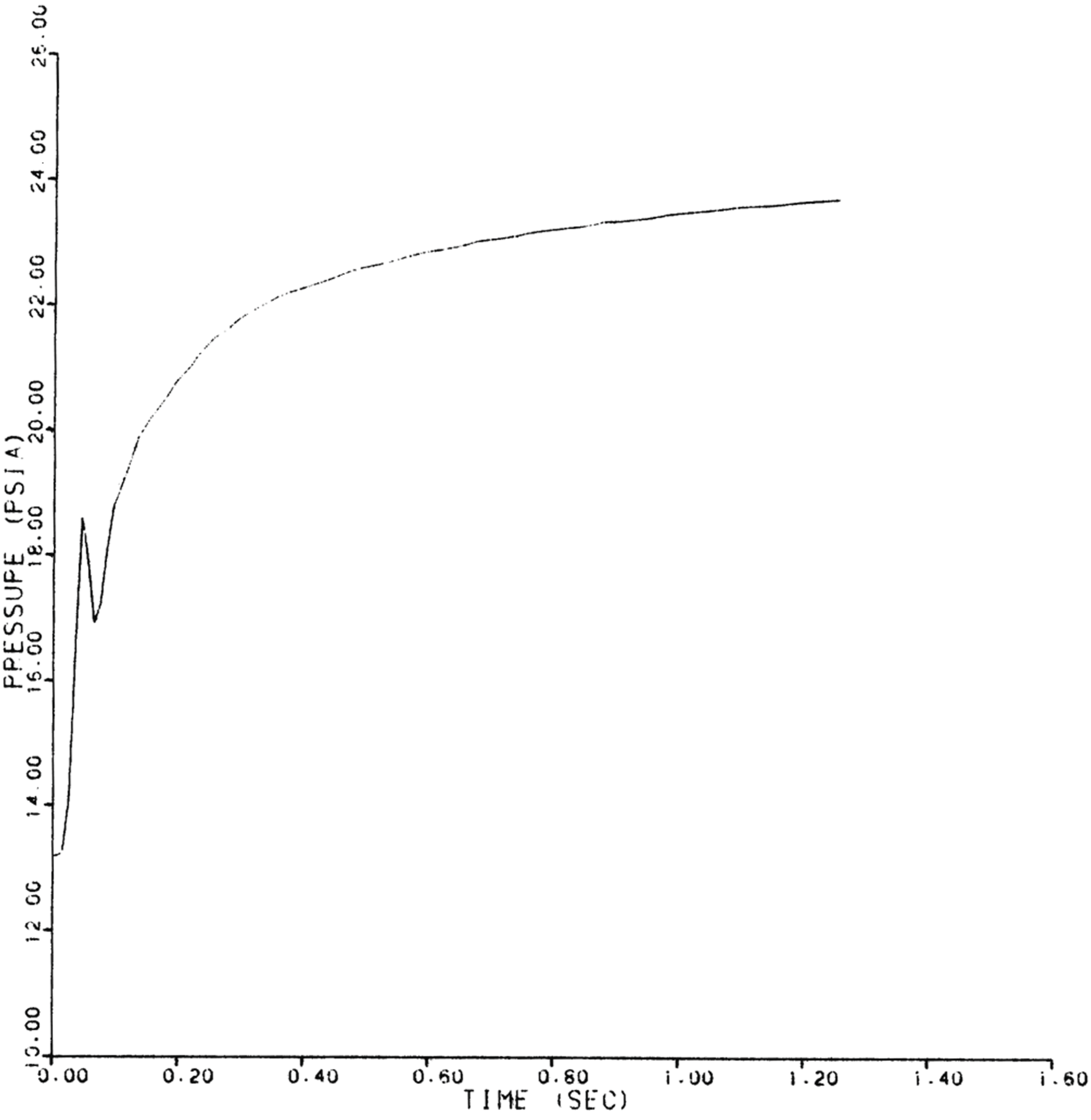

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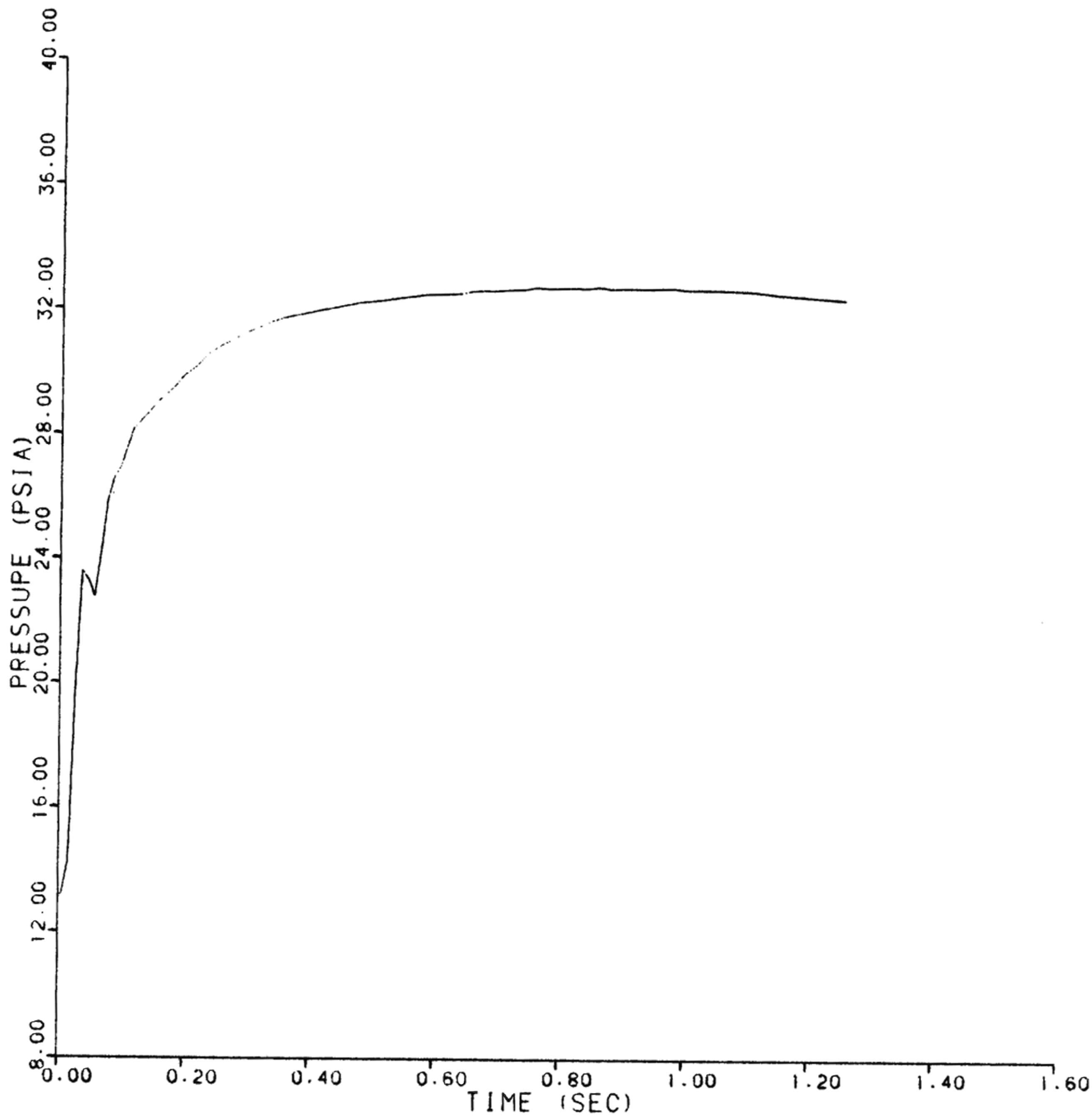
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E1
(763–in.^{2} BRE AK AREA)

FIGURE 6.2.1–22 (SHEET 1 OF 74)



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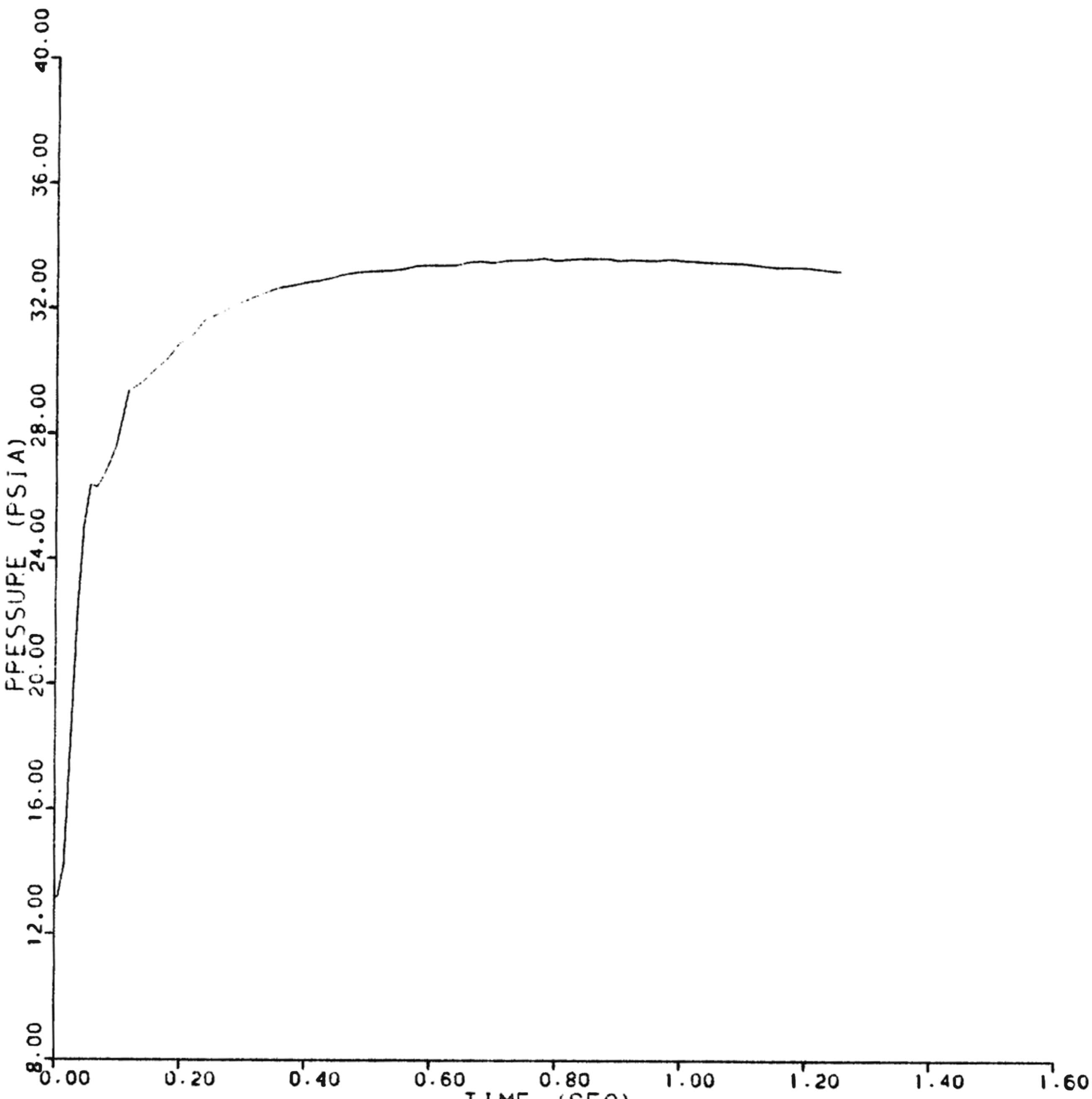
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E2
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 2 OF 74)



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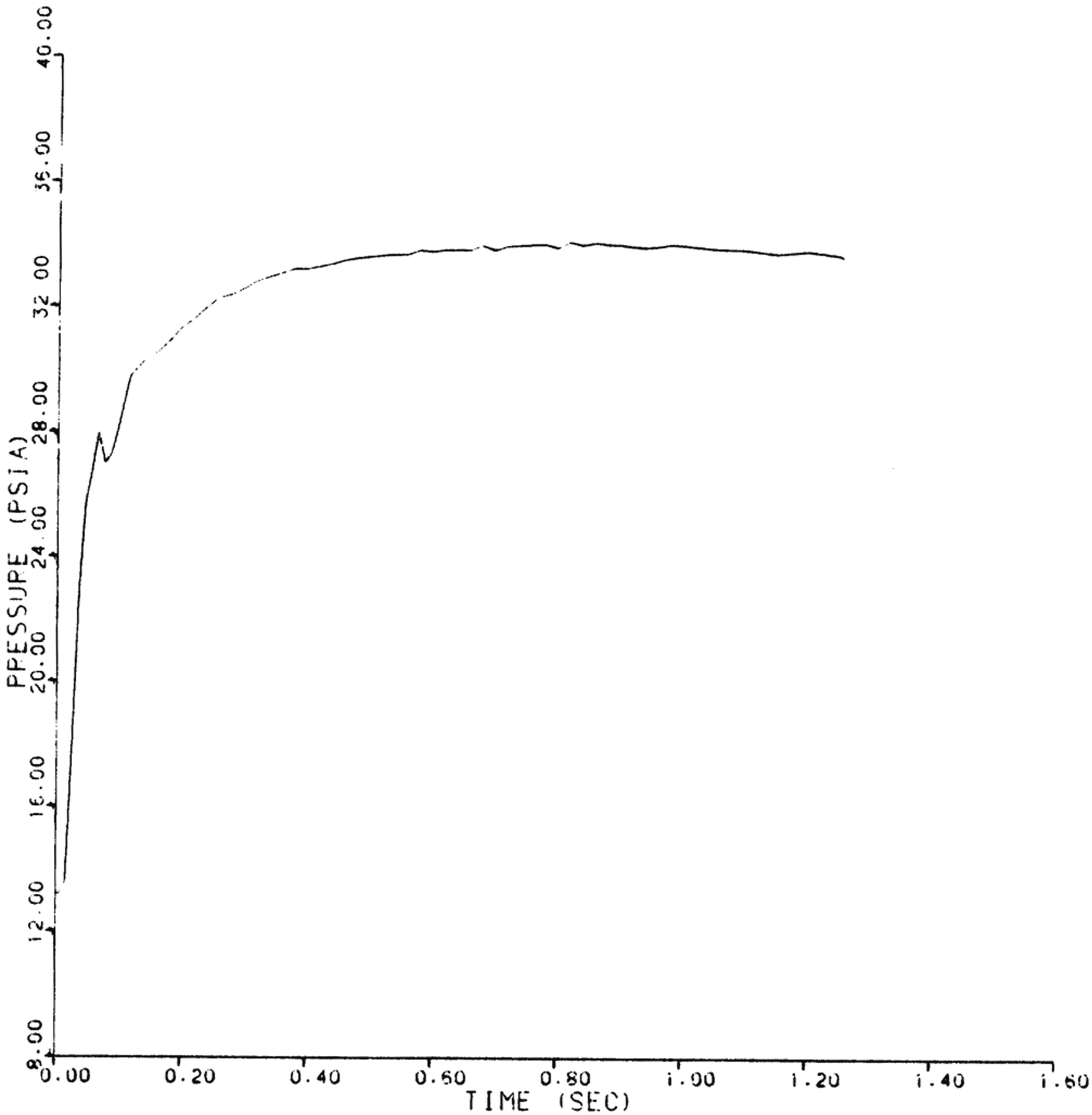
SOUTHERN COMPANY *Energy to Serve Your World®* **VOGTLE** **ELECTRIC GENERATING PLANT** **UNIT 1 AND UNIT 2**	STEAM GENERATOR INLET ELBOW NODE – E3 (763–in.^{2} BREAK AREA)
	FIGURE 6.2.1–22 (SHEET 3 OF 74)



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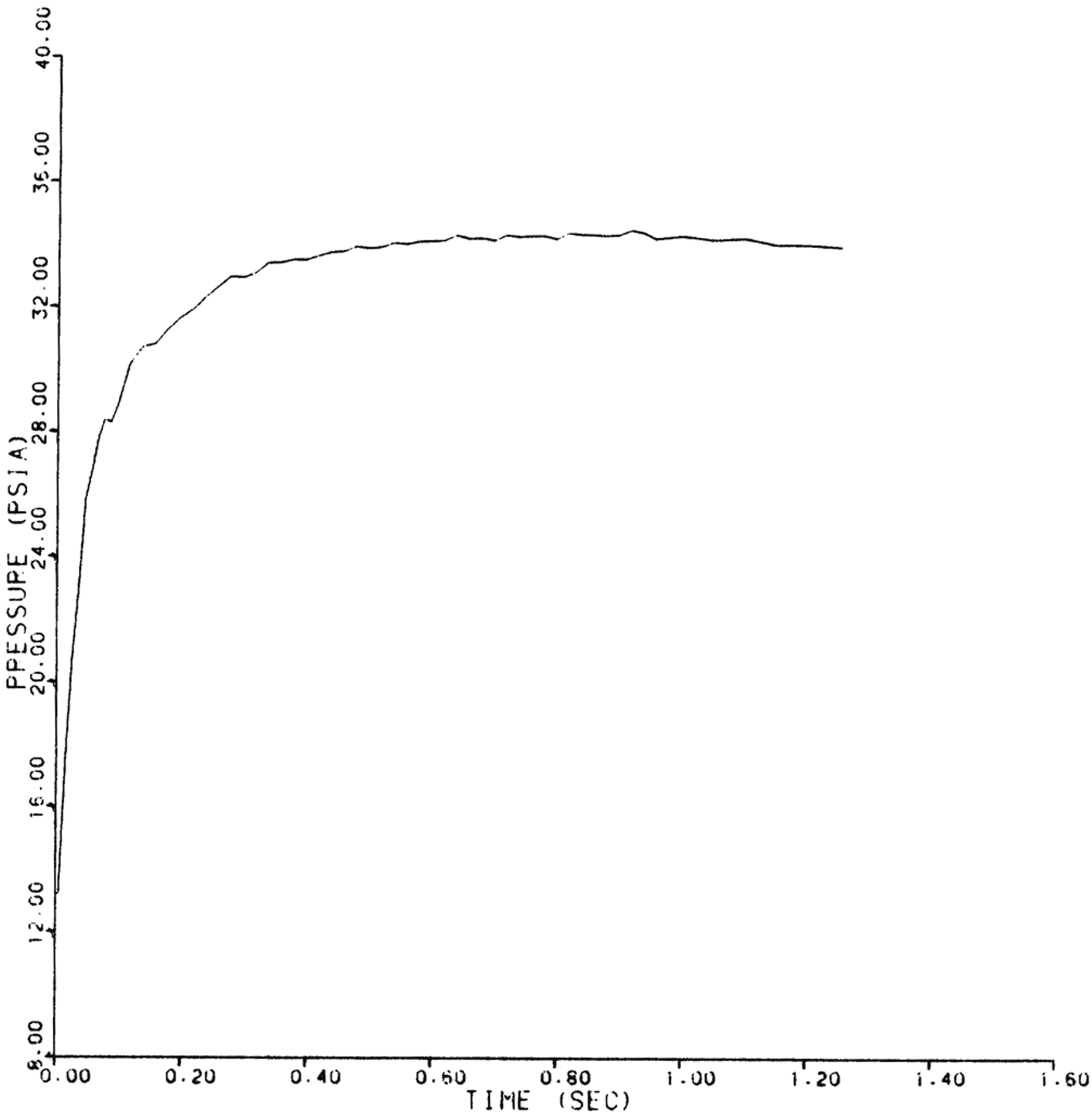
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E4
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 4 OF 74)



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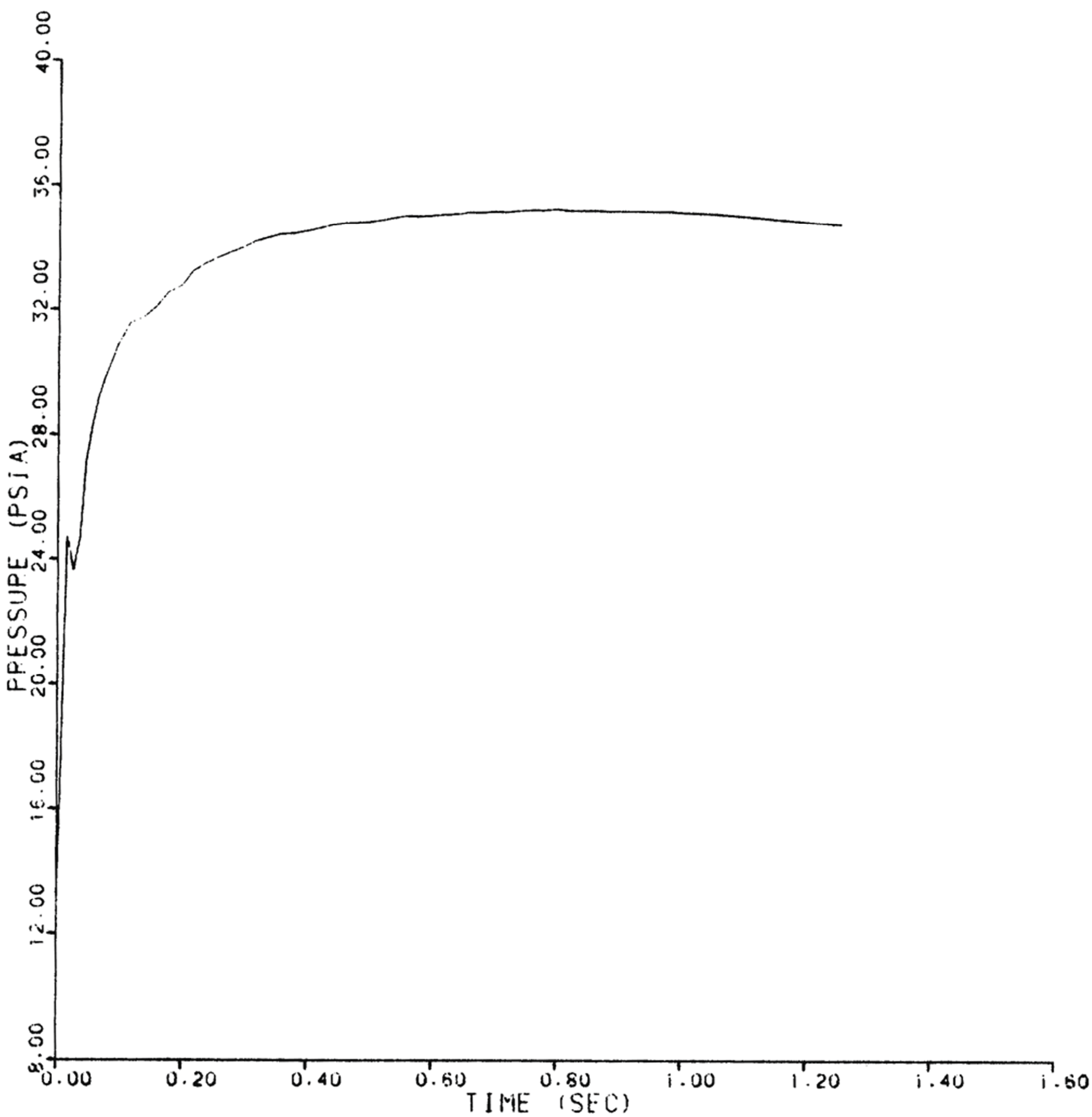
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E5
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 5 OF 74)



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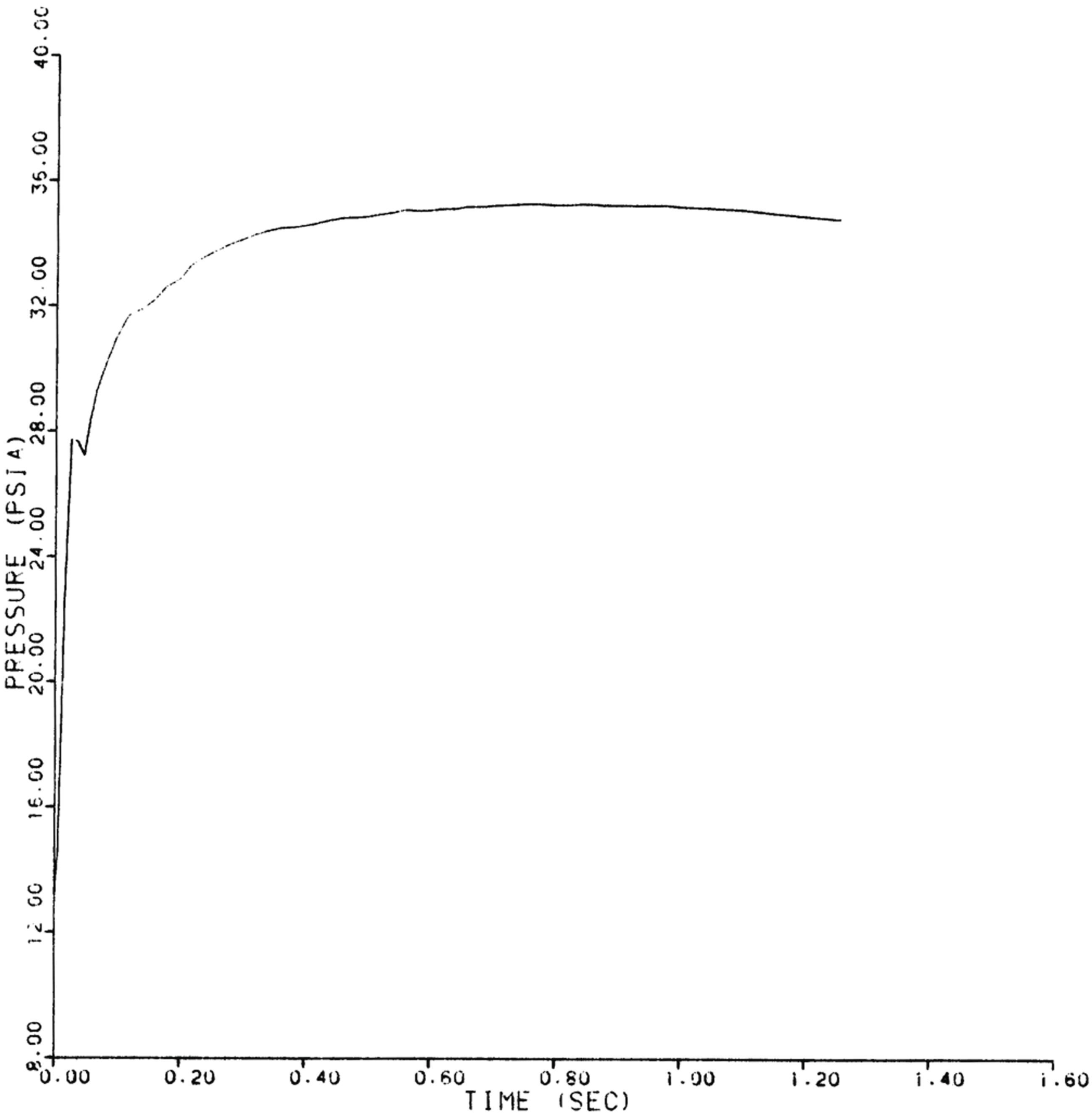
SOUTHERN COMPANY Energy to Serve Your World®	VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	STEAM GENERATOR INLET ELBOW NODE – E6 (763–in.^{2} BREAK AREA)
		FIGURE 6.2.1–22 (SHEET 6 OF 74)



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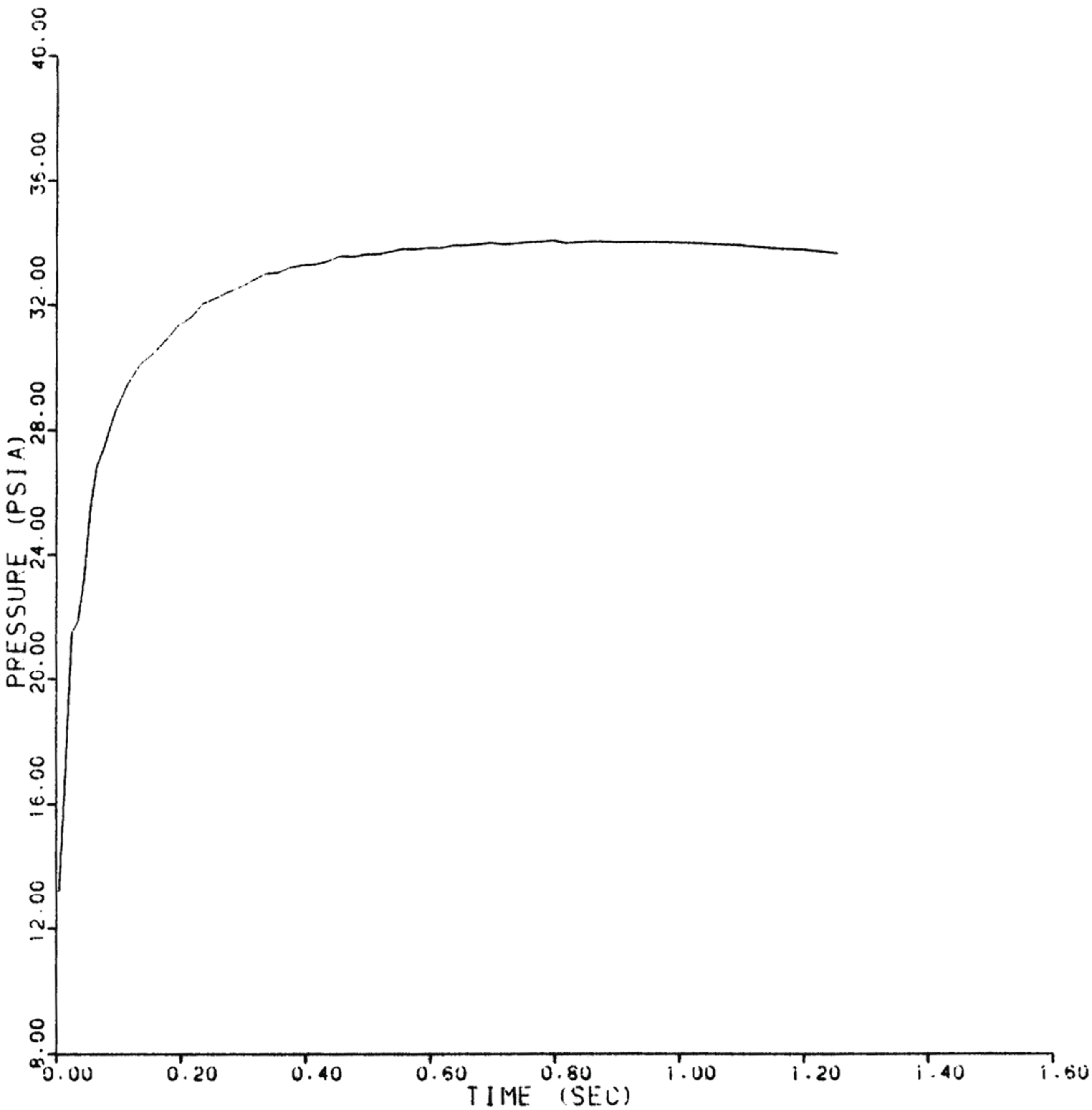
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E7
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 7 OF 74)



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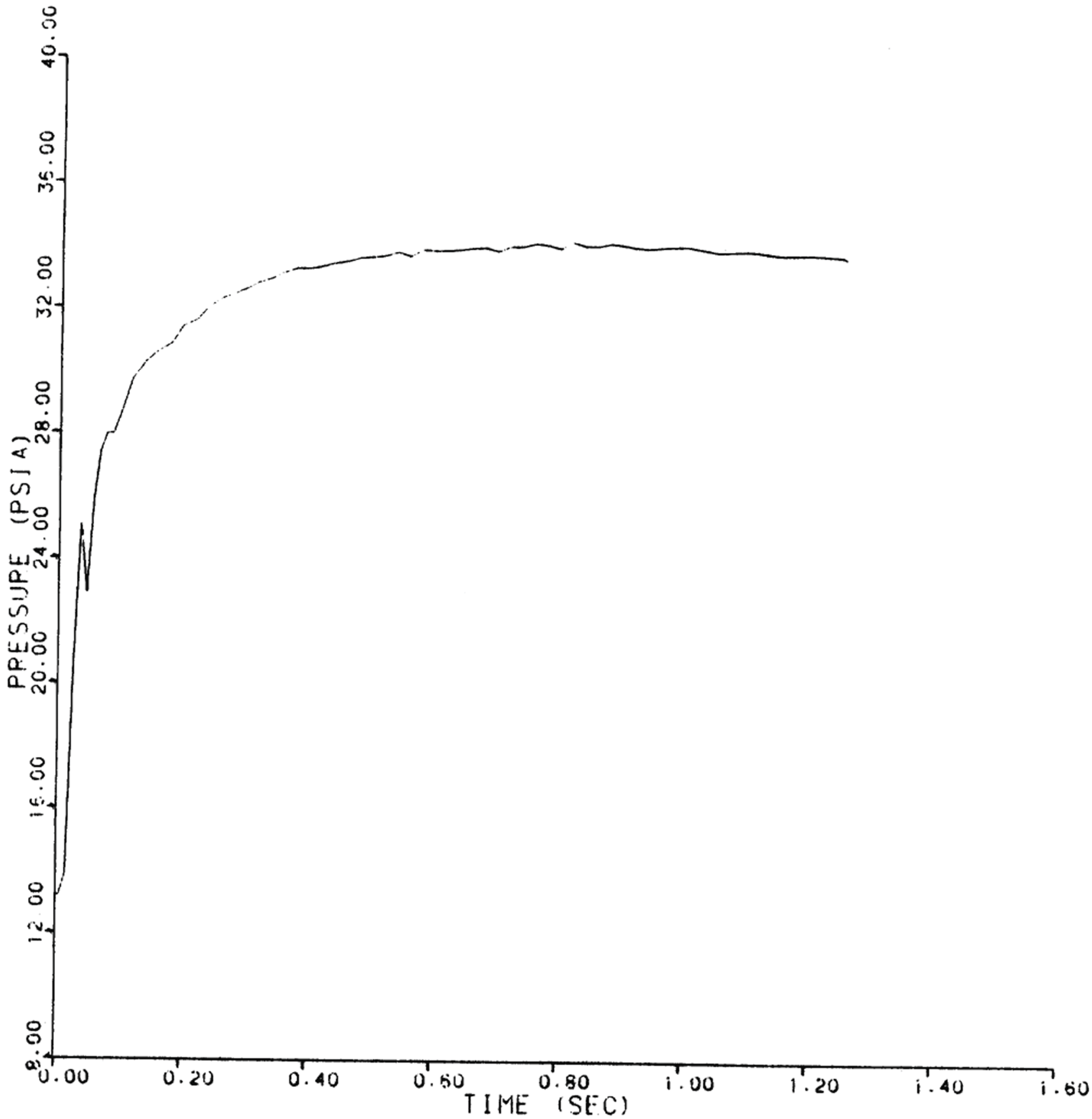
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E8
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 8 OF 74)



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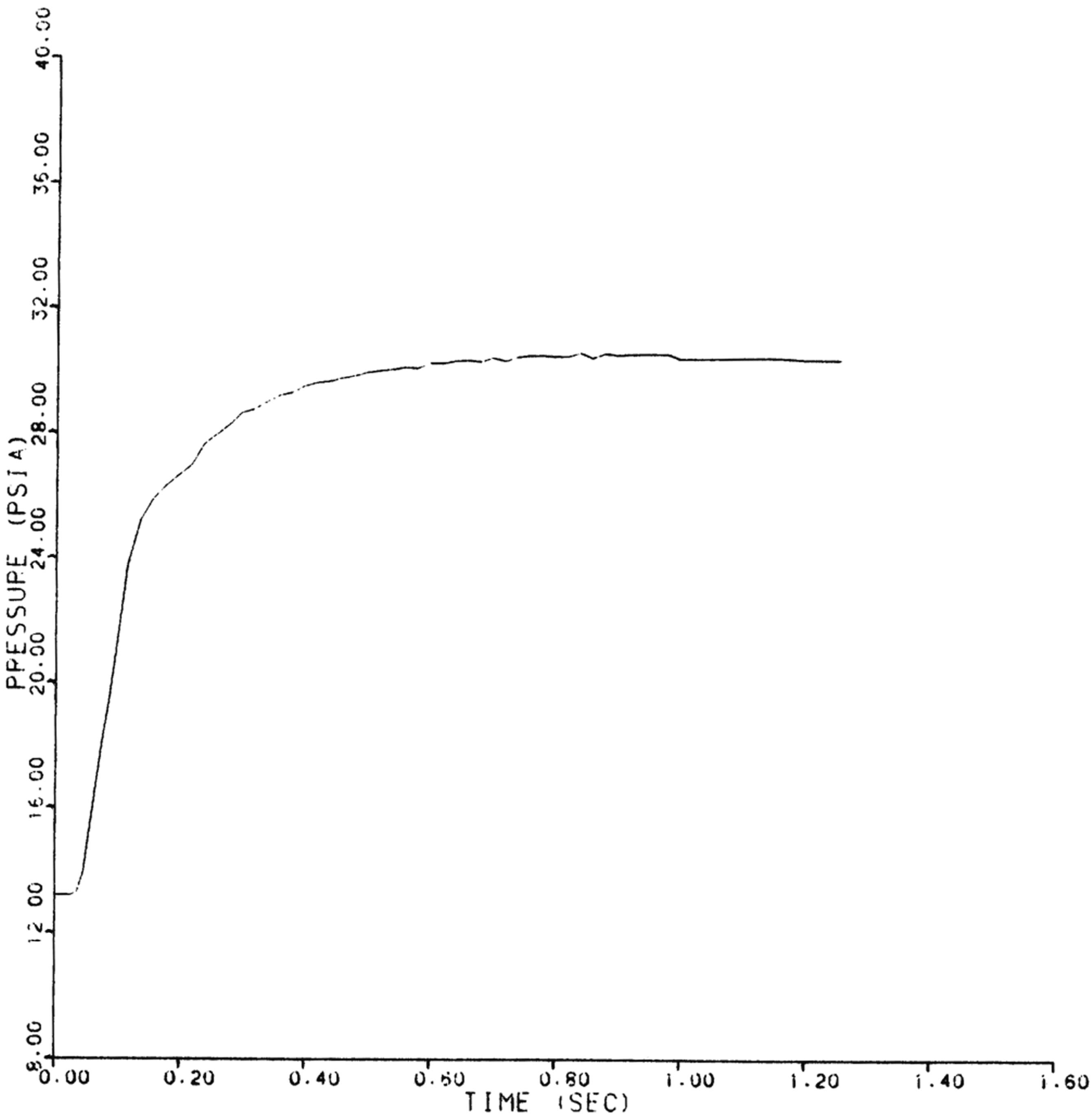
SOUTHERN COMPANY *Energy to Serve Your World®* VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	STEAM GENERATOR INLET ELBOW NODE – E9 (763–in.^{2} BREAK AREA)
	FIGURE 6.2.1–22 (SHEET 9 OF 74)



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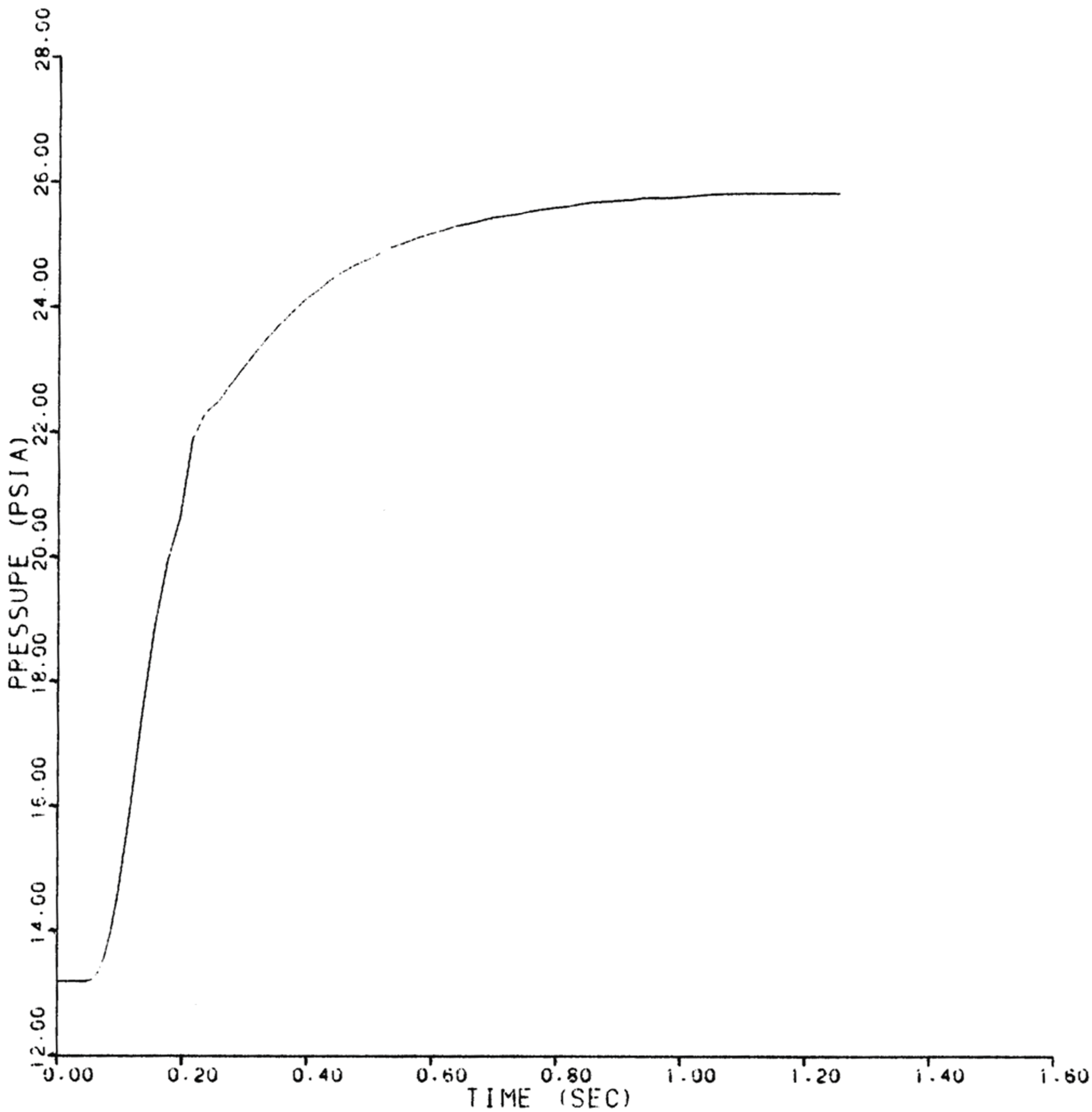
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E10
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 10 OF 74)



