAR Chapter 1 Section 8.

Regulatory Guide 1.155, Station Blackout

Addressing Station Blackout is site specific.

Harris addresses conformance with Regulatory Guide 1.155 in UFSAR Chapter 1 Section 8.

Regulatory Guide 4.15, Quality Assurance for Radiological Monitoring Programs (Normal Operations) – Effluent Streams and the Environment

Quality assurance for radiological monitoring program (normal operations) – effluent streams and the environment is site specific.

Harris does not address conformance to Regulatory Guide 4.15 in UFSAR Chapter 1 Section 8. The radiological monitoring program is addressed in UFSAR Chapter 11.

B17.3.1 MANAGEMENT

B17.3.1.1 Methodology

There are no Harris specific amplifications for this section.

B17.3.1.2 Organization

There are no Harris specific amplifications for this section.

B17.3.1.3 Responsibility

There are no Harris specific amplifications for this section.

B17.3.1.4 Authority

The program and procedures require that the authority and duties of persons and organizations performing activities affecting quality be clearly established and delineated in writing and that these individuals and organizations have sufficient authority and organizational freedom to:

1. Identify quality, nuclear safety, and performance problems.
2. Order unsatisfactory work to be stopped and control further processing, delivery, or installation of nonconforming material.
3. Initiate, recommend, or provide solutions for conditions adverse to quality.
4. Verify implementation of solutions.

B17.3.1.5 Personnel Training and Qualification

There are no Harris specific amplifications for this section.

B17.3.1.6 Corrective Action

The program requires that an evaluation of adverse conditions such as conditions adverse to quality, nonconformances, failures, malfunctions, deficiencies, deviations, and defective material and equipment is conducted to determine need for corrective action. Conditions adverse to quality are identified through inspections, assessments, tests, checks, and review of documents.

The program requires corrective action to be initiated to preclude recurrence of significant conditions adverse to quality.

For significant conditions adverse to quality, procedures require follow-up reviews, verifications, inspections, etc., to be conducted to verify proper implementation of corrective action and to close out the corrective action documentation.

The program outlines the methodology for resolution of disputes involving quality and nuclear safety issues arising from a difference of opinion between identifying personnel and other groups.

Significant conditions adverse to quality are reported to appropriate management for review and evaluation.

Periodic review and evaluation of adverse trends are performed by management.

B17.3.1.7 Regulatory Commitments

There are no Harris specific amplifications for this section.

B17.3.2 PERFORMANCE/VERIFICATION

B17.3.2.1 Methodology

There are no Harris specific amplifications for this section.

B17.3.2.2 Design Control

Controls are applied to the development, content and use of computer codes to ensure (1) the codes are developed, documented, verified and certified for use per approved procedures; (2) the codes are properly controlled to preclude use of outdated or obsolete codes; (3) that proper instructions concerning the use of the codes are provided; and (4) adequate QA provisions are implemented for the procurement of computer codes.

B17.3.2.3 Design Verification

There are no Harris specific amplifications for this section.

B17.3.2.4 Procurement Control

Potential contractors and suppliers are evaluated prior to award of a procurement contract when needed to assure the contractor's or supplier's capability to comply with applicable technical and quality requirements.

Procurement documents, such as purchase specifications, contain or reference the following:

1. Technical, administrative, regulatory, and reporting requirements, including material and component identification requirements, drawings, specifications, codes and industrial standards, test and inspection requirements, and special process instructions.
2. Identification of the documentation to be prepared, maintained, or submitted (as applicable) to HNP for review and approval. These documents may include, as necessary, inspection and test records, qualification records, or code required documentation.
3. Identification of those records to be retained, controlled, and maintained by the supplier, and those delivered to the purchaser prior to use or installation of the hardware.

Procurement documents require suppliers to operate in accordance with QA programs which are compatible with the applicable requirements of the HNP QA Program and procedures where their services are utilized in support of plant activities.

B17.3.2.5 Procurement Verification

There are no Harris specific amplifications for this section.

B17.3.2.6 Identification and Control of Items

Procedures require that materials, parts, and components be identified and controlled to prevent the use of incorrect or defective items.

These procedures also require that identification of items be maintained either on the item in a manner that does not affect the function or quality of the item, or on records traceable to the item.

Procedures implementing these requirements provide for the following:

1. Verification that items received at the plant are properly identified and can be traced to the appropriate documentation, such as drawings, specifications, purchase orders, manufacturing and inspection documents, nonconformance reports, or material test reports.
2. Verification of item identification consistent with the HNP inventory control system and traceable to documentation which identifies the proper uses or applications of the item.
3. Verification of correct identification of material, parts and components prior to fabrication, assembly installation or use, and results documented.

B17.3.2.7 Handling, Storage, and Shipping

Provisions are established to control the shelf life and storage of chemicals, reagents, lubricants, and other consumable materials.

B17.3.2.8 Test Control

Test procedures incorporate or reference the following, as required:

1. Instructions and prerequisites for performing the test.
2. Use of proper test equipment.
3. Mandatory inspection hold points.
4. Acceptance criteria.

Test results are documented, evaluated, and their acceptability determined by a qualified, responsible individual or group.

When the acceptance criteria is not met, affected areas are to be retested or evaluated, as appropriate.

B17.3.2.9 Measuring and Test Equipment Control

Portable measuring and test equipment is calibrated by standards which are at least four times as accurate as the portable measuring and test equipment, unless limited by the state of the art. In cases where the accuracy is not achievable or is limited by the state of the art, an engineering evaluation or other appropriate justification is performed and documented to justify acceptability of the M&TE in question. The evaluation is reviewed in accordance with approved procedures.

Calibration of installed plant devices shall be against M&TE having sufficient accuracy, greater than the device being calibrated, to assure that the system containing the device is within the specified system tolerance. The basis for determining the "greater than accuracy" shall be documented.

Reference and transfer standards are traceable to nationally recognized standards; or where national standards do not exist, provisions are established to document the basis for the calibration.

B17.3.2.10 Inspection, Test, and Operating Status

These procedures include the application, removal, and verification of inspection and welding stamps, or other status indicators as appropriate.

Altering the sequence of required tests, inspections, and other operations important to safety can only be accomplished by methods outlined in procedures.

B17.3.2.11 Special Process Control

There are no Harris specific amplifications for this section.

B17.3.2.12 Inspection

There are no Harris specific amplifications for this section.

B17.3.2.13 Corrective Action

The primary goal of the corrective action program is to improve overall plant operations and performance by identifying and correcting root causes of equipment and human performance problems.

Procedures define requirements for a corrective action program that charges personnel working at or supporting the nuclear plants with the responsibility to identify adverse conditions (including conditions adverse to quality).

Procedures include requirements for verification of the acceptability of the rework/repair of items by reinspection and/or testing in accordance with the original inspection or test requirements or by an accepted alternative inspection and testing method.

Conditions that require rework/repairs are identified through the use of maintenance work request forms.

B17.3.2.14 Control of Documents

Changes to documents are reviewed and approved by the same organization that performed the original review and approval or by other designated qualified responsible organizations.

B17.3.2.15 Records

The structure in which single copy records are maintained is designed to prevent destruction, deterioration, or theft. This structure ensures protection against destruction by fire, flooding, theft, and deterioration by the environmental conditions of temperature and humidity.

B17.3.3 ASSESSMENT

B17.3.3.1 Methodology

There are no Harris specific amplifications for this section.

B17.3.3.2 Independent Review

There are no Harris specific amplifications for this section.

B17.3.3.3 Independent Assessment

There are no Harris specific amplifications for this section.

B17.3.3.3.1 Organization

There are no Harris specific amplifications for this section.

B17.3.3.3.2 Internal Assessment Process

There are no Harris specific amplifications for this section.

B17.3.3.3.3. Internal Audit Program

B17.3.3.3.3.1 Other Reviews Prescribed by the Code of Federal Regulations

There are no Harris specific amplifications for this section.

B17.3.3.3.3.2 Independent Audit of Fire Protection Program

There are no Harris specific amplifications for this section.

B17.3.3.3.4 Results

There are no Harris specific amplifications for this section.

B17.3.3.3.5 Supplier Oversight

There are no Harris specific amplifications for this section.

B17.3.3.3.6 Independent Audit of QA Functions

There are no Harris specific amplifications for this section.

B17.3.3.3.7 Audit Frequency Extensions

There are no Harris specific amplifications for this section.

B17.3.4 ADMINISTRATIVE CONTROLS

This section was added to the HNP UFSAR description of the QA Program to relocate certain administrative controls from HNP Technical Specifications. These relocated administrative controls include Review and Audit, Procedure Review Requirements, and Record Retention.

Review and Audit

B17.3.4.1 10CFR50.59 and technical reviews

There are no Harris specific amplifications for this section.

B17.3.4.2 Plant Nuclear Safety Committee (PNSC)

This content is addressed in Section 17.3.3.2, Independent Review.

B17.3.4.3 HNP Independent Review Program

This content is addressed in Section 17.3.3.2, Independent Review.

B17.3.4.4 Independent Safety Engineering Group

B17.3.4.4.1 Organization

The Independent Safety Engineering Group (ISEG) functions of improving licensee safety performance and ability to respond to accidents by providing onsite technical support and continuous evaluation and feedback of lessons learned from operating experience are performed by a combination of different groups through the performance of their normal activities.

B17.3.4.4.2 Activities

Key ISEG activities are outlined below with the groups that currently perform these activities:

1. Examination of Unit Operating Characteristics:
    - HNP has an established Corrective Action Program that includes processes for the identification, classification, trending and correcting of conditions adverse to quality.
    - NOS performs independent monitoring and audit of activities as defined in Section 17.3.3.3.
    - HNP has implemented a Maintenance Rule Program that provides reasonable assurance that structures, systems, trains, and components are capable of fulfilling their intended safety significant functions.
    - Harris Engineering Section has implemented a program that provides for the systematic trending of system and component performance to determine the effectiveness of system/component maintenance
    - A corporate Probabilistic Safety Assessment Unit has been established with the mission of maintaining and updating plant specific risk models and risk based tools that are used to provide risk insights and tools to: support on-line maintenance and outage risk assessments; support the Maintenance Rule Program; evaluate proposed plant changes for risk impact; monitor the risk effectiveness of plant on-line maintenance activities; and support other regulatory activities.
2. Examination of NRC Issuances, Industry Advisories, and Licensee Event Reports and other Sources of Unit Design Information which May Indicate Areas of Improving Unit Safety:
    - Duke Energy has implemented an Operating Experience (OE) Program that provides for the receipt, processing, status reporting, screening, reviewing, evaluating, and taking preventive/corrective actions in response to OE information.
    - The Nuclear Oversight organization independently evaluates the use of OE in the conduct of audits.
    - The On-Site Review Committee reviews License Event Reports developed pursuant to 10CFR50.73 as part of the Independent Review in Section 17.3.3.2.
3. Review of Plant Operations, Modifications, Maintenance, and Surveillances to Verify Independently that these Activities are Performed Safely and Correctly and that Human Errors are Reduced as Much as Practical:
    - NOS audits in Section 17.3.3.3 and the Independent Review Program in Section 17.3.3.2accomplish this function.

B17.3.4.5 Outside agency inspection and audit program

The fire protection audit is addressed in Section 17.3.3.3.3.2, Independent Audit of Fire Protection Program.

B17.3.4.6 Procedure Review Requirements

See Section 17.3.2.14 for required reviews for changes to procedures, tests, and experiments.

B17.3.4.7 Record Retention

A list of typical operational phase QA Records is included in 17.3.2.15.

Attachment C, Robinson Specific QAPD

Information presented in this attachment is specific to Robinson and was contained in the UFSAR prior to Amendment 41.

Where a section contains no descriptive information beyond that in the generic text in the body of the document, a statement is made to that effect and no content is included. See C17.3.1.2, Organization for example.

C17. QUALITY ASSURANCE

C17.1 QA DURING DESIGN AND CONSTRUCTION

See Robinson UFSAR Chapter 17 for historic information from the description of the QA Program for design and construction.

C17.2 OPERATIONAL QA

Deleted

(NOTE: In April 1995, NRC approved the reformatting of the description of the Robinson QA Program to follow Standard Revision Plan Section 17.3, replacing the content of 17.2.)