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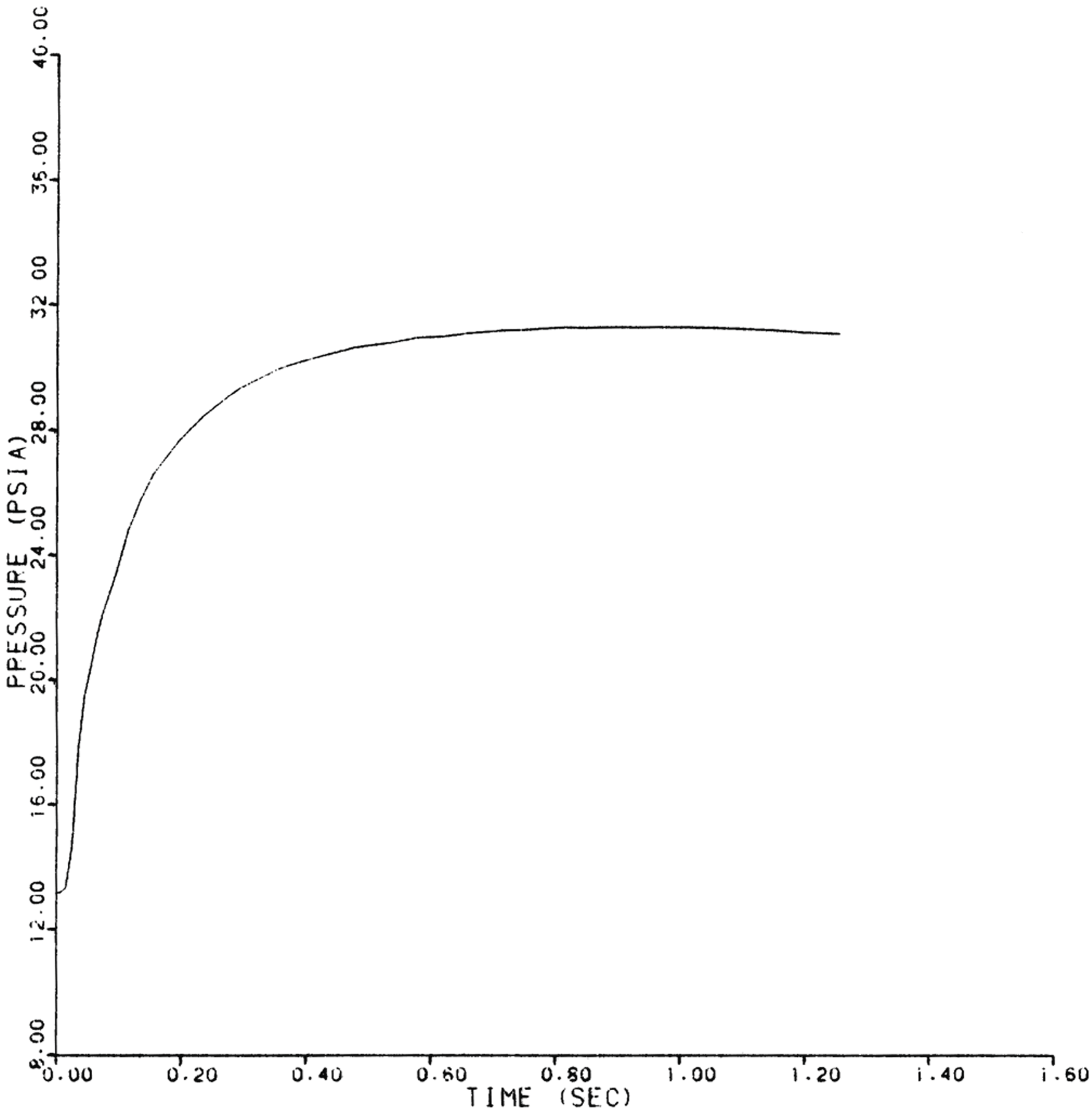
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E11
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 11 OF 74)



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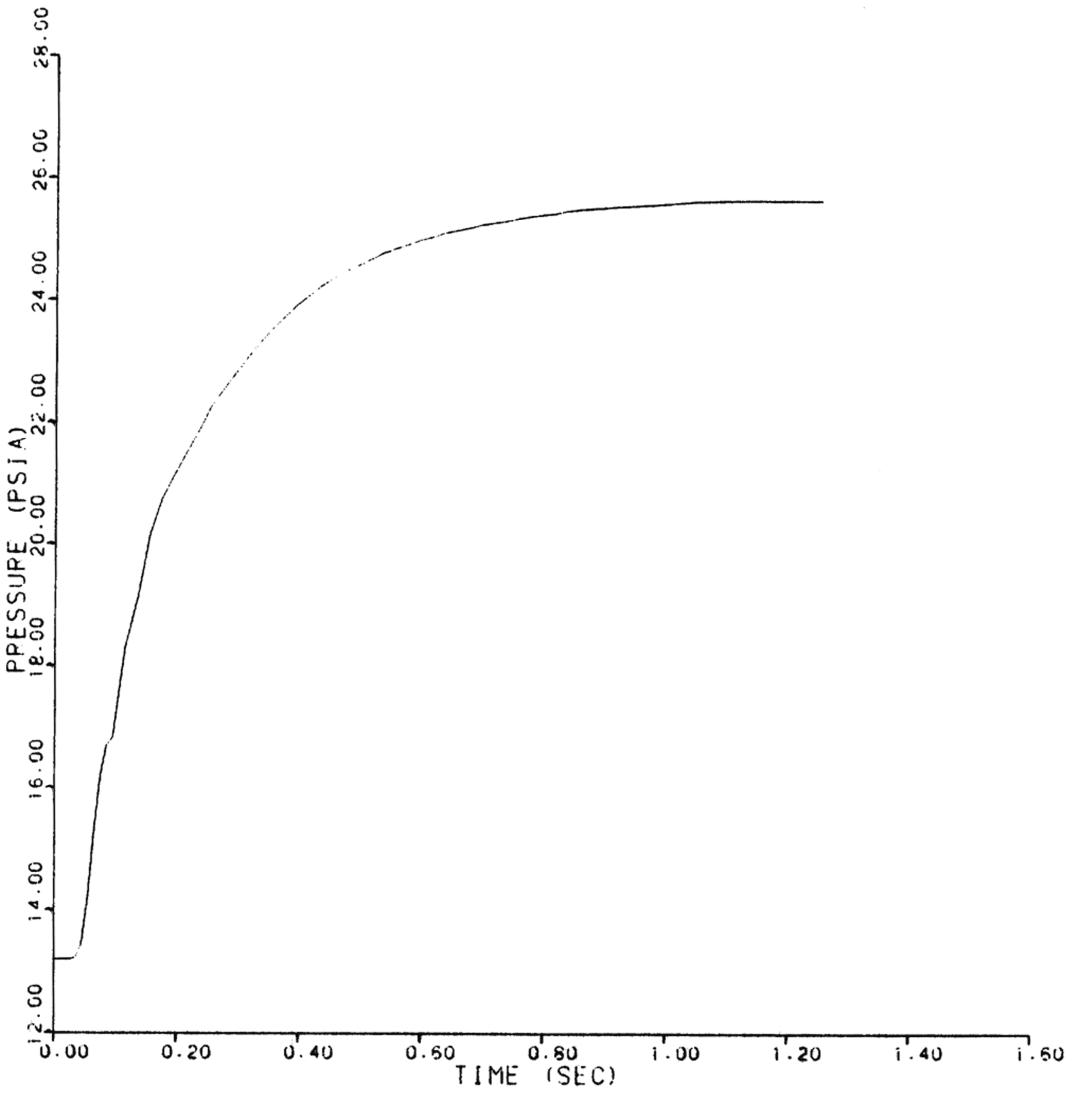
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E12
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 12 OF 74)



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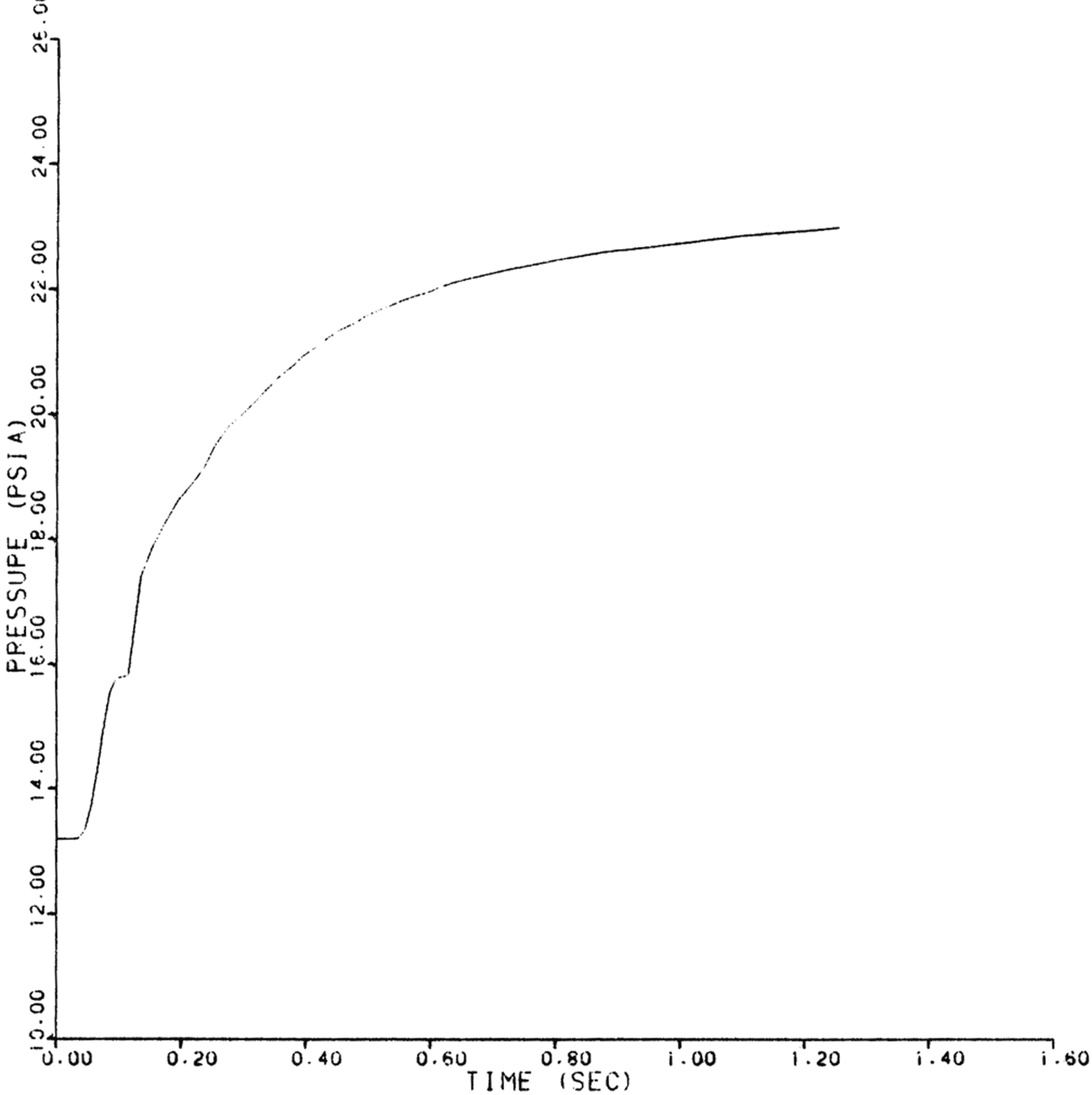
SOUTHERN COMPANY *Energy to Serve Your World®* VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	STEAM GENERATOR INLET ELBOW NODE – E13 (763–in.^{2} BREAK AREA)
	FIGURE 6.2.1–22 (SHEET 13 OF 74)



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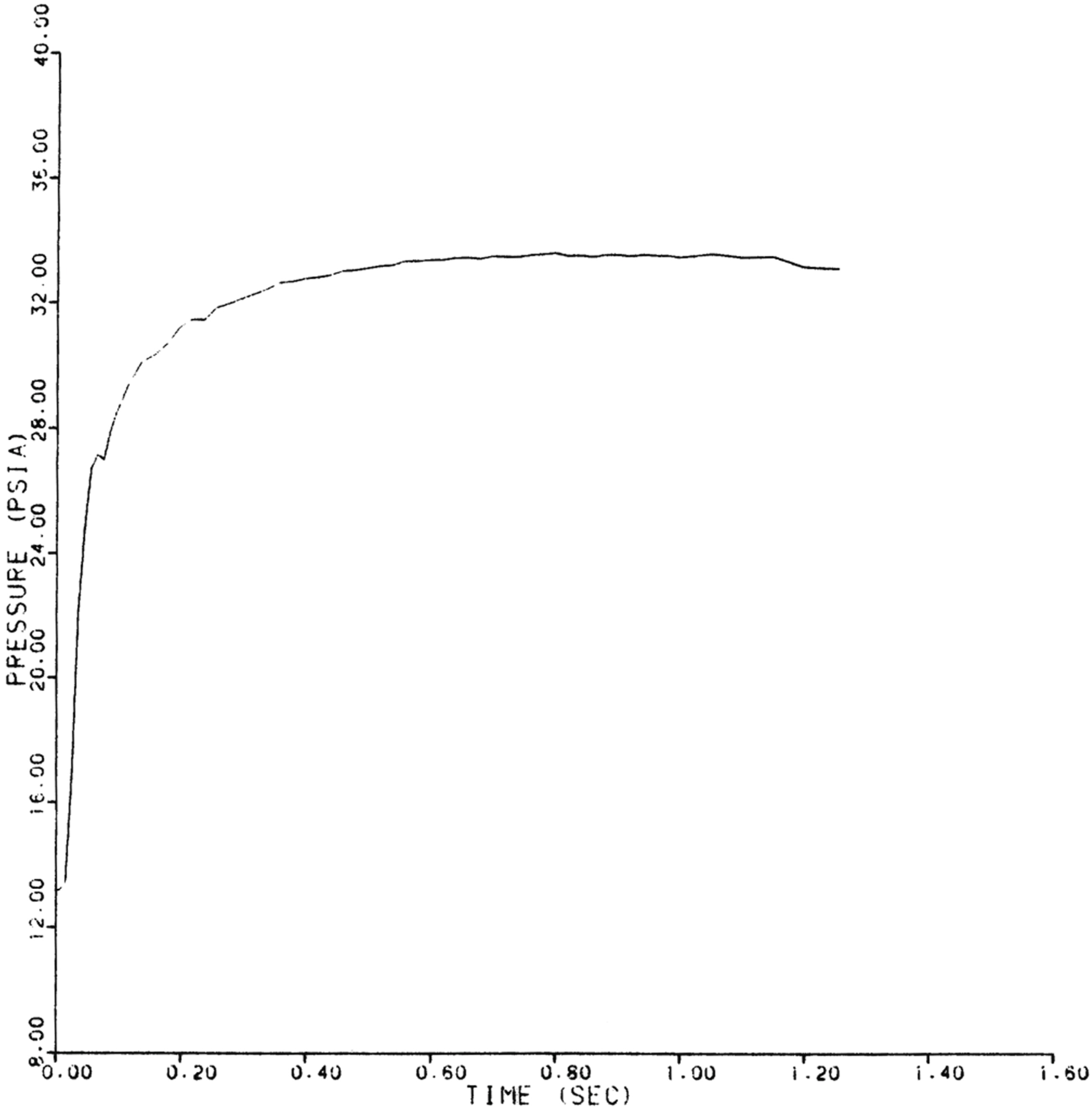
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E14
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 14 OF 74)



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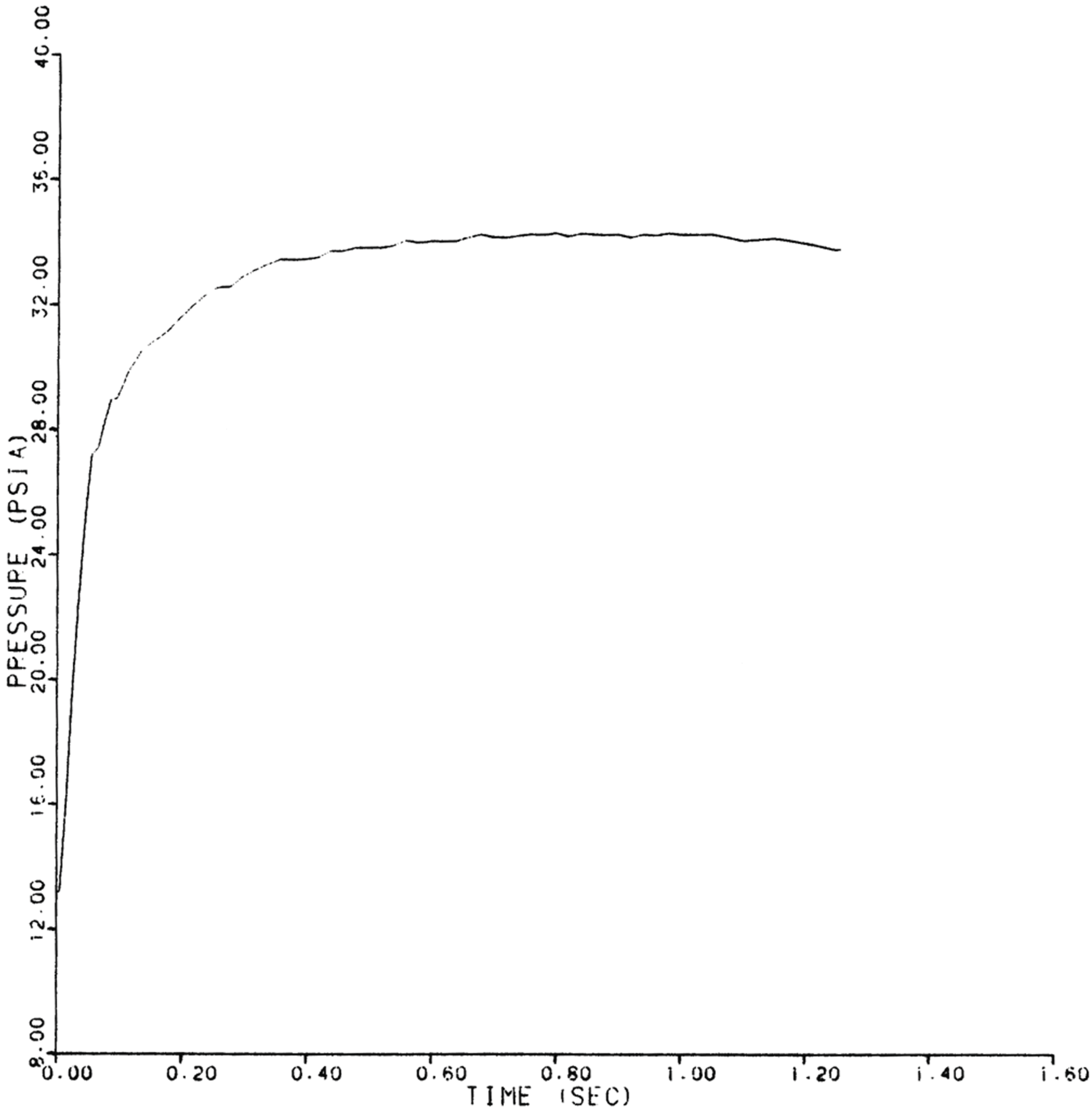
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E15
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 15 OF 74)



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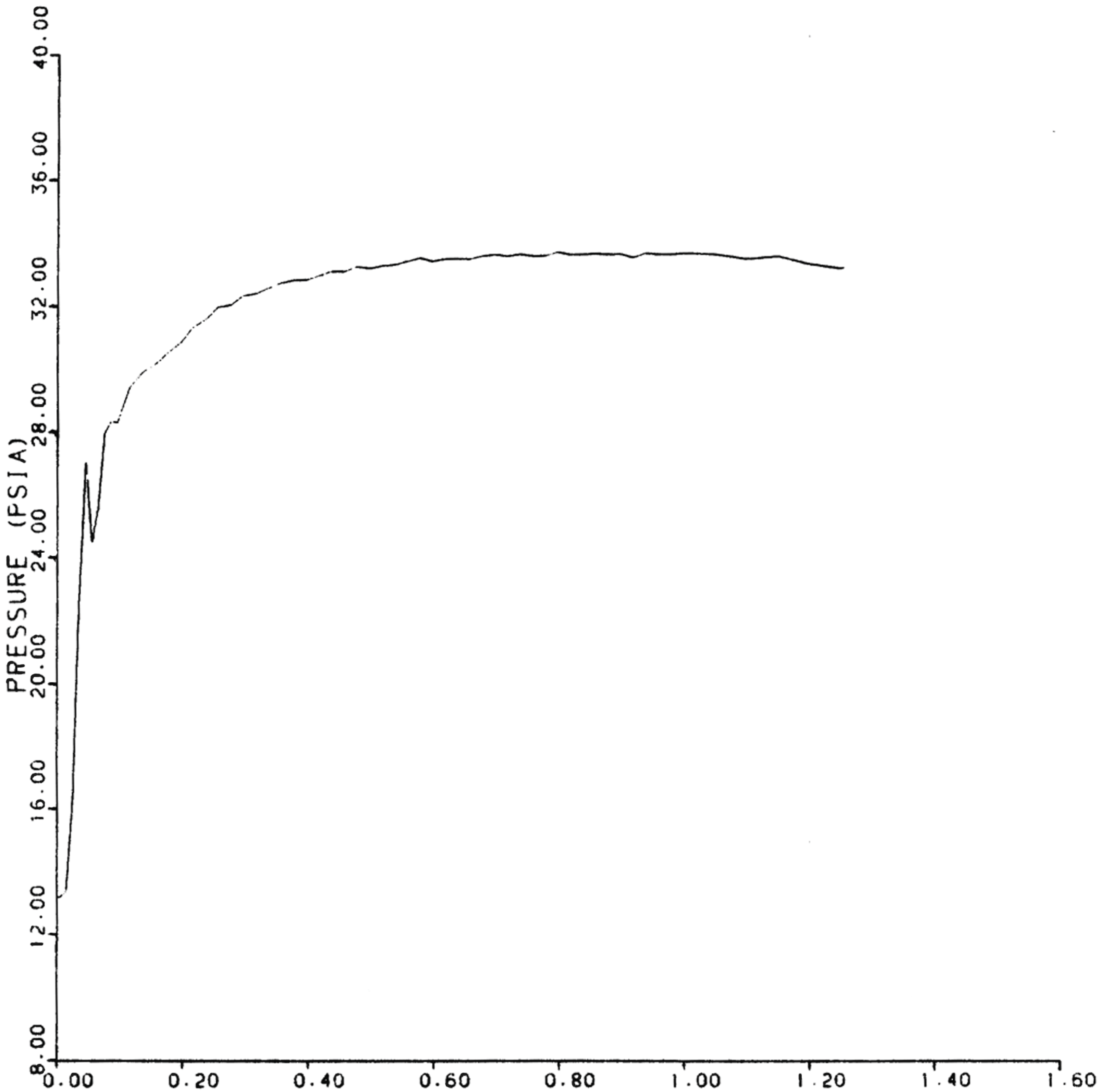
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E16
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 16 OF 74)



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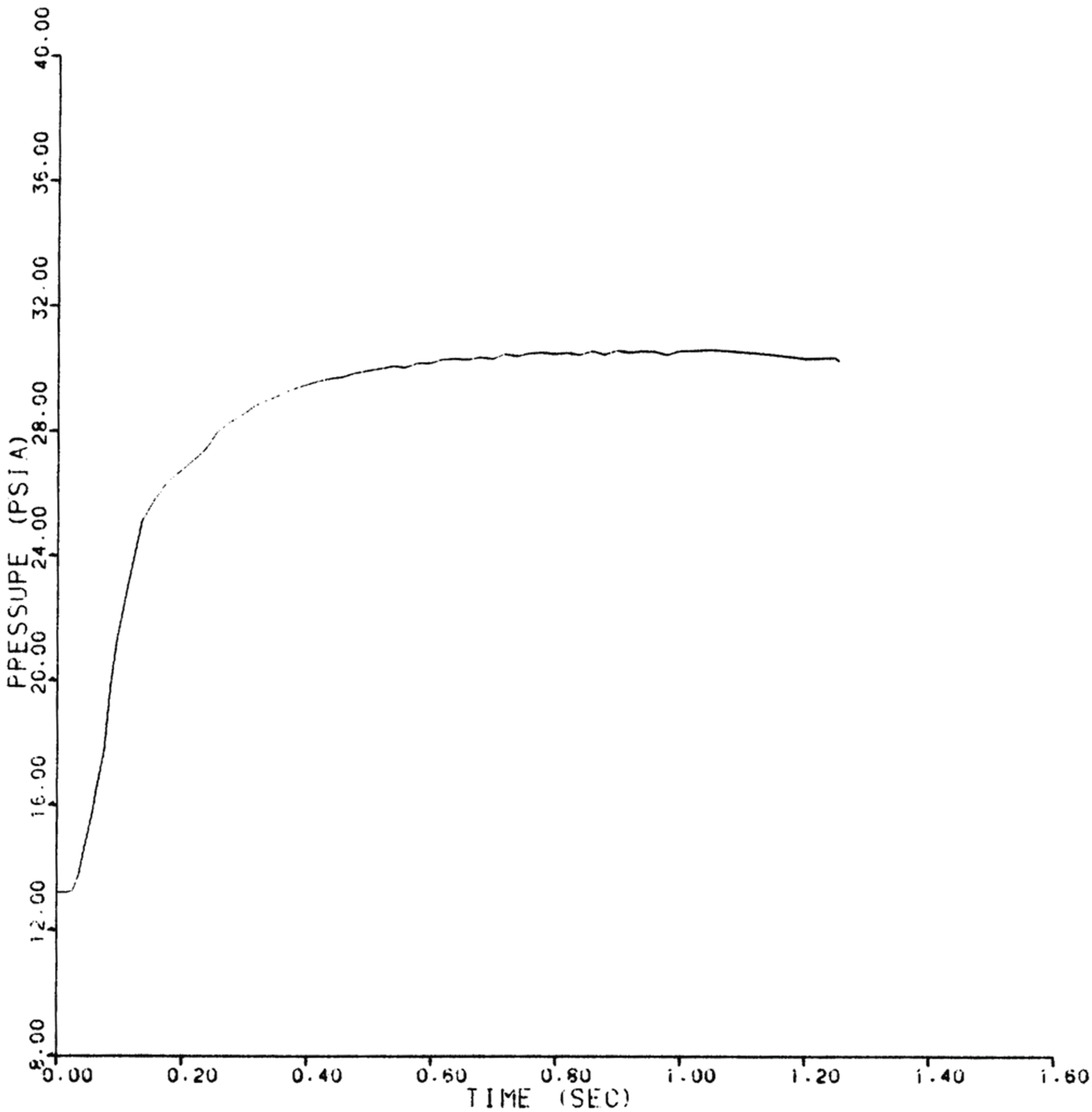
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E17
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 17 OF 74)



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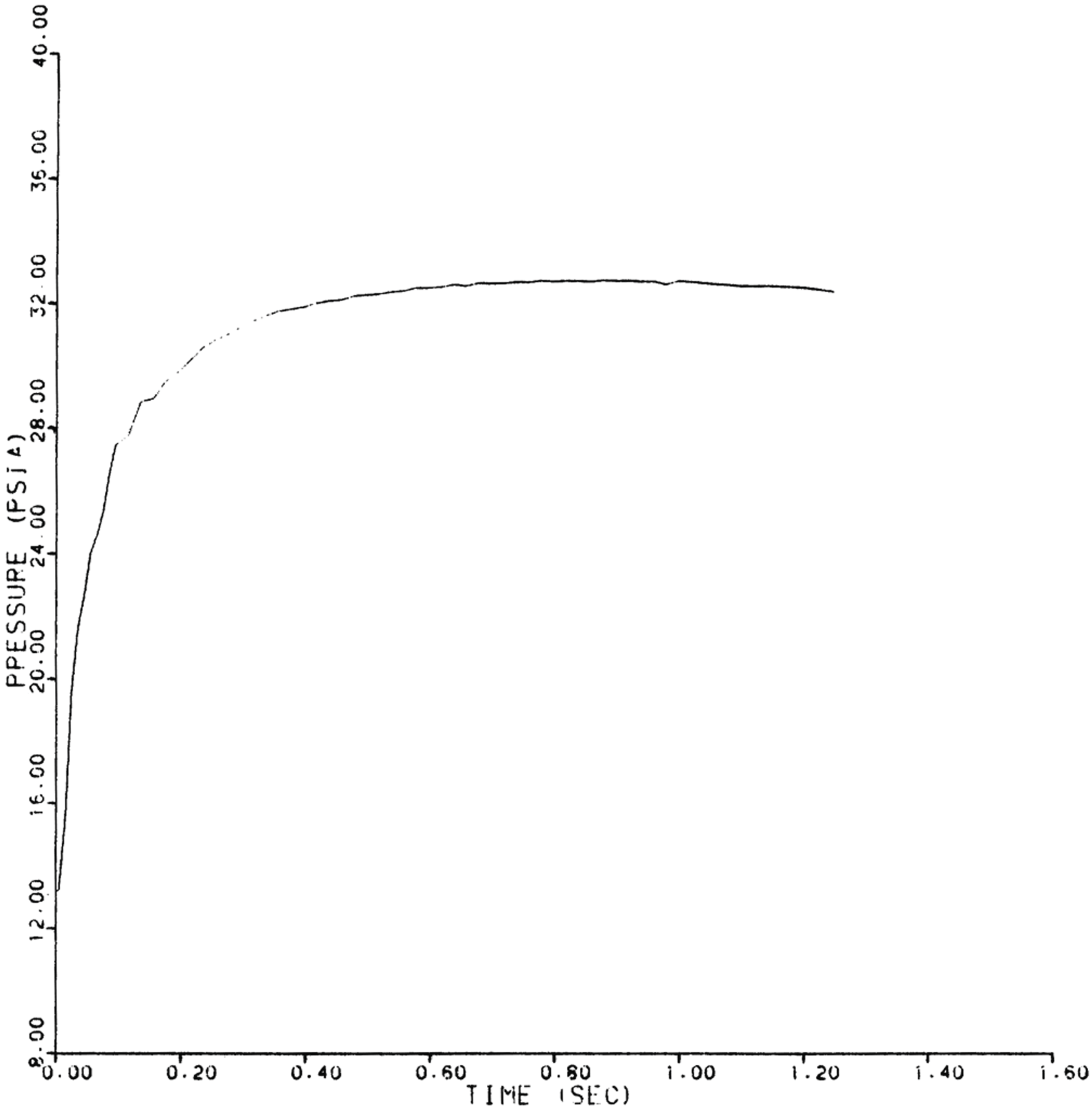
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E18
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 18 OF 74)



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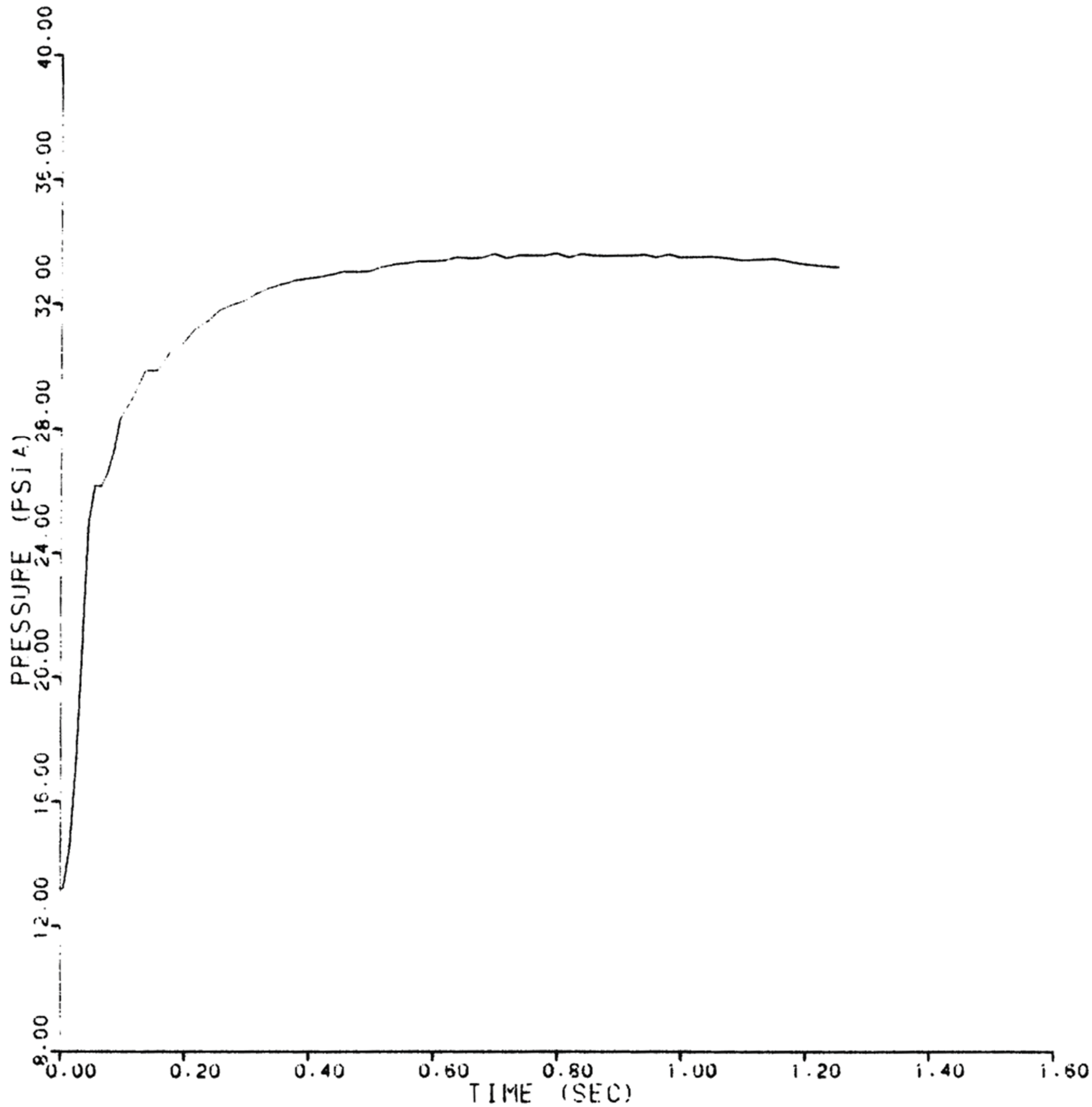
SOUTHERN COMPANY *Energy to Serve Your World®*	**VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2**	STEAM GENERATOR INLET ELBOW NODE – E19 (763–in.^{2} BREAK AREA)
		FIGURE 6.2.1–22 (SHEET 19 OF 74)



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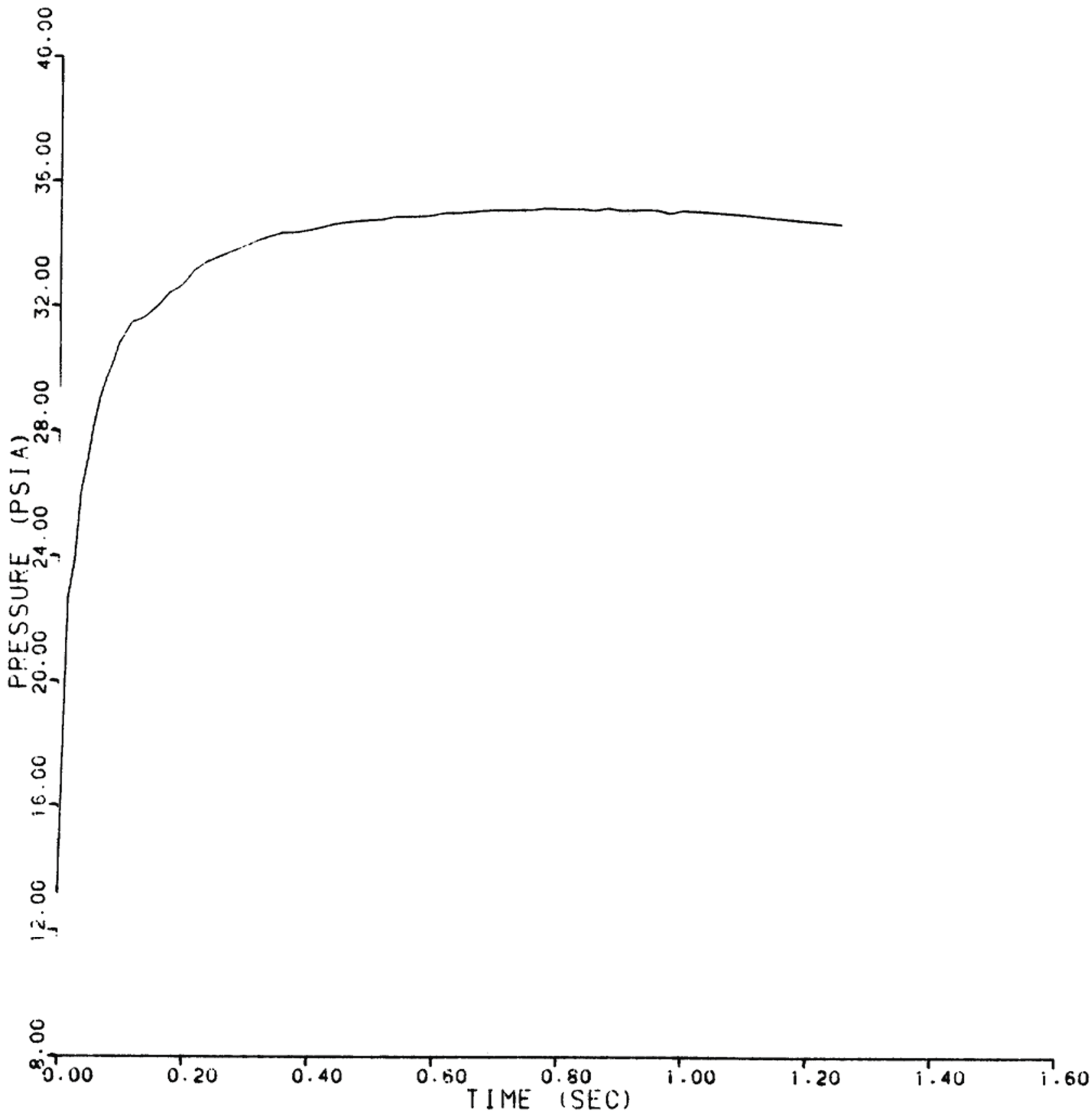
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E20
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 20 OF 74)



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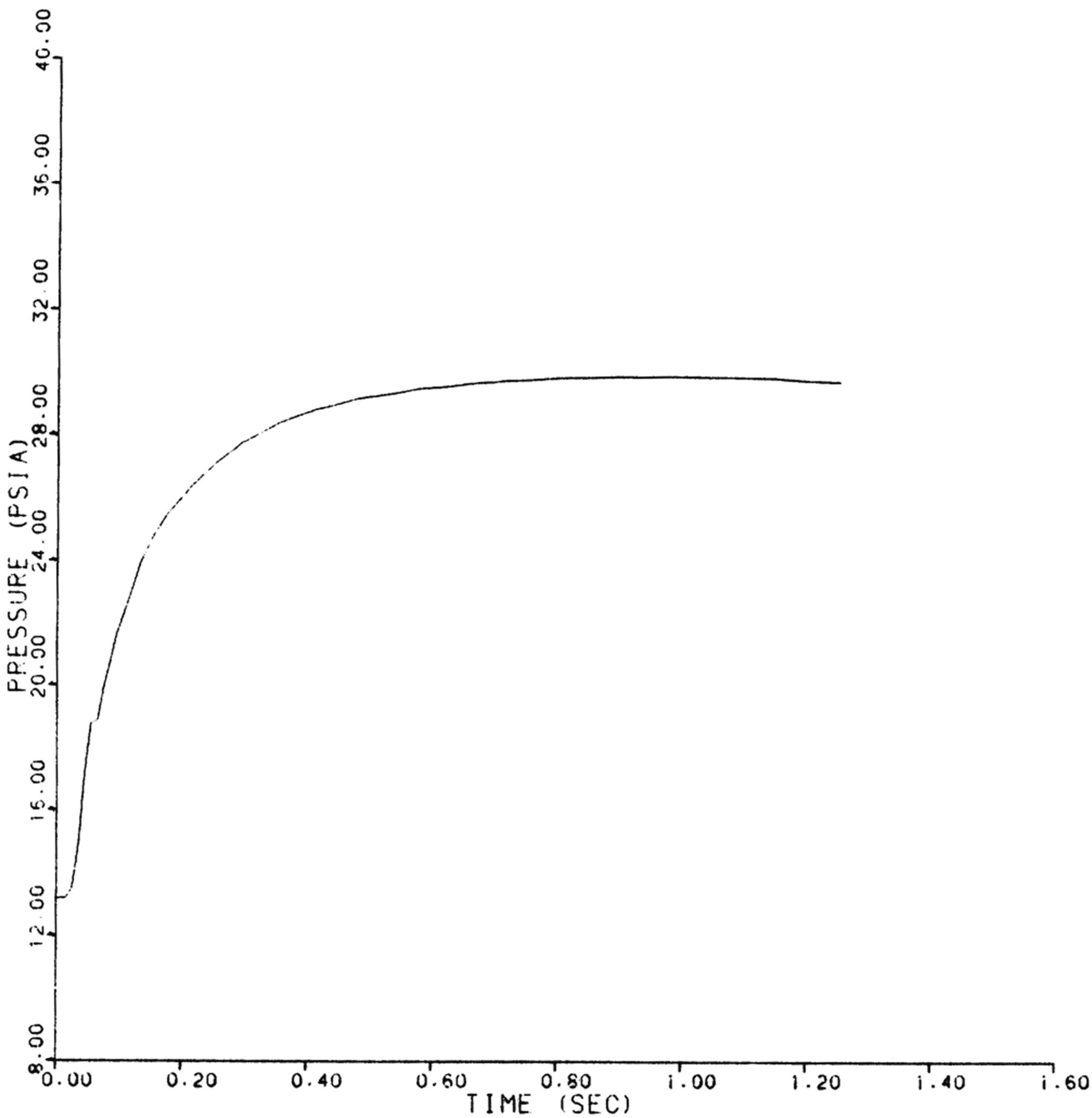
SOUTHERN COMPANY *Energy to Serve Your World®* **VOGTLE** **ELECTRIC GENERATING PLANT** **UNIT 1 AND UNIT 2**	STEAM GENERATOR INLET ELBOW NODE – E21 (763–in.^{2} BREAK AREA)
	FIGURE 6.2.1–22 (SHEET 21 OF 74)



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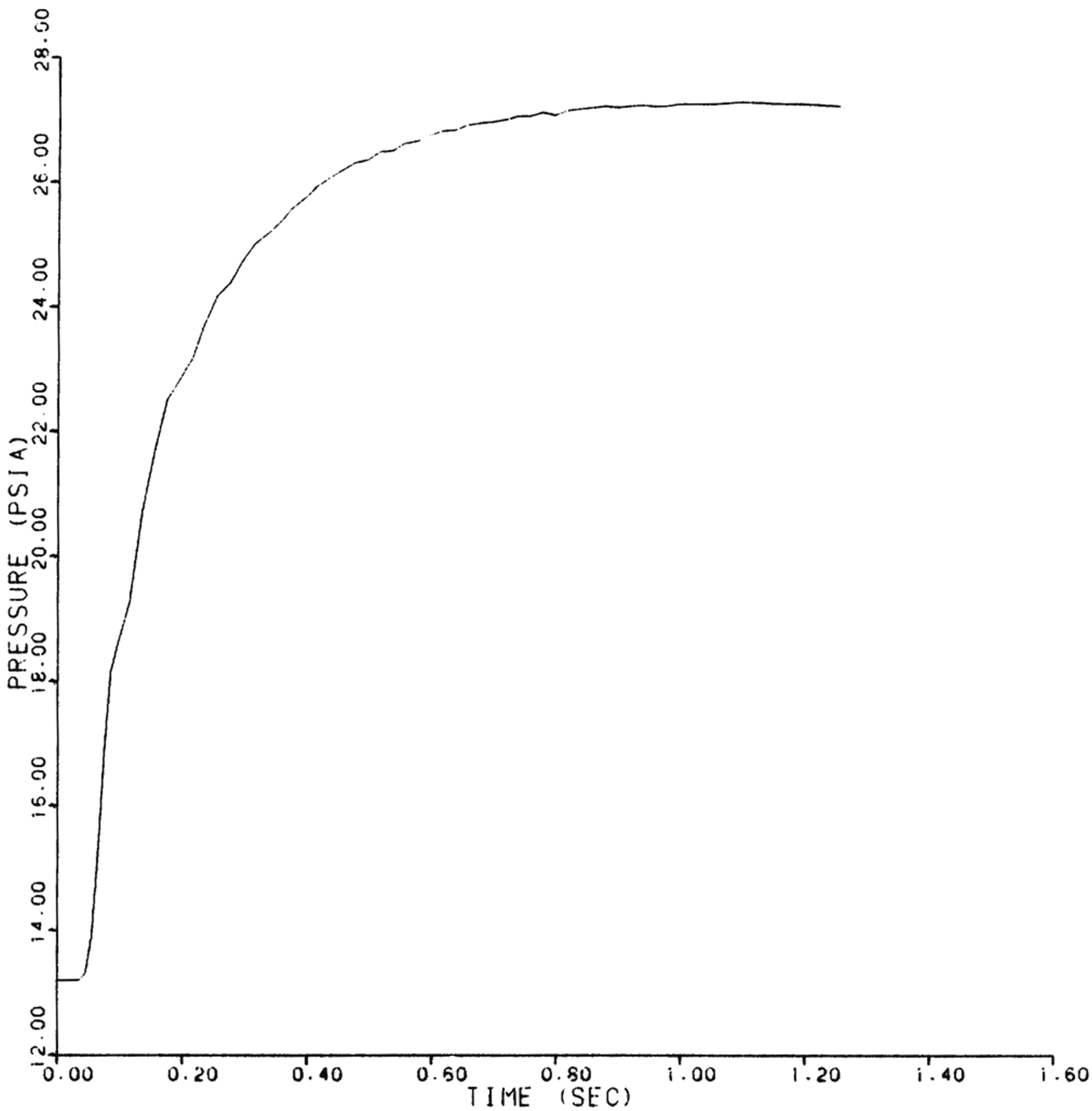
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E22
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 22 OF 74)



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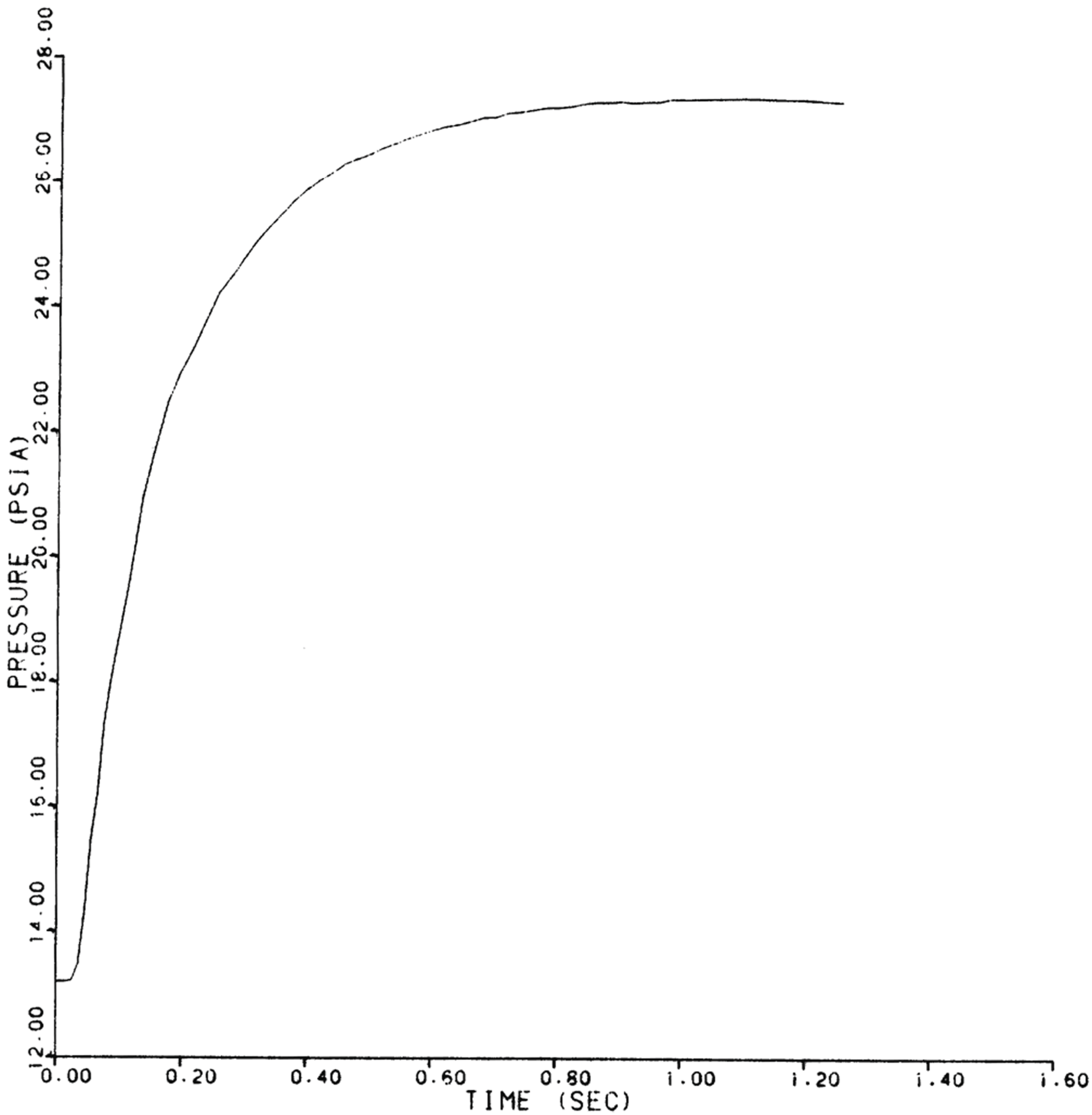
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E23
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 23 OF 74)



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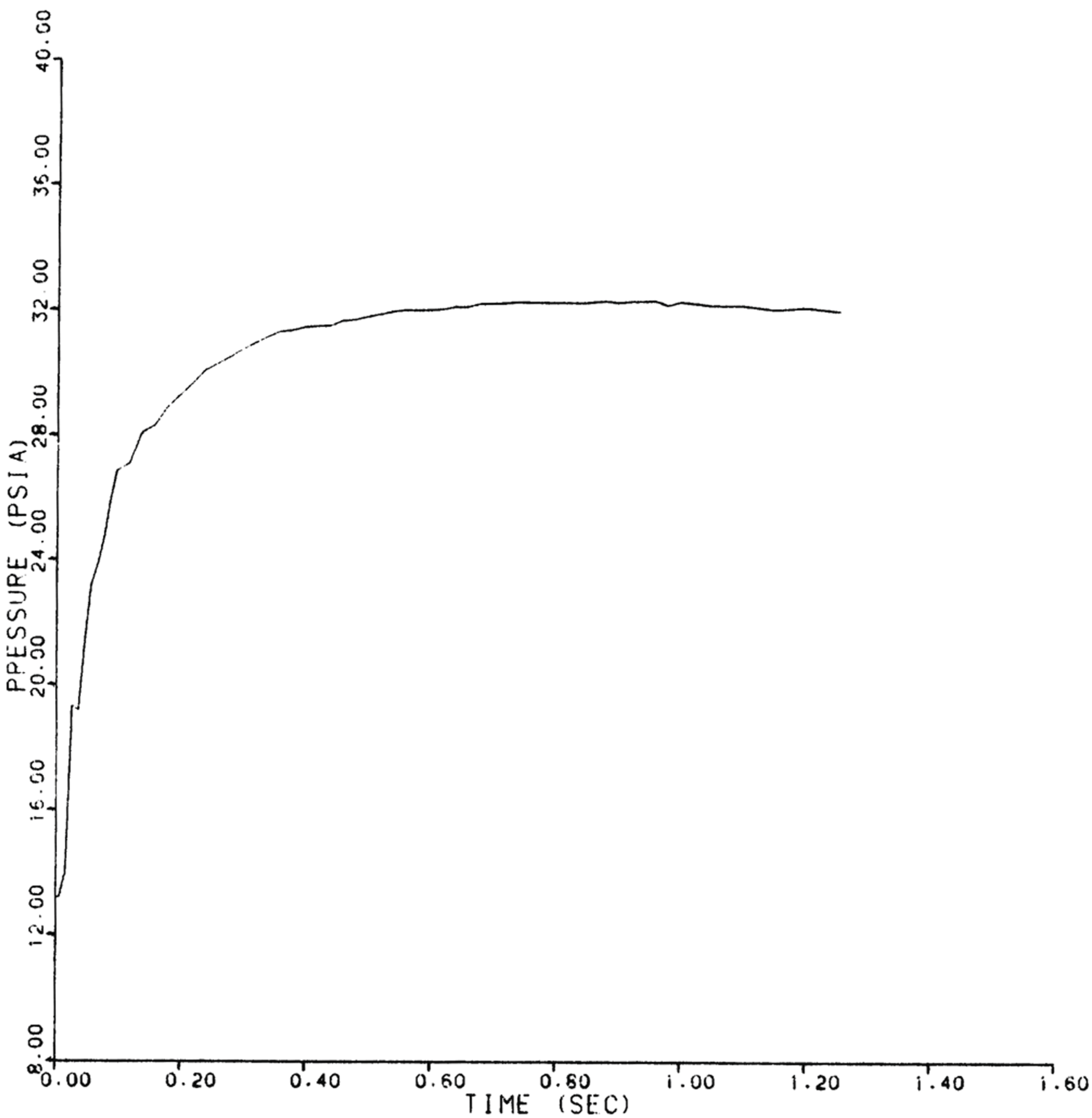
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E24
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 24 OF 74)



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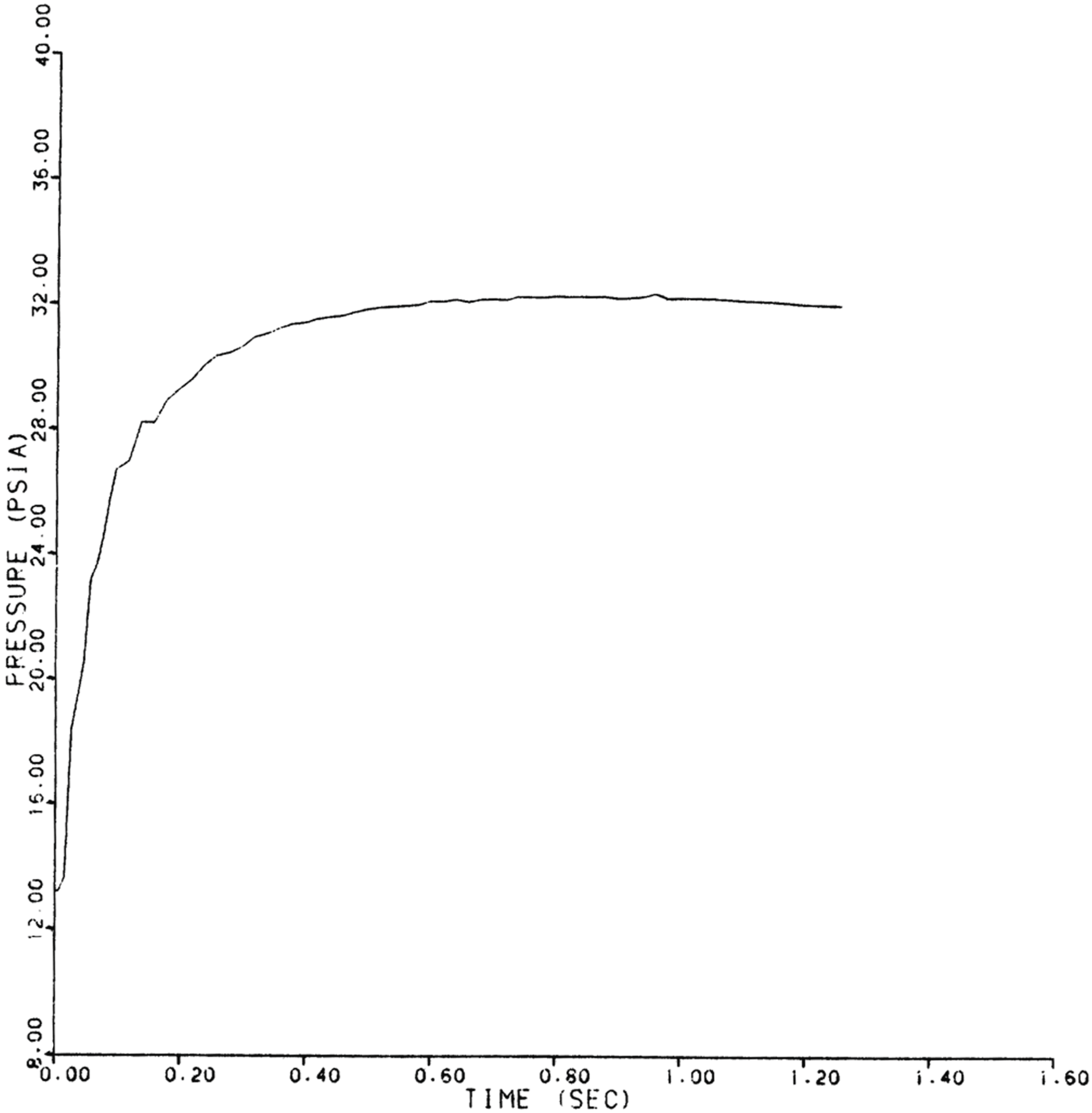
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E25
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 25 OF 74)



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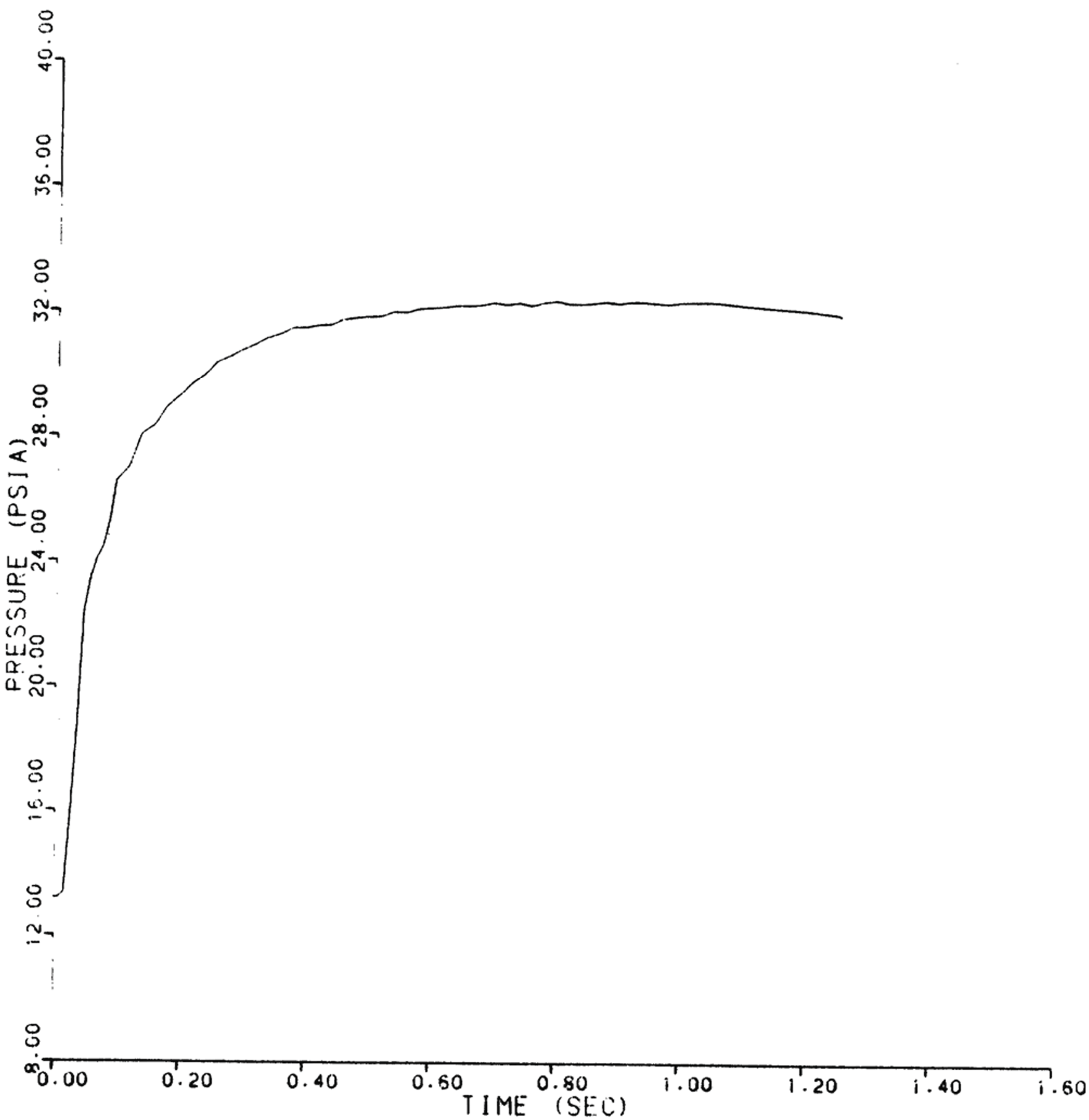
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E26
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 26 OF 74)



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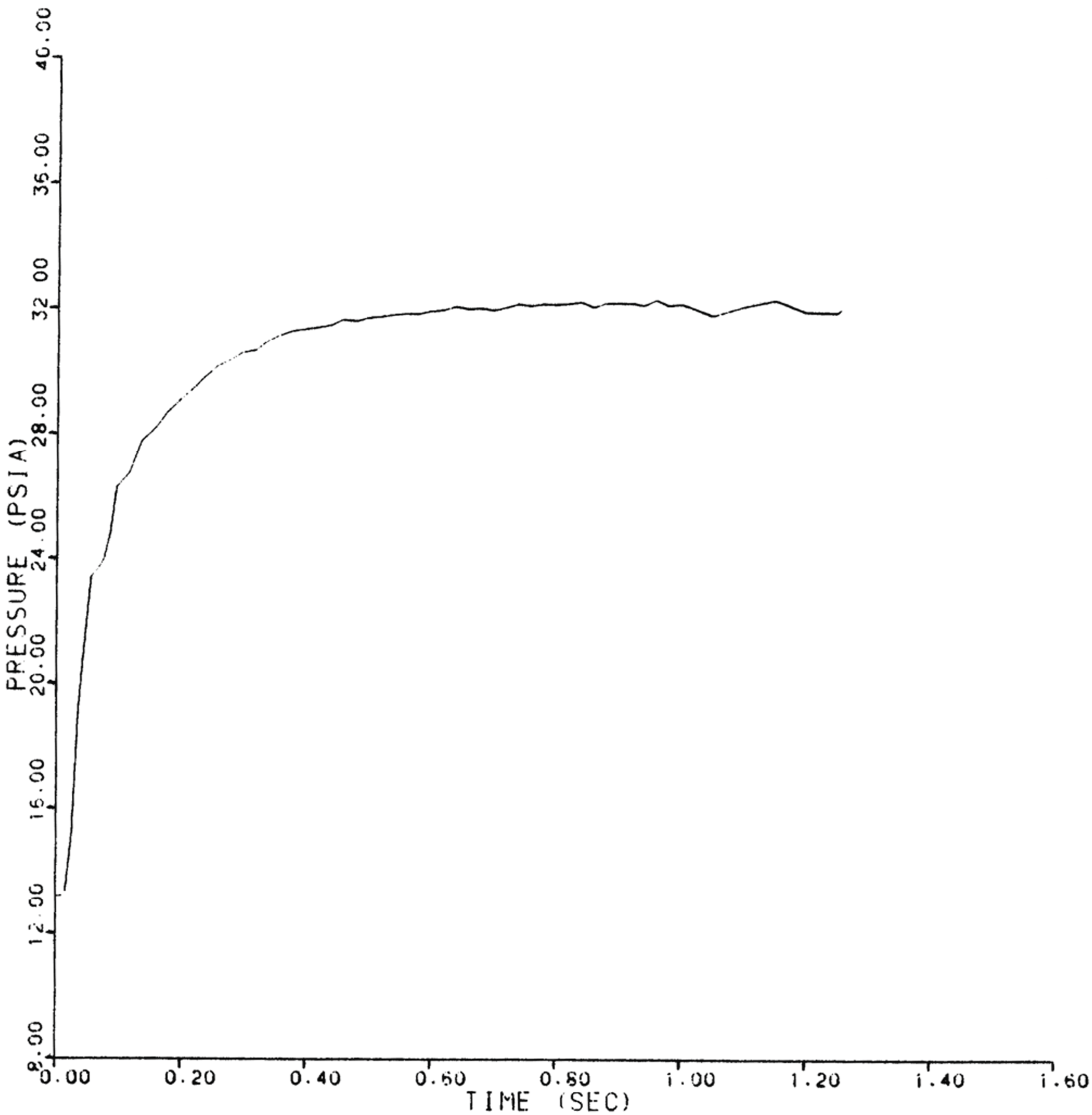
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E27
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 27 OF 74)



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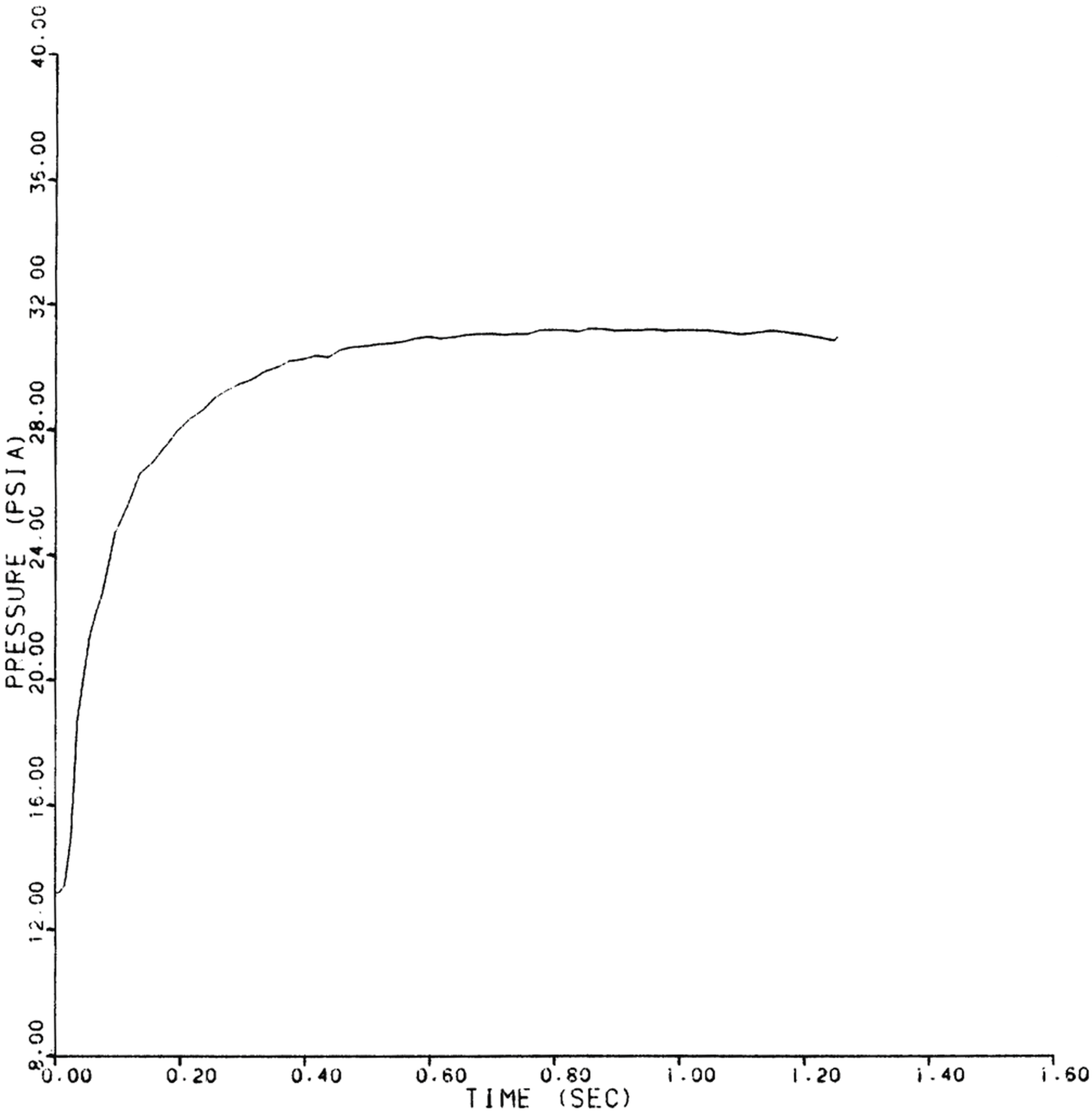
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E28
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 28 OF 74)



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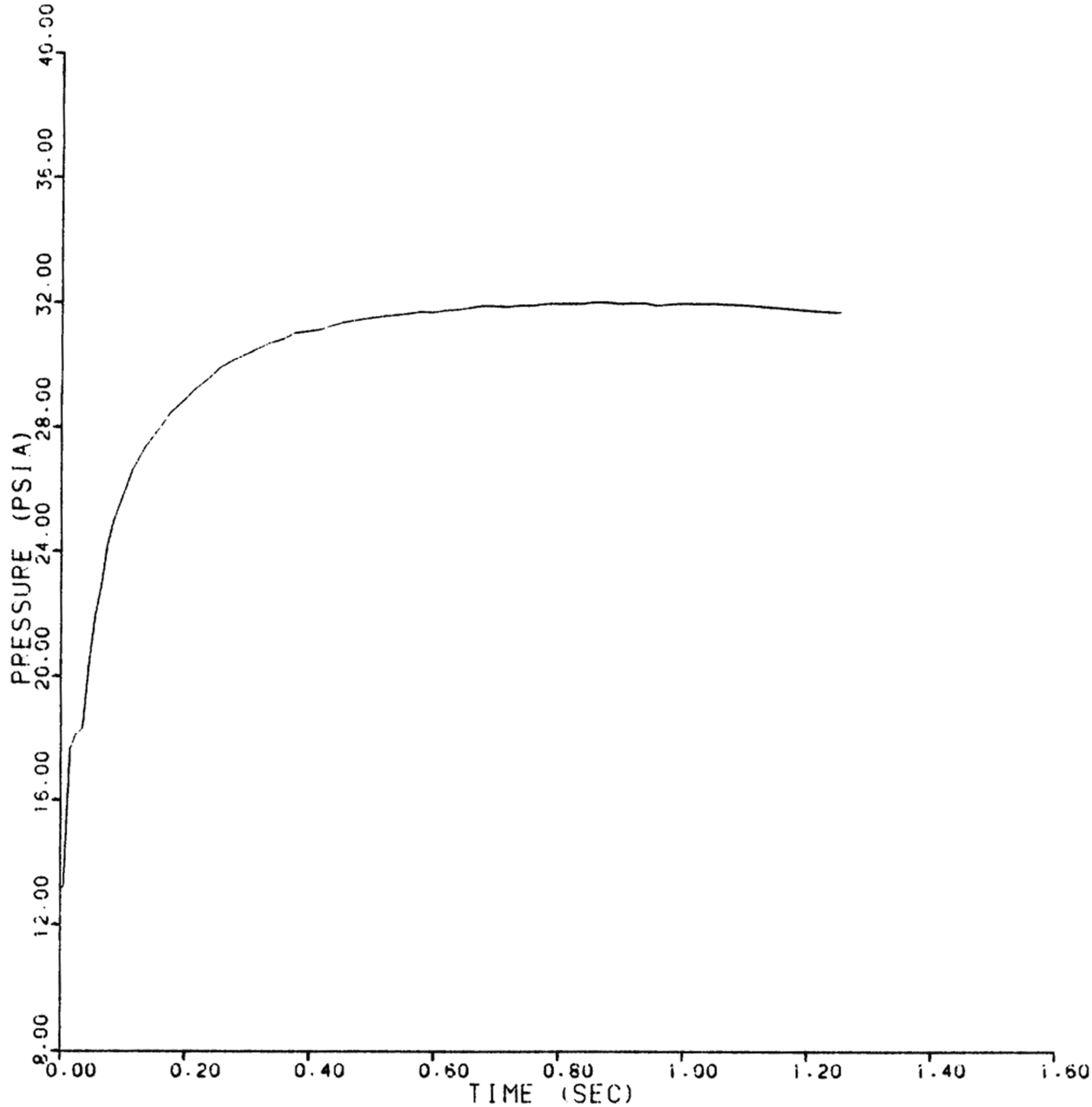
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E29
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 29 OF 74)



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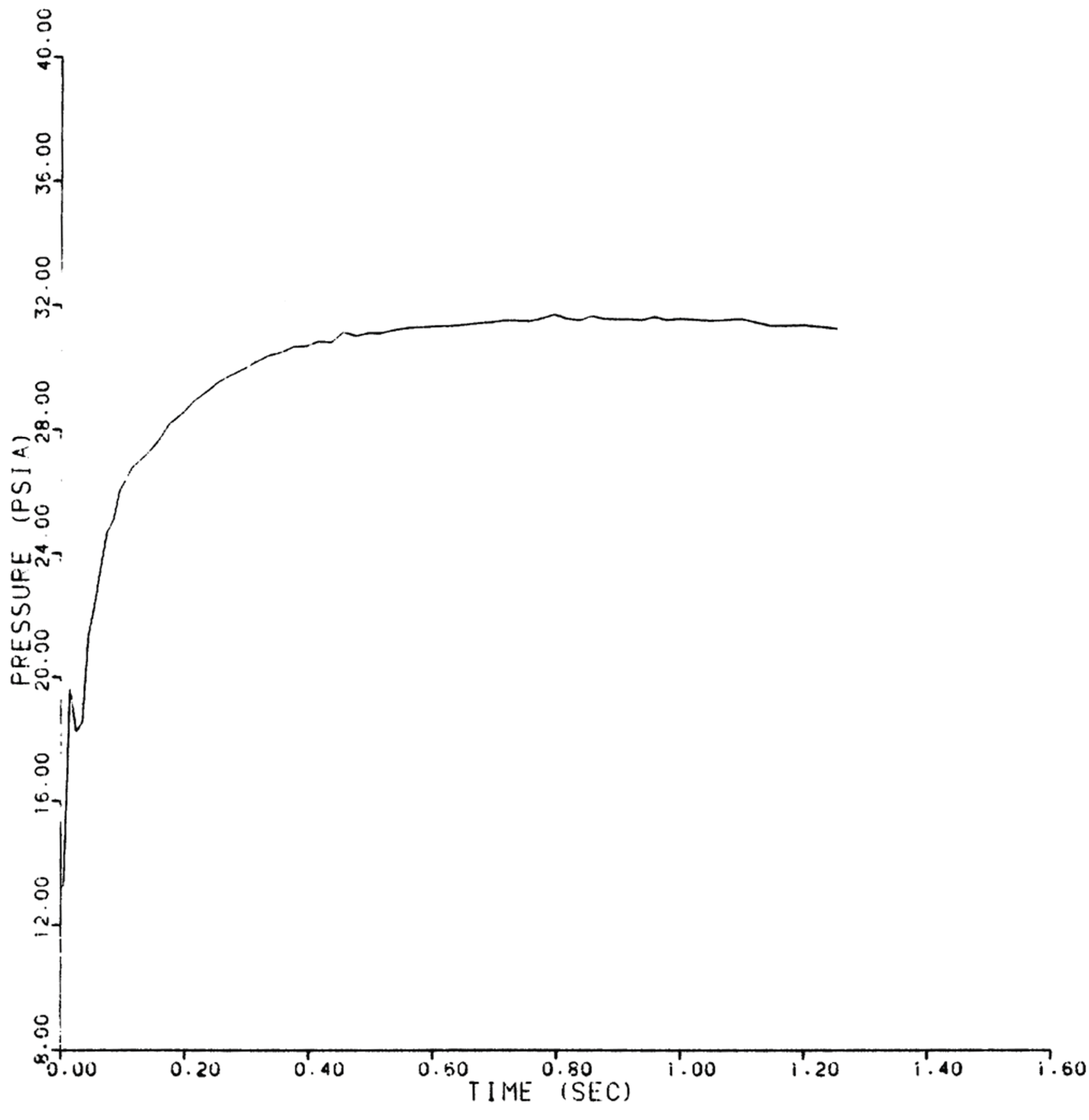
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E30
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 30 OF 74)



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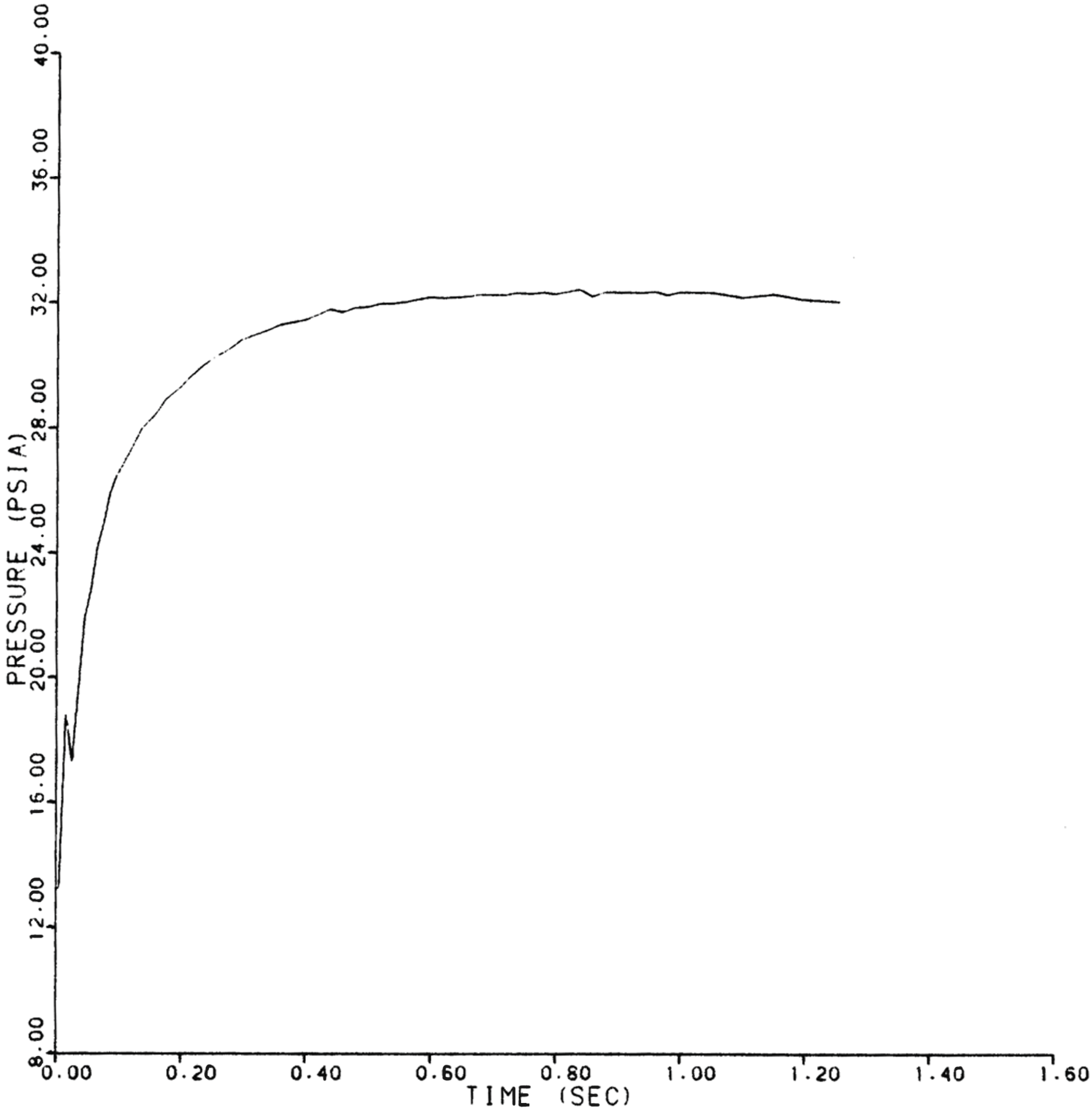
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E31
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 31 OF 74)



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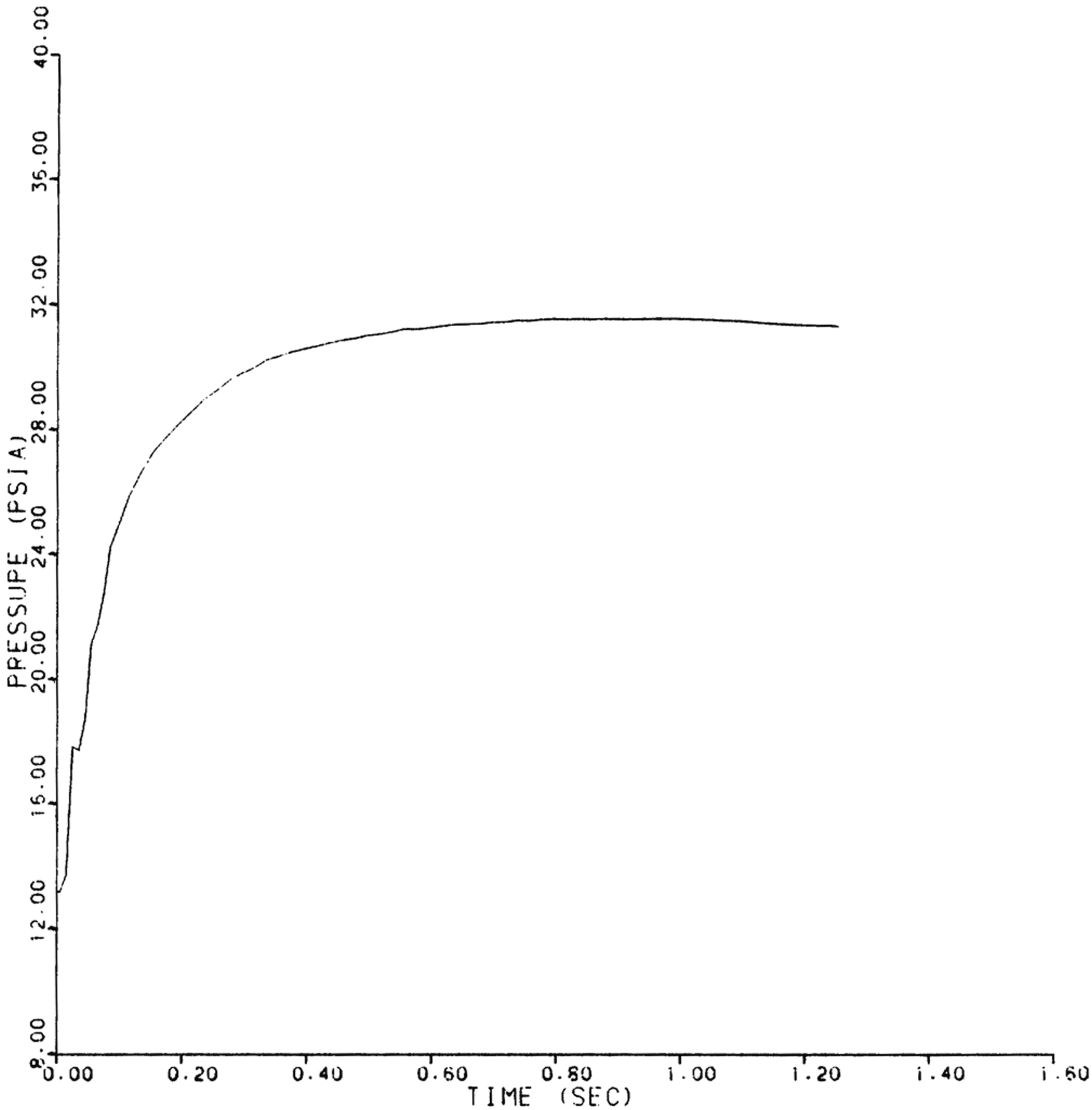
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E32
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 32 OF 74)



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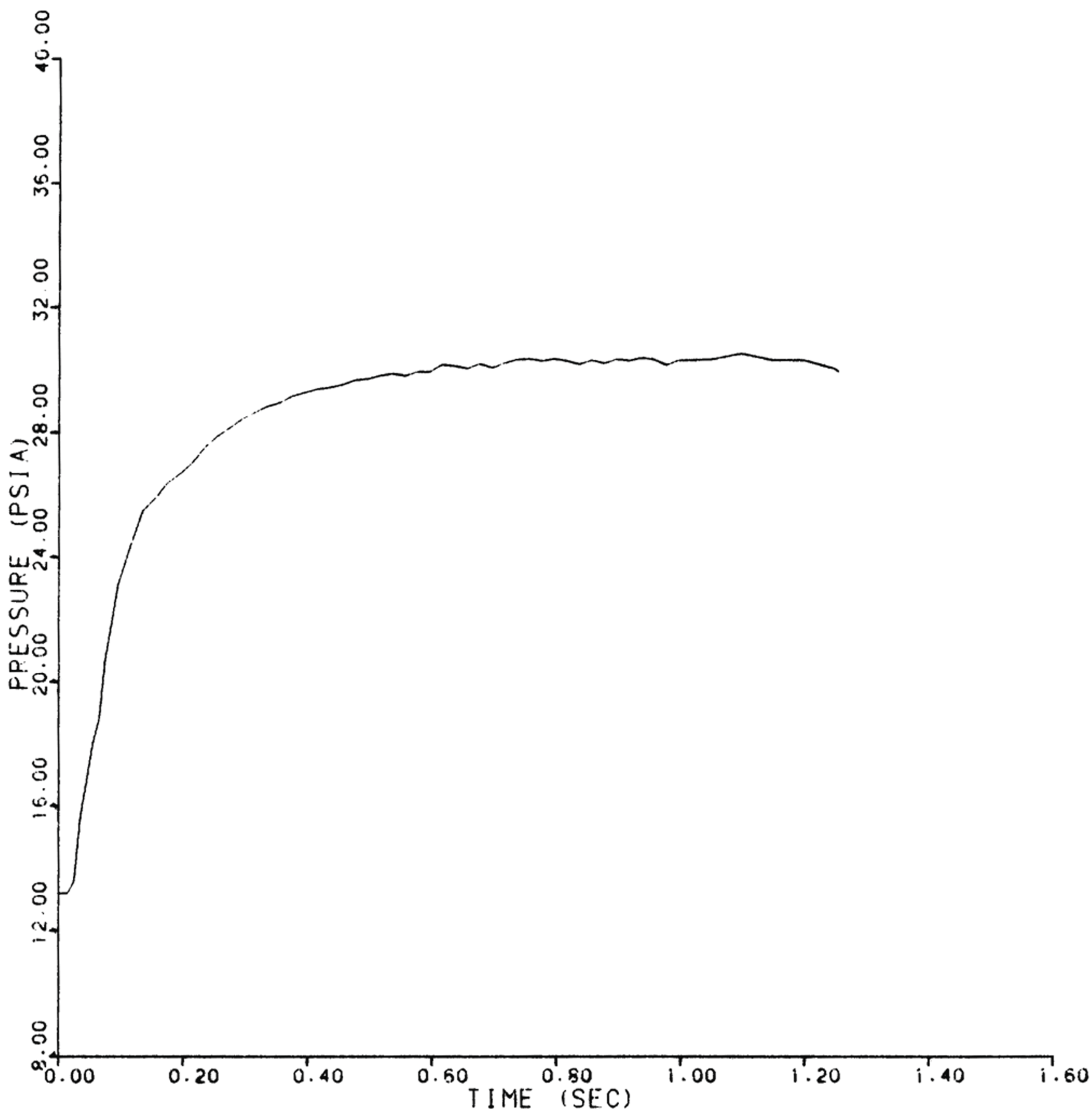
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E33
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 33 OF 74)