C17.3 QUALITY ASSURANCE PROGRAM (QAP) DESCRIPTION

INTRODUCTION

This content is not addressed in SRP Section 17.3; therefore, the Robinson description of the QA Program did not include this section.

DEFINITIONS

There are no Robinson specific definitions.

EXPLANATION OF "QUALITY ASSURANCE"

There is no Robinson specific content.

QA STANDARDS AND GUIDES

The Robinson QAP conforms to Appendix B of 10CFR 50, as discussed in Section 17, "Quality Assurance." The QAP also conforms to applicable NRC Regulatory Guides and approved ANSI Standards, or applicable alternatives. Table C17-1 and C17-2 address QAP conformance to the referenced regulatory and program guidance contained in NUREG-0800 Section 17.3.

The content of Table C17-1 was transferred from Section 1.8 of the Robinson UFSAR. Changes to the content of Table C17-1 are controlled in accordance with 10 CFR 50.54(a). Subsequent changes to the Robinson QAP are incorporated in this document as identified in Section 17.3.1.7.

Table C17-2 addresses additional Regulatory Guides that relate to implementation of the QAP but the implementation is site specific and controlled with the Robinson UFSAR in accordance with 10 CFR 50.59.

Table C17-1. Conformance with QA Regulatory Guides and Industry Standards

Generic Exception:

Table C17-1 addresses Robinson's Conformance of the Quality Assurance Program to certain NRC Regulatory Guides. In so doing, specific editions of industry standards are identified for compliance with exceptions and alternatives. Those identified standards include references to other industry standards for activities including, but not limited to; design, fabrication, inspection, and testing. Those included reference industry standards are considered to be guidance documents for details of how activities may be accomplished. The actual standard to be used in such cases is controlled by each station's current licensing and design bases.

The content of Table C17-1 was transferred from H. B. Robinson (RNP) UFSAR Section 1.8. As identified therein, Regulatory Guides (originally called Safety Guides) have been published beginning in late 1970. Since H. B. Robinson (RNP) was licensed for operation prior to that time, they were not addressed. Applicable QA Regulatory Guides which have been addressed during the operating phase are discussed below.

Regulatory Guide 1.28, Quality Assurance Program Requirements (Design and Construction) (Rev. 0)
ANSI Standard N45.2-1971, Quality Assurance Requirements for Nuclear Power Plants
This guide and the standard it endorses have been superseded for operations activities by Regulatory Guide 1.33 and ANSI N18.7-1976 which it endorses. The Operational Quality Assurance Program complies with Regulatory Guide 1.33 and ANSI N18.7-1976 as stipulated in Appendix A to that program; therefore, Regulatory Guide 1.28 (Safety Guide 28) and ANSI N45.2-1971 which it endorses are not considered necessary and are not included as part of the program.

Regulatory Guide 1.30, Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electrical Equipment (Revision 0) (August, 1972)
ANSI standard N45.2.4-1972, (IEEE-336-1971), Installation, Inspection, and Testing Requirements for Instrumentation and Electrical Equipment During the Construction of Nuclear Power Generating Stations
RNP shall comply with the provisions of Regulatory Guide 1.30, August 1972, as indicated below:
The installation, inspection, and testing of nuclear power plant instrumentation and electrical equipment at RNP will be in accordance with the applicable requirements of ANSI N45.2.4-1972 with the following exceptions:
a) Section 1.4 titled Definitions: Definitions in this standard which are not included in ANSI N45.2.10 will be used; definitions which are included in ANSI N45.2.10 will be used as clarified in Duke Energy Progress, Inc.'s (DEP) commitment to Regulatory Guide 1.74. b) Section 1.5 titled Referenced Documents: DEP's commitment to other documents referenced in this standard shall be as stated in our commitment to that document.

Table C17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.30, Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electrical Equipment (Revision 0) (August, 1972)

ANSI standard N45.2.4-1972, (IEEE-336-1971), Installation, Inspection, and Testing Requirements for Instrumentation and Electrical Equipment During the Construction of Nuclear Power Generating Stations

c) Section 2.5 titled Measuring and Test Equipment: DEP will implement the applicable portions of this Section as follows:
The status of portable items of measuring and test equipment and reference standard shall be identified by use of tags, stickers, labels, routing cards, computer programs, or other suitable means for the date recalibration is due or the frequency of recalibration. These items are in a calibration program which requires recalibration on a specified frequency or, in certain cases, prior to use.
Instrumentation and electrical equipment in the categories listed below shall be in a calibration program. This program provides, by the use of status cards, computer schedules, or tags, for the date that recalibration is due and indicates the status of calibration. The identity of person(s), performing calibration is provided on the calibration documents.
    1) Instruments installed as listed in the RNP Technical Specifications
    2) Installed instrumentation used to verify RNP Technical Specification parameters, and
    3) Installed safety-related instruments and electrical equipment that provide an active function during operation or during shutdown; i.e., not a device being designated safety-related solely because the instrument is an integral part of a pressure retaining boundary.

d) Section 7 titled Data Analysis and Evaluation states in part, "Procedures shall be established for processing inspection and test data and their analysis and evaluation." At RNP, data processing procedures per se have not been developed; instead, test data are recorded, processed, and analyzed in accordance with procedures and instructions in appropriate functional areas; e.g., maintenance, startup.

Regulatory Guide 1.33, Quality Assurance Program Requirements (Operation) Revision 2, February 1978

ANSI Standard N18.7-1976, Administrative Controls and Quality Assurance Requirements for the Operational Phase of Nuclear Power Plants

Comply with the provisions of Regulatory Guide 1.33, Rev. 2 February 1978, and the requirements and recommendations for administrative controls described in ANSI N18.7-1976, except as stated below:

1. Exception to Paragraph C.3 of Regulatory Guide 1.33 and ANSI N18.7-1976 Paragraph 4.3: Independent Review Program requirements are replaced by Section 17.3.3.2, Independent Review. This exception uses NRC Safety Evaluation dated January 13, 2005 to Nuclear Management Company (ADAMS ML050210276).
2. In lieu of the audit program provisions contained in Regulatory Position C.4 of Regulatory Guide 1.33, audits of facility activities will be conducted in accordance with Section 17.3.3.3.3.
3. Paragraph 4.5 - Written audit reports are not formally reviewed as part of the Independent Review function.

Table C17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.33, Quality Assurance Program Requirements (Operation) Revision 2, February 1978

ANSI Standard N18.7-1976, Administrative Controls and Quality Assurance Requirements for the Operational Phase of Nuclear Power Plants

4. Paragraph 4.5 - The Chief Nuclear Officer will assure that an independent assessment of the overall Nuclear Oversight program is conducted at least once every 24 months. Results of the independent assessment will be reported directly to the Chief Nuclear Officer and entered into the Corrective Action Program for resolution. (For scheduling consistency, the exceptions included in paragraph 5 of this section will be used as clarification for scheduling this independent assessment).
5. Paragraph 4.5, Audit Program- ANSI N18.7-1976/ANS-3.2, Section 4.5 is implemented with the following clarification: The audits of selected aspects of operational phase activities as identified in Section 17.3.3.3.3, Internal Audit Program, are scheduled based on plant performance and importance to safety but at a frequency not to exceed twenty-four months with extensions as allowed in Section 17.3.3.3.7, Audit Frequency Extensions.
6. Section 5.2.16 titled <u>Measuring and Test Equipment:</u> See Section 17.3.2.9 for clarification.
7. The applicable procedures recommended in Appendix "A" of Regulatory Guide 1.33, Rev. 2, February 1978, shall be established, implemented, and maintained as specified in the RNP Technical Specifications.
8. Section 5.2.17 titled <u>Inspections:</u> The second to the last sentence in the last paragraph, "Deviations, their cause, and any," to be consistent with Paragraph 5.2.11 and 10CFR50, Appendix B, the cause of the deviation will be determined for only significant conditions adverse to safety.
9. Section 5.3.9.1 titled <u>Emergency Procedure Format and Content:</u> Emergency procedures shall be in the format as committed to in NUREG-0737, <u>TMI Action</u> <u>Plan.</u>
10. Section 5.2.2 titled <u>Procedure Adherence:</u> Temporary changes to approved procedures, tests, or experiments may be approved by two members of the plant staff, at least one of whom holds a Senior Reactor Operator License if such change does not change the intent of the original procedure, test, or experiment. Temporary changes shall be documented and approved as a permanent change or deleted within 21 days of receiving temporary approval.
11. Section 5.2.15 titled <u>Review, Approval and Control of Procedures,</u> states that, "Plant procedures shall be reviewed by an individual knowledgeable in the area affected by the procedure no less frequently than every two years to determine if changes are necessary. A revision to a procedure constitutes a procedure review." In lieu of this commitment, H. B. Robinson Steam Electric Plant, Unit No. 2 has programmatic controls in place to continually identify procedure revisions which may be needed to ensure that procedures are appropriate for the circumstance and are maintained current.
12. Paragraph 5.2.13.1, Procurement Document Control: When purchasing commercial-grade calibration services from certain accredited calibration laboratories, the procurement documents are not required to impose a quality assurance program consistent with ANSI N45.2-1971. Alternate requirements described in Section 1.8 for Regulatory Guide 1.123 may be implemented in lieu of imposing a quality assurance program consistent with ANSI N45.2-1971.

Table C17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.37, Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants (March 1973)

ANSI Standard N45.2.1-1973, Cleaning of Fluid Systems and Associated Components During Construction Phase of Nuclear Power Plants

Those areas of the QA Program applicable to onsite cleaning of materials and components, cleanliness control, and preoperation cleaning and layup of RNP fluid systems, will be in accordance with ANSI N45.2.1-1973, with the following exceptions:

a) At RNP a classification system similar to ANSI N45.2.1-1973 has been developed and is fully implemented for cleaning of fluid systems.
b) Section 1.4 titled Definitions: Definitions in this standard which are not included in ANSI N45.2.10 will be used; definitions which are included in ANSI N45.2.10 will be used as clarified in DEP commitment to Regulatory Guide 1.74.
c) Section 1.5 titled Referenced Documents: DEP's commitment to other documents referenced in this standard shall be as stated in our commitment to that document.

Regulatory Guide 1.38, Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants (March 1973)

ANSI Standard N45.2.2-1972, Packing, Shipping, Receiving, Storage, and Handling of Items for Nuclear Power Plants

Packaging, shipping, receiving, storage, and handling of RNP items are in accordance with applicable requirements of ANSI N45.2.2-1972 with the following specific exceptions:

a) Section 1.4 titled Definitions: Definitions in this standard which are not included in ANSI N45.2.10 will be used; definitions which are included in ANSI N45.2.10 will be used as clarified in DEP commitment to Regulatory Guide 1.74.
b) Section 1.5 titled Referenced Documents: DEP's commitment to other documents referenced in this standard shall be as stated in our commitment to that document.
c) Section 2.7 titled Classification of Items and Section 6.1.2 titled Levels of Storage:
    1) Special electronic equipment and instrumentation received as assembled panels will be stored as recommended by the manufacturer and/or based on engineering evaluation to prevent damage, deterioration, or contamination, but not necessarily in a Level A storage area.
    2) Chemicals used at RNP are stored at the point of use and/or in warehouse areas that satisfy the requirement of Level B storage. These storage areas have been evaluated and determined to be adequate for the limitations established by the manufacturer.
    3) Special nuclear materials are stored in areas specifically designed for such storage.
d) Section 7.3.4 - DEP intends to comply with the requirements of this section with the following clarification: Test loads equal to or greater than the original crane rating shall not pass over locations where special nuclear material is stored or where reactor system components or high cost equipment are located.
e) Section 6.4.2 of ANSI N45.2.2 - 1972, titled Care, sub-items (5), (6), and (7) are clarified as follows:
    1) Sub-item (5), space heaters in electrical equipment shall be energized, unless a documented engineering evaluation determines that such space heaters are not required.
    2) Sub-item (6). large rotating electrical equipment (i.e. greater than or equal to 50 horsepower) shall be given insulation resistance tests on a scheduled basis, unless a documented engineering evaluation determines such tests are not needed.