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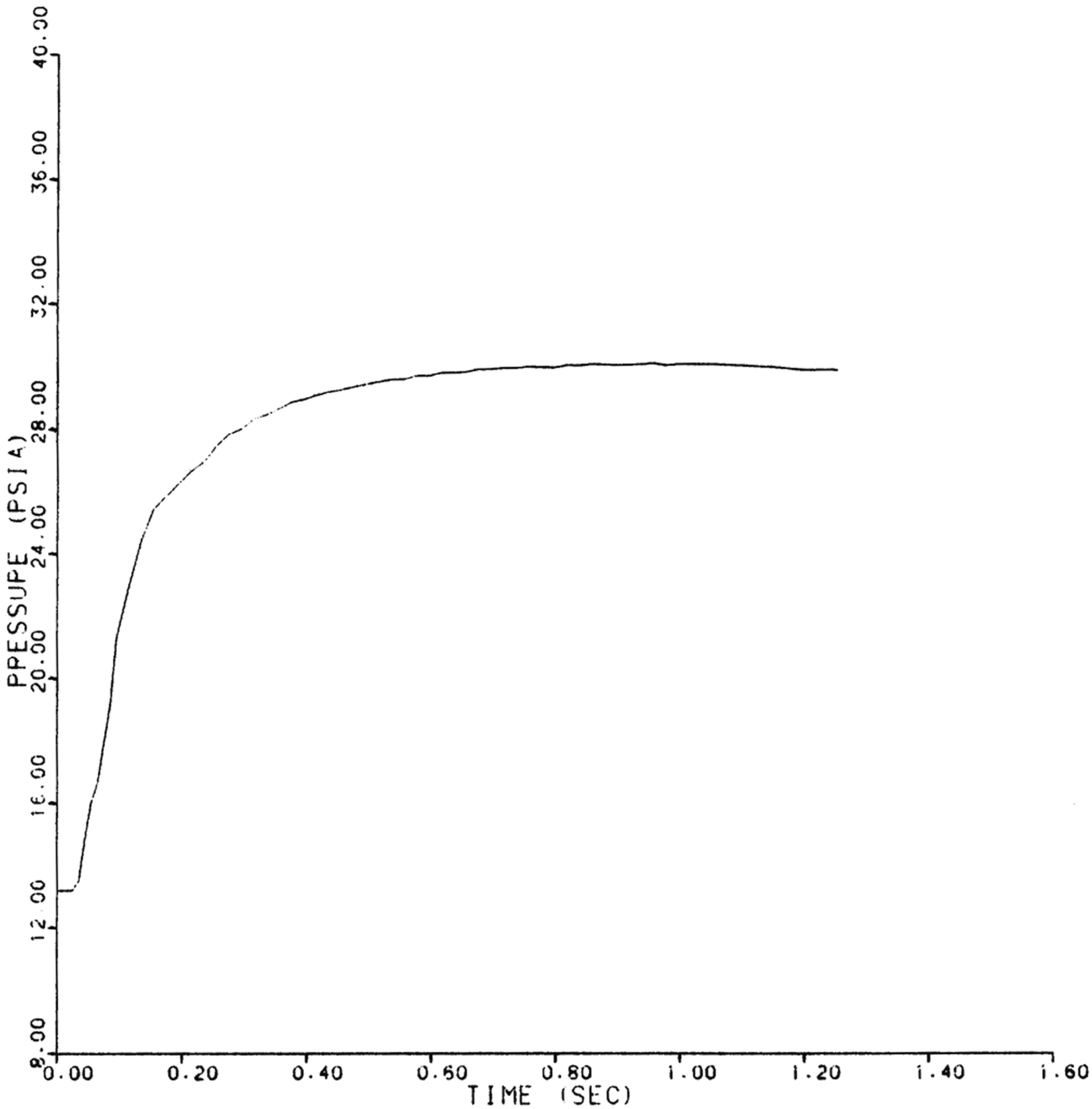
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E34
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 34 OF 74)



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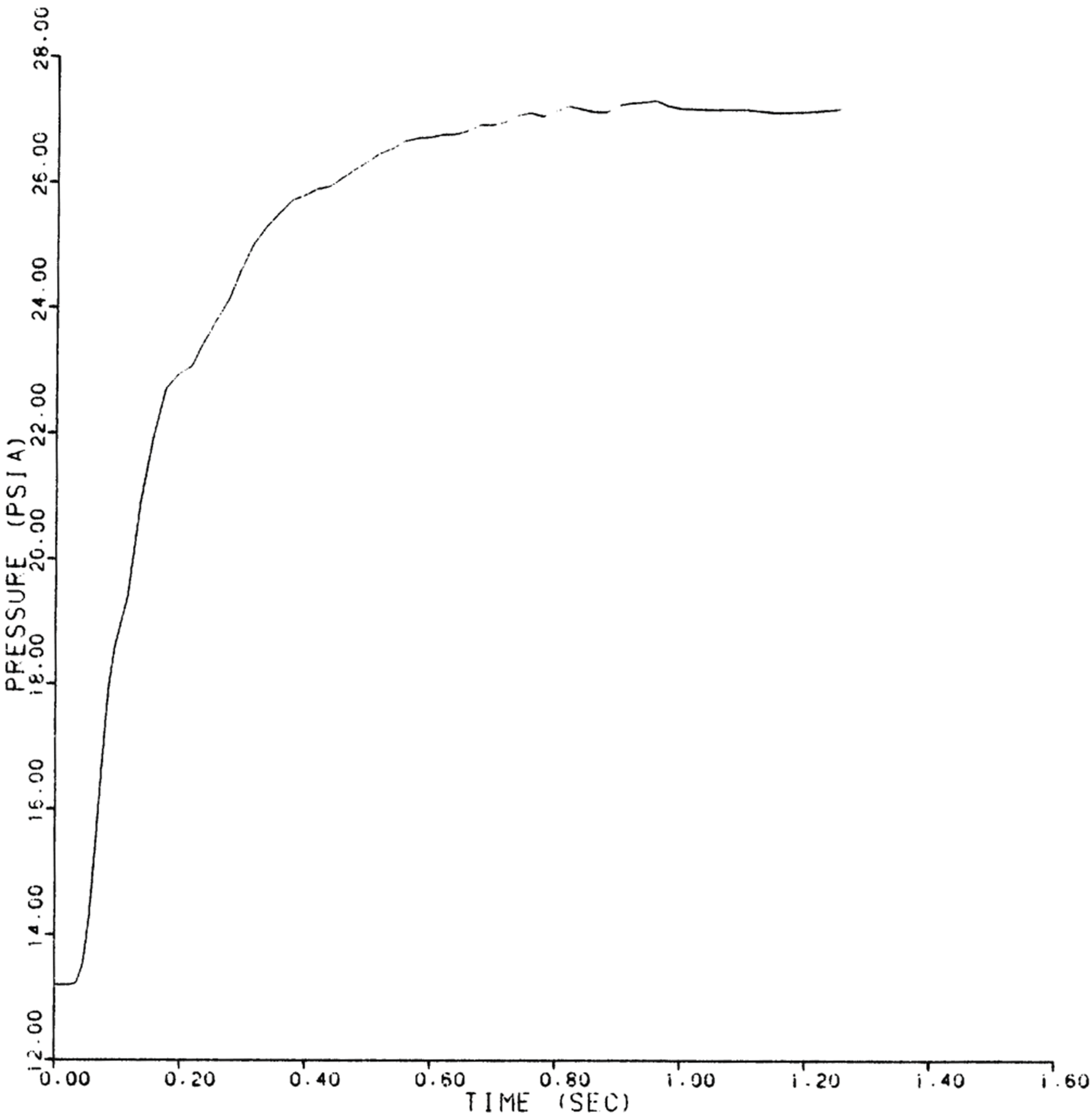
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E35
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 35 OF 74)



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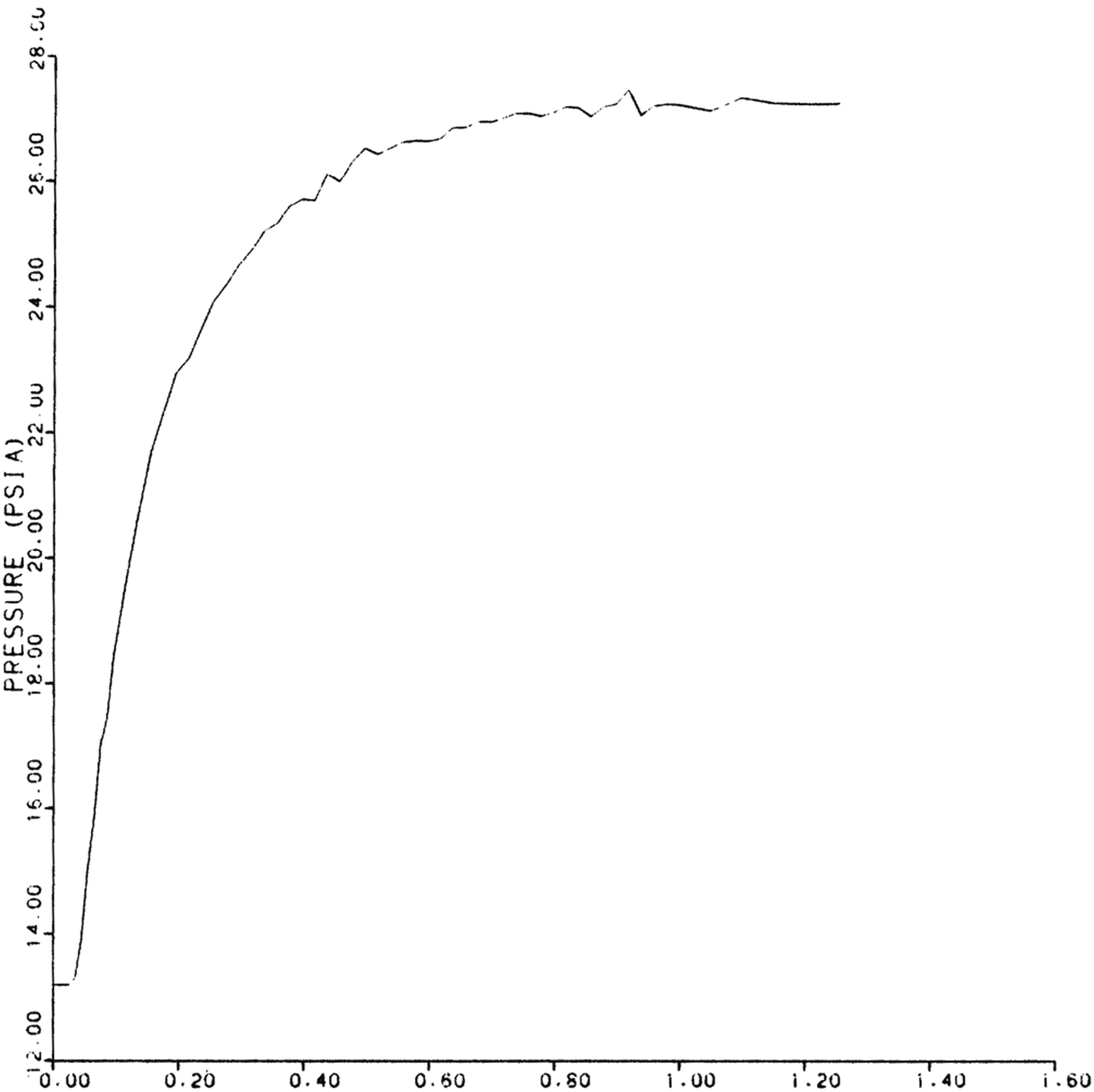
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E36
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 36 OF 74)



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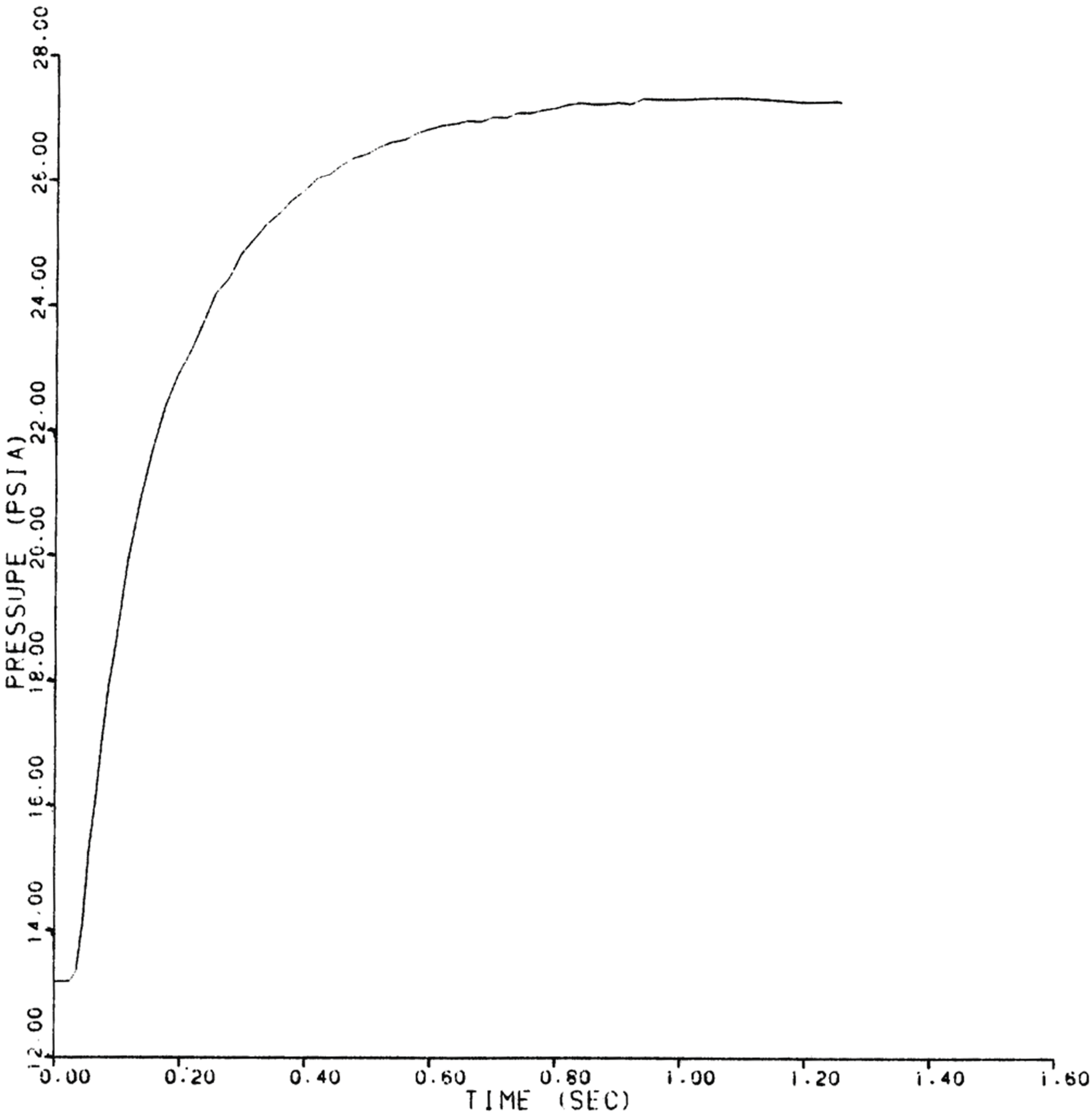
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E37
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 37 OF 74)



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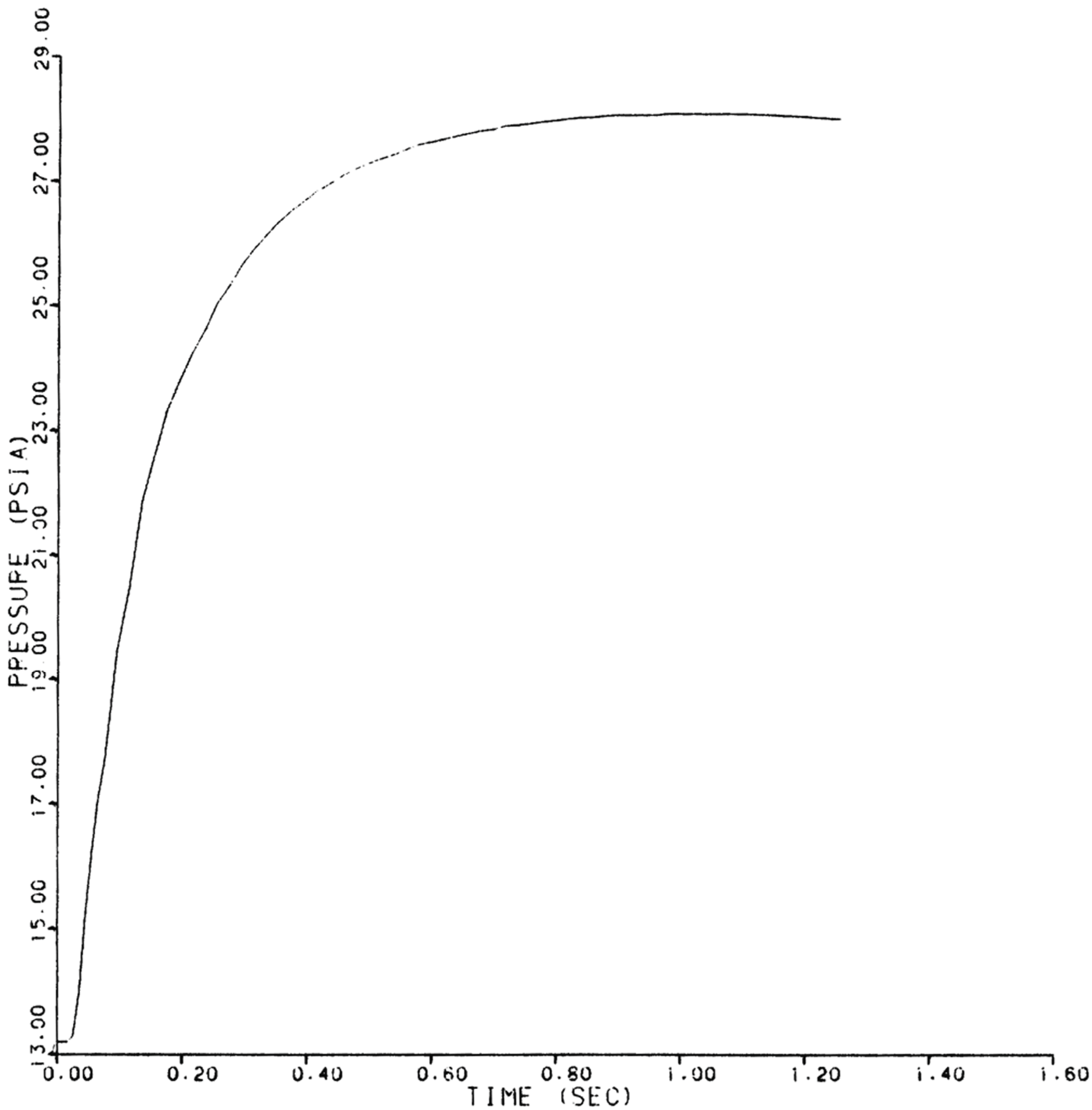
STEAM GENERATOR INLET ELBOW
NODE – E38
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 38 OF 74)



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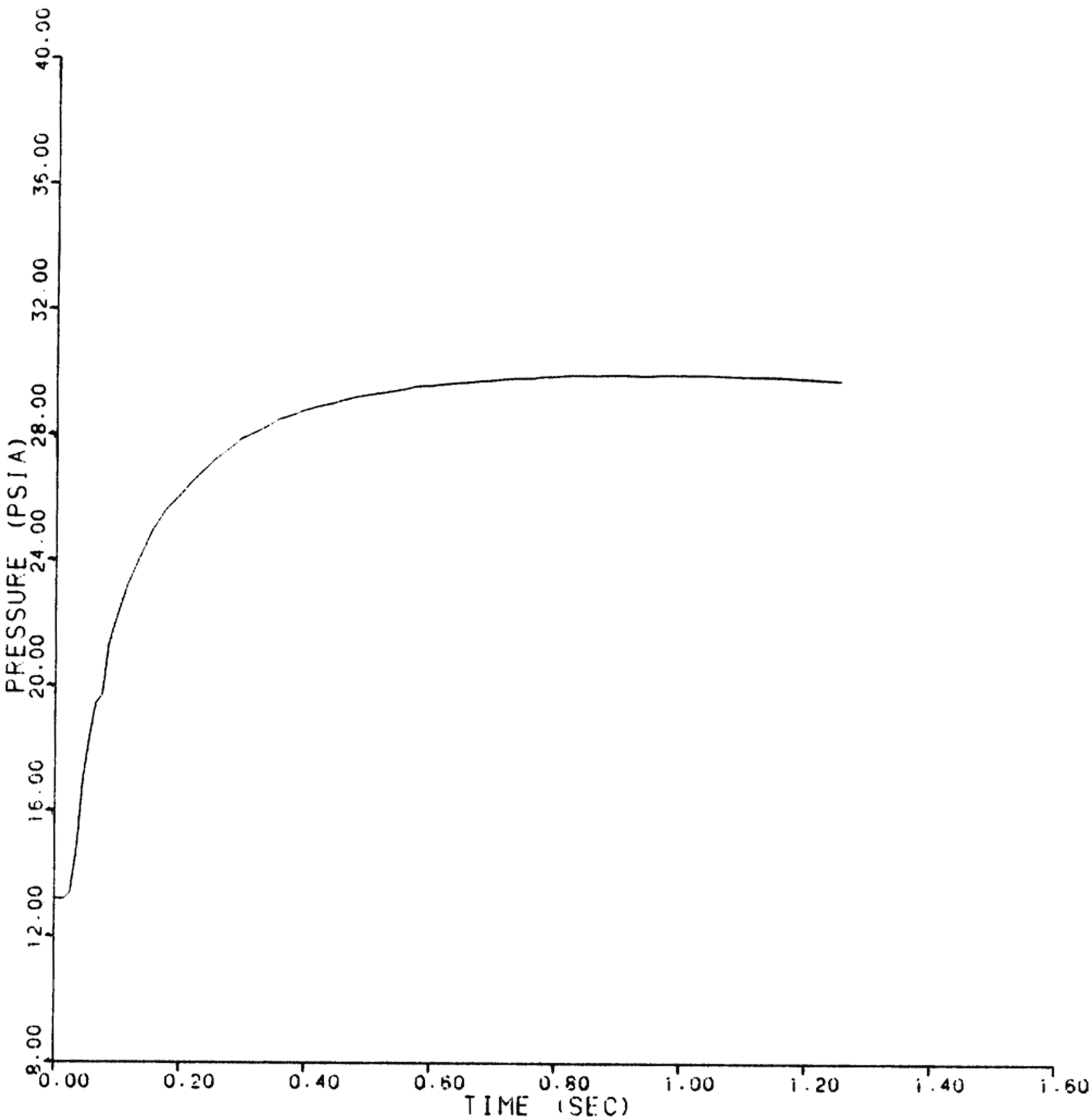
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E39
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 39 OF 74)



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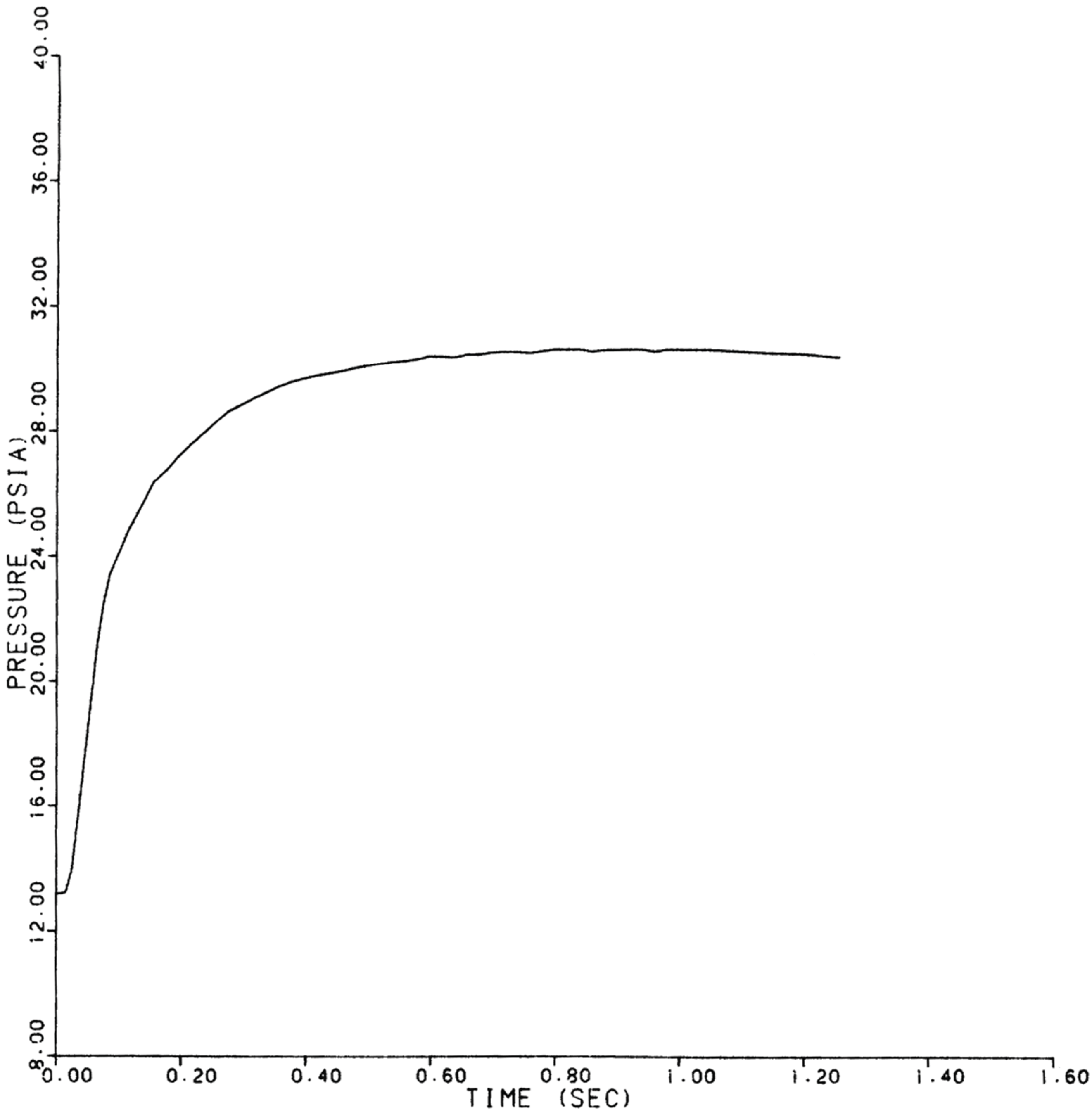
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E40
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 40 OF 74)



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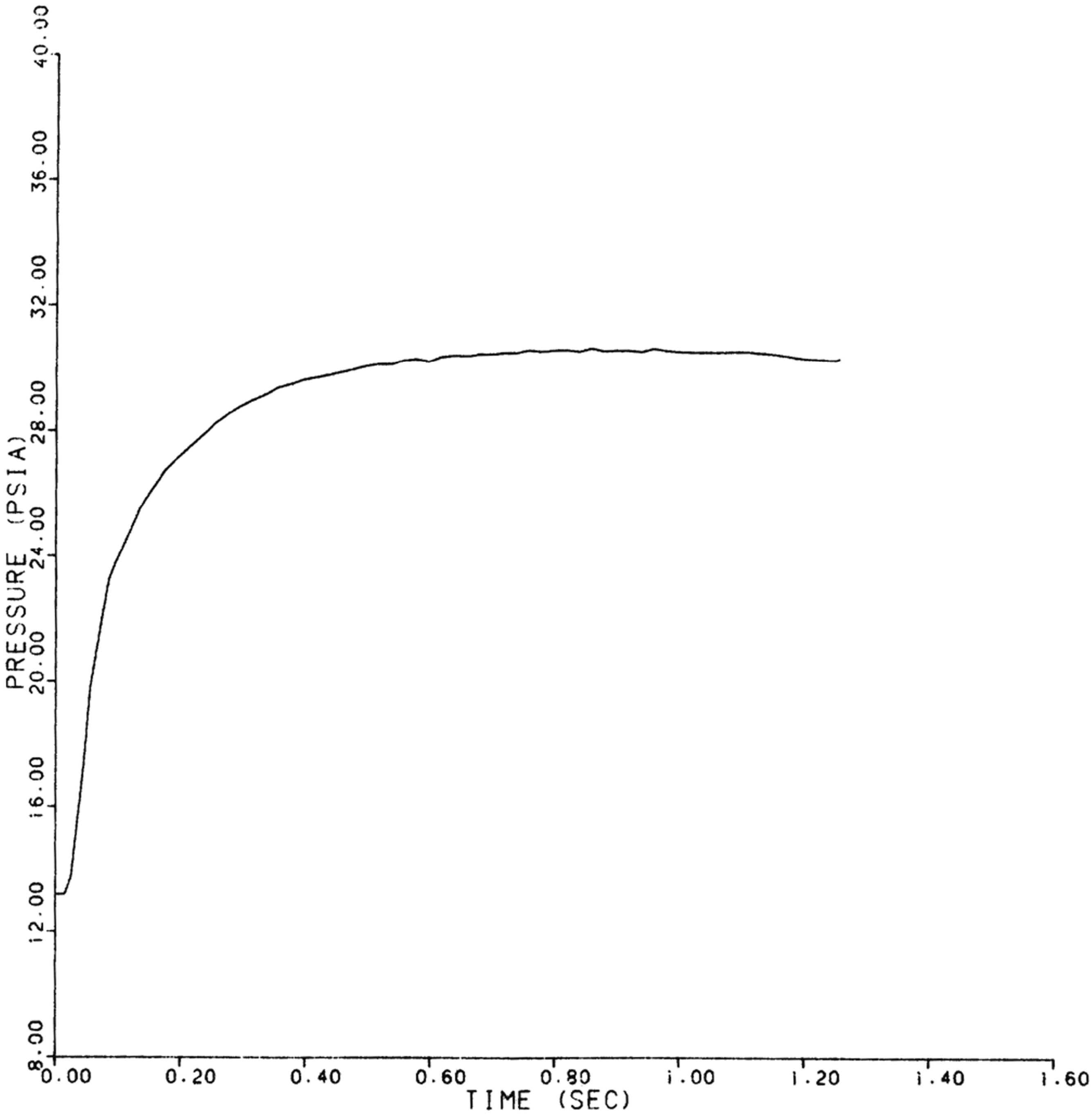
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E41
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 41 OF 74)



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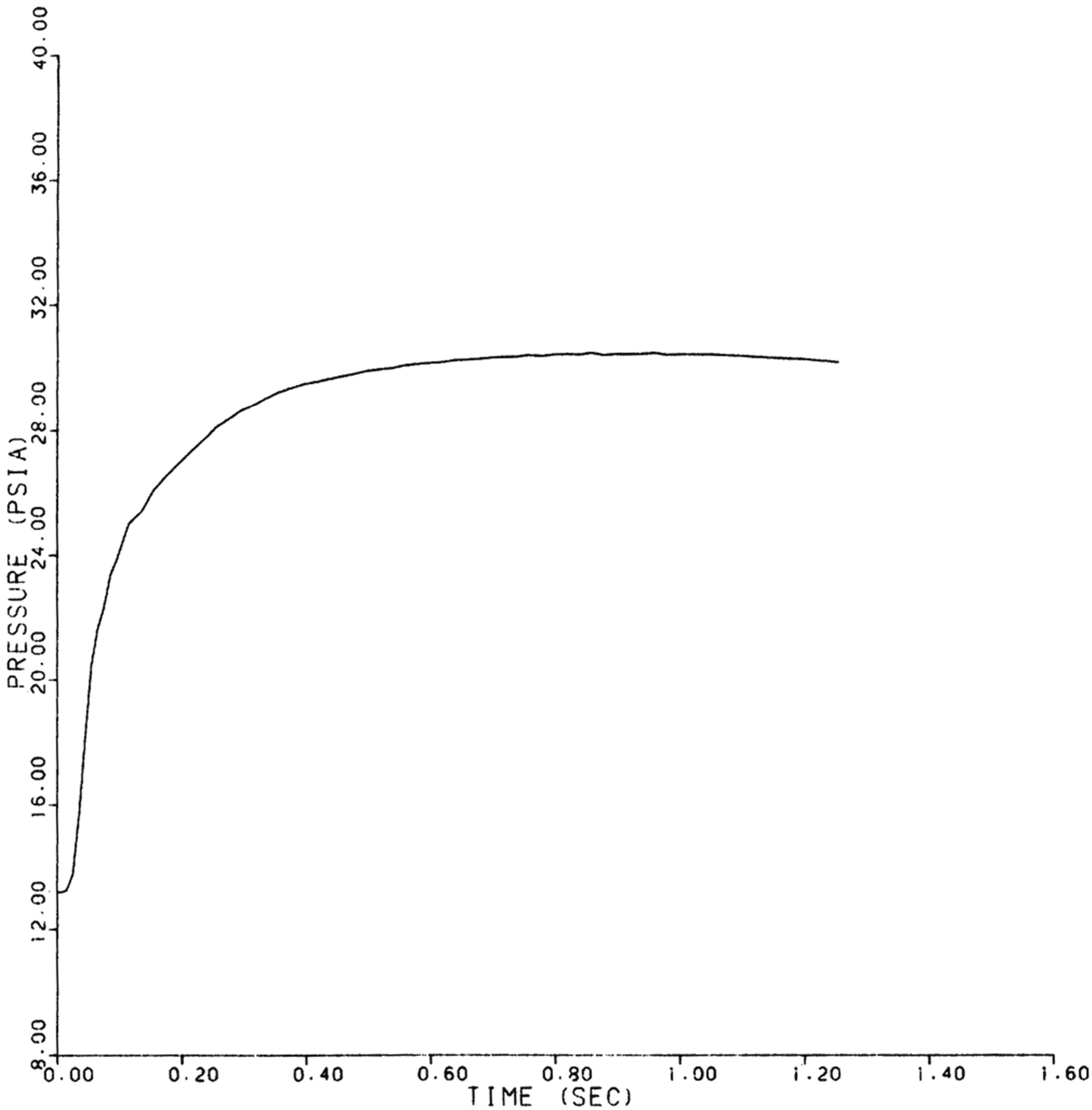
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E42
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 42 OF 74)



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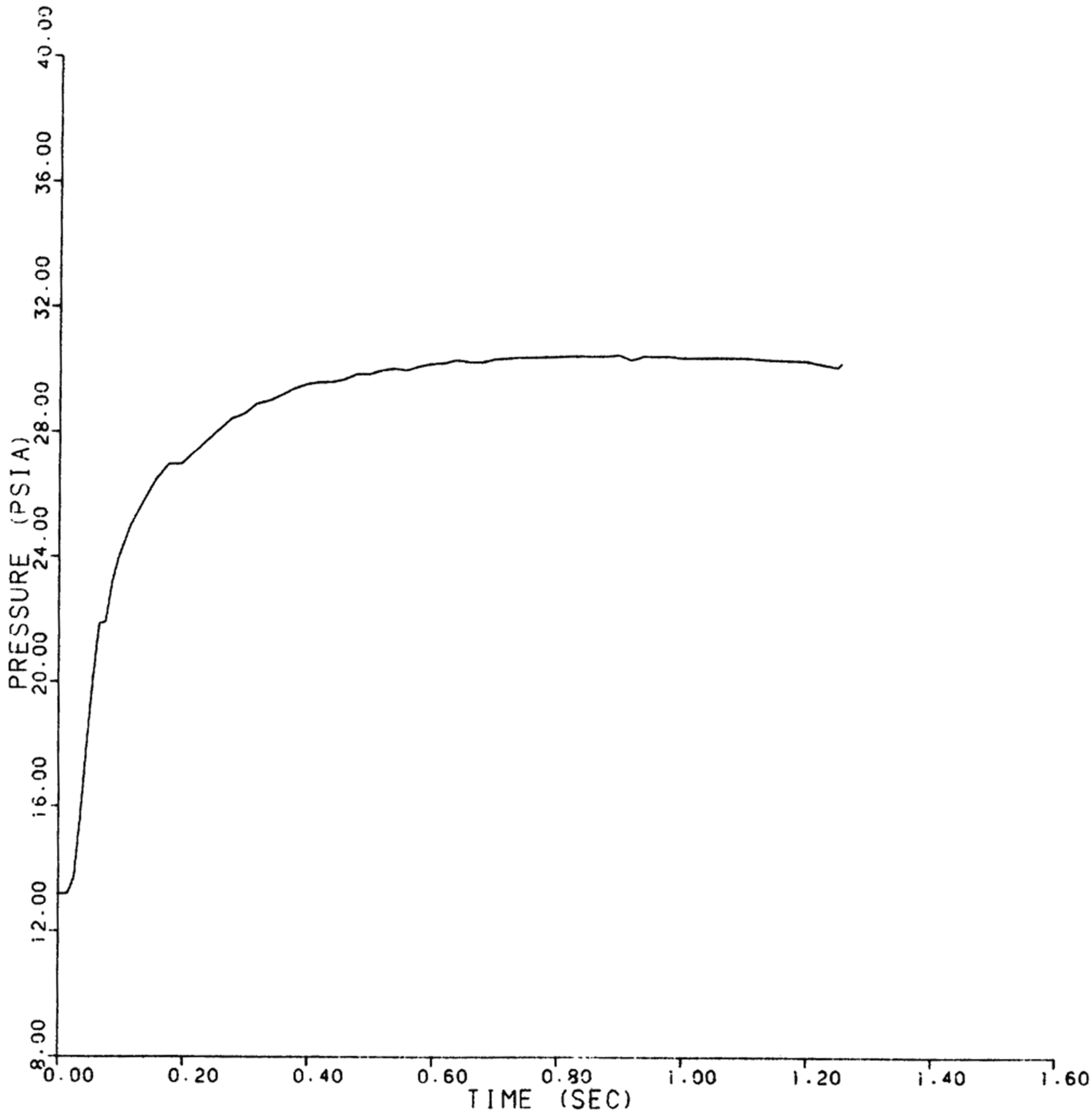
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E43
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 43 OF 74)



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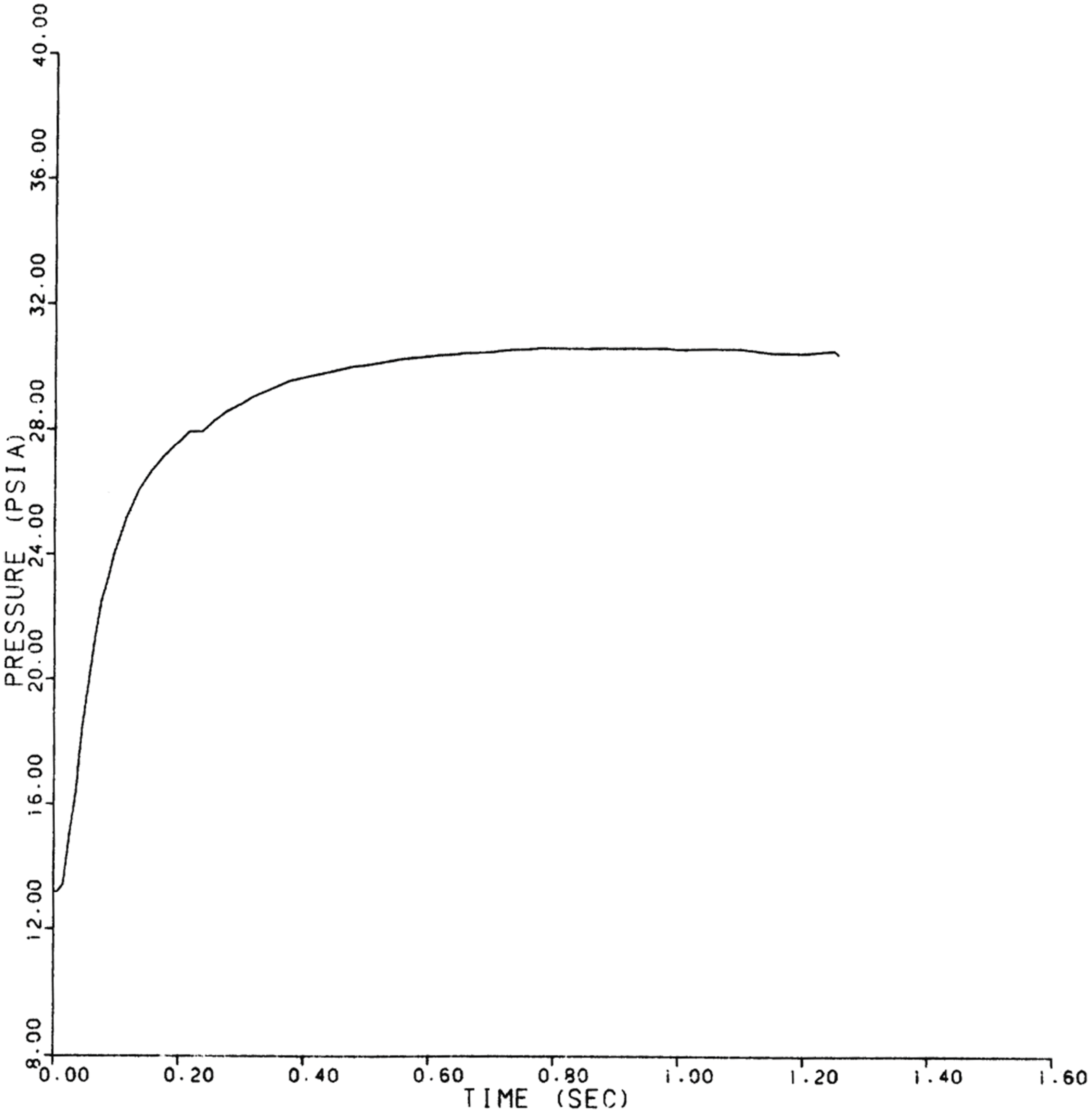
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E44
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 44 OF 74)



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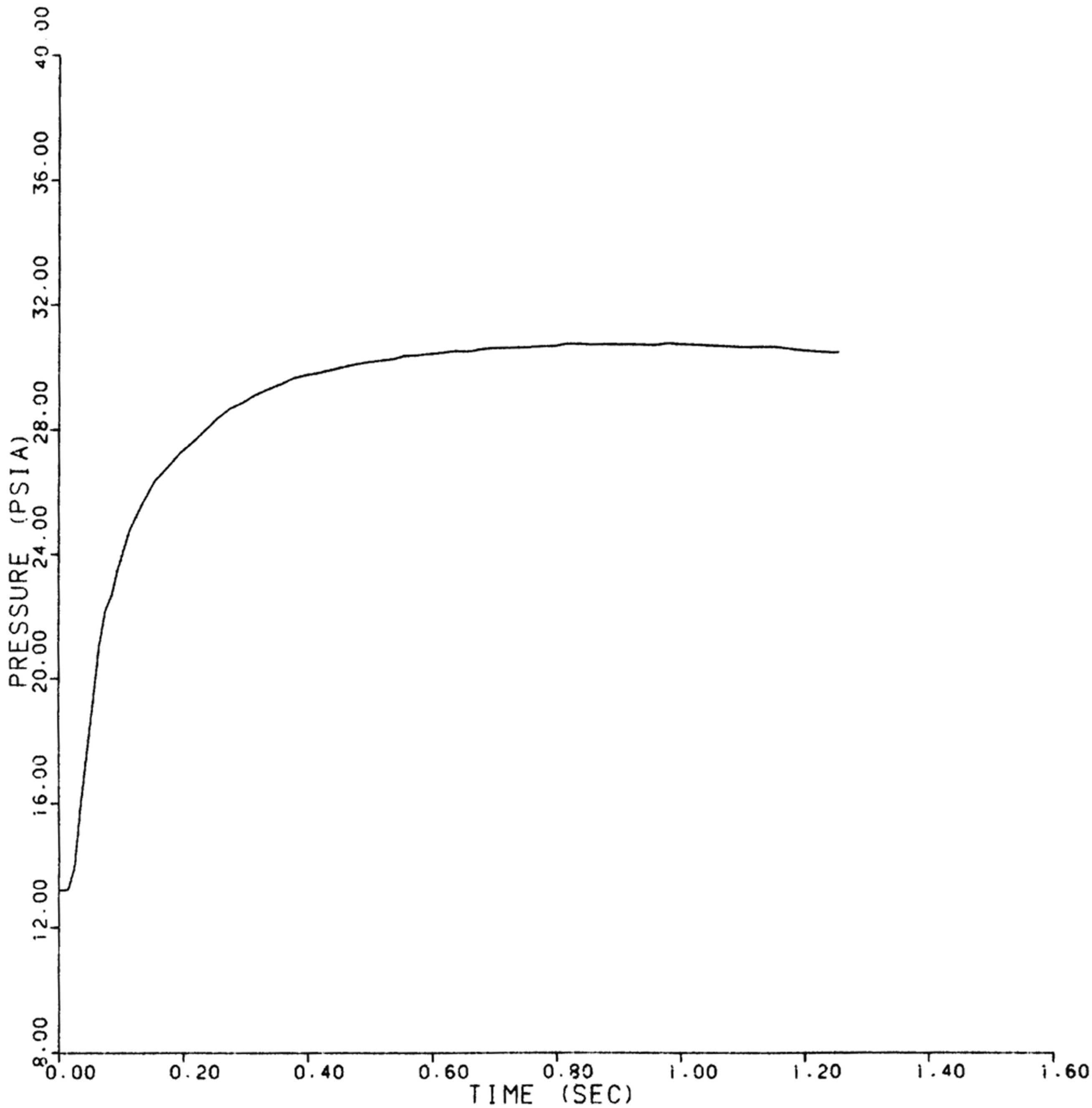
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E45
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 45 OF 74)



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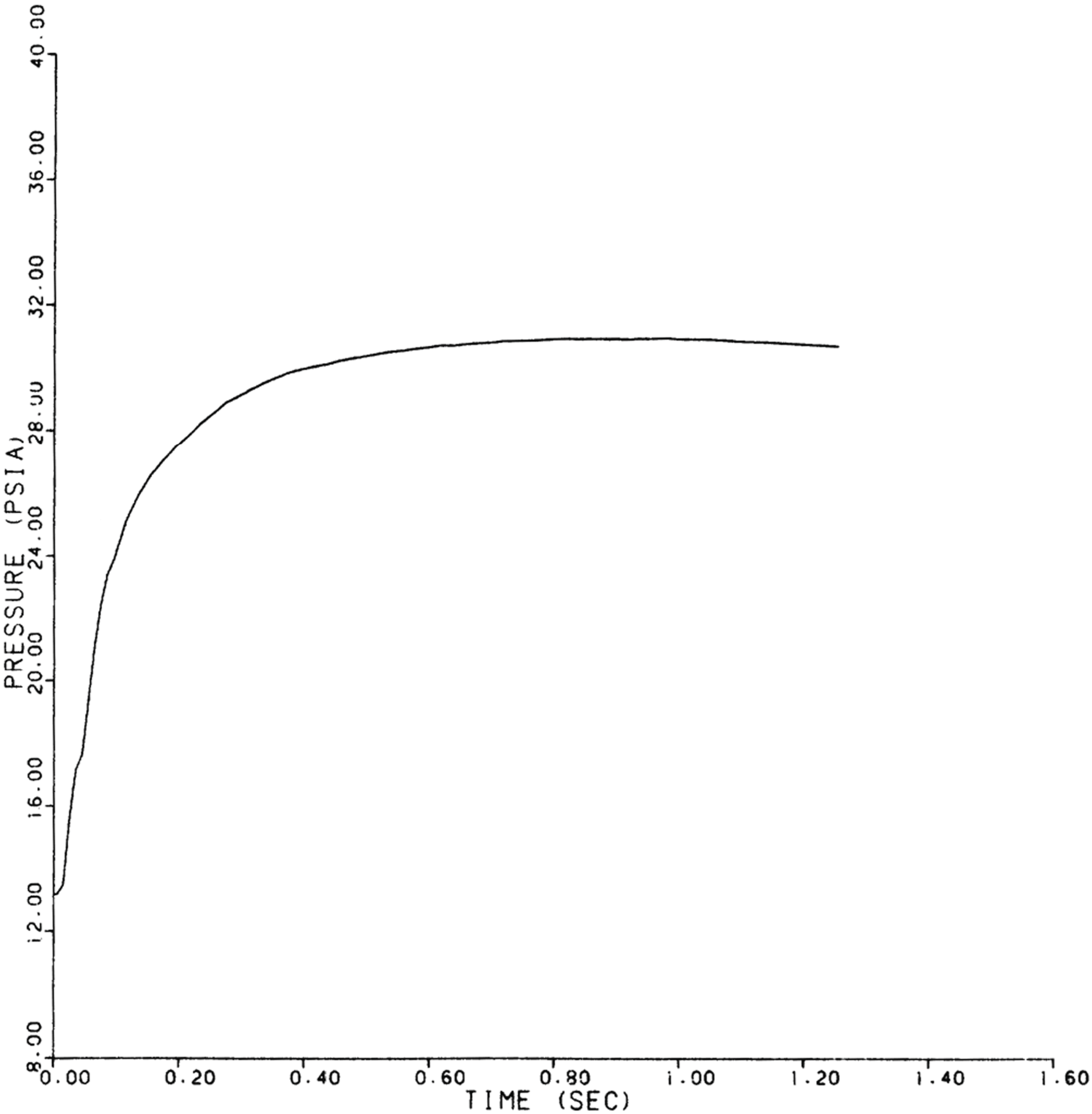
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E46
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 46 OF 74)



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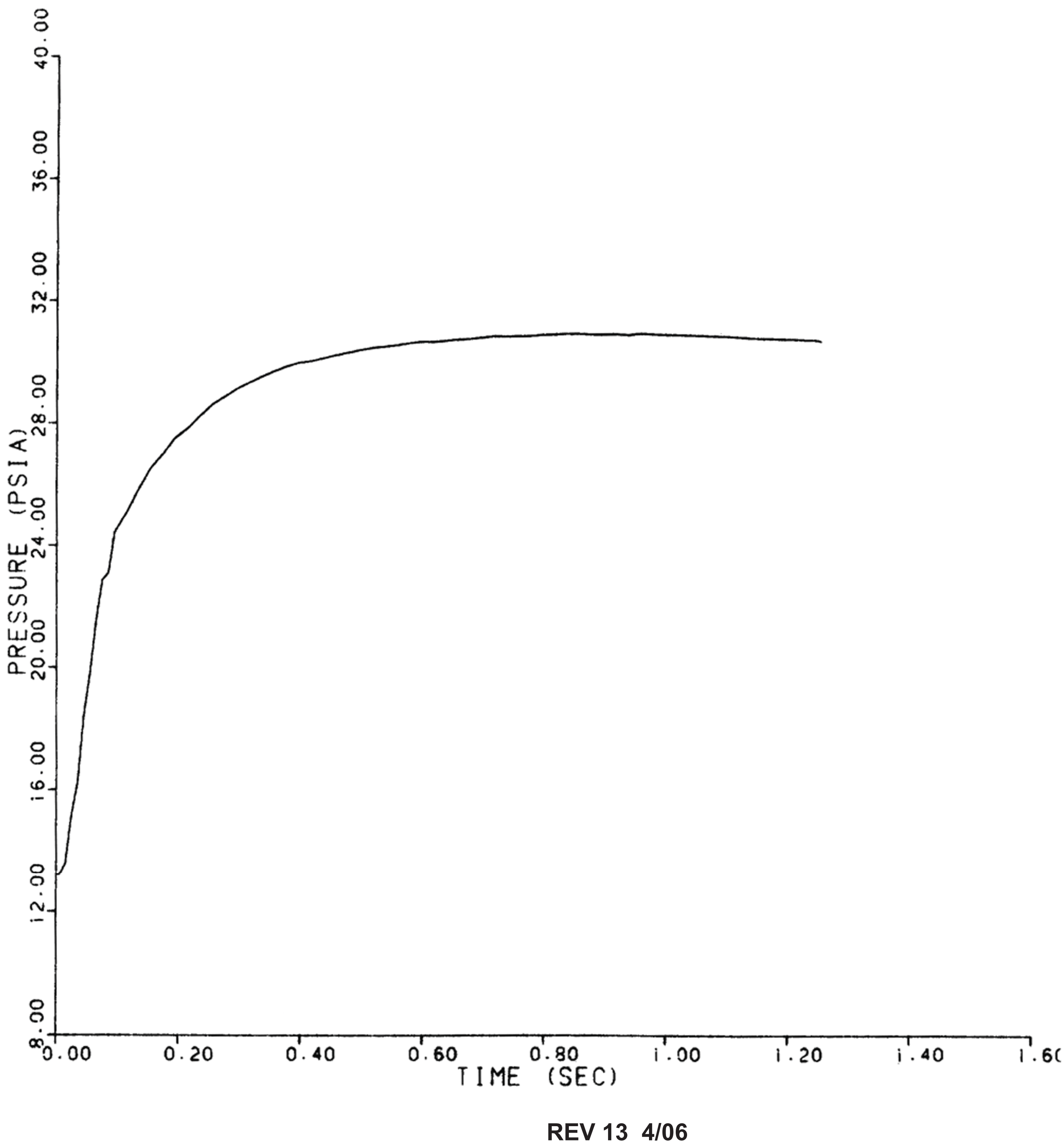
SOUTHERN COMPANY *Energy to Serve Your World®*	VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	STEAM GENERATOR INLET ELBOW NODE – E47 (763–in.^{2} BREAK AREA)
		FIGURE 6.2.1–22 (SHEET 47 OF 74)



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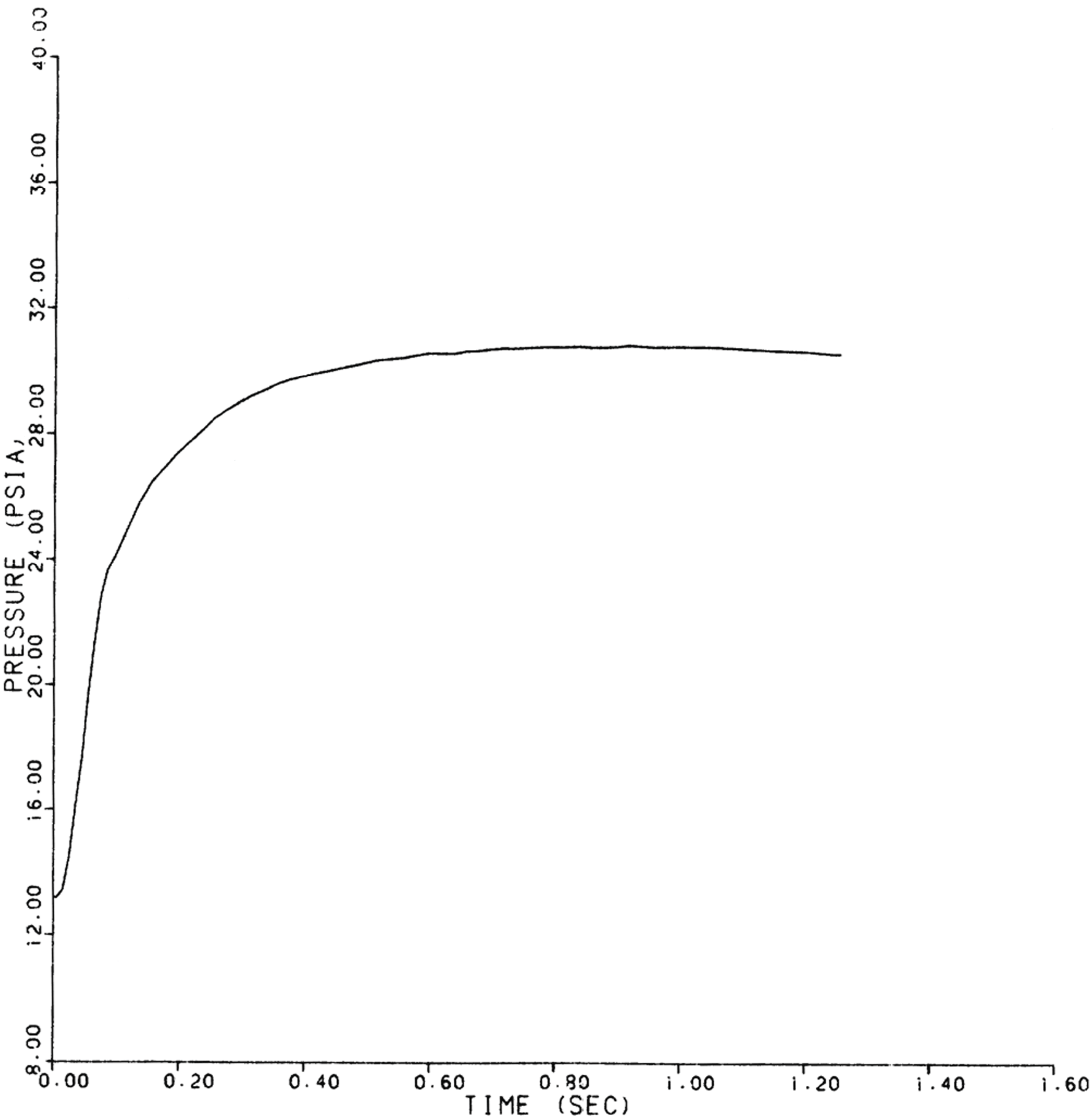
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E48
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 48 OF 74)



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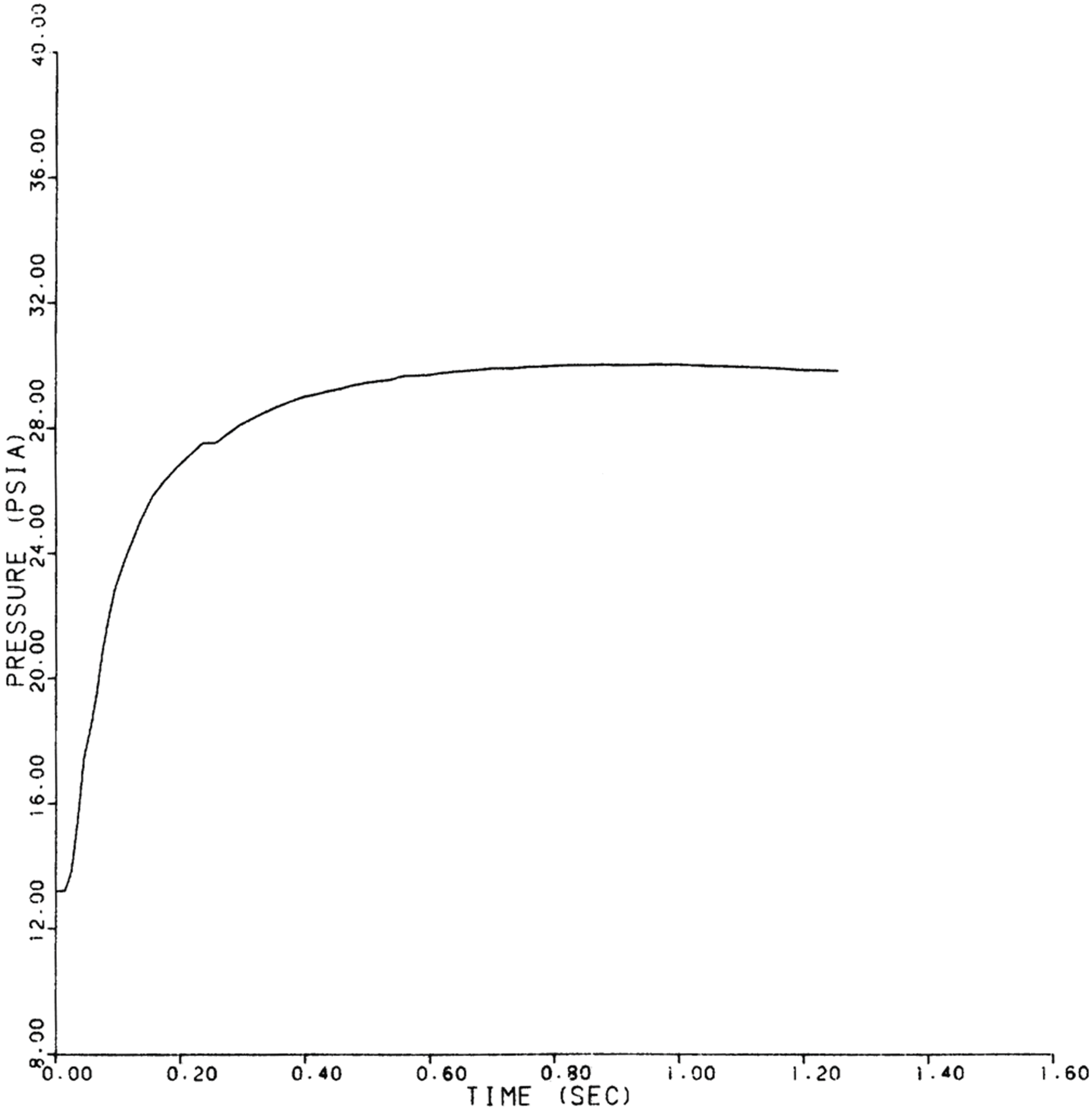
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E49
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 49 OF 74)



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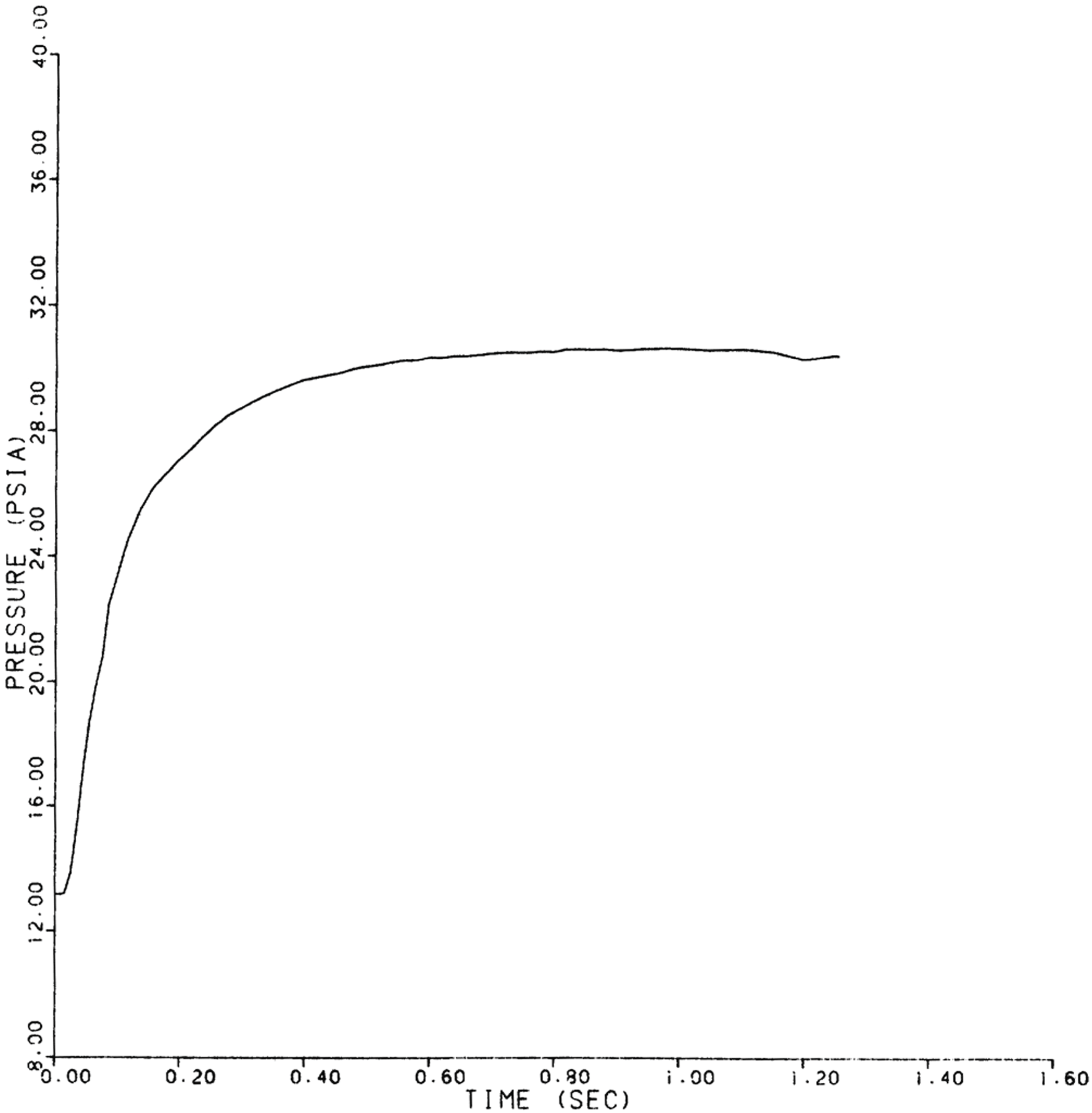
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E50
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 50 OF 74)



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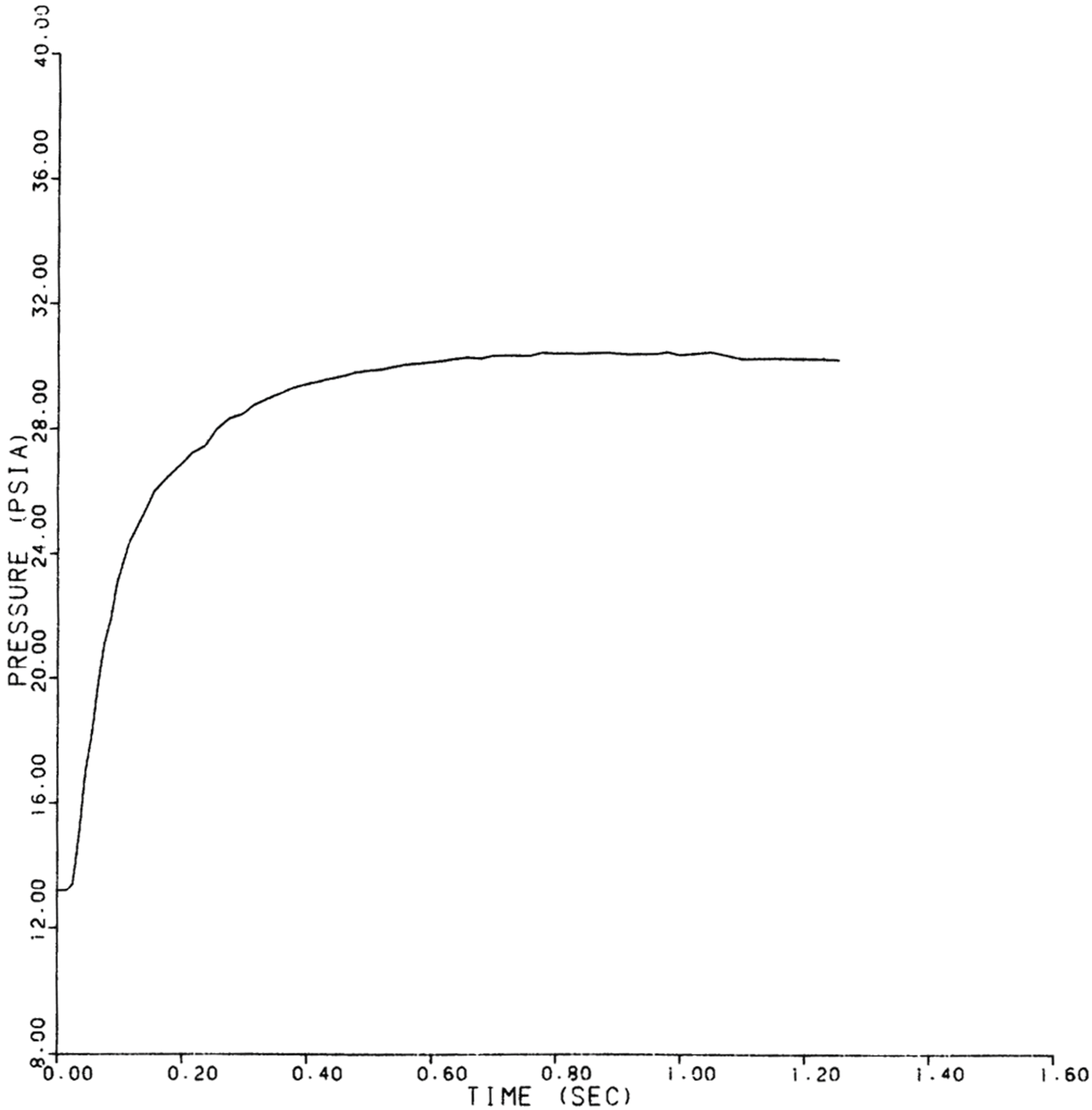
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E51
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 51 OF 74)



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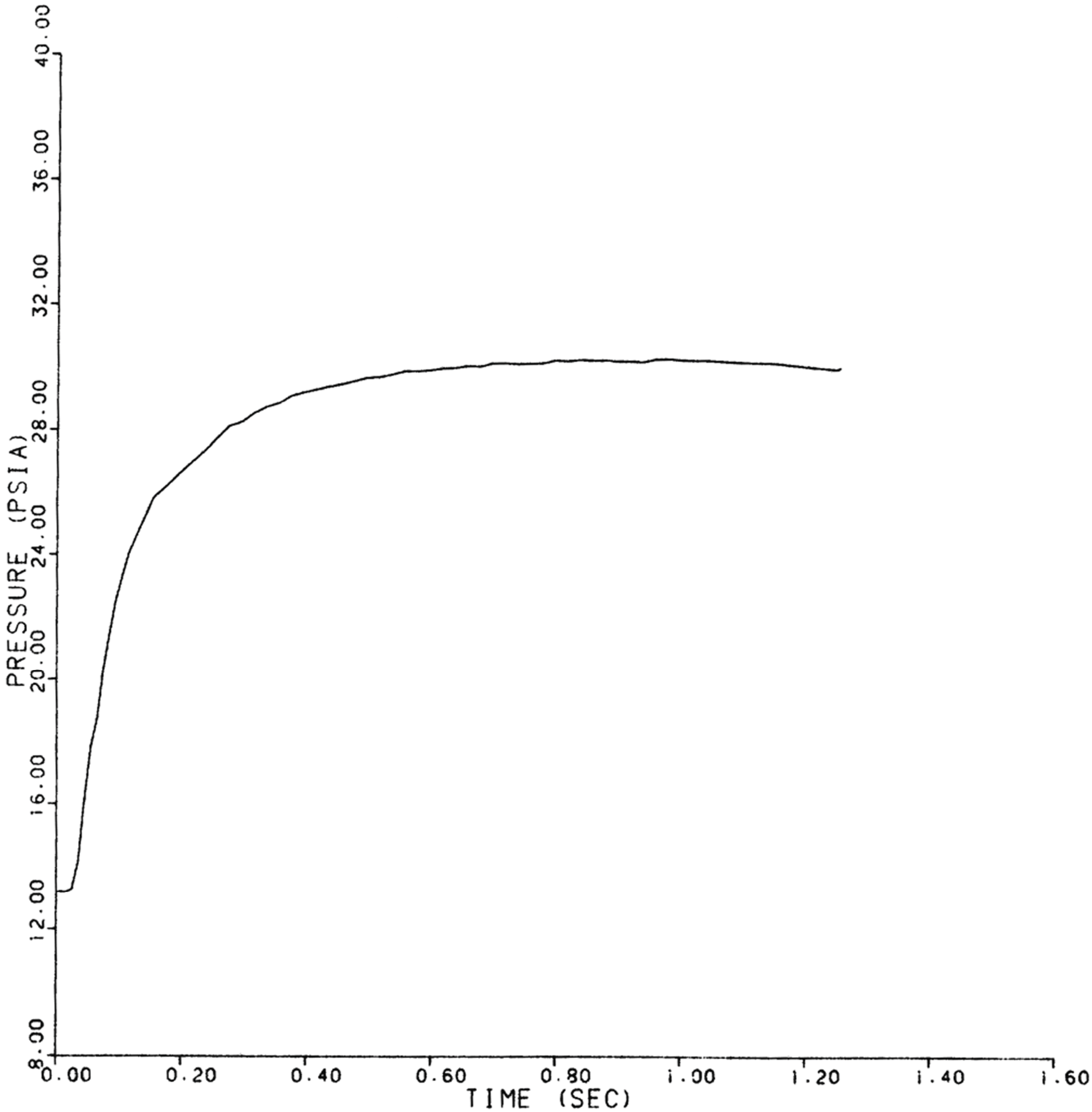
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E52
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 52 OF 74)



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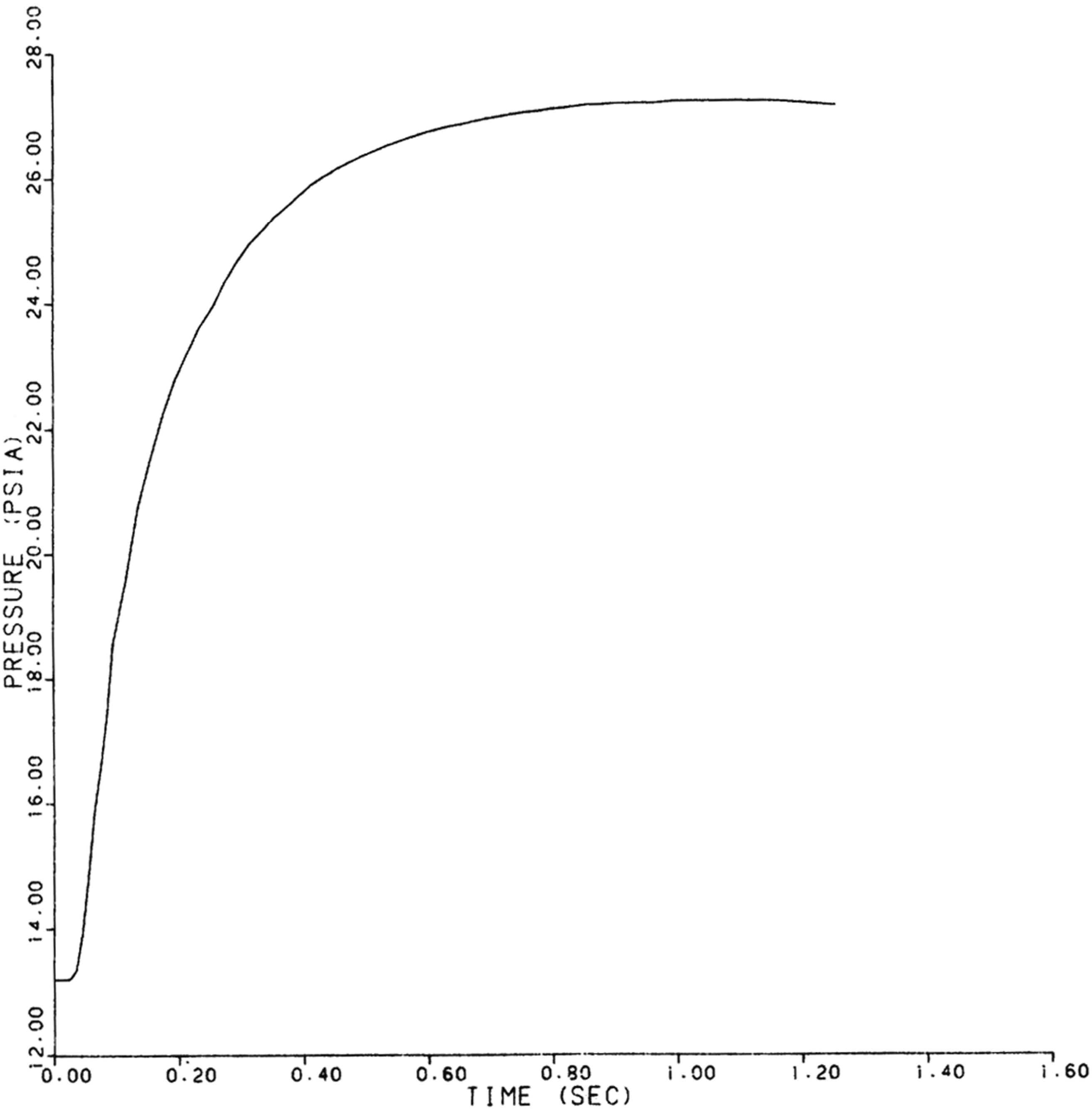
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E53
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 53 OF 74)



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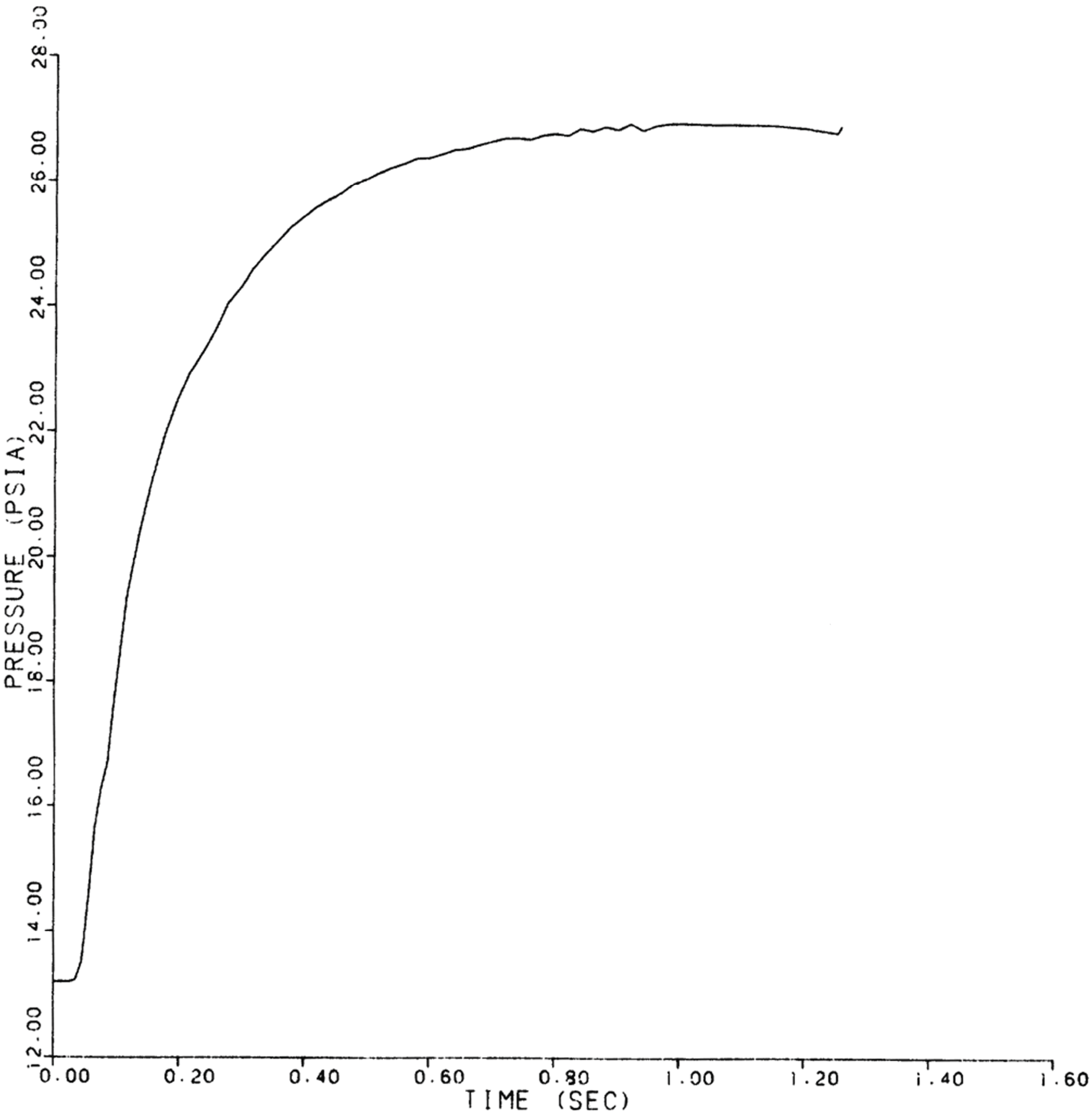
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E54
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 54 OF 74)



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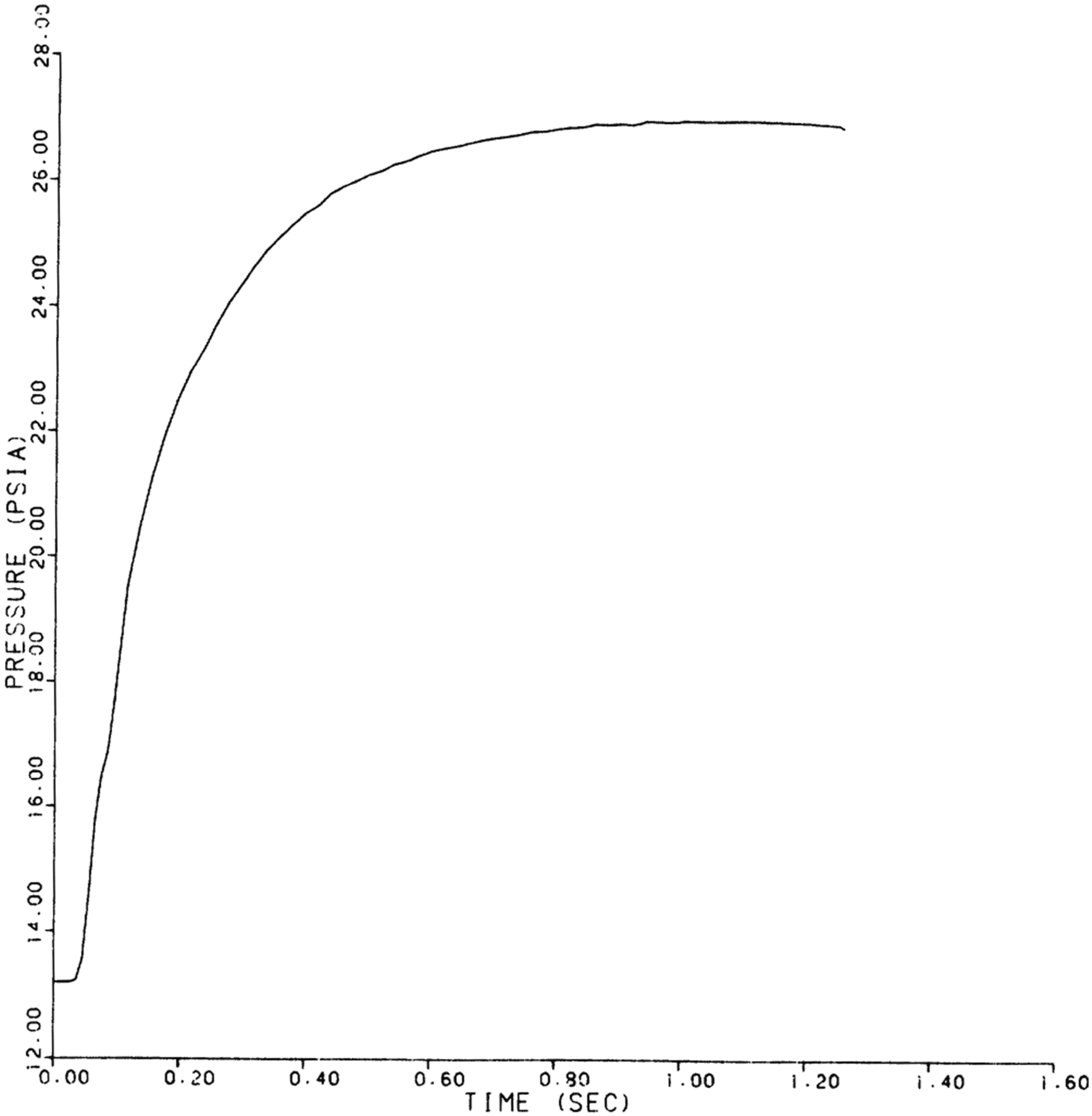
SOUTHERN COMPANY *Energy to Serve Your World®* **VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2**	STEAM GENERATOR INLET ELBOW NODE – E55 (763–in.^{2} BREAK AREA)
	FIGURE 6.2.1–22 (SHEET 55 OF 74)