Table C17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.38, Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants (March 1973)

ANSI Standard N45.2.2-1972, Packing, Shipping, Receiving, Storage, and Handling of Items for Nuclear Power Plants

3) Sub-item (7). prior to being placed in storage, rotating equipment weighing over approximately 50 lbs. shall be evaluated and documented by engineering personnel to determine if shaft rotation during storage is required. If rotation is required the degree of turn shall be such that the parts receive lubrication where applicable and the shaft does not come to rest in a previous position. Required rotation shall be performed at the necessary intervals and documented.

Regulatory Guide 1.39, Housekeeping Requirements for Water- Cooled Nuclear Power Plants (March 1973)

ANSI Standard N45.2.3-1973, Housekeeping, During the Construction Phase of Nuclear Power Plants

The applicable requirements of ANSI N45.2.3-1973 are followed at Robinson 2 within the context of the established QA Program with the following specific exception -- the zone designations of Section 2.1 of ANSI N45.2.3 and the requirements associated with each zone are considered impractical for implementation, as stated, at Robinson 2 during the operations phase. Instead, procedures or instruction for housekeeping activities, which include the applicable requirements outlined in Section 2.1 of ANSI N45.2.3 and which take into account radiation control considerations, security considerations, and cleanliness requirements are developed on a case basis for work to be performed.

Regulatory Guide 1.58, Qualification of Nuclear Power Plant Inspection, Examination, and Testing Personnel (September, 1980)

ANSI Standard N45.2.6-1978, Qualification of Inspection, Examination, and Testing Personnel for Nuclear Power Plants

RNP shall comply with NRC Regulatory Guide 1.58, September 1980 which endorses ANSI N45.2.6-1978, with the following exceptions:

1. Section 1.2 titled Applicability: DEP elects not to apply the requirements of this guide to those personnel who are involved in the daily operations of surveillance, maintenance, and certain technical and support services whose qualifications are controlled by the RNP Technical Specifications or are controlled by other QA Program commitment requirements. Only personnel in the following listed categories will be required to meet ANSI N45.2.6-1978 requirements:
   a. Nondestructive examination (NDE) personnel
   b. QC inspection personnel
   c. Receipt inspection personnel
2. The fourth paragraph of Section 1.2 requires that the Standard be imposed on personnel other than DEP employees. The applicability of the Standard to suppliers and contractors will be documented and applied, as appropriate, in the procurement documents for such suppliers and contractors or in interface agreements for Duke Energy non-nuclear organizations providing services identified in Section 17.3.1.2.3.

Table C17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.58, Qualification of Nuclear Power Plant Inspection, Examination, and Testing Personnel (September, 1980)

ANSI Standard N45.2.6-1978, Qualification of Inspection, Examination, and Testing Personnel for Nuclear Power Plants

3. Section 1.4 titled Definitions: Definitions in this Standard which are not included in ANSI N45.2.10 will be used; definitions which are included in ANSI N45.2.10 will be used as clarified in DEP commitment to Regulatory Guide 1.74.
4. Section 2.5 titled Physical: DEP will implement the requirements of this Section with the stipulation that, where no special physical characteristics are required, none will be specified. The converse is also true: if no special physical requirements are stipulated by DEP, none are considered necessary. DEP employees receive an initial physical examination to assure satisfactory physical condition; however, only the following listed personnel will receive an annual (± 2 months) examination:
   a. NDE personnel
   b. QC inspection personnel
   c. Receipt inspection personnel

   This annual examination shall consist of the near visual acuity using the standard Jaeger's type chart or equivalent test.
5. Section 3 titled Qualifications: Only personnel performing NDE (such as LP, MT, UT, & RT) will be grouped in levels of capability and certified as such. Personnel performing inspection will be certified for inspection, review and evaluation of inspection data, and reporting of inspection and test results.
6. Section 3.5 titled Education & Experience Recommendations: DEP will certify individual inspectors through training and experience to requirements appropriate to the specific assignment; however, except for NDE, personnel will not be classified by levels of capability. The training and experience requirements will be directed toward qualifying personnel for specific inspection and testing operations.

Regulatory Guide 1.64, Quality Assurance Requirements for the Design of Nuclear Power Plants (October 1973)

ANSI Standard N45.2.11-1974, Quality Assurance Requirements for the Design of Nuclear Power Plants

Those areas of the QA Program for RNP applicable to design or modification of the plant are in accordance with the applicable guidance of ANSI N45.2.11-1974, with the following exception:

a) Section 1.4 titled Definitions: Definitions in this standard which are not included in ANSI N45.2.10 will be used; definitions which are included in ANSI N45.2.10 will be used as clarified in DEP commitment to Regulatory Guide 1.74.

Regulatory Guide 1.74, Quality Assurance Terms and Definitions (February, 1974)

ANSI Standard N45.2.10-1973, Quality Assurance Terms and Definitions

The quality assurance terms and definitions of ANSI N45.2.10-1973 and Regulatory Guide 1.74 are being complied with for use in describing and implementing the Robinson 2 QA Program.

Table C17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.88 , Requirements for Collection, Storage, and Maintenance of Quality Assurance Records for Nuclear Power Plants

ANSI Standard N45.2.9-1979 , "Requirements for Collection, Storage, and Maintenance of Quality Assurance Records for Nuclear Power Plants"

As documented in DEP Letter to the NRC dated March 23, 1993, RNP is no longer committed to Regulatory Guide 1.88 "Collection, Storage, and Maintenance of Nuclear Power Plant Quality Assurance Records," August 1974.

See standard exception in Table 17-1 Regulatory Guide 1.88 for the appropriate controls on quality in the management of electronic records.

The requirements for collection, storage, and maintenance of QA records at RNP will be in accordance with ANSI N45.2.9-1979 and Section 17.3.2.15, subject to the following:

1. Section 1.5 titled Referenced Documents: DEP's commitment to other documents referenced in this standard shall be as stated in our commitment to that document.
2. Section 5.4 Item 2 "Records shall be firmly attached in binders or placed in folders or envelopes for storage in steel file cabinets or on shelving in containers." RNP complies with this requirement except for periods when records are in the receipt process.
3. Section 5.6 states: "Records shall be stored in facilities constructed and maintained in a manner which minimizes the risk of damage or destruction from the following:
   a. Natural disasters such as winds, floods, or fires.
   b. Environmental conditions such as high and low temperatures and humidity.
   c. Infestation of insects, mold, or rodents."

   Records are stored in permanent and temporary facilities as follows:
   1) One hour UL-rated fireproof file cabinets are utilized for temporary storage of hardcopy records. These file cabinets are located at work locations throughout the plant and will contain the records until the records are transmitted to the appropriate Document Control Center. Records being processed in Document Control Centers will be stored in fireproof cabinets when they are not being processed and until they are sent to the vault. In addition, records that are generated and authenticated electronically are afforded protection as described in N45.2.9-(1979) prior to conversion to permanent storage media.
   2) Permanent storage of QA records will be in the plant vault constructed to meet the requirements of this ANSI standard, and via electronic means which also meet applicable provisions of this standard, in addition to those delineated below.
   3) Selected records may be stored off-site by a QA Records Storage supplier provided that supplier meets the applicable sections of this ANSI standard.
4. Section 6.2 states: "Storage systems shall provide for retrieval of information in accordance with planned retrieval times based upon the record type." Retrieval of records at RNP is via a random access computer system using key words and document identification numbers, or through a manual index for records completed prior to 1982. The manual system is keyed to Plant Systems.
5. Section 7.3.3 states: "Various regulatory agencies have requirements concerning records that are within the scope of this Standard. The most stringent requirements shall be used in determining the retention period."
6. RNP will continue to adhere to the recommendations of Appendix A of ANSI N45.2.9-1974, or with the most stringent requirement with respect to records retention.

Table C17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.94, Quality Assurance Requirements for Installation, Inspection, and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants (April 1976)

ANSI Standard N45.2.5-1974, Supplementary Quality Assurance Requirements for Installation, Inspections, and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants

The original specification requirements, applicable guidance contained in Regulatory Guide 1.94, or acceptable alternatives based on an engineering evaluation will be utilized in the event future structural work is to be performed which falls under the established requirements of the Robinson 2 QA Program.

Future field production welding acceptance criteria will be based on NCIG-01, "Visual Weld Acceptance Criteria for Structural Welding at Nuclear Power Plants," Revision 2, dated May 7, 1985, Prepared by the Nuclear Construction Issues Group (NCIG) for structural safety-related and non-safety related pipe, conduit, cable tray, duct, and equipment supports where welding is specified to be in accordance with AWSD1.1.

This will be implemented through appropriate RNP specifications.

Regulatory Guide 1.116, QA Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems (June, 1976)

ANSI Standard N45.2.8-1975, Supplementary Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems for the Construction Phase of Nuclear Power Plants

Regulatory Guide 1.116, June, 1976, endorses ANSI N45.2.8-1975. RNP does not commit to Regulatory Guide 1.116 but does endorse parts of ANSI N45.2.8-1975 as described below.

Within the context of the established QA Program, the applicable guidance contained in ANSI N45.2.8-1975 will be utilized in relation to mechanical maintenance or modification with the following exceptions:

a) Section 1.4 titled Definitions: Definitions in this standard which are not included in ANSI N45.2.10 will be used; definitions which are included in ANSI N45.2.10 will be used as clarified in DEP commitment to Regulatory Guide 1.74.
b) Section 1.5 titled Referenced Documents: DEP's commitment to other documents referenced in this standard shall be as stated in our commitment to that document.
c) Section 2.8 titled Measuring and Test Equipment: DEP will implement the applicable portions of this section as follows:

   The status of portable items of measuring and test equipment and reference standards shall be identified by use of tags, stickers, labels, routing cards, computer programs, or other suitable means for the date recalibration is due or the frequency of recalibration. These items are in a calibration program which requires recalibration on a specified frequency or, in certain cases, prior to use.

   Instrumentation and electrical equipment in the categories listed below shall be in a calibration program. This program provides, by the use of status cards, computer schedules, or tags, for the date that recalibration is due and indicates the status of calibration. The identity of person(s) performing the calibration is provided on the calibration documents.

   1) Instruments installed as listed in the RNP Technical Specifications,
   2) Installed instrumentation used to verify RNP Technical Specification parameters, and

Table C17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.116, QA Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems (June, 1976)

ANSI Standard N45.2.8-1975, Supplementary Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems for the Construction Phase of Nuclear Power Plants

3) Installed safety-related instruments and electrical equipment that provide an active function during operation or during shutdown; i.e., not a device being designated safety-related solely because the instrument is an integral part of a pressure retaining boundary.

d) Section 6 titled <u>Data Analysis and Evaluation</u> states in part, "Procedures shall be established for processing inspection and test data and their analysis and evaluation." At H. B. Robinson 2 data processing procedures per se have not been developed; instead, test data are recorded, processed, and analyzed in accordance with procedures and instructions in appropriate functional areas; e.g., maintenance, startup.

Regulatory Guide 1.123, Quality Assurance Requirements for Control or Procurement of Items and Services for Nuclear Power Plants (July, 1977)

ANSI Standard N45.2.13, Quality Assurance Requirements for (Draft 2, Rev. 4, April, 1974) Control or Procurement of Items and Services for Nuclear Power Plants

RNP does not commit to Regulatory Guide 1.123; however, the applicable guidance contained in ANSI N45.2.13-1974, Draft 2, Rev. 4, and ANSI N18.7-1976 will be utilized in relation to procurement of items and services performed under the established requirements of the RNP QA Program.

See standard exceptions in Table 17-1 for Regulatory Guide 1.123 for the procurement of Commercial Grade Items and services including, purchasing commercial-grade calibration services from calibration laboratories.

Regulatory Guide 1.144, Auditing of Quality Assurance (January 1979)

ANSI Standard N45.2.12-1977, Requirements for Auditing of Quality Assurance Programs for Nuclear Power Plants

DEP will follow the requirements and recommendations of Regulatory Guide 1.144 and ANSI N45.2.12 with the following clarifications:

1. DEP will follow the requirements and recommendations of Regulatory Guide 1.144 paragraphs C.1, C.2, C.3.a.2, C.3.b, and C.4. Our position on paragraph C.3.a.1 is as follows:

   Audits of operational phase activities, as outlined in Section 17.3.3.3.3, shall be performed at the frequencies specified therein.

   See standard exceptions in Table 17-1 for Regulatory Guide 1.123 for the procurement of Commercial Grade Items and services including, purchasing commercial-grade calibration services from calibration laboratories.

2. DEP will comply with the last paragraph of Section 4.4 of ANSI N45.2.12 concerning issuing audit reports with the following clarification: “Audit reports shall be issued within thirty working days after the last day of the audit. The last day of an audit shall be considered to be the day of the post-audit conference. If a post-audit conference is not held because it was deemed unnecessary, the last day of the audit shall be considered to be the date the post-audit conference was deemed unnecessary as documented in the audit report.”

Regulatory Guide 1.144, Auditing of Quality Assurance (January 1979)

ANSI Standard N45.2.12-1977, Requirements for Auditing of Quality Assurance Programs for Nuclear Power Plants

3. ANSI N45.2.12 Paragraph 4.3. 1, Preaudit Conference: DEP will comply with the requirement of this paragraph by inserting the word "Normally" at the beginning of the first sentence. This clarification is required because, in the case of certain unannounced audits or audits of a particular operation or work activity, a preaudit conference might interfere with the spontaneity of the operation or activity being audited. In other cases, persons who should be present at a preaudit conference may not always be available. Such lack of availability should not be an impediment to beginning an audit. Even in the above examples, which are not intended to be all inclusive, the material set forth in Paragraph 4.3.1 will normally be covered during the course of the audit.
4. ANSI N45.2.12 Paragraph 4.3.3, Post Audit Conference: DEP will substitute and comply with the following paragraphs: "For all external audits, a post audit conference shall be held with management of the audited organization to present audit findings and clarify misunderstandings.
   Where no adverse findings exist, this conference may be waived by management of the audited organization. Such waiver shall be documented in the audit report. For all internal audits, unless unusual operating or maintenance conditions preclude attendance by appropriate managers/supervisors, an audit exit shall be held with managers/supervisors. If there are no adverse findings, management of the audited organization may waive the audit exit. Such waiver shall be documented in the audit report."
5. ANSI N45.2.12 Paragraph 4.4, Reporting:
   a. This paragraph requires that the audit report be signed by the audit team leader which is not always the most expeditious route for the audit report to be issued as soon as practical. DEP will comply with Paragraph 4.4 as clarified to read:
      "An audit report shall be signed by the audit team leader or the leader's supervisor in the absence of the audit team leader. In cases where the audit report is not signed by the audit team leader due to the leader's absence, the record copy of the report must be signed by the audit team leader upon return . The report shall not require the audit team leader's review/concurrence/signature if the audit team leader is no longer employed by DEP at the time audit report is issued. The audit report shall provide:"
   b. DEP will comply with subparagraph 4.4.3 clarified to read: "Supervisory level personnel with whom significant discussions were held during the course of preaudit (where conducted) , audit, and post audit (where conducted) activities.
   c. Subparagraph 4.4.6 requires audit reports to include recommendations for corrective actions. DEP may choose not to comply with this requirement. Instead, DEP audit reports are required to document findings.

Regulatory Guide 1.146, Qualification of QA Program Audit Personnel for Nuclear Power Plants (Revision 0) (August, 1980)

ANSI Standard N45.2.23-1978, Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants

RNP shall comply with NRC Regulatory Guide 1.146, Revision 0, which endorses ANSI N45.2.23-1978, with the following exceptions:

1. Section 1.4 titled Definitions: Definitions in this Standard which are not included in ANSI N45.2.10 will be used; definitions which are included in ANSI N45.2.10 will be used as clarified in DEP commitment to Regulatory Guide 1.74.

Table C17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.146, Qualification of QA Program Audit Personnel for Nuclear Power Plants (Revision 0) (August, 1980)

ANSI Standard N45.2.23-1978, Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants

2. Section 2.2 titled Qualification of Auditors: Subsection 2.2.1 references an ANSI B45.2, which will be assumed to be N45.2. DEP will comply with an alternate subsection 2.2.1 which reads:
   Orientation to provide a working knowledge and understanding of the DEP QA program, including the Regulatory Guides and ANSI standards included in the program, and DEP procedures for performing audits and reporting results.
3. Section 4.1 titled Organizational Responsibility: DEP will comply with this Section with the substitution of the following sentence in place of the last sentence in the Section.
   NOS Management or the Audit Team Leader shall, prior to commencing the audit, assign personnel who collectively have experience or training commensurate with the scope, complexity, or special nature of the activities to be audited.
4. Section 5.3 titled Updating of Lead Auditors' Records: DEP will substitute the following sentence for this Section:
   Records for each Lead Auditor shall be maintained and updated during the annual management assessment as defined in Section 3.2 (as clarified).
5. Section 5.4 titled Record Retention: DEP will substitute the following sentence for this section.
   Qualification records shall be retained as required by the DEP QA Program.
6. Section 2.3.4 titled For Audits: DEP will substitute the following instead of the cited sentence. Prospective Lead Auditors shall demonstrate the ability to effectively implement the audit process and effectively lead an audit team. This process is described in written procedures, which provide for evaluation and documentation of the results of this demonstration. In addition, the prospective Lead Auditor shall have participated in at least two Nuclear Oversight audits within a one-year period preceding the individual's effective date of qualification. Upon successful demonstration of the ability to effectively implement the audit process and effectively lead audits, and having met other provisions of Section 2.3 of ANSI/ASME N45.2.23-1978, the individual may be certified to lead audits.

Table C17-2. Site Specific Response to Regulatory Guides and Industry Standards

Table C17-2 identifies additional Regulatory Guides addressing subjects related to implementation of the QAP but the implementation is site specific and controlled with the UFSAR in accordance with 10 CFR 50.59.

Regulatory Guide 1.8, Personnel Selection and Training

Personnel selection and training is site specific.

> Robinson addresses conformance with Regulatory Guide 1.8 in UFSAR Chapter 1 Section 8.

Regulatory Guide 1.26, Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants

---

Quality group classifications and standards trace to the original design and construction of the nuclear power plant and therefore are site specific.

> Robinson does not address Regulatory Guide 1.26 in UFSAR Chapter 1 Section 8. Quality group classifications are addressed in UFSAR Chapter 3.

Regulatory Guide 1.29, Seismic Design Classification

Seismic design classification trace to the original design and construction of the nuclear power plant and therefore is site specific.

> Robinson addresses conformance with Regulatory Guide 1.29 in UFSAR Chapter 1 Section 8.

Regulatory Guide 1.36, Nonmetallic Thermal Insulation for Austenitic Stainless Steel

---

Nonmetallic thermal insulation for austenitic stainless steel trace to the original design and construction of the nuclear power plant and therefore is site specific.

> Robinson does not address conformance with Regulatory Guide 1.36 in UFSAR Chapter 1 Section 8. See UFSAR Chapters 5 and 6 for insulation of austenitic stainless steel.

Regulatory Guide 1.54, Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants

---

Quality assurance requirements for protective coatings applied to water-cooled nuclear power plants trace to the original design and construction of the nuclear power plant and therefore is site specific.

> Robinson addresses conformance with Regulatory Guide 1.54 in UFSAR Chapter 1 Section 8.

Table C17-2. Site Specific Response to Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.143, Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light-Water-Cooled Nuclear Power Plants

Design guidance for radioactive waste management systems, structures, and components installed in light-water-cooled nuclear power plants trace to the original design and construction of the nuclear power plant and therefore is site specific.

Robinson does not address conformance with Regulatory Guide 1.143 in UFSAR Chapter 1 Section 8. Design guidance for radioactive waste management systems, structures, and components is addressed in UFSAR Chapter 11.

Regulatory Guide 1.155, Station Blackout

Addressing Station Blackout is site specific.

Robinson addresses conformance with Regulatory Guide 1.155 in UFSAR Chapter 1 Section 8.

Regulatory Guide 4.15, Quality Assurance for Radiological Monitoring Programs (Normal Operations) – Effluent Streams and the Environment

Quality assurance for radiological monitoring program (normal operations) – effluent streams and the environment is site specific.

Robinson addresses Regulatory Guide 4.15 in UFSAR Chapter 1 Section 8.

C17.3.1 MANAGEMENT

C17.3.1.1 Methodology

There are no Robinson specific amplifications for this section.

C17.3.1.2 Organization

There are no Robinson specific amplifications for this section.

C17.3.1.3 Responsibility

There are no Robinson specific amplifications for this section.

C17.3.1.4 Authority

The program and procedures require that the authority and duties of persons and organizations performing activities affecting quality functions be clearly established and delineated in writing and that these individuals and organizations have sufficient authority and organizational freedom to:

1. Identify quality, nuclear safety, and performance problems.
2. Order unsatisfactory work to be stopped and control further processing, delivery, or installation of nonconforming material.
3. Initiate, recommend, or provide solutions for conditions adverse to quality.
4. Verify implementation of solutions.

C17.3.1.5 Personnel Training and Qualification

There are no Robinson specific amplifications for this section.

C17.3.1.6 Corrective Action

The program requires that an evaluation of adverse conditions such as conditions adverse to quality, nonconformances, failures, malfunctions, deficiencies, deviations, and defective material and equipment is conducted to determine need for corrective action.

Conditions adverse to quality are identified through inspections, assessments, tests, checks, and review of documents.

The program requires corrective action to be initiated to preclude recurrence of significant conditions adverse to quality.

Procedures require follow-up reviews, verifications, inspections, etc., to be conducted to verify proper implementation of corrective action and to close out the corrective action documentation.

The program outlines the methodology for resolution of disputes involving quality and nuclear safety issues arising from a difference of opinion between identifying personnel and other groups.

Significant conditions adverse to quality are reported to appropriate management for review and evaluation.

Periodic review and evaluation of adverse trends are performed by management.

C17.3.1.7 Regulatory Commitments

There are no Robinson specific amplifications for this section.

C17.3.2 PERFORMANCE/VERIFICATION

C17.3.2.1 Methodology

There are no Robinson specific amplifications for this section.

C17.3.2.2 Design Control

There are no Robinson specific amplifications for this section.

C17.3.2.3 Design Verification

There are no Robinson specific amplifications for this section.

C17.3.2.4 Procurement Control

Potential contractors and suppliers are evaluated prior to award of a procurement contract when needed to assure the contractor's or supplier's capability to comply with applicable technical and quality requirements.

Procurement documents, such as purchase specifications, contain or reference the following:

1. Technical, administrative, regulatory, and reporting requirements, including material and component identification requirements, drawings, specifications, codes and industrial standards, test and inspection requirements, and special process instructions.
2. Identification of the documentation to be prepared, maintained, or submitted (as applicable) to RNP for review and approval. These documents may include, as necessary, inspection and test records, qualification records, or code required documentation
3. Identification of those records to be retained, controlled, and maintained by the supplier, and those delivered to the purchaser prior to use or installation of the hardware.

Procurement documents require suppliers to operate in accordance with QA programs which are compatible with the applicable requirements of RNP's QA Program and procedures where their services are utilized in support of plant activities.

C17.3.2.5 Procurement Verification

There are no Robinson specific amplifications for this section.

C17.3.2.6 Identification and Control of Items

Procedures require that materials, parts, and components be identified and controlled to prevent the use of incorrect or defective items. These procedures also require that identification of items be maintained either on the item in a manner that does not affect the function or quality of the item, or on records traceable to the item.

Procedures implementing these requirements provide for the following:

1. Verification that items received at the plant are properly identified and can be traced to the appropriate documentation, such as drawings, specifications, purchase orders, manufacturing and inspection documents, nonconformance reports, or material test reports.
2. Verification of item identification consistent with the RNP inventory control system and traceable to documentation which identifies the proper uses or applications of the item.

C17.3.2.7 Handling, Storage, and Shipping

Provisions are established to control the shelf life and storage of chemicals, reagents, lubricants, and other consumable materials.

C17.3.2.8 Test Control

Test procedures incorporate or reference the following, as required:

1. Instructions and prerequisites for performing the test,
2. Use of proper test equipment,
3. Mandatory inspection hold points,
4. Acceptance criteria

Test results are documented, evaluated, and their acceptability determined by a qualified, responsible individual or group.