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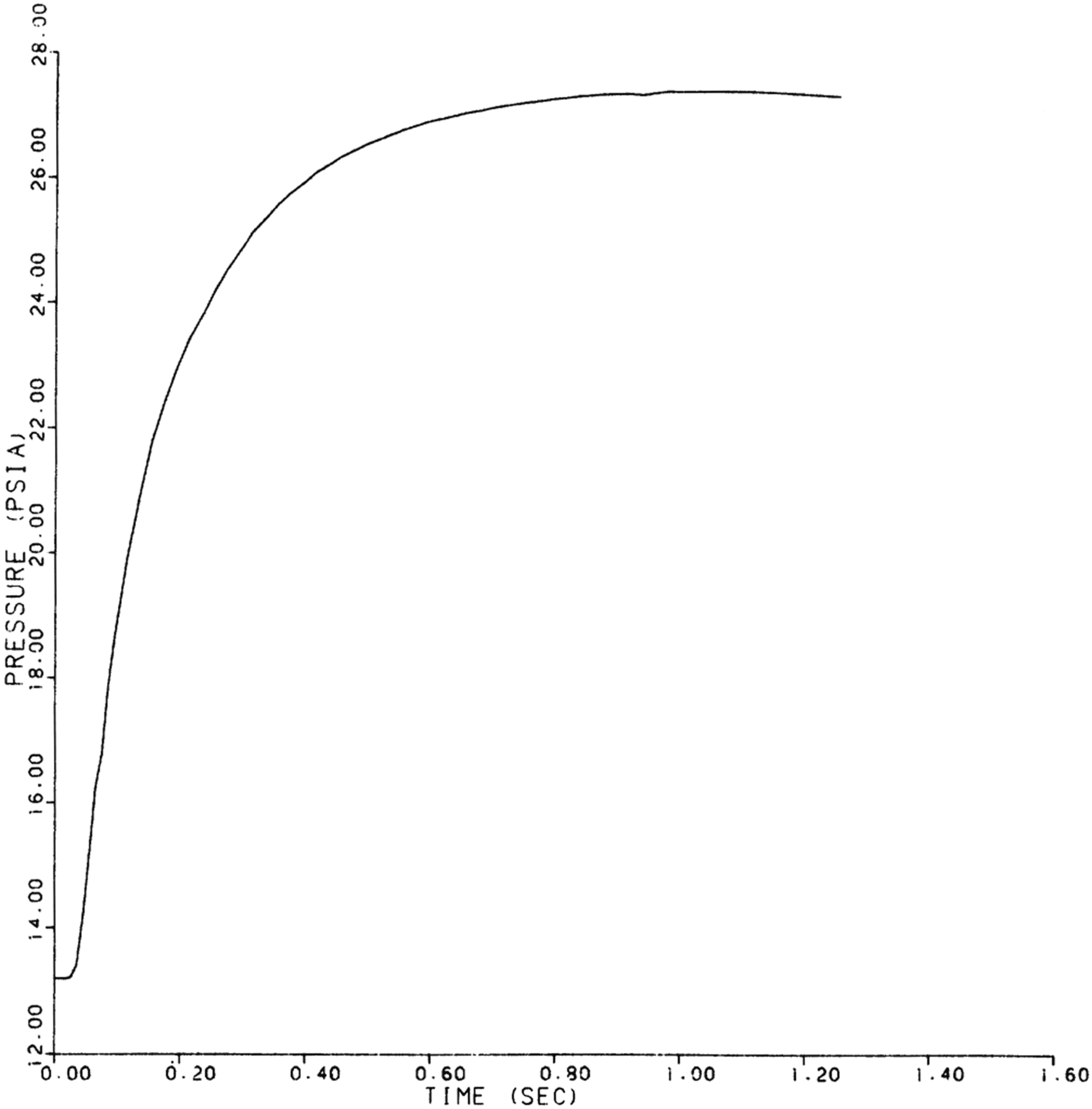
SOUTHERN COMPANY Energy to Serve Your World®	VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	STEAM GENERATOR INLET ELBOW NODE – E56 (763–in.^{2} BREAK AREA)
		FIGURE 6.2.1–22 (SHEET 56 OF 74)



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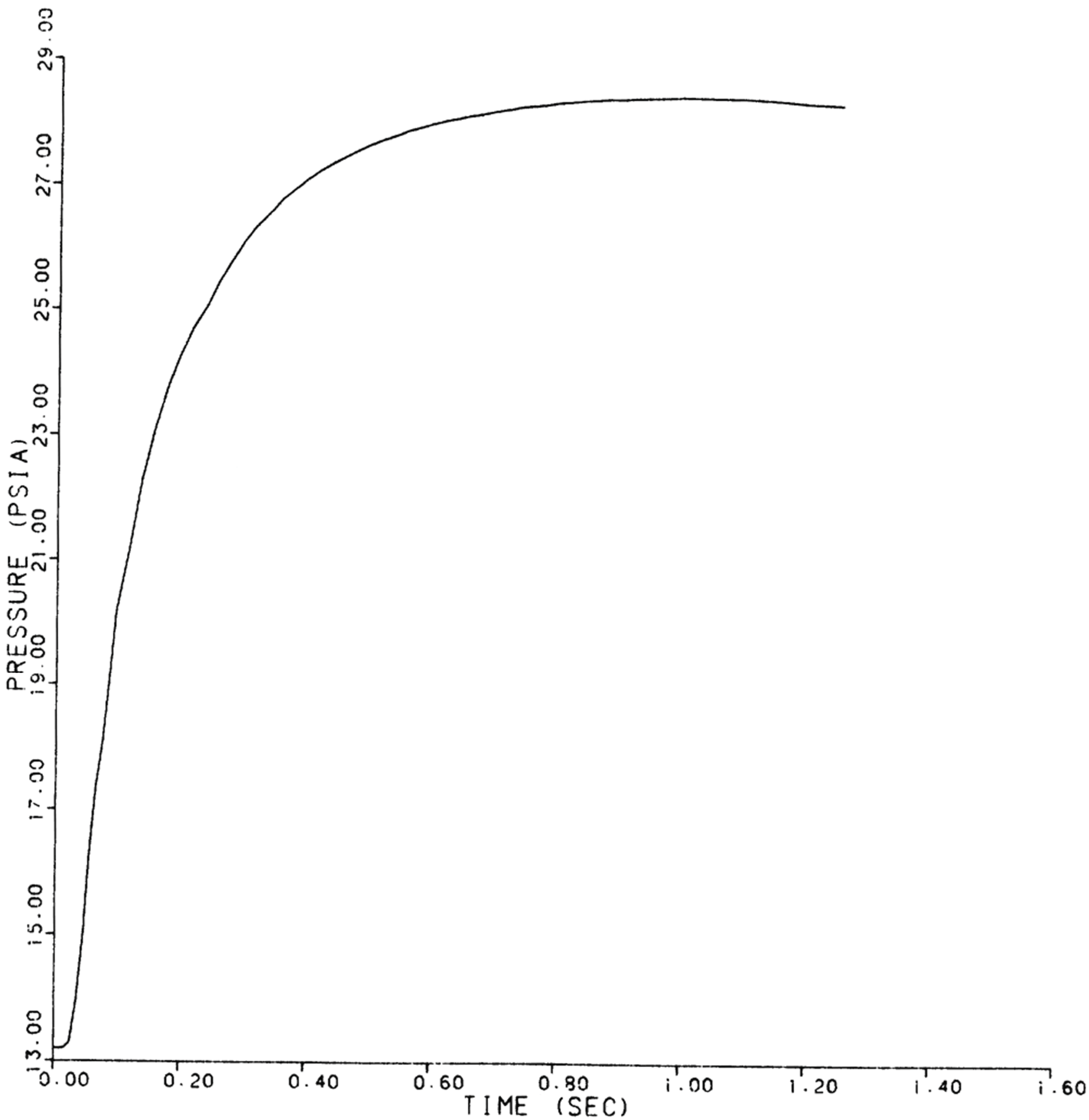
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E57
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 57 OF 74)



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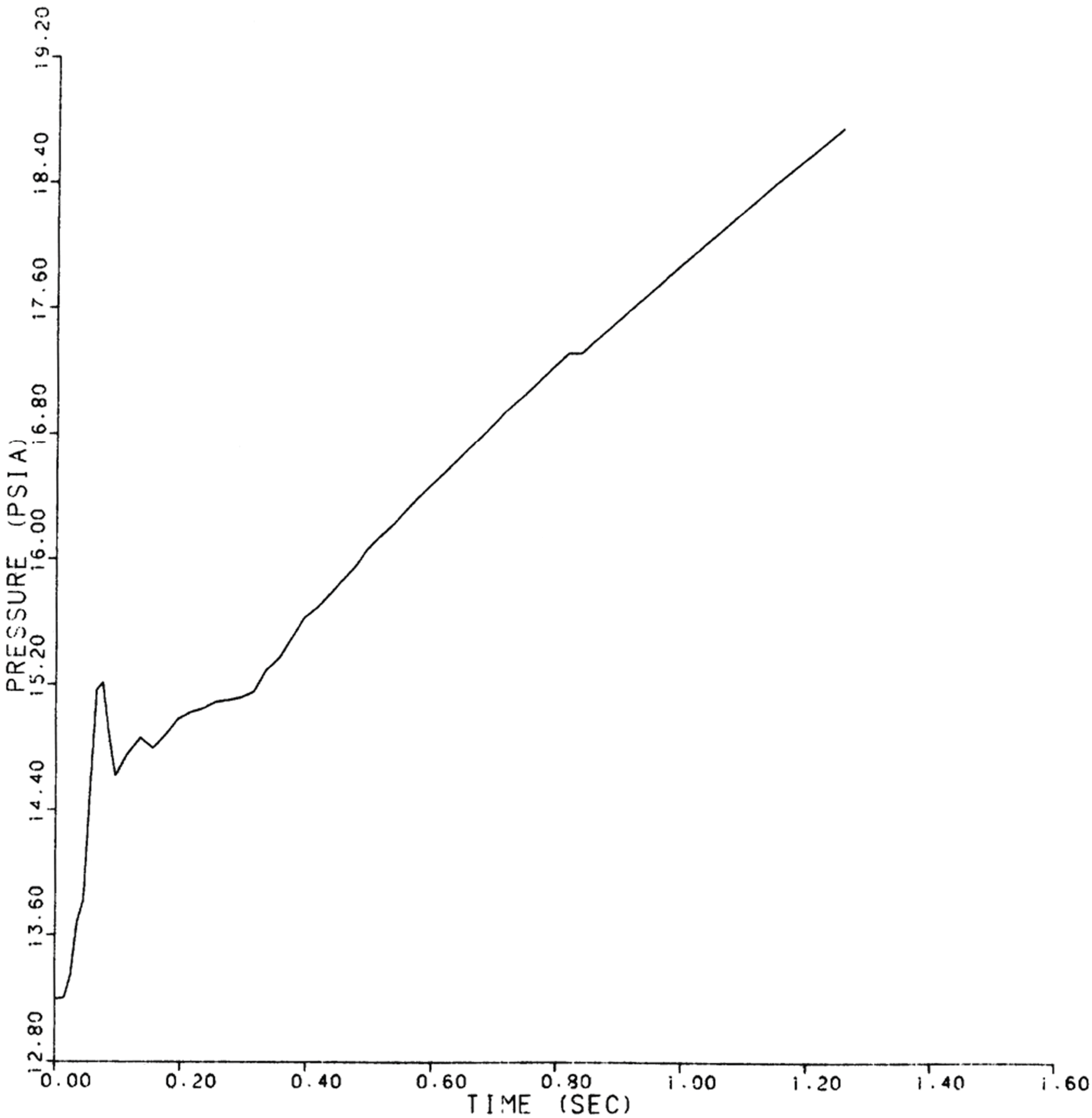
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E58
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 58 OF 74)



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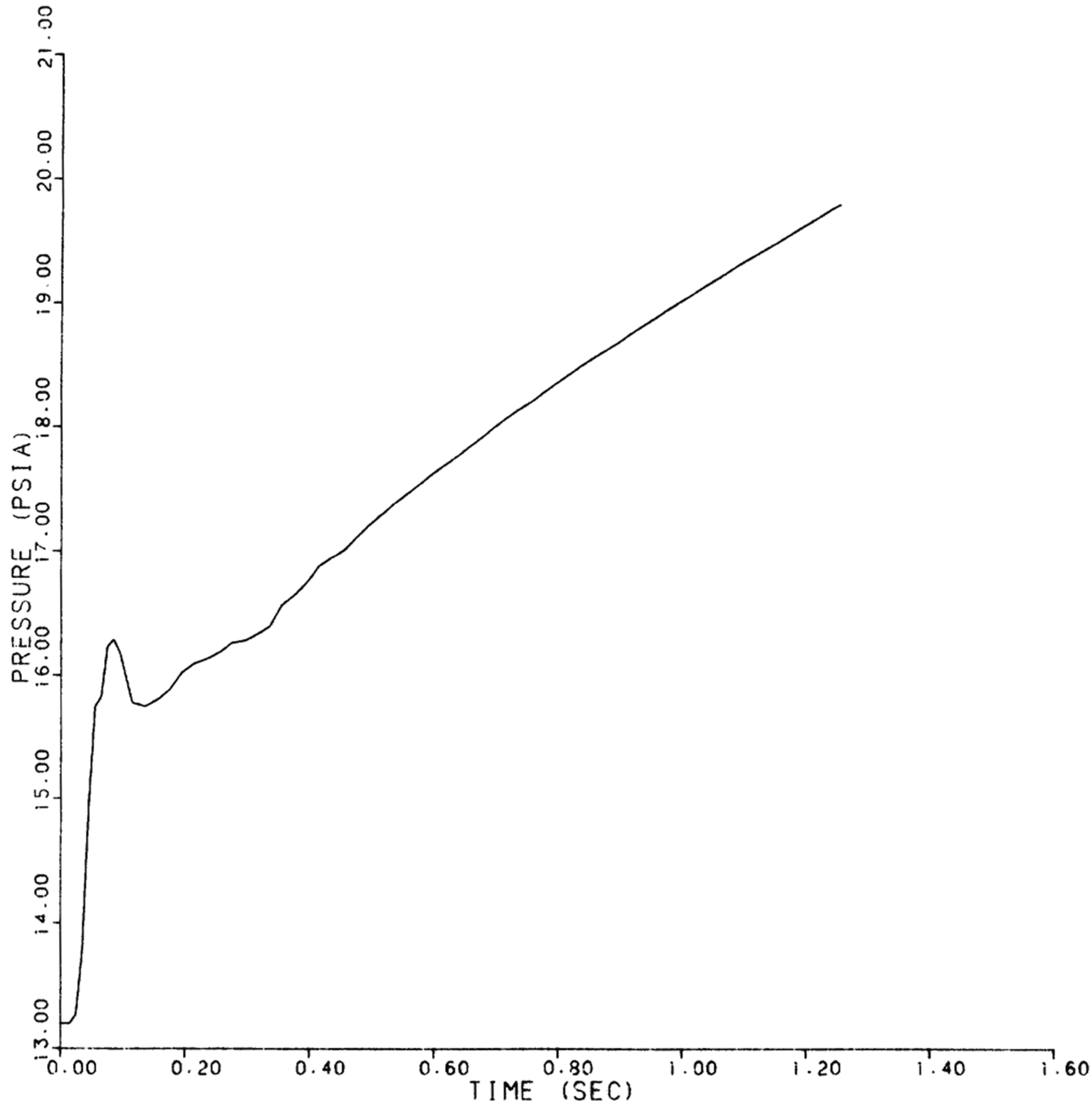
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E59
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 59 OF 74)



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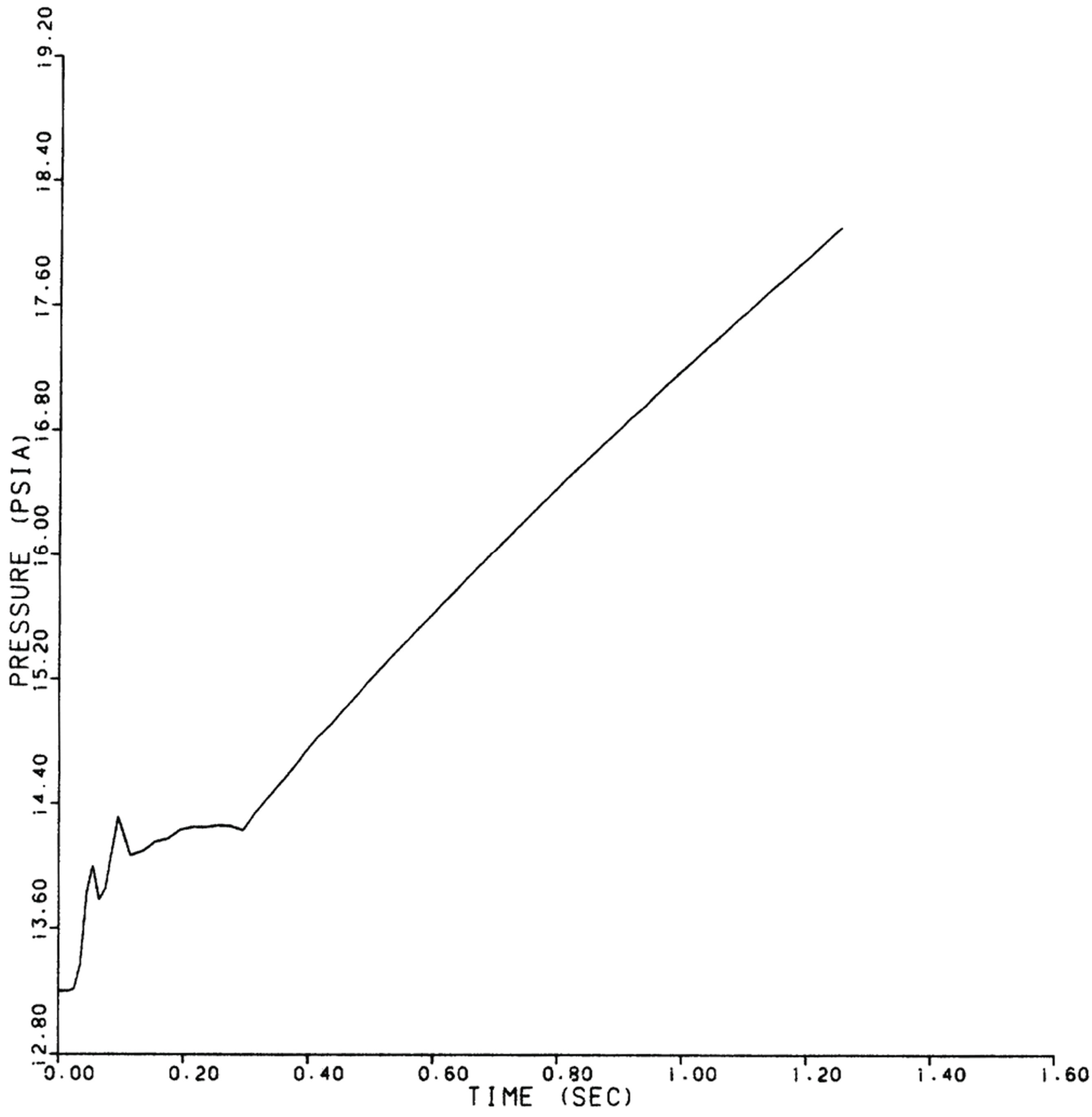
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E60
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 60 OF 74)



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SOUTHERN COMPANY
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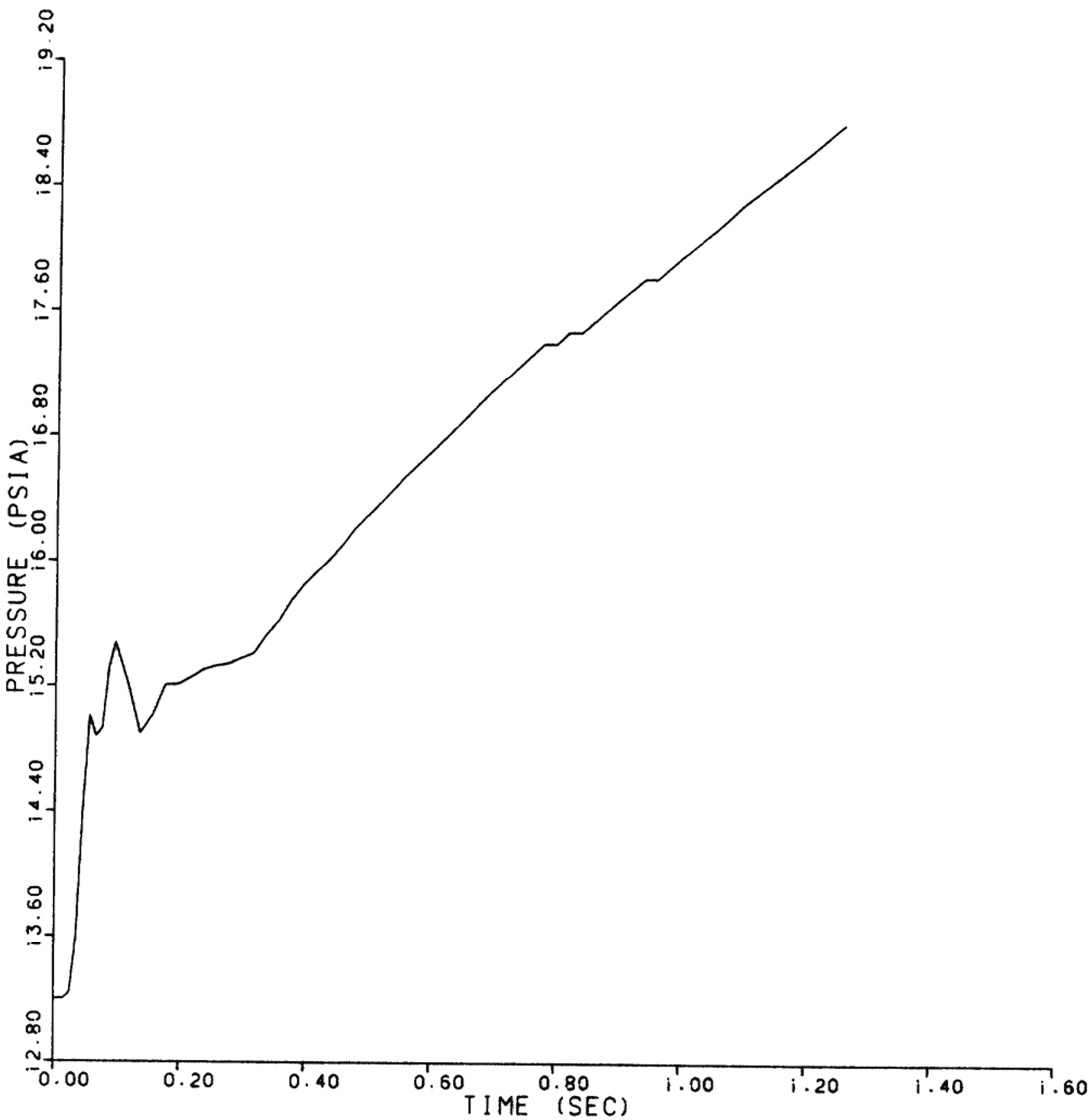
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E61
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 61 OF 74)



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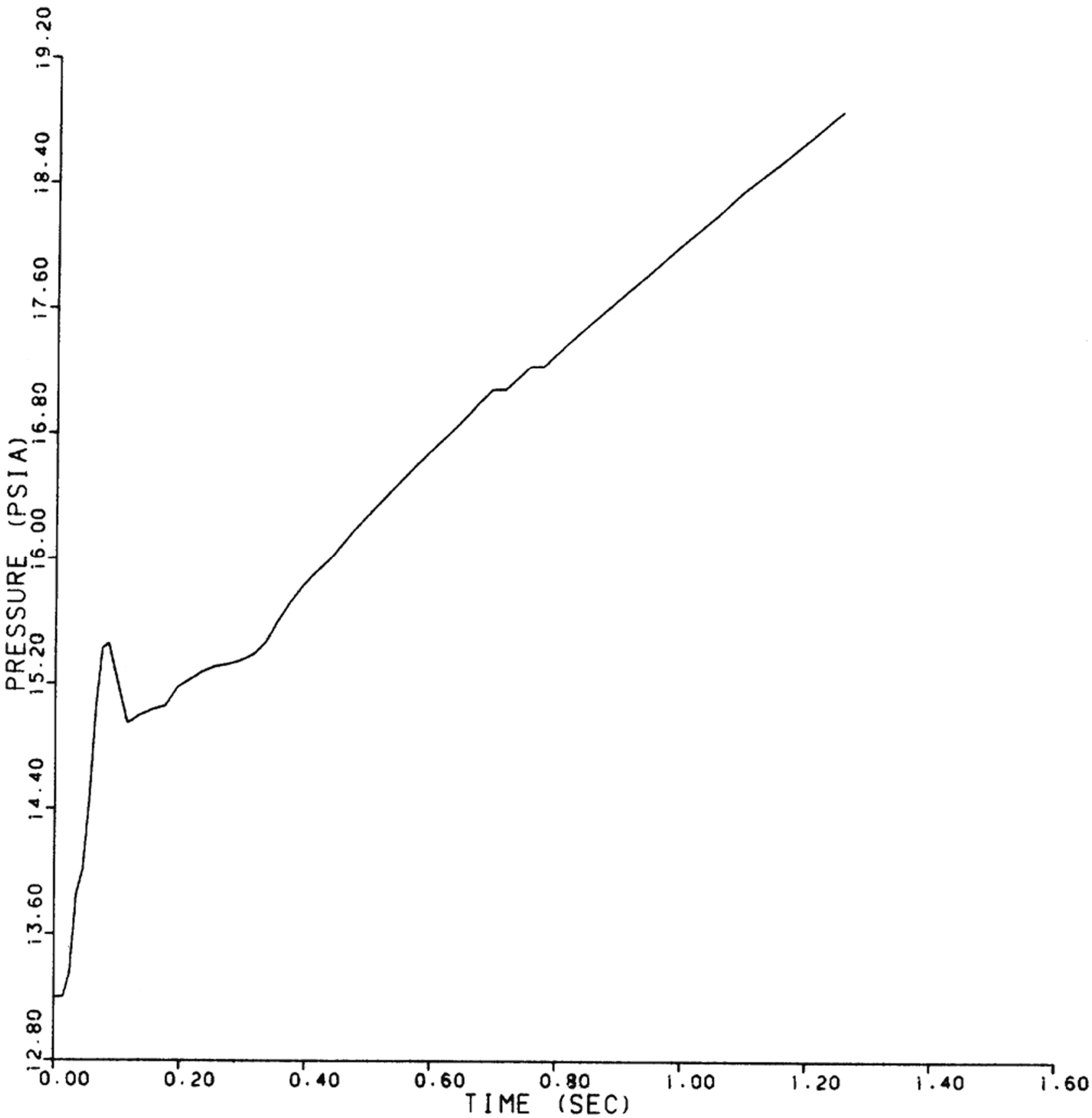
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E62
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 62 OF 74)



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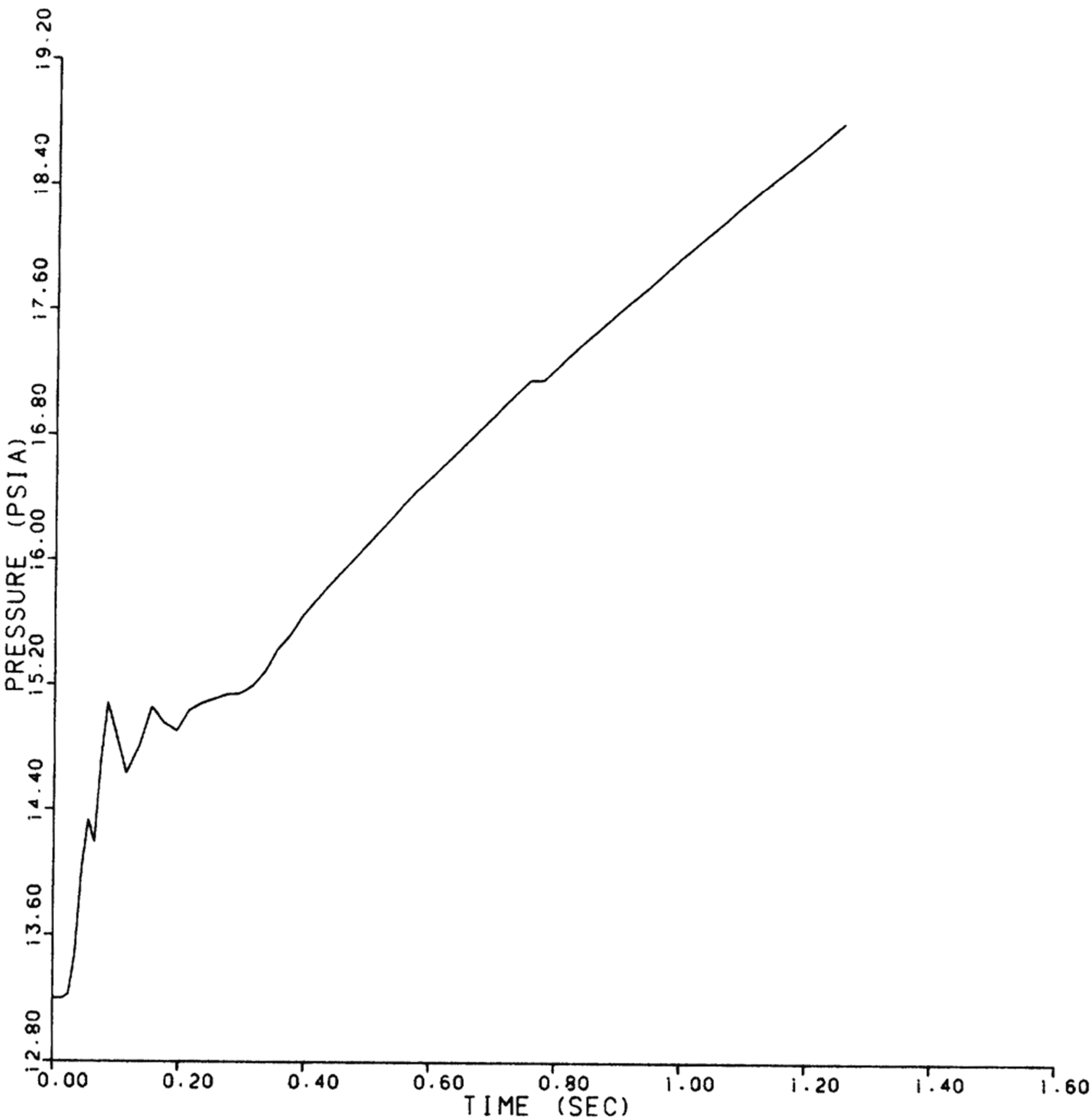
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E63
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 63 OF 74)



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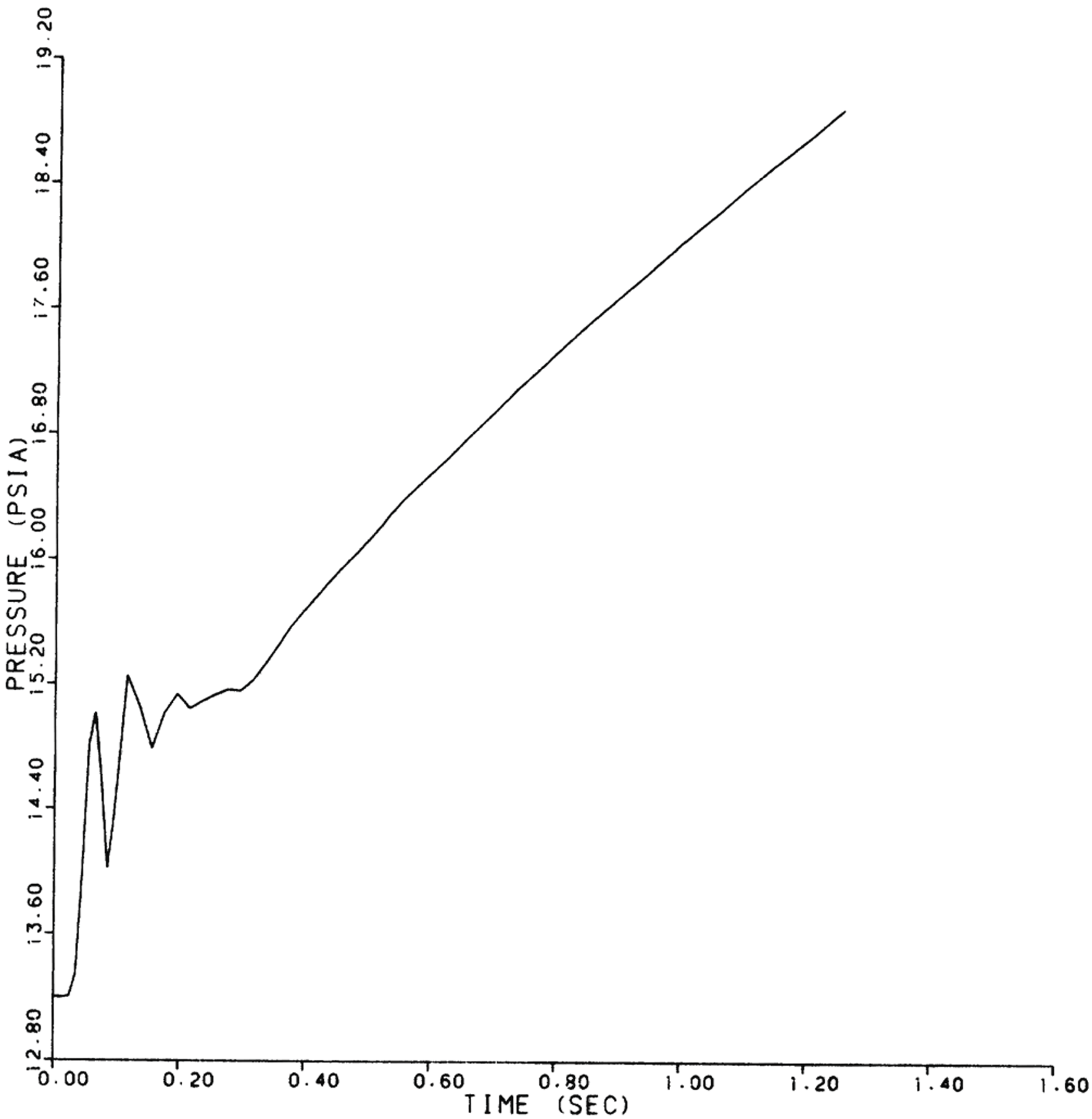
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E64
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 64 OF 74)



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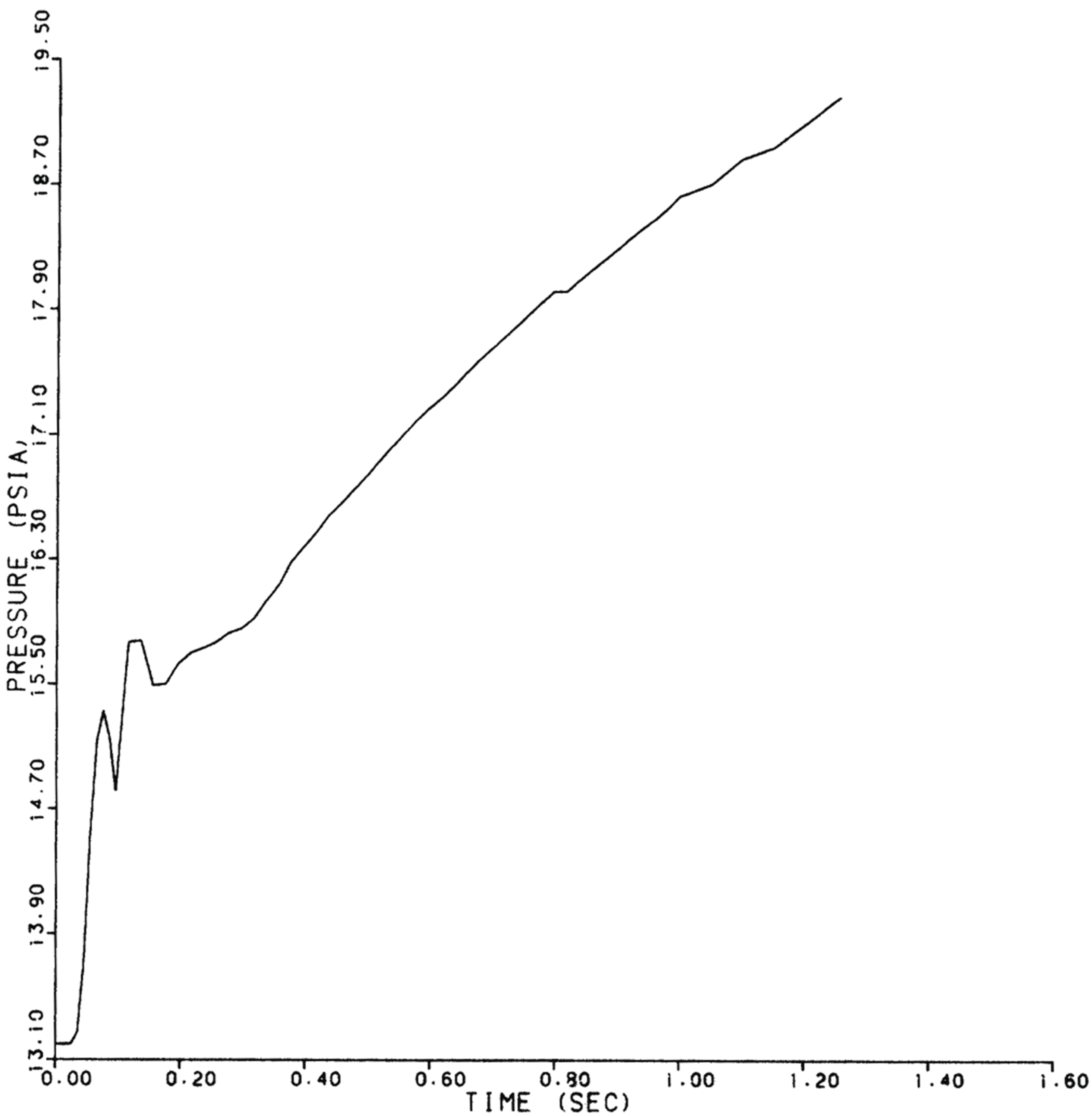
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E65
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 65 OF 74)



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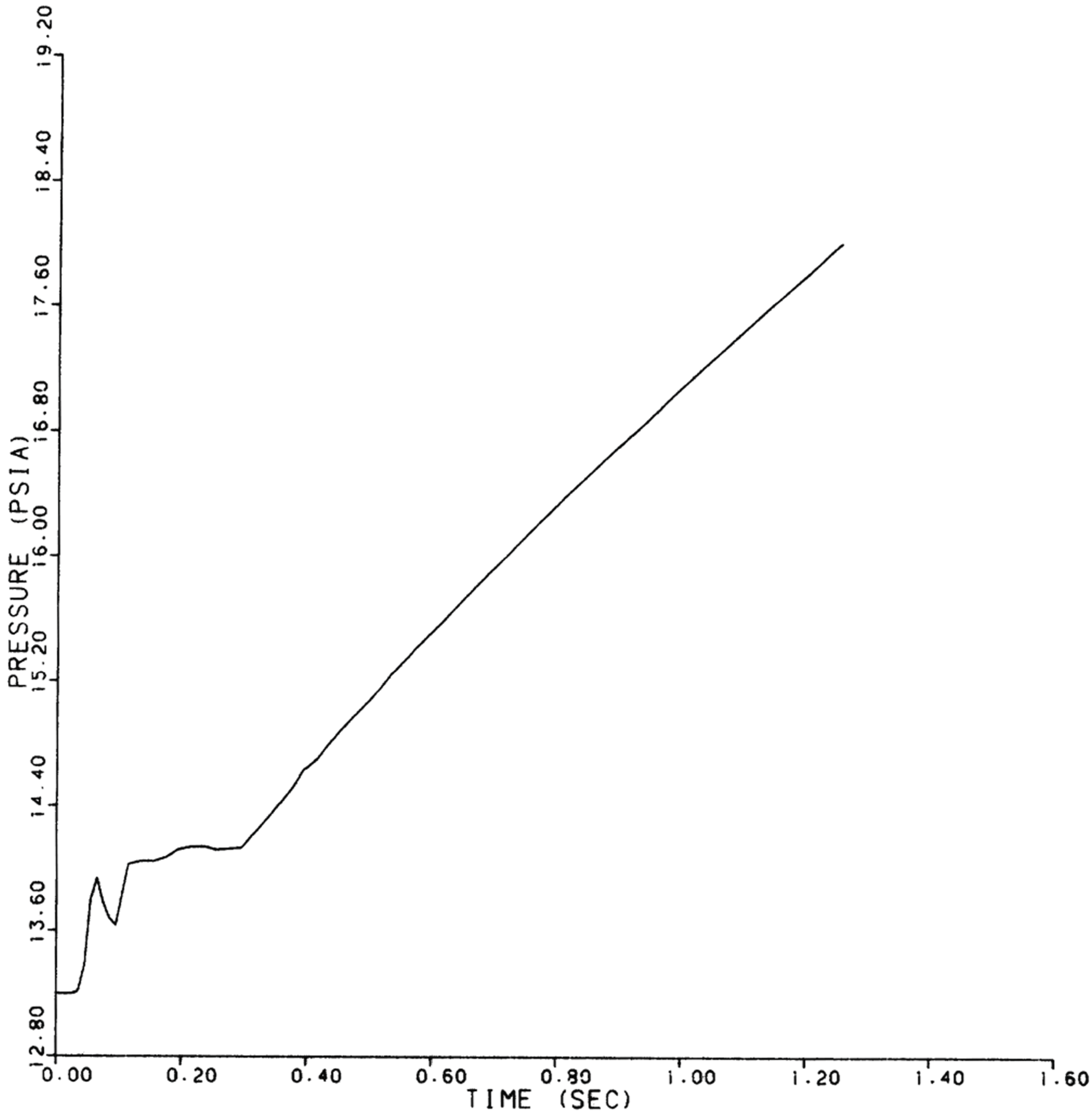
SOUTHERN COMPANY *Energy to Serve Your World®*	**VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2**	STEAM GENERATOR INLET ELBOW NODE – E66 (763–in.^{2} BREAK AREA)
		FIGURE 6.2.1–22 (SHEET 66 OF 74)



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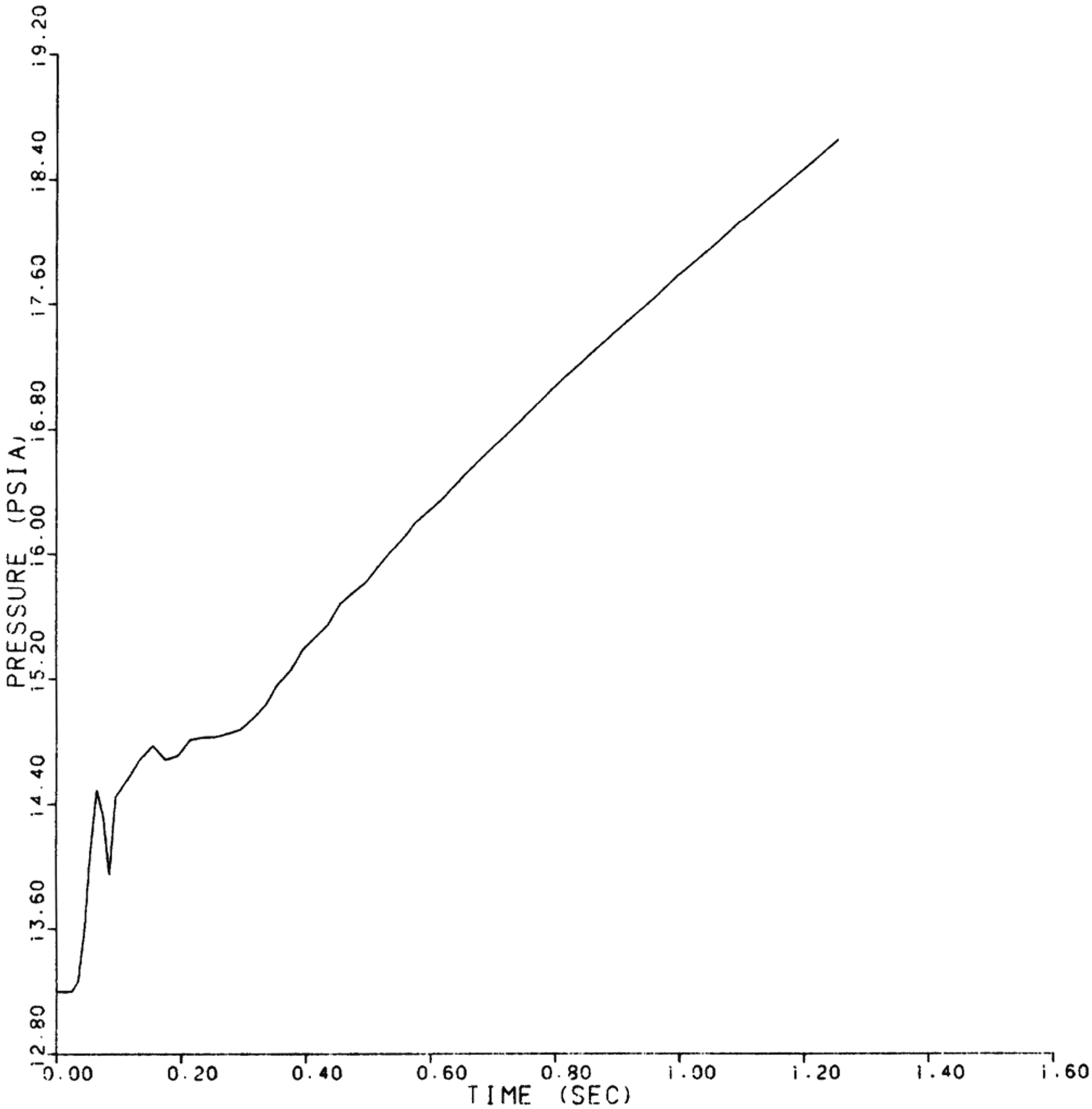
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E67
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 67 OF 74)