When the acceptance criteria is not met, affected areas are to be retested or evaluated, as appropriate.

C17.3.2.9 Measuring and Test Equipment Control

Portable measuring and test equipment are calibrated by standards at least four times as accurate as the portable measuring and test equipment, unless limited by the state of the art.

Special tools such as torque wrenches, calipers, and micrometers are calibrated to be at least as accurate as the application(s) for which it is used, using standards which are at least as accurate as the special tool being calibrated.

Installed measuring and test instruments are calibrated by instruments at least as accurate as the installed, unless limited by the state of the art.

Reference and transfer standards are traceable to nationally recognized standards; or where national standards do not exist, provisions are established to document the basis for the calibration.

C17.3.2.10 Inspection, Test, and Operating Status

These procedures include the application, removal, and verification of inspection and welding stamps, or other status indicators as appropriate.

Altering the sequence of required tests, inspections, and safety-related operations can only be accomplished by methods outlined in procedures.

C17.3.2.11 Special Process Control

There are no Robinson specific amplifications for this section.

C17.3.2.12 Inspection

There are no Robinson specific amplifications for this section.

C17.3.2.13 Corrective Action

The primary goal of the RNP corrective action program is to improve overall plant operations and performance by identifying and correcting root causes of equipment and human performance problems.

Procedures define requirements for a corrective action program that charges personnel working at or supporting the nuclear plants with the responsibility to identify adverse conditions (including conditions adverse to quality).

Procedures include requirements for verification of the acceptability of the rework/repair of items by reinspection and/or testing in accordance with the original inspection or test requirements or by an accepted alternative inspection and testing method.

Conditions that require rework/repairs are identified through the use of maintenance work request forms.

C17.3.2.14 Control of Documents

Changes to documents are reviewed and approved by the same organization that performed the original review and approval or by other designated qualified responsible organizations.

C17.3.2.15 Records

The structures in which certain records are maintained are designed to prevent destruction, deterioration, or theft. These structures ensure protection against destruction by fire, flooding, theft, and deterioration by the environmental conditions of temperature and humidity.

C17.3.3 ASSESSMENT

C17.3.3.1 Methodology

There are no Robinson specific amplifications for this section.

C17.3.3.2 Independent Review

There are no Robinson specific amplifications for this section.

C17.3.3.3 Independent Assessment

There are no Robinson specific amplifications for this section.

C17.3.3.3.1 Organization

There are no Robinson specific amplifications for this section.

C17.3.3.3.2 Internal Assessment process

There are no Robinson specific amplifications for this section.

C17.3.3.3.3 Internal Audit Program

C17.3.3.3.3.1 Other Reviews Prescribed by the Code of Federal Regulations

There are no Robinson specific amplifications for this section.

C17.3.3.3.3.2 Independent Audit of Fire Protection Program

There are no Robinson specific amplifications for this section.

C17.3.3.3.4 Results

There are no Robinson specific amplifications for this section.

C17.3.3.3.5 Supplier Oversight

There are no Robinson specific amplifications for this section.

C17.3.3.3.6 Independent Audit of QA Functions

There are no Robinson specific amplifications for this section.

C17.3.3.3.7 Audit Frequency Extensions

There are no Robinson specific amplifications for this section.

C17.3.4 REVIEW AND AUDIT

C17.3.4.1 Procedures, Tests, and Experiments

Content from Robinson UFSAR Section 17.3 Appendix A, QA Program Relocated Technical Specifications Requirements, Section 1.1 follows:

1. The procedures established, implemented, and maintained for the Quality Assurance Program for effluent and environmental monitoring use guidance from Regulatory Guide 4.15. RNP is not committed to specific guidance within Regulatory Guide 4.15 or to a specific revision to the Regulatory Guide.
2. 10 CFR 50.59 reviews are addressed in Section 17.3.4.2.

C17.3.4.2 Modifications

Content from Robinson UFSAR Section 17.3 Appendix A, QA Program Relocated Technical Specifications Requirements, Section 1.2 modifications are addressed in Section 17.3.2.2, Design Control.

C17.3.4.3 RNP Technical Specifications and License Changes

Content from Robinson UFSAR Section 17.3 Appendix A, QA Program Relocated Technical Specifications Requirements, Section 1.3 follows:

Each proposed RNP Technical Specification or Operating License change for the 10CFR 50 license and 7P-ISFSI license is reviewed per Section 17.3.3.2and submitted to the NRC for approval. The 24P ISFSI RNP Technical Specifications and License are processed by Transnuclear, Inc., and will only be reviewed by the On-Site Review Committee if a plant specific safety issue is identified.

C17.3.4.4 Review of RNP Technical Specifications Violations

Addressed in Section 17.3.4.6.

C17.3.4.5 10CFR 50.59 Review Qualification

Robinson UFSAR Section 17.3 Appendix A, QA Program Relocated Technical Specifications Requirements, Section 1.5 is addressed in Section 17.3.4.2.

C17.3.4.6 Plant Nuclear Safety Committee (PNSC)

Robinson UFSAR Section 17.3 Appendix A, QA Program Relocated Technical Specifications Requirements, Section 1.6 is addressed in Section 17.3.3.2, Independent Review.

C17.3.4.7 Independent Review Program

Robinson UFSAR Section 17.3 Appendix A, QA Program Relocated Technical Specifications Requirements, Section 1.7, Nuclear Oversight Section Independent Review Program, has been replaced by Section 17.3.3.2, Independent Review.

C17.3.4.8. (Deleted)

There was no content in Robinson UFSAR Section 17.3 Appendix A, QA Program Relocated Technical Specifications Requirements, Section 1.8.

C17.3.4.9. Outside Agency Inspection and Audit Program

Content from Robinson UFSAR Section 17.3 Appendix A, QA Program Relocated Technical Specifications Requirements, Section 1.9 is reflected in Section 17.3.3.3.3.2, Independent Audit of Fire Protection Program.

C17.3.4.10. Reportable Event Action

Content from Robinson UFSAR Section 17.3 Appendix A, QA Program Relocated Technical Specifications Requirements, Section 2.0 is addressed in Section 17.3.4.6, Reportable Event Action.

C17.3.4.11. Safety Limit Violation

Content from Robinson UFSAR Section 17.3 Appendix A, QA Program Relocated Technical Specifications Requirements, Section 3.0 is addressed in 17.3.4.6.

C17.3.4.12. Record Retention

A list of typical operational phase QA Records is included in 17.3.2.15.

Attachment D, Catawba, McGuire, and Oconee Specific QAPD

The term 'Duke Energy Carolinas' as used in this document means Catawba, McGuire, and Oconee Nuclear Plants. If content is specific to a single nuclear plant, that nuclear plant will be identified by name. See Table D17-2 addressing Regulatory Guide 1.8 for example.

Information presented in this attachment was contained in the Duke Energy Carolinas Topical Report Quality Assurance Program prior to Amendment 41.

Where a section contains no descriptive information beyond that in the generic text in the body of the document, a statement is made to that effect and no content is included. See D17.3.1.2, Organization for example.

D17. QUALITY ASSURANCE

D17.1 QA DURING DESIGN AND CONSTRUCTION

Deleted

D17.2 OPERATIONAL QA

Deleted

(NOTE: In August 1992, Amendment 15 of the Duke Energy Carolinas Topical Report reformatted the description of the QA Program to follow Standard Revision Plan Section 17.3, replacing the content of 17.1 and 17.2.)

D17.3 QUALITY ASSURANCE PROGRAM (QAP) DESCRIPTION

INTRODUCTION

As discussed herein, the Quality Assurance Program (QAP) includes the description contained in this document and the procedures providing implementation of the requirements of this document, including the requirements of industry standards to the degree identified in Table 17-1. This Topical Report describes the QAP for those systems, components, items, and services which have been determined to be nuclear safety related. The QAP provides a method of applying graded controls to certain non-nuclear safety related systems, components, items, and services (such as fire protection and radioactive waste structures, systems, and components) through implementing documents.

Duke Energy Carolinas may use QA Conditions as a method for identifying applicability of the QAP, where implementing documents define a Quality Assurance (QA) "Condition" for each level of QA required. These will be designated as "QA Condition _____". The quality of systems, components, items, and services within the scope of QA Conditions is assured through implementing documents commensurate with the system's, component's, item's, or service's importance to safety.

In this approach, QA Condition 1 identifies those systems and their attendant components, items, and services which have been determined to be nuclear safety related. These systems are detailed in the Safety Analysis Report applicable to each nuclear station. The Topical Report applies in its entirety to systems, components, items, and services identified as QA Condition 1.

QA Condition 5 covers those systems, components, items, and services which are important to the mitigation of design basis and other selected events as defined in applicable procedures and directives. QA Condition 5 only applies to Oconee Nuclear Station.

QA Conditions 2, 3, 4, and others are defined in implementing documents. These address SSCs and related functions important to the management and containment of liquid, gaseous, and solid radioactive waste, important to fire protection, seismic interaction, etc.

QA Condition 3 includes those fire protection features (systems, components, items, and services) which are credited in addressing 10 CFR 50.48.

Quality assurance program requirements for Oconee, McGuire, and Catawba dry cask storage activities are performed in accordance with applicable 10CFR72.212 reports for each site which invokes the NRC approved 10CFR50 Appendix B QAP as described in this Topical Report.

DEFINITIONS

There are no Duke Energy Carolinas specific definitions.

EXPLANATION OF “QUALITY ASSURANCE”

There is no Duke Energy Carolinas specific content.

QA STANDARDS AND GUIDES

Table D17-1 and D17-2 address Catawba, McGuire, and Oconee conformance to the referenced regulatory and program guidance contained in NUREG-0800 Section 17.3.

Changes to the content of Table D17-1 are controlled in accordance with 10 CFR 50.54(a). Subsequent changes are incorporated in this document as identified in Section 17.3.1.7.

Table D17-2 addresses additional Regulatory Guides that relate to implementation of the QAP but the implementation is site specific and controlled with each site's UFSAR.

Table D17-1**. Conformance with QA Regulatory Guides and Industry Standards**

Generic Exception:

Table D17-1 addresses Duke Energy Carolinas Conformance of the Quality Assurance Program to certain NRC Regulatory Guides. In so doing, specific editions of industry standards are identified for compliance with exceptions and alternatives. Those identified standards include references to other industry standards for activities including, but not limited to; design, fabrication, inspection, and testing. Those included reference industry standards are considered to be guidance documents for details of how activities may be accomplished. The actual standard to be used in such cases is controlled by each station's current licensing and design bases.

Regulatory Guide 1.28, Rev (2), Feb. 1979 – Quality Assurance Program Requirements (Design and Construction)

The Duke Energy Carolinas QAP conforms to Regulatory Guide 1.28 Rev (2) and ANSI N45.2-1977 with the clarifications and exceptions noted below.

Exception to ANSI N45.2 Section 5. Duke Energy Corporation procurement documents shall require suppliers to provide a quality assurance program consistent with the pertinent requirements of 10 CFR Part 50 Appendix B instead of ANSI N45.2-1977.

Alternate requirements for purchase of Commercial Grade Items are described in this table addressing compliance for Regulatory Guide 1.123.

Regulatory Guide 1.30, Rev 0, Quality Assurance Requirements for the Installation, Inspection and Testing of Instrumentation and Electric Equipment

---

The Duke Energy Carolinas QAP conforms to Regulatory Guide 1.30 Rev 0 and ANSI N45.2.4-1972 with the following Clarifications and Exceptions:

Conforms with no exceptions.

Regulatory Guide 1.33, Rev 2, Quality Assurance Program Requirements (Operation)

The Duke Energy Carolinas QAP conforms to Regulatory Guide 1.33 Rev 2 and ANSI N18.7-1976/ANS-3.2 with the following Clarifications and Exceptions:

Regulatory position C.4 modifies the audit frequencies in Section 4.5 of ANSI N18.7. Duke Energy Carolinas takes exception to this regulatory position. The audits of selected aspects of operational phase activities as identified in Section 17.3.3.3.3, Internal Audit Program, are performance based. The schedule is based on plant performance and importance to safety but at a frequency not to exceed twenty-four months with extensions as allowed in Section 17.3.3.3.7, Audit Frequency Extensions.

Table D17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.33, Rev 2, Quality Assurance Program Requirements (Operation)

Exception to ANSI N18.7-1976, Section 5.2.15, Review, Approval and Control of Procedures, which states in part that, "Plant procedures shall be reviewed by an individual knowledgeable in the area affected by the procedure no less frequently than every two years to determine if changes are necessary. A revision to a procedure constitutes a procedure review." In lieu of this paragraph, Duke Energy Carolinas has programmatic controls in place to continually identify procedure revisions which may be needed to ensure that procedures are appropriate for the circumstance and are maintained current.

When purchasing commercial-grade calibration services from certain accredited calibration laboratories, the procurement documents are not required to impose a QAP consistent with ANSI N45.2-1977. Alternate requirements described in the QA Topical Report for Regulatory Guide 1.123 may be implemented in lieu of imposing a QAP consistent with ANSI N45.2-1977.

Exception to Paragraph C.3 of Regulatory Guide 1.33 and ANSI N18.7-1976 Paragraph 4.3: Independent Review Program requirements are replaced by Section 17.3.3.2, Independent Review. This exception uses NRC Safety Evaluation dated January 13, 2005 to Nuclear Management Company (ADAMS ML050210276).

Section 5.2.2 titled Procedure Adherence first paragraph addresses temporary change to procedures, which is clarified as follows: Temporary changes to procedures, tests, or experiments may be made provided; a) such change does not change the intent of the original procedure, test, or experiment; b) the change is approved by two members of the plant management staff, at least one of whom holds a Senior Reactor Operator License on the unit affected; and c) the change is documented and approved as a permanent change or deleted within 14 days of implementation.

Regulatory Guide 1.37, Rev 0, Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants

The Duke Energy Carolinas QAP conforms to Regulatory Guide 1.37 Rev 0 and ANSI N45.2.1-1973 with the following clarifications and exceptions:

Conforms with no exceptions.

Regulatory Guide 1.38, Rev 2, May 1977 – Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage and Handling of Items for Water-Cooled Nuclear Power Plants

The Duke Energy Carolinas QAP conforms to Regulatory Guide 1.38 Rev 2 and ANSI N45.2.2-1972 with the following Clarifications and Exceptions:

Container markings shall be marked on at least one side (A.3.9(1)) and shall be applied with waterproof ink or paint in characters of a legible size, and caps and plugs for pipe and fittings are required unless specified by Engineering, and off-site inspection, examination, and testing is monitored by personnel qualified to ANSI N45.2.12 in lieu of ANSI N45.2.6.

Table D17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.39, Rev (2), Sept. 1977 – Housekeeping Requirements for Water-Cooled Nuclear Power Plants

The Duke Energy Corporation QAP conforms to Regulatory Guide 1.39 Rev 2 and ANSI N45.2.3-1973 with the following clarifications and exceptions.

Personnel accountability for personnel entering housekeeping zones I, II, and III without materials shall be maintained by housekeeping logs or alternate methods such as radiation work permits, confined space permits, work requests or other accepted methods capable of assuring personnel accountability.

Regulatory Guide 1.58, Rev (1), Sept. 1980 – Qualification of Nuclear Power Plant Inspection, Examination and Testing Personnel

The Duke Energy Carolinas QAP conforms Regulatory Guide 1.58 Rev 1 and ANSI N45.2.6-1978 with the following Clarifications and Exceptions:

Duke Energy Carolinas' DEC's nondestructive examination (NDE) personnel will meet the qualification requirements of SNT TC-1A and ANSI/SNT-CP-189 as governed by the applicable ASME Section XI requirement or other code requirement. Operational/functional testing personnel will meet the requirements of ANSI N18.1-1971 rather than ANSI N45.2.6. Also, Level I inspectors receive a minimum of 4 months experience as Level I before being certified as Level II, in lieu of one year experience recommended by ANSI N45.2.6. Inspectors are only assigned tasks for which they have been qualified.

Regulatory Guide 1.64, Rev (2), June 1976 – Quality Assurance Requirements for the Design of Nuclear Power Plants

The Duke Energy Carolinas QAP conforms to Regulatory Guide 1.64, Rev. 2 and ANSI Standard N45.2.11-1974 with the following Clarifications and Exceptions:

The use of the originator's immediate supervisor for design verification shall be restricted to special situations where the immediate supervisor is the only individual capable of performing the verification. Advance justification for such use shall be documented and signed by the supervisor's management. And the frequency and effectiveness of the supervisor's use as design verifier are independently verified to guard against abuse. The supervisor will not be the design verifier on work for which he is the actual performer / originator.

Regulatory Guide 1.74, Rev (0), Feb. 1974 – Quality Assurance Terms and Definitions

The Duke Energy Corporation QAP conforms to Regulatory Guide 1.74, Rev 0 and ANSI N45.2.10-1973 with the following Clarifications and Exceptions:

The quality assurance terms and definitions contained in ANSI N45.2.10-1973 are generally used in describing and implementing the quality assurance program described in this QAPD except where terms are explicitly defined in this document.

Table D17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.88, Rev (2), Oct. 1976 - Collection, Storage, and Maintenance of Nuclear Power Plant Quality Assurance Records

---

The Duke Energy Carolinas QAP conforms to Regulatory Guide 1.88, Rev. 2 and ANSI N45.2.9-1974 with the following Clarifications and Exceptions:

The records storage facilities have a minimum 3-hour rating. A qualified Fire Protection Engineer (meeting Professional Member grade qualifications of the SFPE) will evaluate record storage areas (including satellite files) to assure records are adequately protected from damage.

The Duke Energy Carolinas program for storage of records on microfilm, dual storage or in electronic format meets the preservation requirement for the retention of QA Records.

See standard exception in Table 17-1 Regulatory Guide 1.88 for the appropriate controls on quality in the management of electronic records.

Regulatory Guide 1.94, Rev (1), Apr. 1976 – Quality Assurance Requirements for Installation, Inspection, and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants

---

The Duke Energy Carolinas QAP conforms to Regulatory Guide 1.94. Rev. 1 and ANSI N45.2.5-1974 with the following Clarifications and Exceptions:

the length of bolts shall be flush with the outside face of the nut.

Paragraph 5.5 requires inspection of structural steel welding to be performed in accordance with the provisions of Section 6 of the AWS D1.1. Visual Weld Acceptance Criteria (VWAC) for Structural Welding at Nuclear Power Plants, NCIG-01, Revision 2, prepared by the Nuclear Construction Issues Group (NCIG) and accepted by the NRC in their letter to the NCIG dated June 26, 1985 may be used as an alternative to AWSD1.1 for non ASME Code structural weld inspections. (July 31, 2000 J M Farley SER)

Regulatory Guide 1.116, Rev (0-R), June 1976, (Reissued May 1977) – Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems

---

The Duke Energy Corporation QAP conforms to Regulatory Guide 1.116 Rev (0-R) and ANSI N45.2.8-1975 with the following Clarifications and Exceptions:

Conforms

Regulatory Guide 1.123, Rev (1), July 1977 – Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants

---

The Duke Energy Corporation QAP conforms to Regulatory Guide 1.123 and ANSI N45.2.13-1976 with the following clarifications and exceptions:

Section 3.2, “Content of the Procurement Documents,” Subsection 3.2.3, “QAP Requirement,” Duke Energy Carolinas takes the following exception:
See standard exceptions in Table 17-1 for Regulatory Guide 1.123 for the procurement of Commercial Grade Items and services including, purchasing commercial-grade calibration services from calibration laboratories.

Table D17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.144, Rev (1), Sept. 1980 - Auditing of Quality Assurance Programs for Nuclear Power Plants

The Duke Energy Carolinas QAP conforms to Regulatory Guide 1.144, Rev 1 and ANSI N45.2.12-1977 with the following clarifications or exceptions:

Section 4.4.6. In lieu of making recommendations for correcting program deficiencies we will identify the deficiencies to the audited organization. For external audits, the results of the audit will be provided to the audited organization in lieu of the audit report. Also, the re-evaluation may be extended to 15 months and the triennial period as specified in Regulatory Position c.3.b.(2) may be extended as described in Section 17.3.3.3.7, Audit Frequency Extensions. Additionally, the Duke Energy Carolinas QAP meets regulatory position C.3.b of this regulatory guide, as clarified by NRC Information Notice 86-21, Supplement 2. Internal Technical Audits shall require a response describing corrective action and implementation schedule as requested by the audit report but not to exceed sixty days of receipt of the audit report.

See standard exceptions in Table 17-1 for Regulatory Guide 1.123 for the procurement of Commercial Grade Items and services including, purchasing commercial-grade calibration services from calibration laboratories.

Regulatory Guide 1.146, Rev (0), Aug. 1980 – Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants

The Duke Energy Carolinas QAP conforms to Regulatory Guide 1.146 Rev 0 and ANSI N45.2.23-1978 with the following clarifications and Exceptions:

In lieu of prospective lead auditors participating in a minimum of five QA audits within a period of three years prior to date of certification, prospective lead auditors shall demonstrate their ability to effectively lead an audit team and shall have participated in at least one nuclear QA audit within one year preceding the individual's effective date of qualification. Upon successful demonstration of the ability to lead audits, and having met the other provisions of ANSI N45.2.23-1978, the individual may be certified as being qualified to lead audits. This process is described in approved procedures which require documentation of the evaluation and demonstration of results.

Regulatory Guide 1.152 Criteria for Programmable Digital Computer System Software in Safety-Related Systems of Nuclear Power Plants

Conformance to Regulatory Guide 1.152 was not addressed during the licensing of the operating Duke Energy Carolinas Nuclear plants.

Regulatory Guide 7.10, Establishing Quality Assurance Programs for Packaging Used in the Transport of Radioactive Material

Duke Energy Carolinas does not conform to Regulatory Guide 7.10. This QAPD is used to satisfy applicable Quality Assurance requirements for packaging and transportation of radioactive material.

Table D17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Generic Letter 89-02, Actions to Improve the Detection of Counterfeit and Fraudulently Marketed Products
Generic Letter 89-02 endorses EPRI NP-5652, *"Guideline for the Utilization of Commercial-Grade Items in Nuclear Safety-Related Applications (NCIG-07)"*, which is used by Duke Energy Carolinas. See Regulatory Guide 1.123 for additional information.

Table D17-2. Site Specific Response to Regulatory Guides and Industry Standards

Table D17-2 identifies additional Regulatory Guides addressing subjects related to implementation of the QAP but the implementation is site specific and controlled with each site's UFSAR in accordance with 10 CFR 50.59.

Regulatory Guide 1.8, Personnel Selection and Training
Personnel selection and training is site specific. Catawba addresses conformance with Regulatory Guide 1.8 in UFSAR Chapter 1 Section 7. McGuire addresses conformance with Regulatory Guide 1.8 in UFSAR Chapter 1 Table 1-4. Oconee does not address conformance with Regulatory Guide 1.8. Personnel selection and training is addressed in UFSAR Chapter 13.

Regulatory Guide 1.26, Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants
Quality group classifications and standards trace to the original design and construction of the nuclear power plant and therefore are site specific. Catawba addresses conformance with Regulatory Guide 1.26 in UFSAR Chapter 1 Section 7. McGuire addresses conformance with Regulatory Guide 1.26 in UFSAR Chapter 1 Table 1-4. Oconee does not address conformance with Regulatory Guide 1.26. Quality group classifications and standards are addressed in UFSAR Section 3.2.2.

Regulatory Guide 1.29, Seismic Design Classification
Seismic design classification trace to the original design and construction of the nuclear power plant and therefore is site specific. Catawba addresses conformance with Regulatory Guide 1.29 in UFSAR Chapter 1 Section 7. McGuire addresses conformance with Regulatory Guide 1.29 in UFSAR Chapter 1 Table 1-4. Oconee does not address conformance with Regulatory Guide 1.29. Seismic design classifications are addressed in UFSAR Section 3.2.1.

Table D17-2. Site Specific Response to Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.36, Nonmetallic Thermal Insulation for Austenitic Stainless Steel

Nonmetallic thermal insulation for austenitic stainless steel trace to the original design and construction of the nuclear power plant and therefore is site specific.