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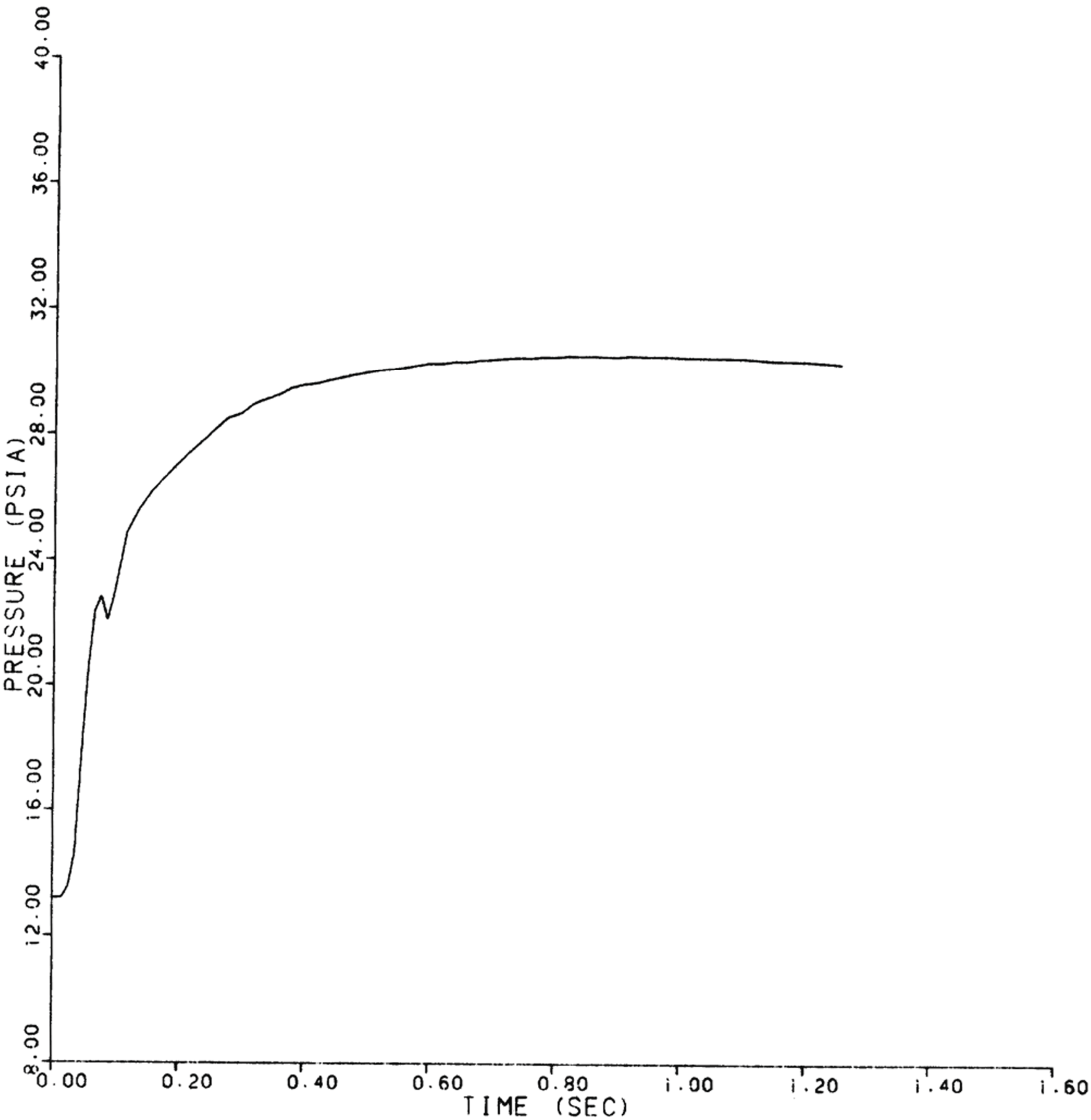
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E68
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 68 OF 74)



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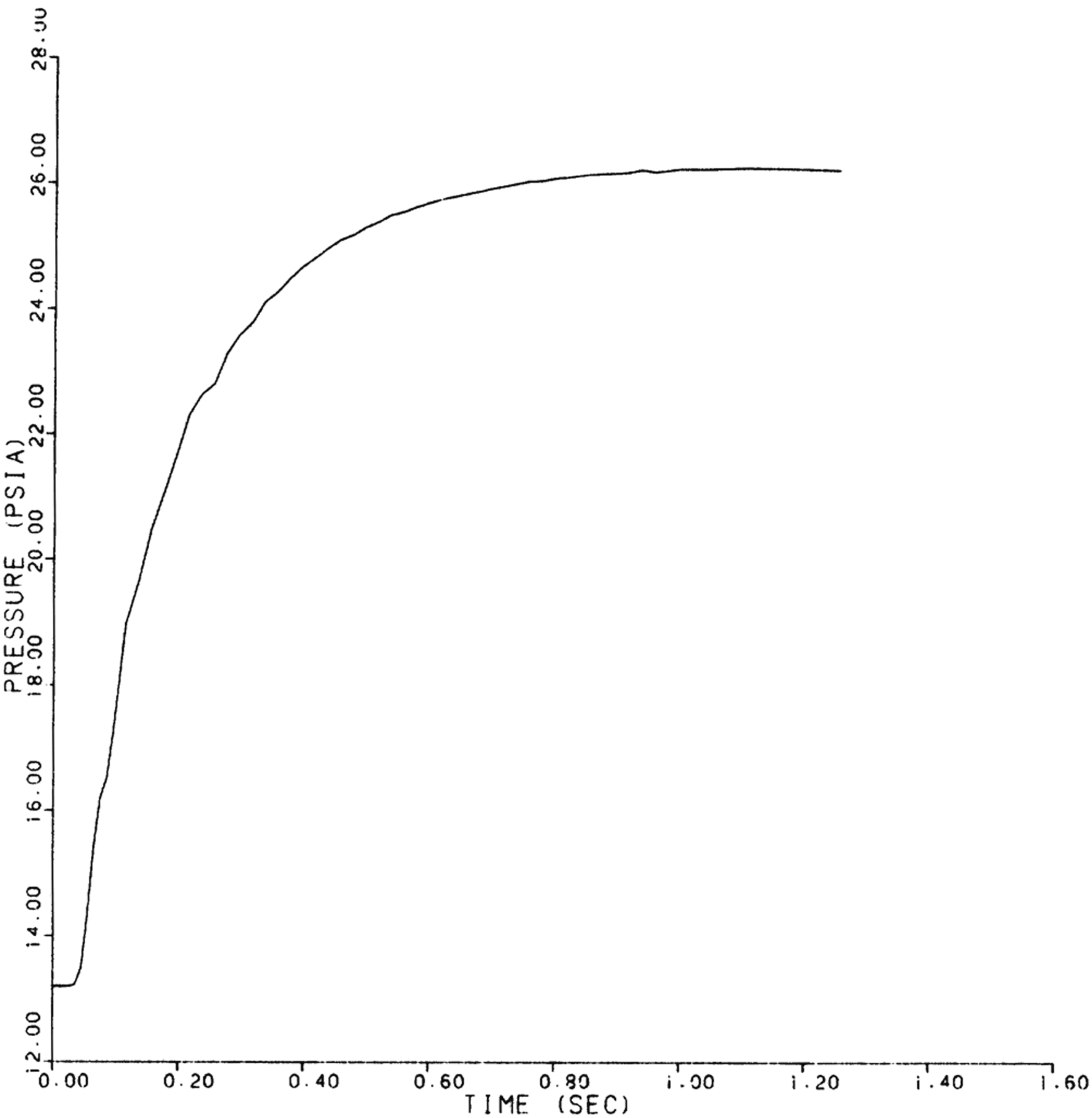
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E69
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 69 OF 74)



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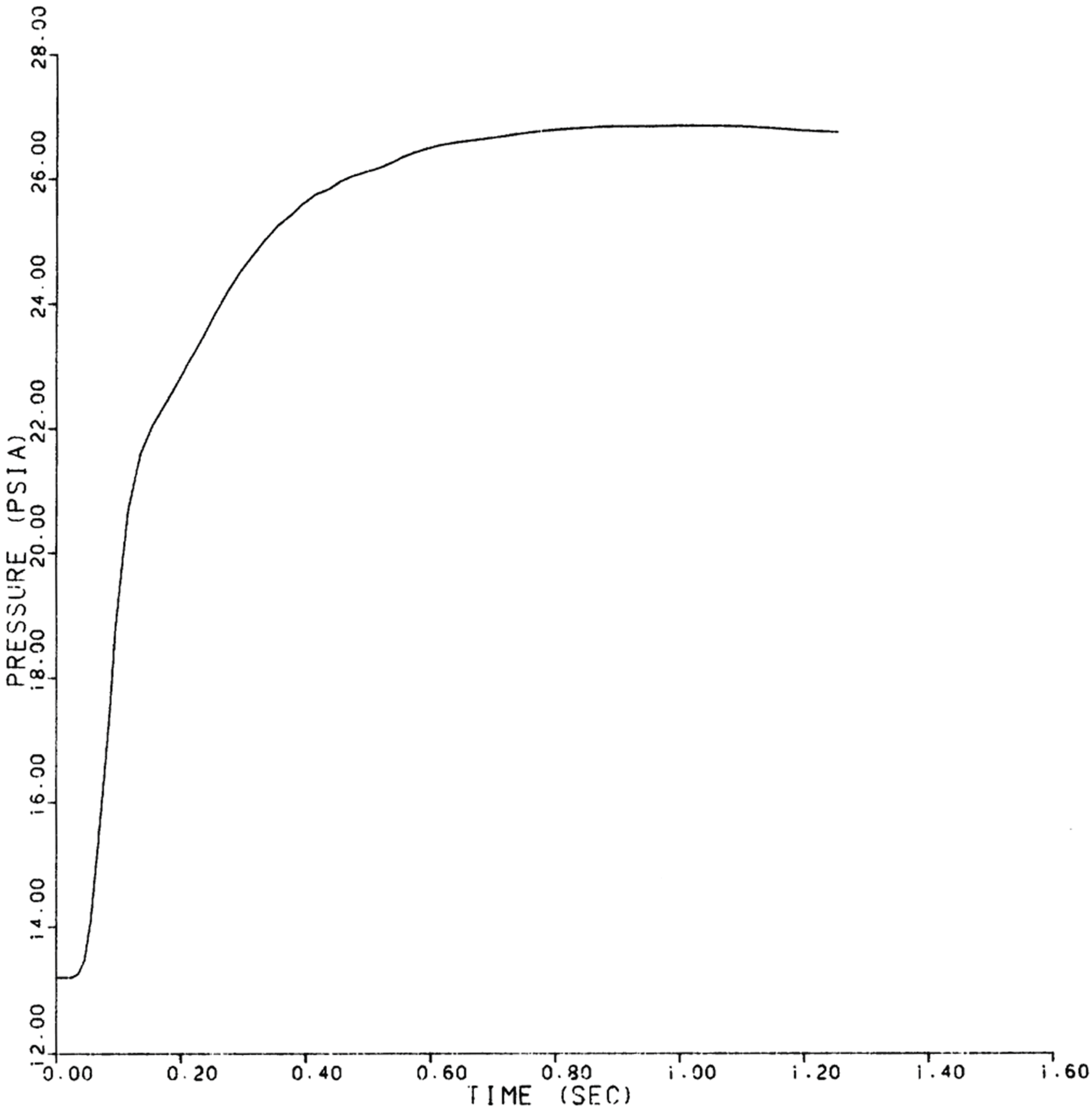
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E70
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 70 OF 74)



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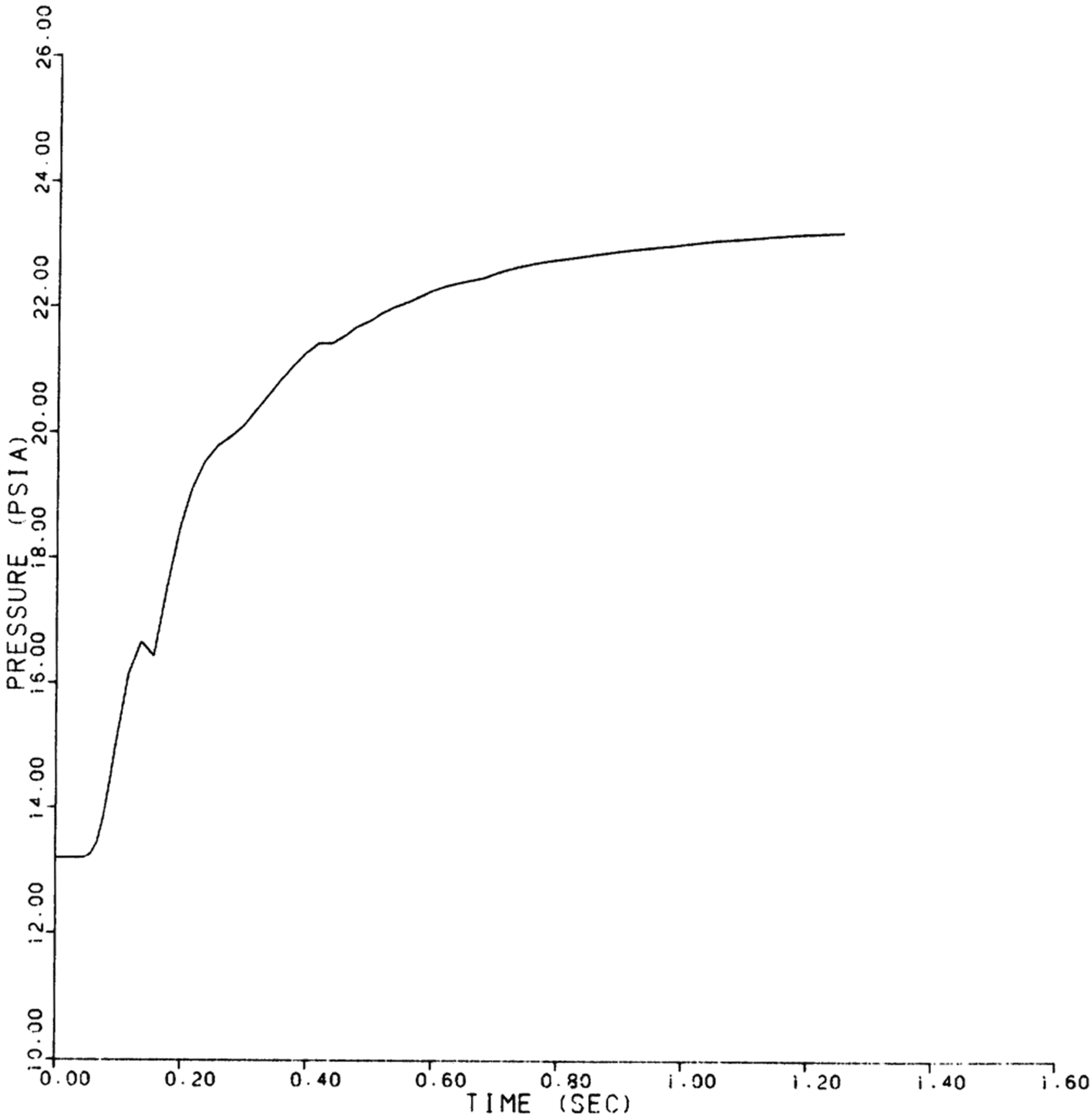
SOUTHERN COMPANY *Energy to Serve Your World®*	**VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2**	STEAM GENERATOR INLET ELBOW NODE – E71 (763–in.^{2} BREAK AREA)
		FIGURE 6.2.1–22 (SHEET 71 OF 74)



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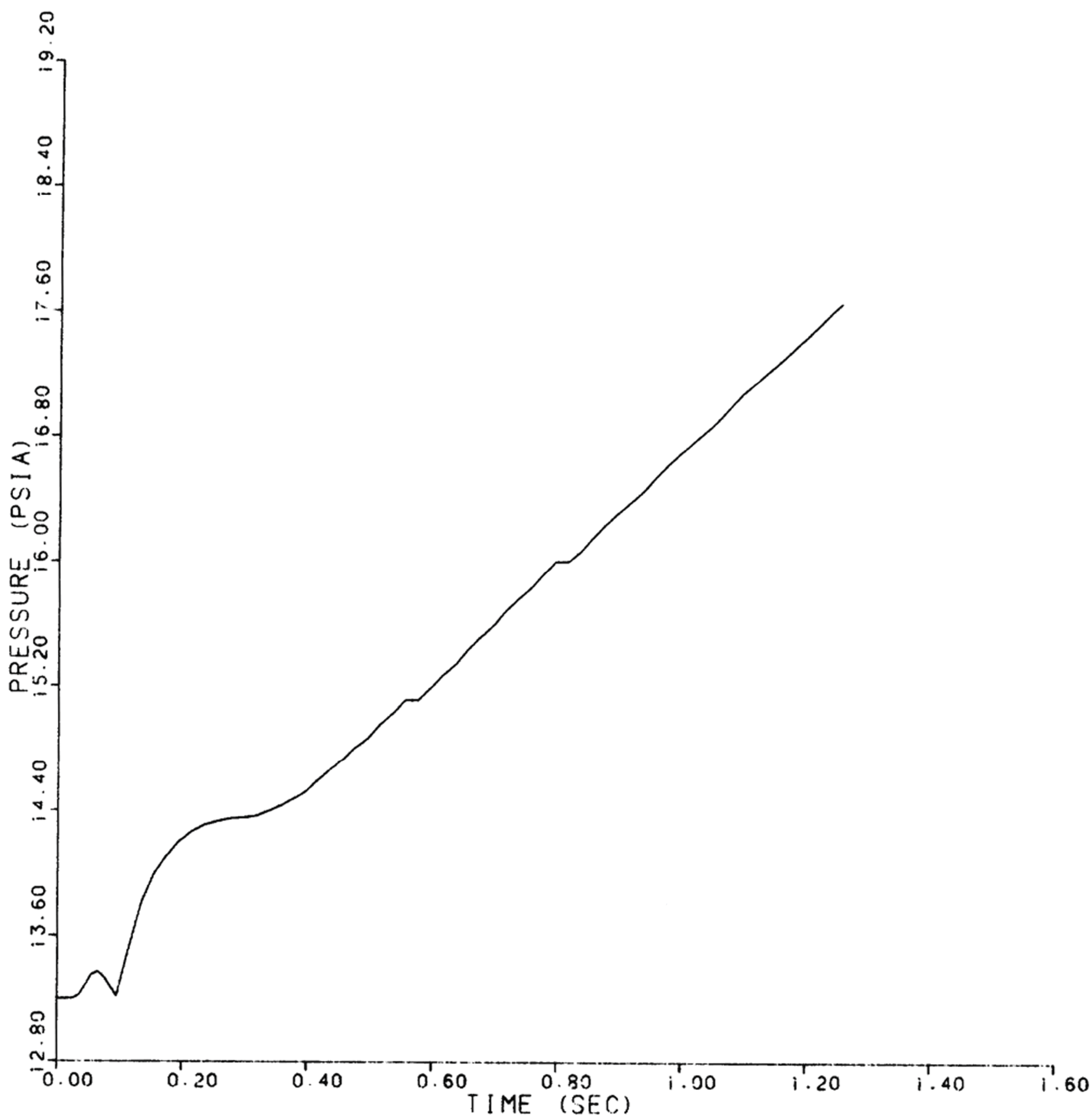
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E72
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 72 OF 74)



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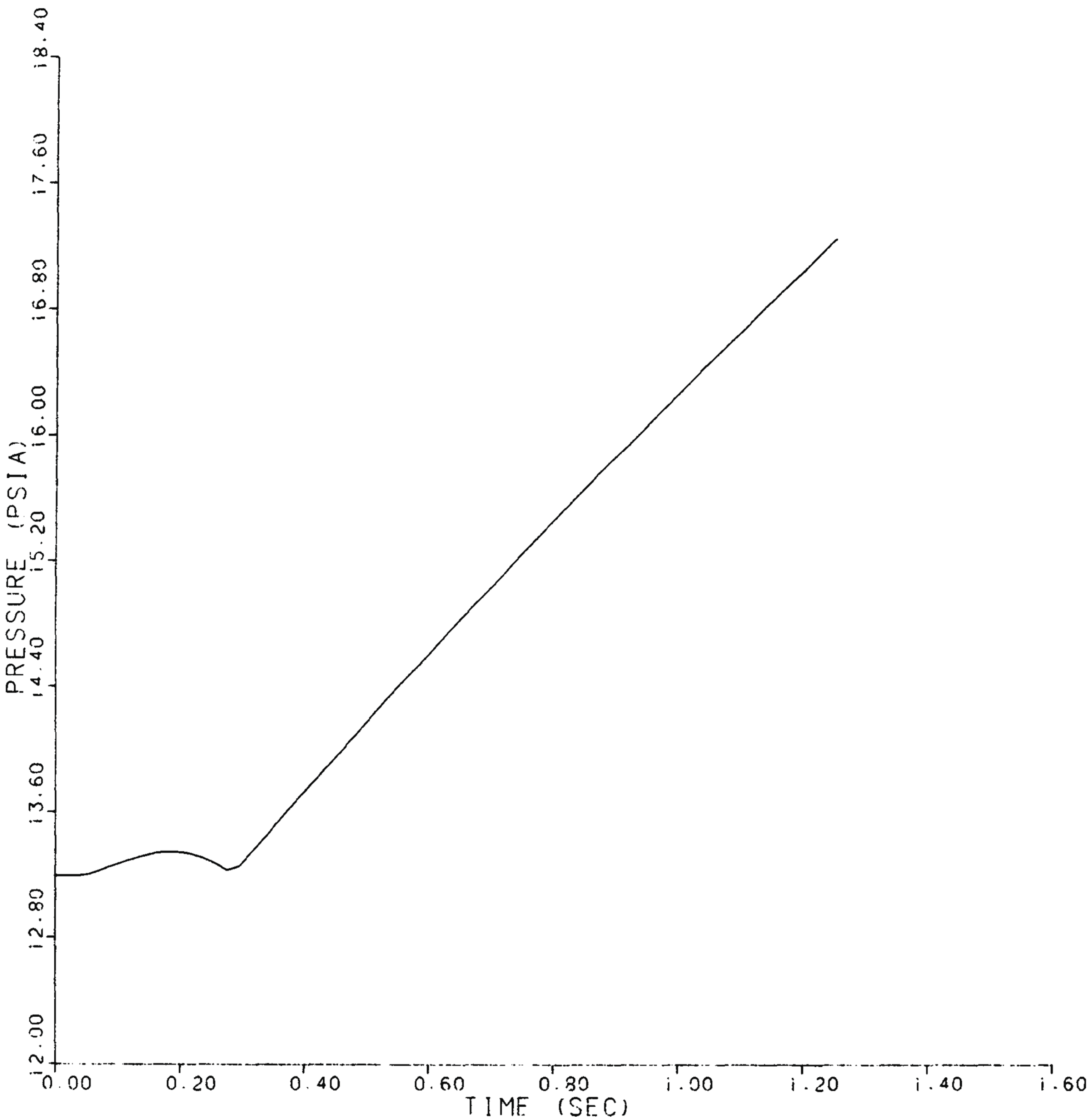
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E73
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 73 OF 74)



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SOUTHERN COMPANY
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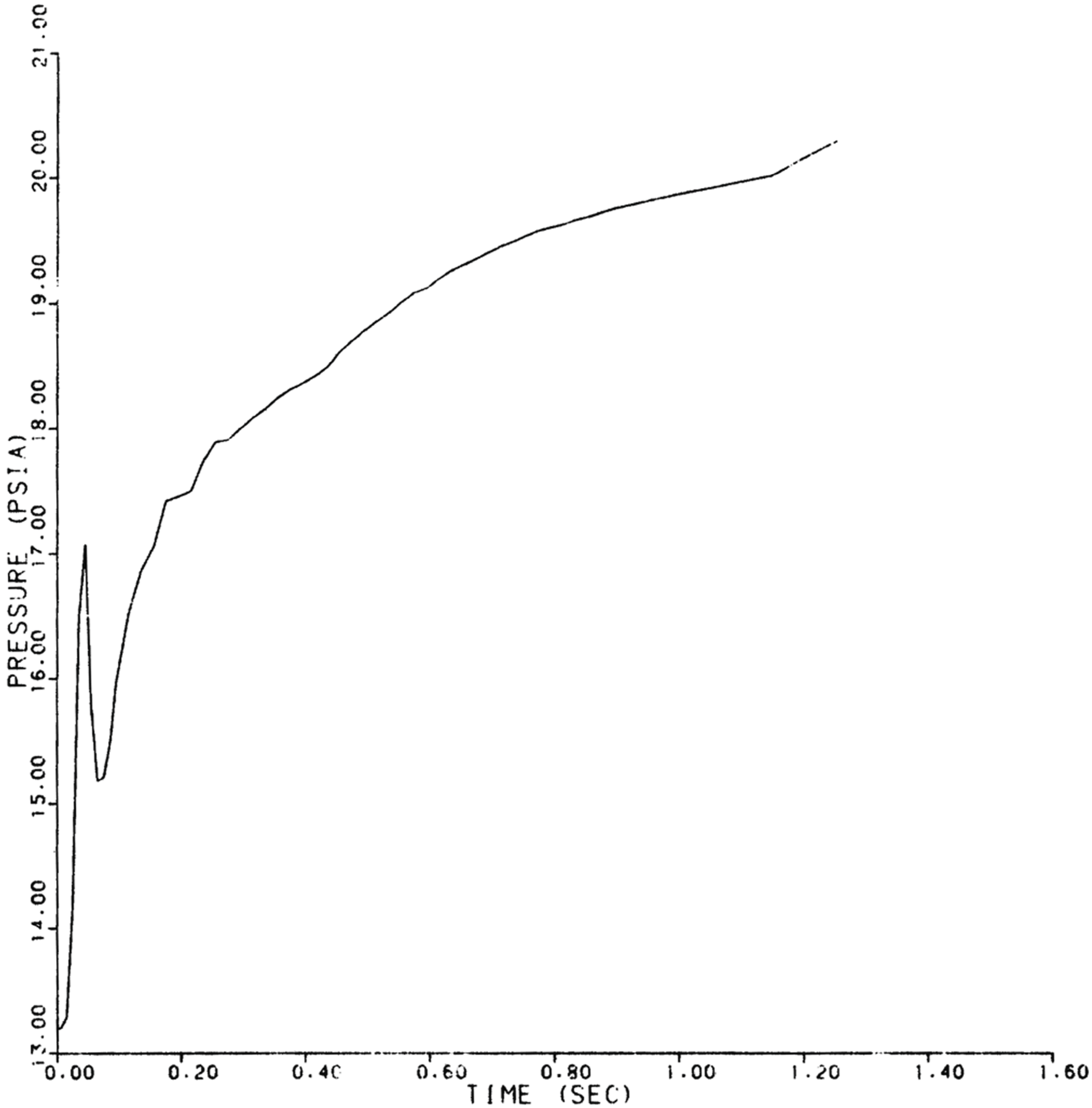
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

STEAM GENERATOR INLET ELBOW
NODE – E74
(763–in.^{2} BREAK AREA)

FIGURE 6.2.1–22 (SHEET 74 OF 74)



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SOUTHERN COMPANY
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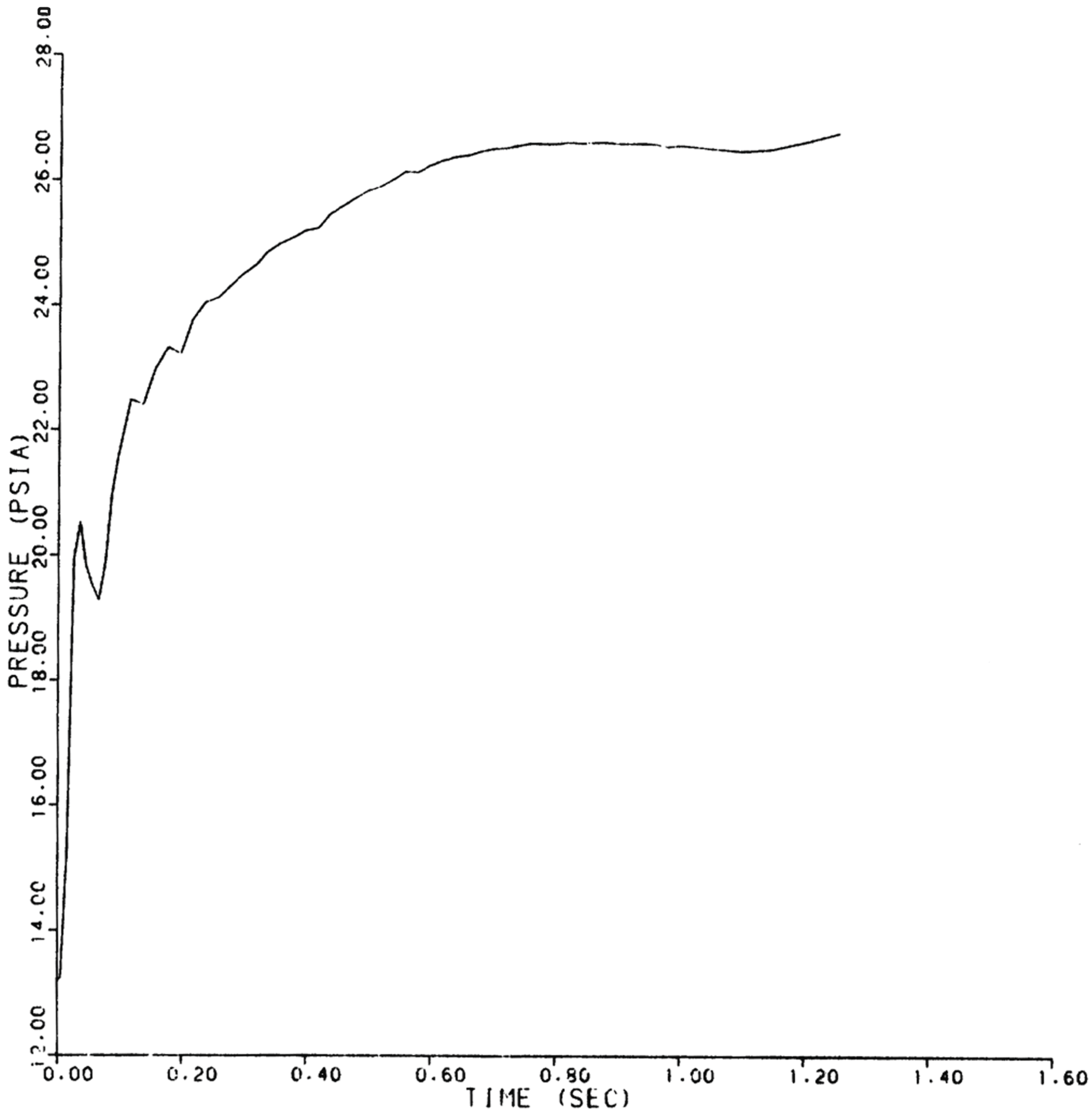
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E1
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 1 OF 74)



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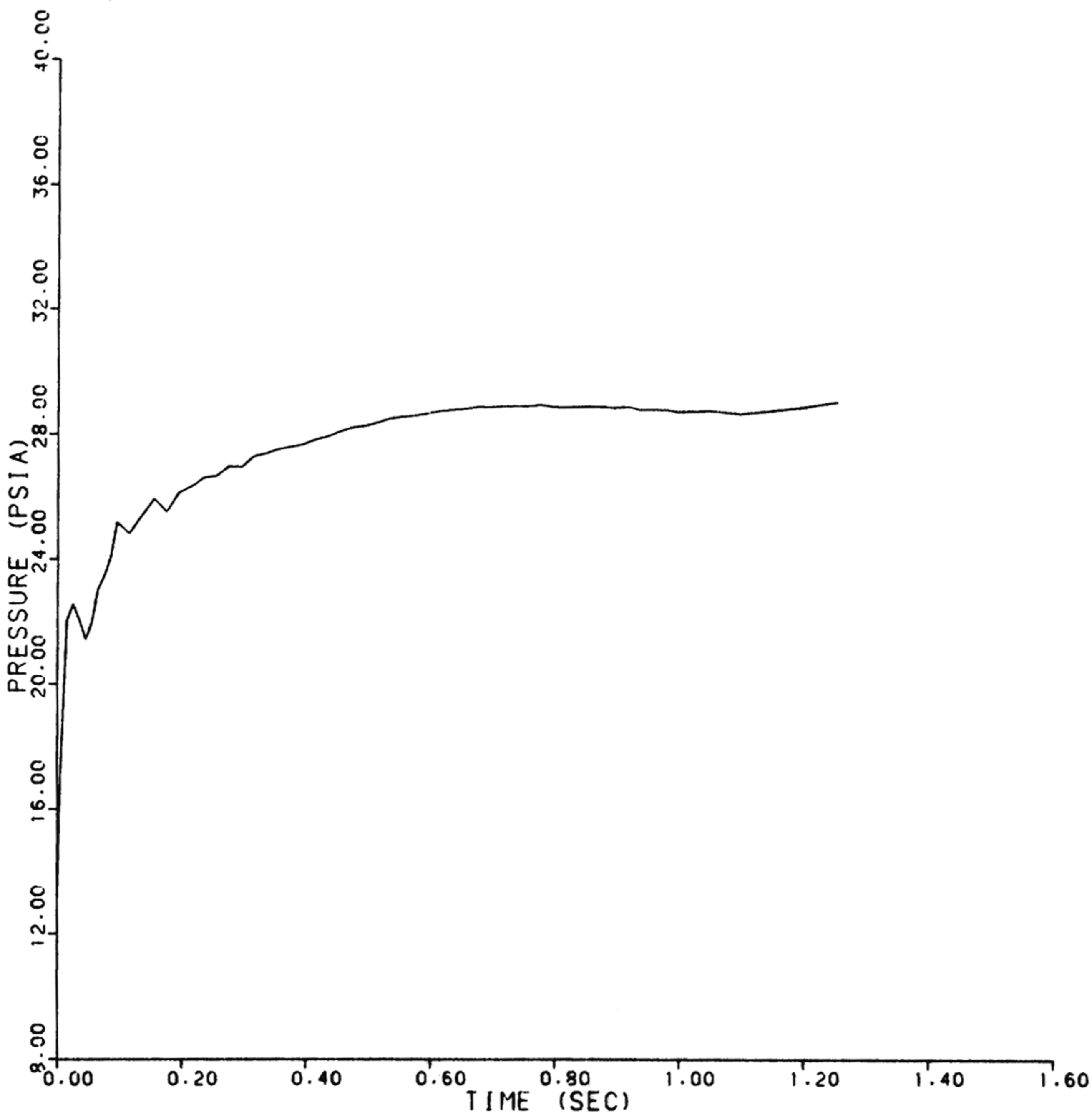
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E2
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 2 OF 74)



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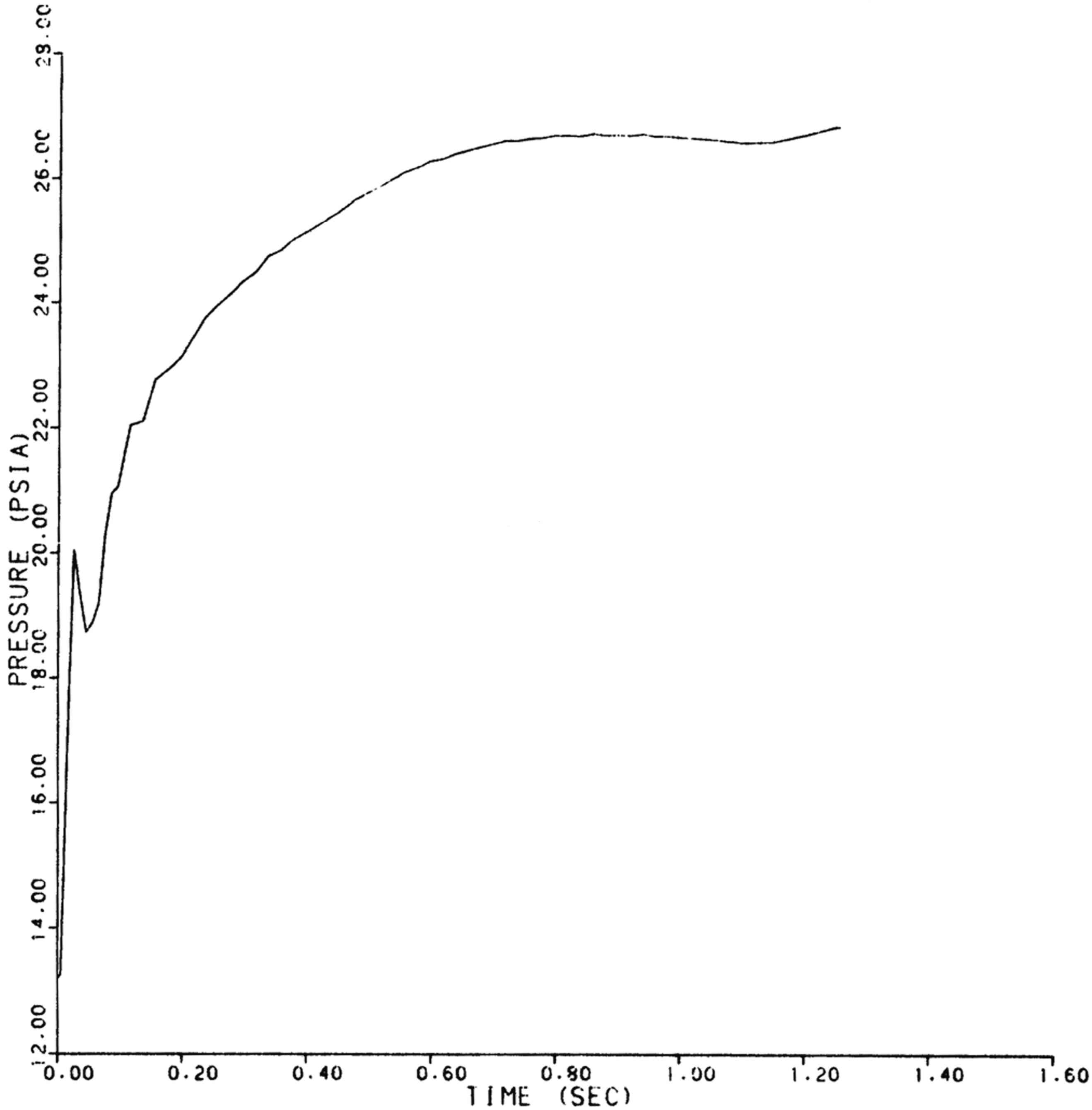
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E3
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 3 OF 74)



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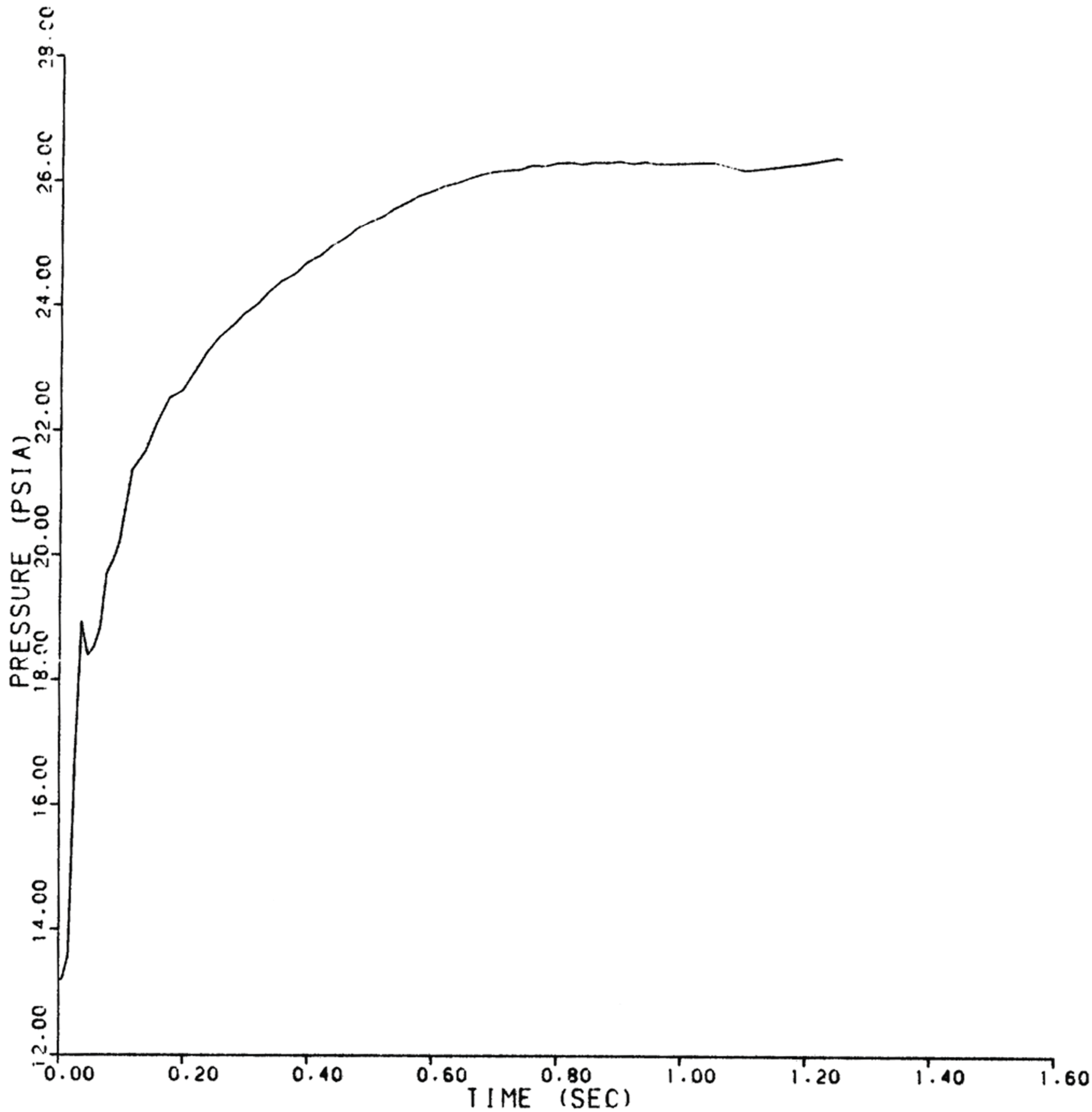
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E4
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 4 OF 74)