Catawba addresses conformance with Regulatory Guide 1.36 in UFSAR Chapter 1 Section 7.

McGuire addresses conformance with Regulatory Guide 1.36 in UFSAR Chapter 1 Table 1-4.

Oconee does not address conformance with Regulatory Guide 1.36. Thermal insulation for austenitic stainless steel is addressed in UFSAR Section 5.4.

Regulatory Guide 1.54, Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants

Quality assurance requirements for protective coatings applied to water-cooled nuclear power plants trace to the original design and construction of the nuclear power plant and therefore is site specific.

Catawba addresses conformance with Regulatory Guide 1.54 in UFSAR Chapter 1 Section 7.

McGuire addresses conformance with Regulatory Guide 1.54 in UFSAR Chapter 1 Table 1-4.

Oconee does not address conformance with Regulatory Guide 1.54. Protective coatings are addressed in UFSAR Section 6.2.1.6.

Regulatory Guide 1.143, Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light-Water-Cooled Nuclear Power Plants

Design guidance for radioactive waste management systems, structures, and components installed in light-water-cooled nuclear power plants trace to the original design and construction of the nuclear power plant and therefore is site specific.

Catawba addresses conformance with Regulatory Guide 1.143 in UFSAR Chapter 1 Section 7.

McGuire addresses conformance with Regulatory Guide 1.143 in UFSAR Chapter 1 Table 1-4.

Oconee does not address conformance with Regulatory Guide1.143. Design guidance for radioactive waste management systems, structures, and components is addressed in UFSAR Chapter 11.

Table D17-2. Site Specific Response to Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.155, Station Blackout
Addressing Station Blackout is site specific. Catawba addresses conformance with Regulatory Guide 1.155 in UFSAR Chapter 1 Section 7. McGuire addresses conformance with Regulatory Guide 1.155 in UFSAR Chapter 1 Table 1-4. Oconee address conformance with Regulatory Guide 1.155 in UFSAR Chapter 8.

Regulatory Guide 4.15, Quality Assurance for Radiological Monitoring Programs (Normal Operations) – Effluent Streams and the Environment
Quality assurance for radiological monitoring program (normal operations) – effluent streams and the environment is site specific. Catawba addresses conformance with Regulatory Guide 4.15 in UFSAR Chapter 1 Section 7. McGuire does not address conformance to Regulatory Guide 4.15 in UFSAR Chapter 1 Table 1-4. The radiological monitoring program is addressed in UFSAR Chapter 11. Oconee does not address conformance with Regulatory Guide 4.15. The radiological monitoring program is addressed in UFSAR Chapter 11.

D17.3.1 MANAGEMENT

D17.3.1.1 Methodology

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.1.2 Organization

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.1.3 Responsibility

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.1.4 Authority

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.1.5 Personnel Training and Qualification

The following provide Duke Energy Carolinas specific amplifications for this section.

A training program is established for each nuclear station and support organization to develop and maintain an organization qualified to be responsible for operation, engineering, testing, inspection, maintenance, engineering changes and other technical aspects of the nuclear station involved. The program is formulated to provide the required training based on individual employee experience and intended position. The program is in compliance with NRC licensing requirements, where applicable. The training program is such that trained and qualified operating, maintenance, work control, engineering, inspection, testing, technical support and supervisory personnel are available in necessary numbers at the times required. In all cases, the objectives of the training program shall be to assure safe and reliable operation of the station.

A continuing effort is used after a station goes into commercial operation for training of replacement personnel and for periodic retraining, reexamining, and/or recertifying as required to assure that personnel remain proficient. Personnel receive orientation training in basic QA policies and practices.

Personnel receive additional training, as appropriate, which addresses specific topics such as NRC regulations and guides, QA procedures, auditing and applicable codes and standards. Special training of personnel in QA related matters, particularly new or revised requirements, is conducted as necessary. Training and qualification records are maintained for each employee. Documentation of training includes the objectives, content of the program, attendees, and date of attendance.

D17.3.1.6 Corrective Action

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.1.7 Regulatory Commitments

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.2 PERFORMANCE/VERIFICATION

D17.3.2.1 Methodology

The following provide Duke Energy Carolinas specific amplifications for this section.

The program receives on-going review and is revised as necessary to assure its continued effectiveness.

D17.3.2.2 Design Control

Each design document is checked by another individual qualified in the same discipline and is reviewed for concept and conformity with applicable codes, standards, and other design inputs (as specified within the design documentation package). The document is approved by the individual having overall responsibility for the design function. A review of each specification is made to assure incorporation of necessary QA information. The entire review process is documented.

Computer programs are controlled in accordance with appropriate department procedures, whereby programs are certified to demonstrate their applicability and validity.

D17.3.2.3 Design Verification

Analytical models, theories, examples, tables, codes, computer programs, etc., used as bases for design must be referenced in the design document and their application verified in the design verification. Model tests, when required, to prove the adequacy of concept or design are reviewed and approved by the responsible engineer. The tests used for design verification must meet all the requirements of the designing activity. Computer programs are controlled in accordance with the applicable software QA document whereby programs are certified to demonstrate their applicability and validity.

Following completion of design and evaluation of an engineering change, the responsible individual/organization summarizes the engineering change design and identifies the design documents and information required for engineering change implementation. This information is provided for design verification. This addresses such items as:

a) A description of the engineering change.
b) References utilized in the evaluation and design of the engineering change, and necessary for the implementation of the engineering change.
c) Special installation instructions.
d) Operational, test, maintenance and inspection requirements.
e) Materials, parts and components required in order to implement the engineering change.
f) Drawings revised and/or requiring revision.
g) UFSAR revision(s) and/or Technical Specifications amendment(s) necessary.
h) Whether or not the engineering change requires a license amendment.

D17.3.2.4 Procurement Control

Procedures identify the responsibility within Nuclear Generation for the technical qualification of suppliers and control of the initial procurement of nuclear safety related items and services. Procurement requirements/specifications are prepared, checked, and approved by appropriate

personnel and forwarded to Nuclear Supply Chain for procurement actions from qualified suppliers.

Technical qualifications are determined by engineering personnel. Commercial qualification is determined by Supply Chain following evaluation of bids from qualified suppliers. Bid evaluation includes evaluation of the technical, quality and commercial qualifications of the prospective suppliers.

NOS performs qualification of supplier QA programs. NOS may place a supplier on the Qualified Suppliers List following review, approval and acceptance of an audit performed by another licensed nuclear utility or joint utility audit team. Review of such third party audits shall ensure that items to be procured are within the audit scope and any unique plant quality and technical requirements are adequately addressed by such audits. When basic components and services are procured from a supplier whose quality performance has not been verified by audit, additional assurance of product quality shall be obtained by supplier surveillance, inspection or test.

Materials, parts and components shall be procured to specified technical and quality requirements at least equivalent to those applicable to the original equipment or those specified by a properly reviewed and approved revision. As required by the applicable purchase documents, suppliers furnish documentation which identifies the material and equipment purchased and the specific procurement requirements met by the items. Also, as required by the applicable purchase documents, suppliers will provide documentation which identifies any procurement requirements which have not been complied with, together with a description of any deviations and repair records.

Procurement of materials, parts, components and services associated with nuclear safety related structures, systems, and components is controlled during the operational life of the station so as to assure the suitability for their intended service and that the safety and reliability of the station are not compromised.

Procurement information for nuclear safety related materials, parts and components is reviewed to assure that QA, technical and regulatory requirements including supplier documentation requirements are adequately incorporated into the purchase document(s). Significant changes to the content of such purchasing information are reviewed and approved in a manner consistent with the original.

Critical characteristics for the dedication of Commercial Grade Items are determined by Procurement Engineering or Supply Chain technical sponsors and approved by the responsible engineering personnel based on the manufacturer's published specifications and the intended safety function for the items. Critical characteristics used for acceptance and dedication of commercial grade items are selected to provide reasonable assurance that the items will meet their catalog or manufacturer specifications and will perform the necessary safety functions in the intended applications. Verification of critical characteristic acceptability will be by manufacturer/supplier survey, source verification, receipt tests or inspections, or post installation testing. Historical data, when documented, will represent industry wide experience.

If verification of a critical characteristic is to be by supplier survey, NOS is responsible for verifying the acceptability of the supplier control of the identified critical characteristic.

D17.3.2.5 Procurement Verification

NOS Vendor Quality performs a documented on-going evaluation of each qualified supplier in order to maintain the supplier on the qualified suppliers list. The evaluation is performed to a depth consistent with the item's or service's importance to safety, complexity, and the quantity

and frequency of procurement. As applicable, this evaluation takes into account (1) review of supplier-furnished documents such as certificates of conformance, nonconformance notices, and corrective actions, (2) results of previous source verifications, audits, and receiving inspections, (3) operating experience of identical or similar products furnished by the same supplier, and (4) results of audits from other sources (e.g., customer, ASME, or NRC audits). The results of the evaluations are reviewed and appropriate corrective action initiated. Adverse findings resulting from these evaluations are periodically reviewed in order to determine if, as a whole, they result in a significant condition adverse to quality and to provide input to support supplier audit activities conducted by the licensee or a third party auditing entity.

Suppliers of nuclear safety related items or services are re-evaluated by means of an audit at least triennially, if initial qualification was by audit or pre-award survey. The triennial audit schedule may be extended as identified in Section 17.3.3.3.7, Audit Frequency Extensions.

NOS is responsible for oversight when procurement documents require characteristics or processes to be witnessed, inspected or verified at the supplier shop. NOS surveillance activities assure that the supplier complies with all quality requirements outlined in the procurement document(s). The surveillance representative has the authority and responsibility to stop work when the required quality standards are not met.

D17.3.2.6 Identification and Control of Items

Specific identification requirements are as follows:

a) Materials, parts, components, assemblies, and subassemblies shall be identified either on the item or records traceable to the item to show that only correct items are received, issued and installed.
b) Some components, such as pressure vessels are identifiable by nameplates as required by applicable codes, or Duke Energy Carolinas specifications. Materials, parts, and components are traceable from such identification to a specific purchase order to manufacturer's records and to QA records and documentation.
c) When required by procurement documents, materials are identified by heat, batch or lot numbers which are traceable to the original material at receipt. Upon receipt, a unique tracking number is assigned to provide traceability. When several parts are assembled, a list of parts and corresponding numbers is included in the documentation.
d) When required by specifications or codes and standards, identification of material or equipment with the corresponding mill test reports, certifications and other required documentation is maintained throughout the life of the material or equipment by a unique tracking number.
e) Sufficient precautions will be taken to preclude identifying materials in a manner that will affect the function or quality of the item being identified.

Control of material, parts and components is governed by approved procedures. Specific control requirements include:

1) Nonconforming or rejected materials, parts, or components are identified to assure that they will not be inadvertently used.
2) The verification of correct identification of material, parts, and components is required prior to release for assembling, shipping and installation.
3) Upon receipt, procedures require that materials, parts or components undergo a receipt inspection to assure they are properly identified and that the supporting documentation is available as required by the procurement

requirements/specifications. Items having limited shelf or service life are identified and controlled.

4) Each organization which performs an operation that results in a change in the material, part or component is required to make corresponding revisions and/or additions to the documentation record as applicable.

When a designated item is subdivided, each subdivision is identified in accordance with the above requirements. Where physical identification of an item is impractical or insufficient, physical separation, administrative controls or other appropriate means are utilized.

D17.3.2.7 Handling, Storage, and Shipping

Conforming nuclear safety related materials, parts and components are stored in controlled, segregated areas designated for the storage of such items. Inspections and examinations are performed on a periodic basis to assure that recommended shelf life of chemicals, reagents, and other consumable materials is not exceeded. Hazardous items are stored in suitable environments with controls to prevent contamination of nuclear safety related structures, systems, or components.

D17.3.2.8 Test Control

Test controls include requirements on the review and approval of test procedures, and on the review and approval of changes to such procedures, as discussed in Section 17.3.2.14, "Document Control." Also, specific criteria are established with regard to procedure content. Examples of items which must be considered in the preparation and review of procedures include:

a) References to material necessary in the preparation and performance of the procedure, including applicable design documents.
b) Tests which are required to be completed prior to, or concurrently with, the specified testing.
c) Special test equipment required to perform the specified testing.
d) Limits and precautions associated with the testing.
e) Station, unit and/or system status or conditions necessary to perform the specified testing.
f) Criteria for evaluating the acceptability of the results of the specified testing, compatible with any applicable design specifications.

Test procedures contain the following information or require this information be documented:

1) Requirements and acceptance limits contained in applicable design and vendor documents.
2) Instructions for performing the test.
3) Test prerequisites such as calibrated instrumentation, adequate test equipment and instrumentation including their accuracy requirements, completeness of the item to be tested, suitable and controlled environmental conditions, and provisions for data collection and storage.
4) Mandatory inspection hold points.
5) Acceptance and rejection criteria.
6) Methods of documenting or recording test data and results.
7) Provisions to assure test prerequisites have been met.

Requirements are also established for verification of test completion and for determining acceptability of tests results. Test results are reviewed and accepted by the testing organization

and the organization responsible for the item being tested. In the event that test results do not meet test acceptance criteria, a review of the test, test procedure and/or test results is conducted to determine the cause, required corrective action, and retest as necessary.

In addition to the above periodic testing, after maintenance to, or modification of, nuclear safety related structures, systems and components, other post maintenance testing, post modification testing, or functional verifications are performed and documented as required to verify satisfactory performance of the affected items. Post maintenance/modification functional verifications are not subject to the requirements of periodic testing described above because they are acceptable good industrial practices that are simple and straightforward. Included in these tests are such items as diesel generators, reactor control rod systems, and leak testing of appropriate pressure isolation valves.

D17.3.2.9 Measuring and Test Equipment Control

Site specific content is retained for item c) as follows:

c) The tag or records for devices that have been acceptably calibrated include the date of calibration, the date the next calibration is due, an indication that the device is within calibration specifications and the identification of the individual who was responsible for performing the calibration.

Installed instrumentation is subject to the requirements of the Technical Specification and is not subject to the tagging requirements discussed in 17.3.2.9 c) and d). The NOS-Audit section verifies implementation of the calibration program through periodic audits.

The basis for this exception on the installed Technical Specification required equipment is the Preventive Maintenance Periodic Testing (PMPT) program. This is a computerized scheduling program that automatically schedules PMPT using model work orders. When devices have been acceptably calibrated, the clock starts for the next calibration due date. The indication that the device is within calibration specifications and identification of the individual who was responsible for performing the calibration is documented within the calibration procedure for the device. If the device fails to meet calibration specifications, it will be repaired, replaced and/or engineering involvement will be requested to further evaluate. The PMPT program along with the calibration procedures address all the requirements in Section 17.3.2.9 items c and d. Therefore, there is no need to place tags on the devices to identify the calibration status.

D17.3.2.10 Inspection, Test, and Operating Status

Inspections and tests required by the written approved procedures which address work activities are infrequently temporarily deferred. When such a deferral does occur, a discrepancy is considered to exist and documentation of the acceptable completion of the affected work activity is not performed until the discrepancy is resolved.

Proposed tests and experiments which affect station nuclear safety and are not addressed in the Updated Final Safety Analysis Report or Technical Specifications shall be prepared and approved in a manner identical to that used for station procedures as described in Section 17.3.2.14, “Document Control.” These proposed tests and experiments shall be reviewed by a knowledgeable individual/organization other than the individual/organization which prepared the proposed tests and experiments.

D17.3.2.11 Special Process Control

The QAP contains or references procedures for the control of special processes such as welding, heat treating, NDE, coatings, crimping and cleaning. These procedures shall provide for documented evidence of acceptable accomplishment of special processes using qualified procedures, equipment, and personnel.

D17.3.2.12 Inspection

Independent inspections, examinations, measurements, observations, or tests of materials, products or activities are conducted, where necessary, to assure quality. If inspection of processed material or products is impossible or disadvantageous, indirect control by monitoring processing methods, equipment, and personnel is provided. Both inspection and process monitoring are provided when control is inadequate without both.

In addition to the content identified in 17.3.2.12, inspection procedures, instructions, and checklists contain the following information or require this information on inspection reports:

a) Measuring and test equipment information
b) Identification of required procedures, drawings, specifications, etc.

The personnel performing these inspections are examined and certified in their particular category. Current qualification and certification files are maintained for each inspector. NDE inspectors are certified in accordance with required codes and standards (See Table 17-1 Regulatory Guide 1.58). Written procedures require the test and certification of inspectors in other categories such as Mechanical, Electrical, and Structural as described in the appropriate QA manual. For cases where inspectors will perform limited functions within a category, they are tested and certified to those limitations. These inspectors are only allowed to perform inspections specifically defined in this limited certification.

For inspections of concrete containments, personnel fulfilling the role of Responsible Engineer, shall be a Registered Professional Engineer experienced in evaluating the in-service condition of structural concrete and knowledgeable of the design and construction codes and other criteria used in the design and construction of the concrete containment structure. The Responsible Engineer may also perform inspections as discussed in this section.

The inspection criteria for performing inspections are established from codes, specifications, and standards applicable to the activity. Examples of activities subject to inspection include:

a) Activities specified by the ASME Code Section XI
b) Special processes
c) Modifications
d) Maintenance
e) Material Receipt

After inspection data is collected and reviewed by the inspector, the reports are technically reviewed by personnel designated to perform that function.

D17.3.2.13 Corrective Action

Procedures require that conditions adverse to quality be corrected. In the case of significant conditions adverse to quality, the procedures assure that the cause of the condition is determined and action be taken to preclude repetition. Performance and verification personnel are to:

a) Identify conditions that are adverse to quality.
b) Suggest, recommend, or provide solutions to the problems as appropriate.
c) Verify resolution of the issue.

Additionally, performance and verification personnel are to ensure that reworked, repaired, and replacement items are to be inspected and tested in accordance with the original inspection and test requirements or specified alternatives.

Discrepancies revealed during the performance of station operation, maintenance, inspection and testing activities must be resolved prior to verification of the completion of the activity being performed. In the event of a significant malfunction of nuclear safety related structures, systems, and components, the cause of the failure is evaluated and appropriate corrective action taken. Items of the same type are evaluated to determine whether or not they can be expected to continue to function in an appropriate manner. This evaluation is documented in accordance with applicable procedures.

Nuclear safety related materials, parts and components which are determined to be nonconforming are identified, segregated or otherwise controlled (e.g. by a conditional release) in such a manner as to preclude their inadvertent substitution for and use as conforming materials, parts and components. The determination of an item's nonconformance is documented and is retained on file by Nuclear Generation and, as appropriate, by tags attached to the item. Nuclear Generation personnel are notified of any nonconformances identified in accordance with approved procedures.

Nuclear Generation maintains a listing of the status of all nonconformance documents. These reports, when complete, identify the nonconforming material, part or component; applicable inspection requirements; and the resolution, and approval thereof, of the nonconformance. Provisions are established for identifying those personnel with the responsibility and authority for approving the resolution of nonconformances. Until a determination of conformance is made, a nuclear safety related material, part or component cannot be placed in service. Tags which are placed on items to identify nonconformances are removed upon resolution.

Significant trends will be/are reported to appropriate levels of management.

D17.3.2.14 Document Control

Procedures provide appropriate administrative controls for the preparation and review of proposed changes to controlled documents. Those procedures assure that required approvals are obtained for proposed changes.

The procedure process includes controls to assure that procedures, tests, and experiments, and changes thereto, covering activities that affect nuclear safety are reviewed per applicable regulations to ensure that licensing documents are maintained current and that changes requiring prior NRC approval are submitted to and approved by the NRC prior to implementation.

Duke Energy Corporation has programmatic controls in place to continually identify procedure revisions to routine procedures which may be needed to ensure that procedures are appropriate

for the circumstance and are maintained current. These controls specify conditions when mandatory review of plant procedures apply, including a requirement to review applicable procedures following an accident or transient and following any modification to a system. The process includes pre job review process and a procedure adherence policy requiring that the job be stopped and the procedure be revised or the situation resolved prior to work continuing if procedures cannot be implemented as written.

Procedures are reviewed for adequacy based upon: lessons learned from normal use, audits, unusual incidents (such as an accident, unexpected transient, significant operator error, or equipment malfunction), station engineering changes, the operating experience program, root cause analysis, or the corrective action program. The procedure process includes a mechanism for procedure users to request changes to the procedures.

Maintenance, instrumentation, and modification procedures are reviewed by cognizant personnel to determine the need for quality control inspections.

The line organization performs a biennial assessment of the procedure process to assure the procedures are maintained current. This assessment includes a requirement to evaluate the procedure change process to ensure identified changes that are required to maintain the procedure current and technically accurate are being implemented in a timely manner.

D17.3.2.15 Records

To the maximum extent practicable, records are stored such that they are protected from possible destruction by causes such as fire, flooding, theft, insects and rodents and from possible deterioration due to a combination of extreme variations in temperature and humidity conditions.

Record storage areas shall be evaluated by a Fire Protection Engineer (meeting Professional Member grade qualifications of the SFPE) to assure the records are adequately protected from damage. The evaluation shall include the following considerations as a minimum:

a) Structural collapse.
b) Unprotected steel (suspended floor slab or roof).
c) Fire frequency of similar occupancies.
d) Quantities of combustible materials.
e) Ceiling height/Room configuration which would contribute to heat dissipation.
f) Fire detection.
g) Fixed fire suppression systems.
h) On-site firefighting organizations including available equipment.

This evaluation shall be documented for each record storage area.

D17.3.3 SELF ASSESSMENT

D17.3.3.1 Methodology

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.3.2 Independent Review

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.3.3 Independent Assessment

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.3.3.1 Organization

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.3.3.2 Internal Assessment Process

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.3.3.3 NOS Audit Program

The following audit topic is added to the list of audit topics in 17.3.3.3.3 for Catawba, McGuire, and Oconee:

- The performance of effluent and environmental monitoring activities.

D17.3.3.3.3.1 Other Reviews Prescribed by the Code of Federal Regulations

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.3.3.3.2 Independent Audit of Fire Protection Program

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.3.3.4 Results

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.3.3.5 Supplier Oversight

Supplier oversight assures that supplier QA programs provide for surveillance, evaluation, and approval of sub-supplier supplying items and services. This assurance is accomplished through one or more of the following: 1) reviewing supplier audits of sub-supplier as part of the pre-bid audit, 2) making supplier control of sub-supplier work a criterion for supplier approval or disapproval, 3) making supplier surveillance of sub-supplier a requirement of the purchase requisition.

Supplier oversight performs source verification and audits on suppliers' QA programs including the activities of their suppliers and sub-suppliers, to assure that operations are in compliance with specified QA requirements. In the case of an audit of a supplier, any deficiencies noted by the auditor are clearly outlined in writing and given to the supplier's QA organization, which takes appropriate steps to resolve the deficiencies.

A re-audit is performed, if appropriate, to verify the implementation of the corrective action.

D17.3.3.3.6 Independent Audit of QA Functions

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.3.3.7 Audit Frequency Extensions

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.4 ADMINISTRATIVE CONTROLS RELOCATED FROM TECHNICAL SPECIFICATIONS

Consistent with NRC Administrative Letter 95-06, certain administrative controls from the original station Technical Specifications have been relocated to the Quality Assurance Program. These relocated administrative controls include technical review, 10 CFR 50.59 review, record

retention, and audit requirements. This section identifies those requirements or provides references to the sections of this document where the administrative controls have been integrated with QAP controls.

D17.3.4.1 Technical Reviews

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.4.2 10 CFR 50.59 Reviews

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.4.3 Record Retention

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.4.4 Audit Types and Frequencies

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.4.5 On-Site Review Committee

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.4.6 Reportable Event Action

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.4.7 Independent Safety Engineering Group Functions

Technical Specifications for Catawba and McGuire included requirements for Independent Safety Engineering Group functions of improving licensee safety performance and ability to respond to accidents by providing onsite technical support and continuous evaluation and feedback of lessons learned from operating experience. Those requirements were transferred to the this document at Amendment 23. At Amendment 36, the specific requirements for Independent Safety Engineering Group were eliminated based on duplication of functionsperformed by a combination of different groups through the performance of their normal activities.