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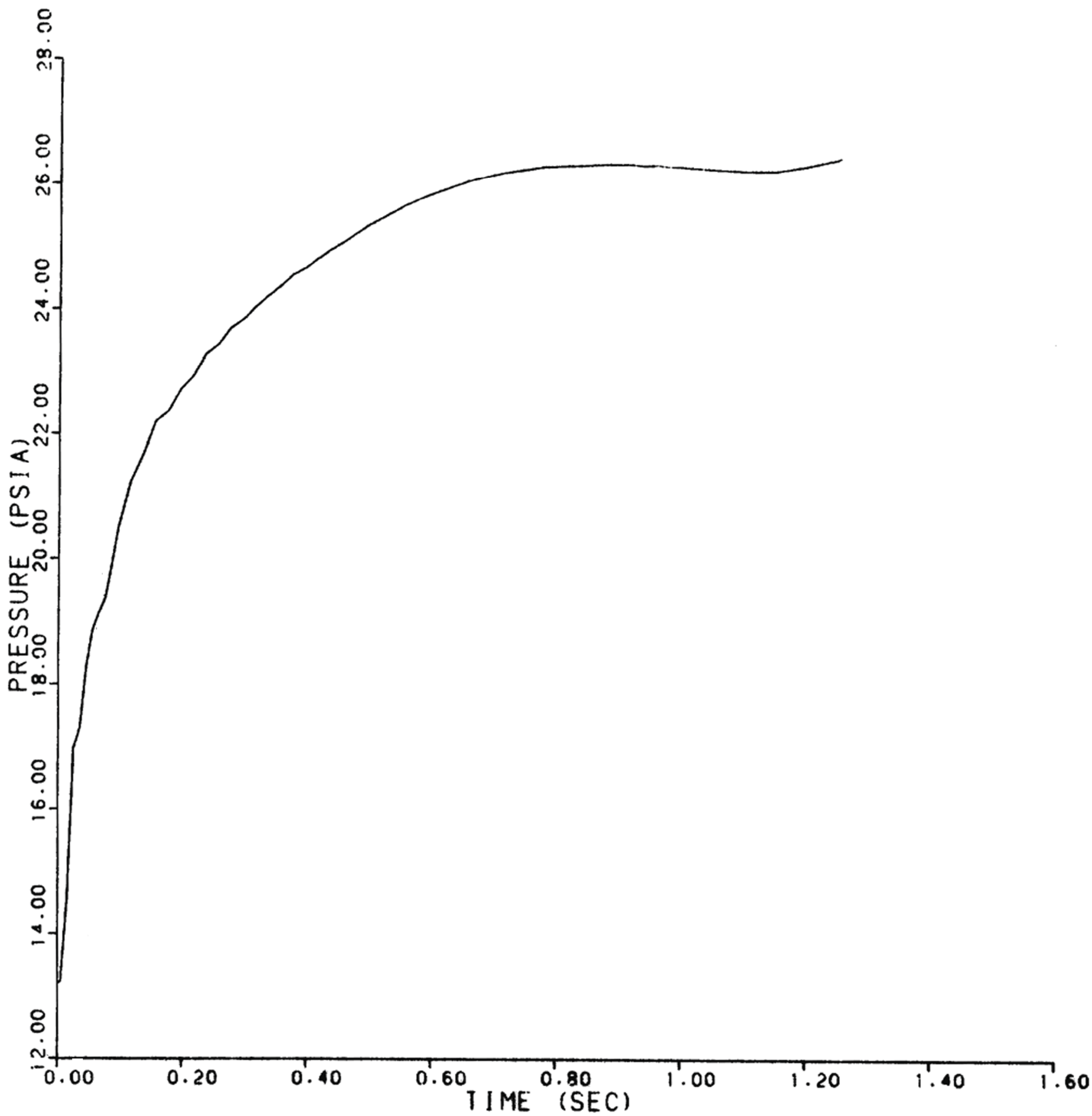
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E5
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 5 OF 74)



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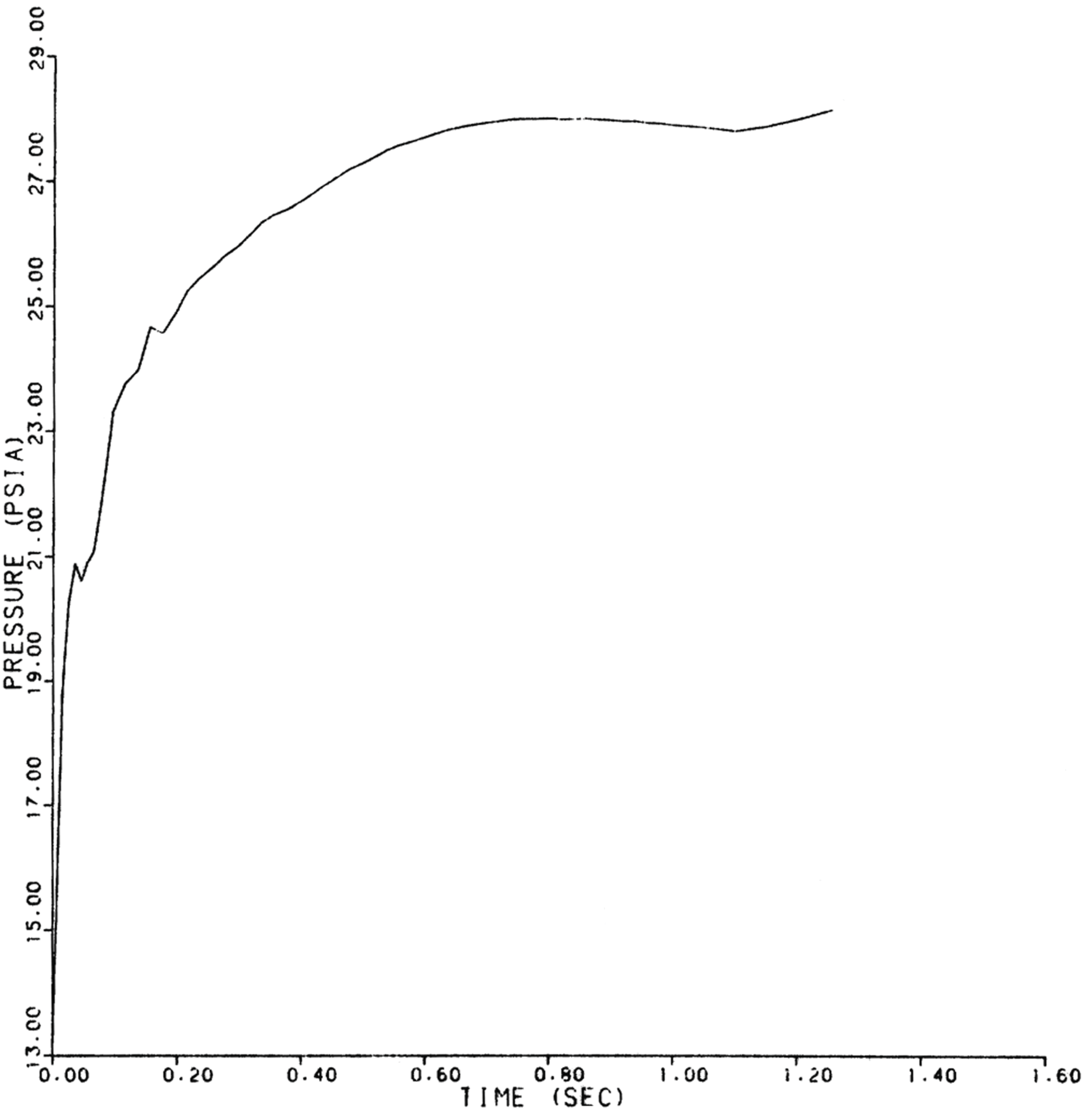
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E6
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 6 OF 74)



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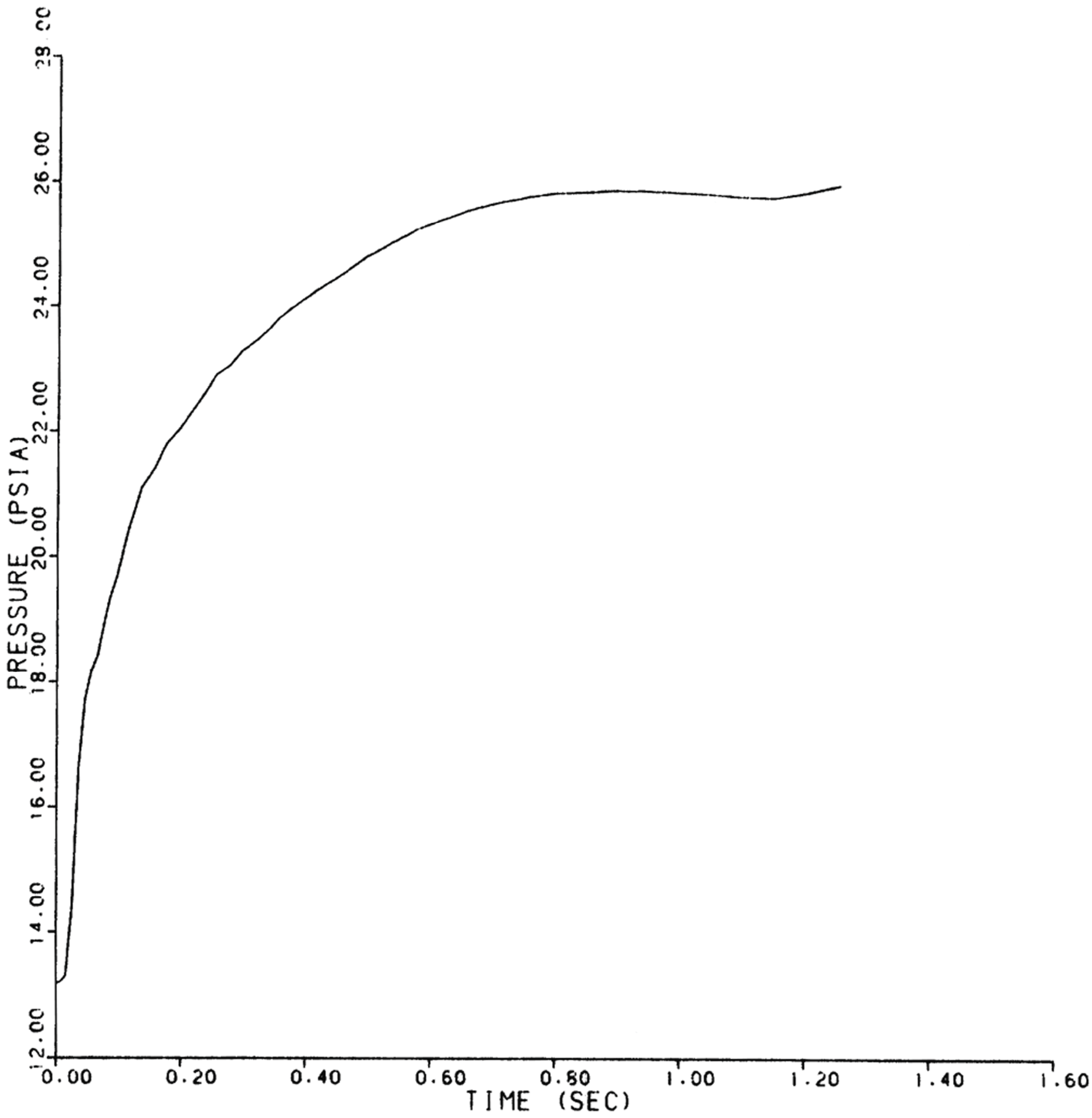
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E7
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 7 OF 74)



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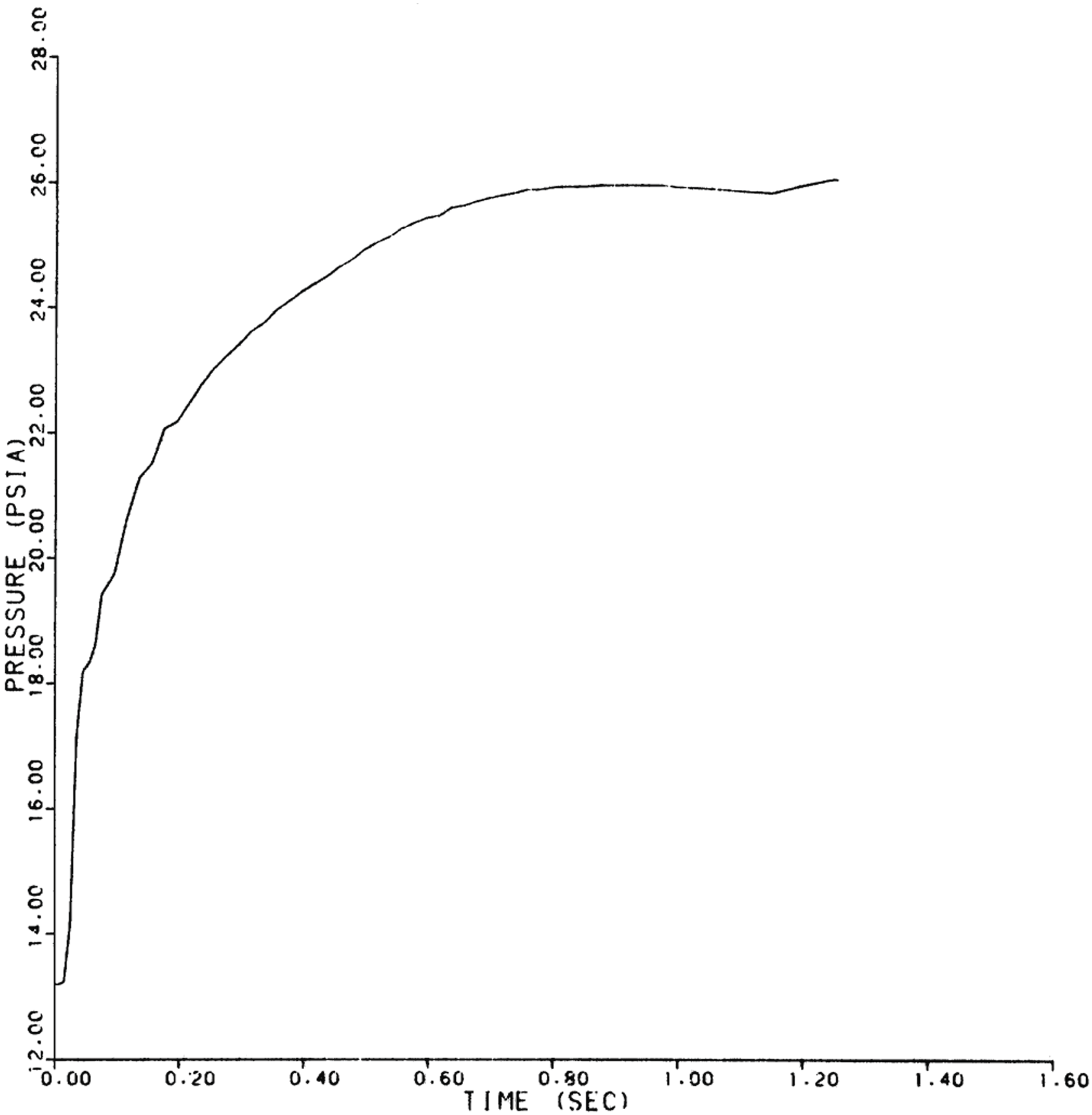
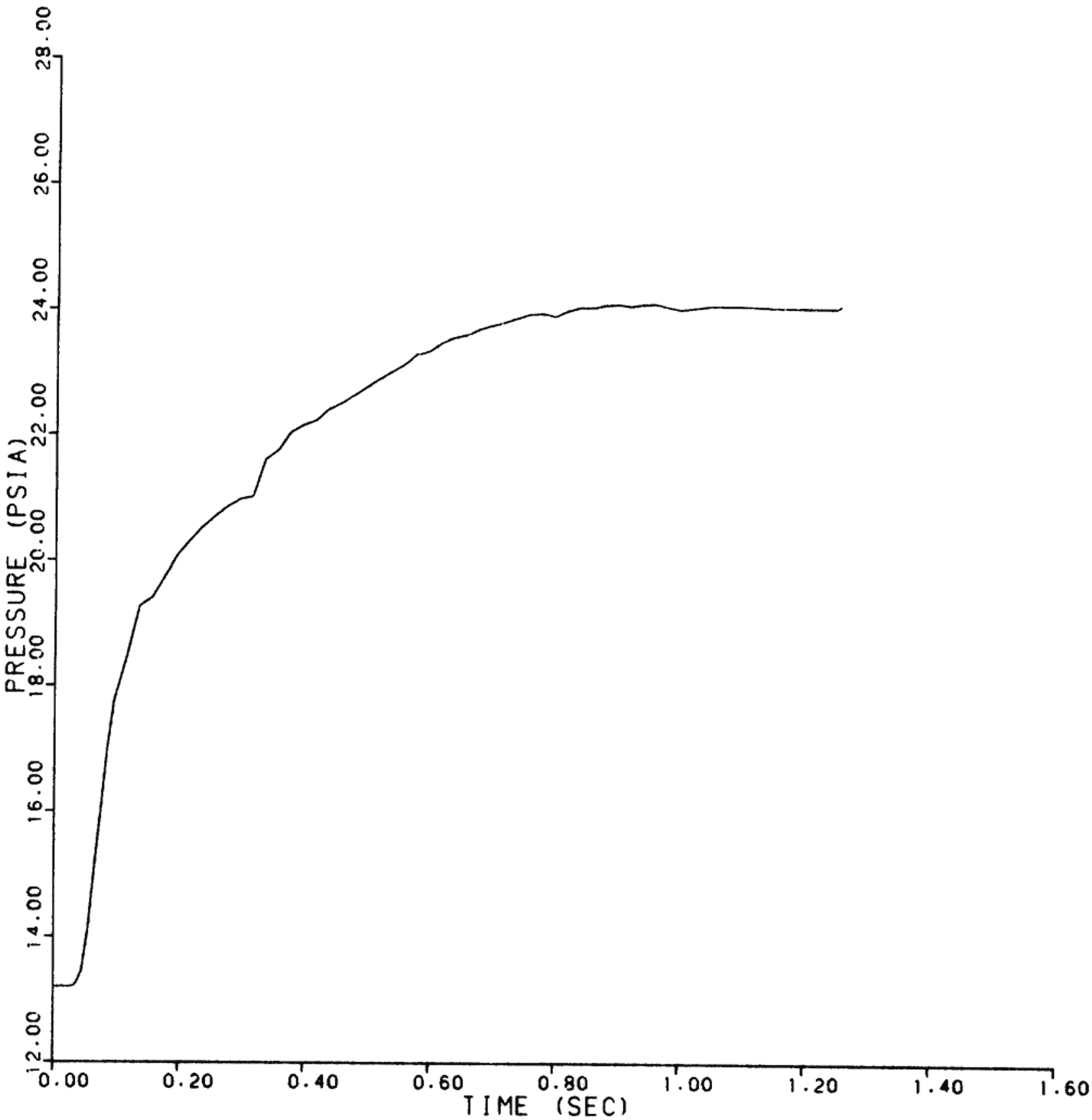
SOUTHERN COMPANY Energy to Serve Your World®	VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	LOOP CLOSURE WELD NODE E8 (336–in.^{2} BREAK AREA)
		FIGURE 6.2.1–23 (SHEET 8 OF 74)



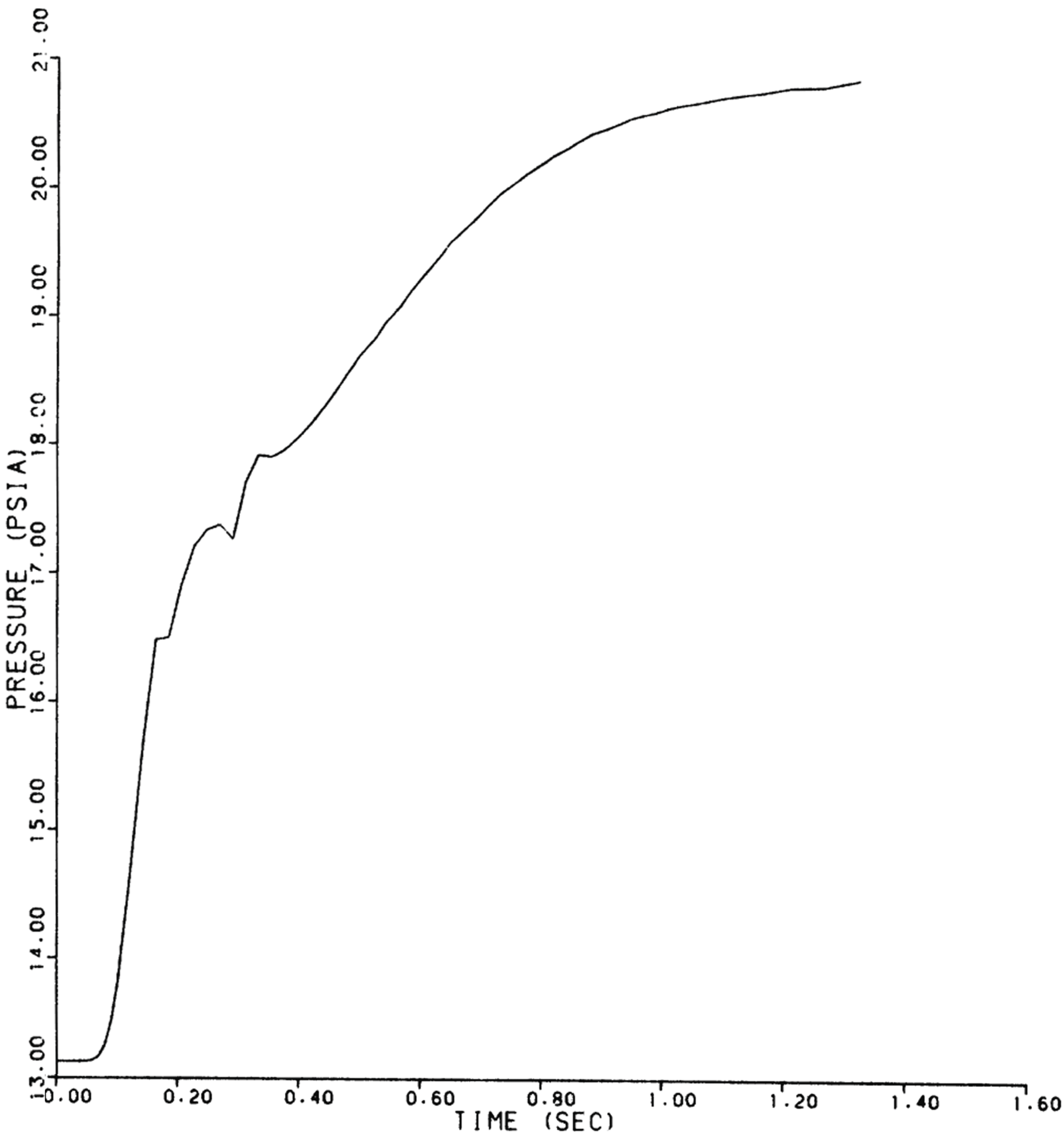
REV 13 4/06

SOUTHERN COMPANY *Energy to Serve Your World®* VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	LOOP CLOSURE WELD NODE E9 (336–in.^{2} BREAK AREA)
	FIGURE 6.2.1–23 (SHEET 9 OF 74)



REV 13 4/06

SOUTHERN COMPANY *Energy to Serve Your World®* **VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2**	LOOP CLOSURE WELD NODE E10 (336–in.^{2} BREAK AREA) FIGURE 6.2.1–23 (SHEET 10 OF 74)



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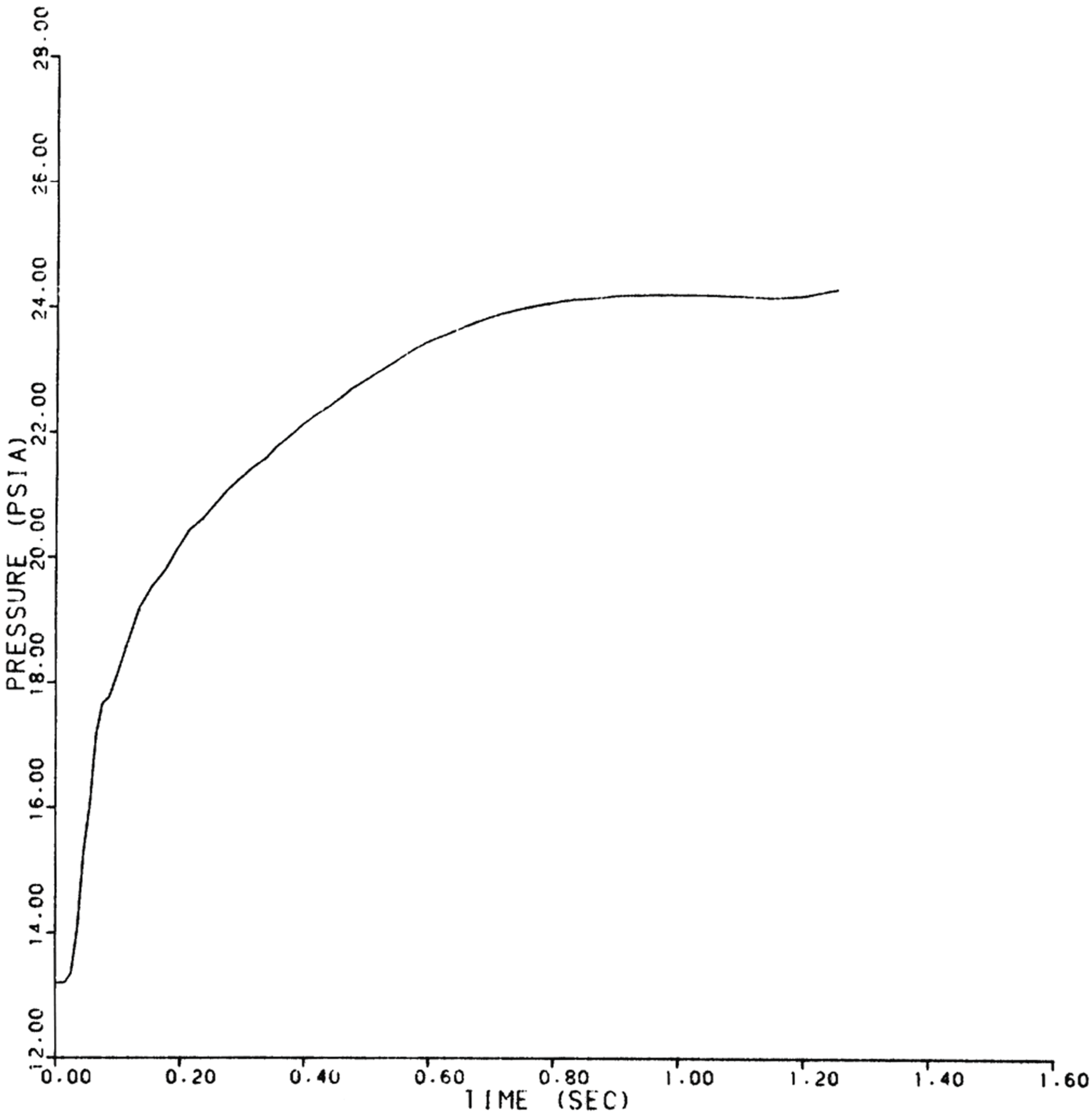
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E11
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 11 OF 74)



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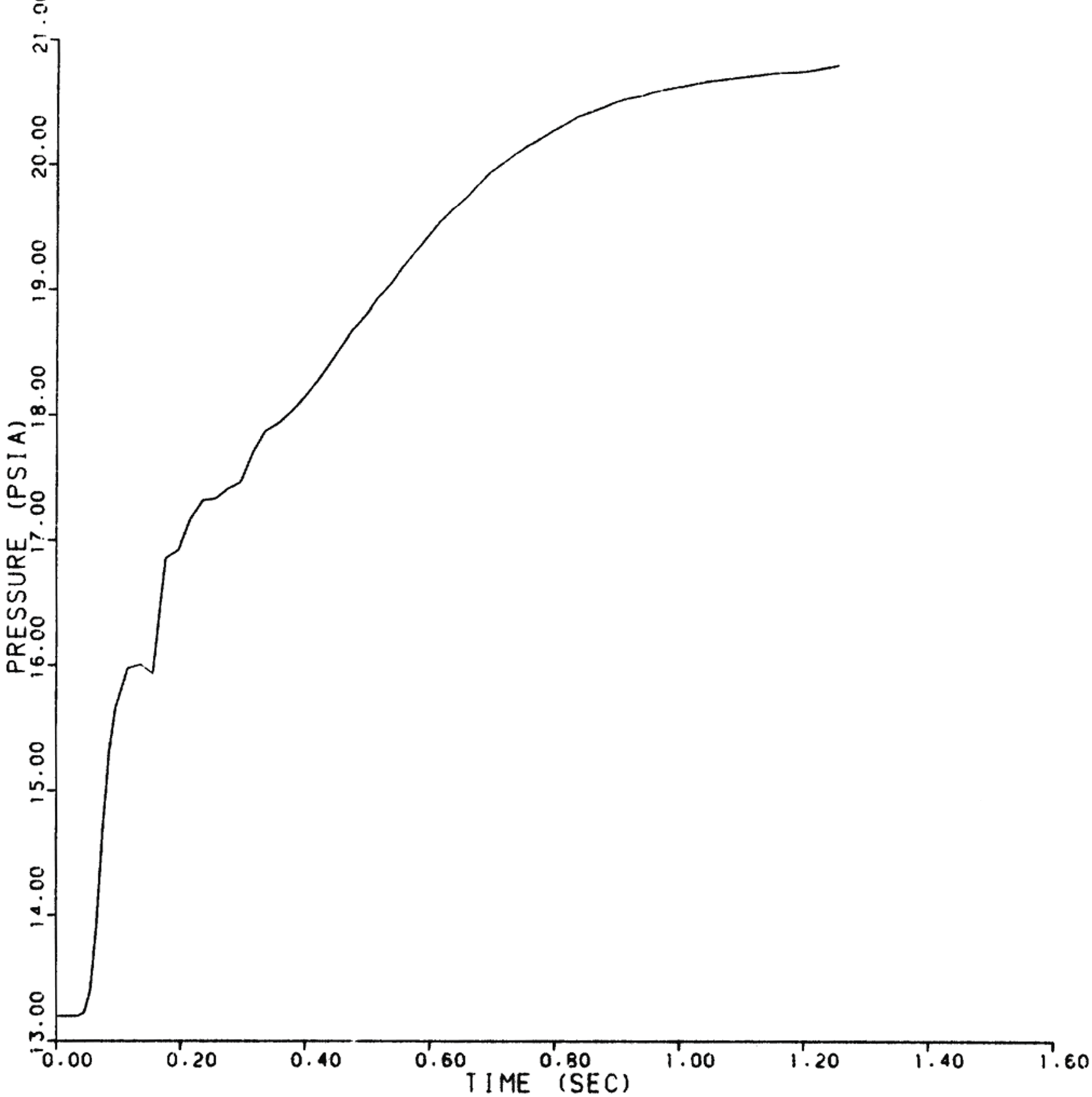
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E12
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 12 OF 74)



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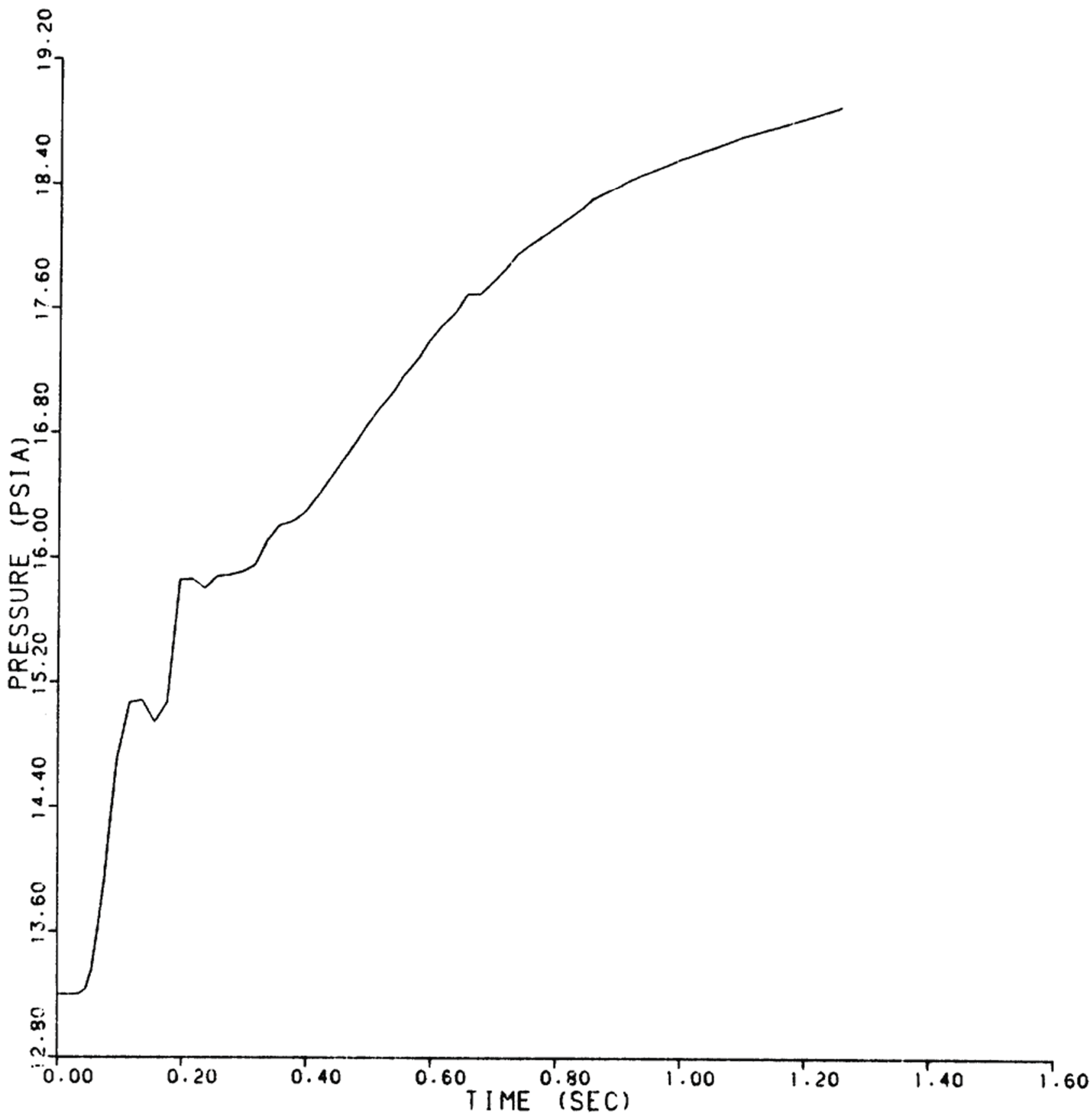
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E13
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 13 OF 74)



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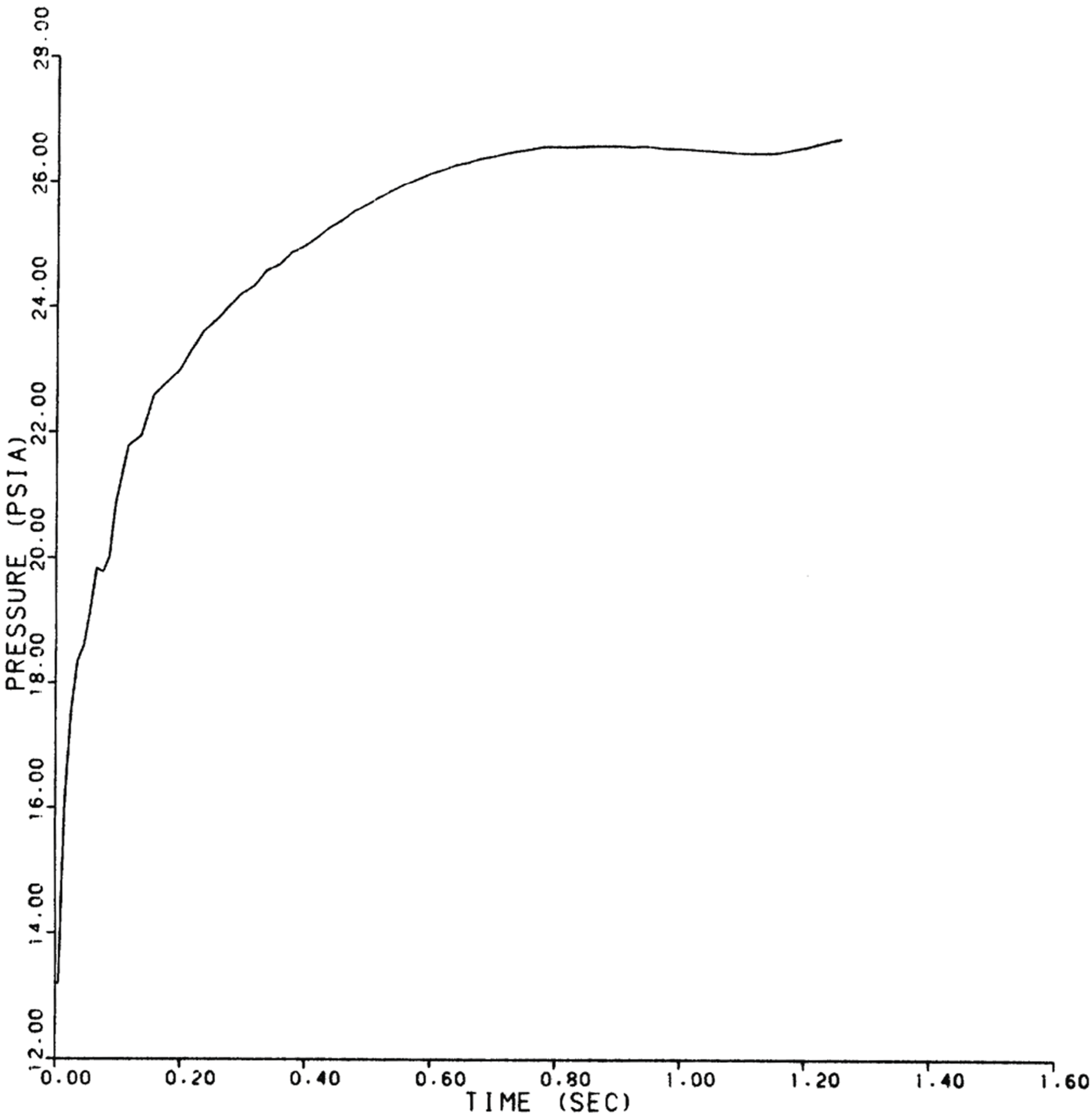
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E14
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 14 OF 74)



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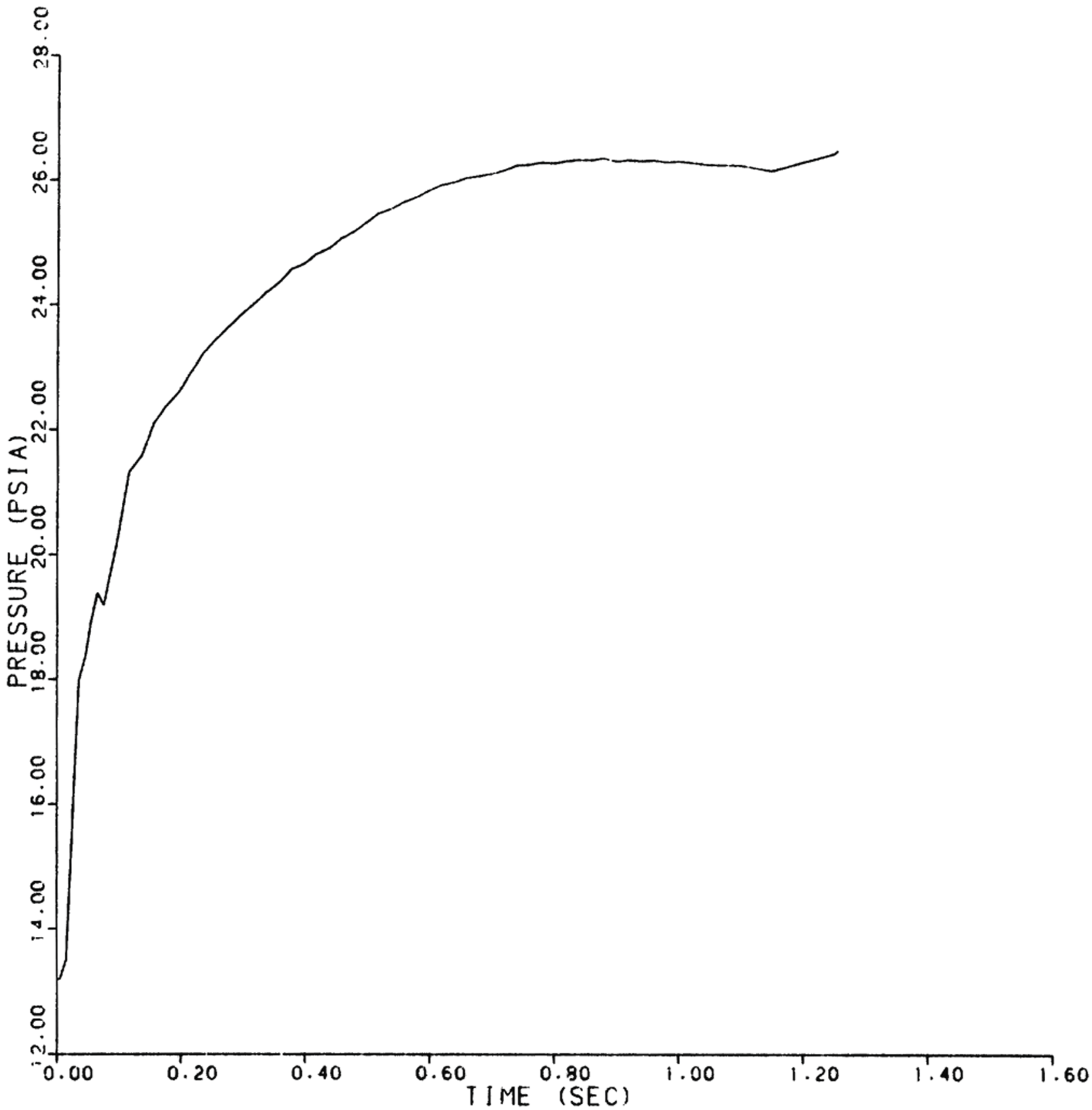
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E15
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 15 OF 74)



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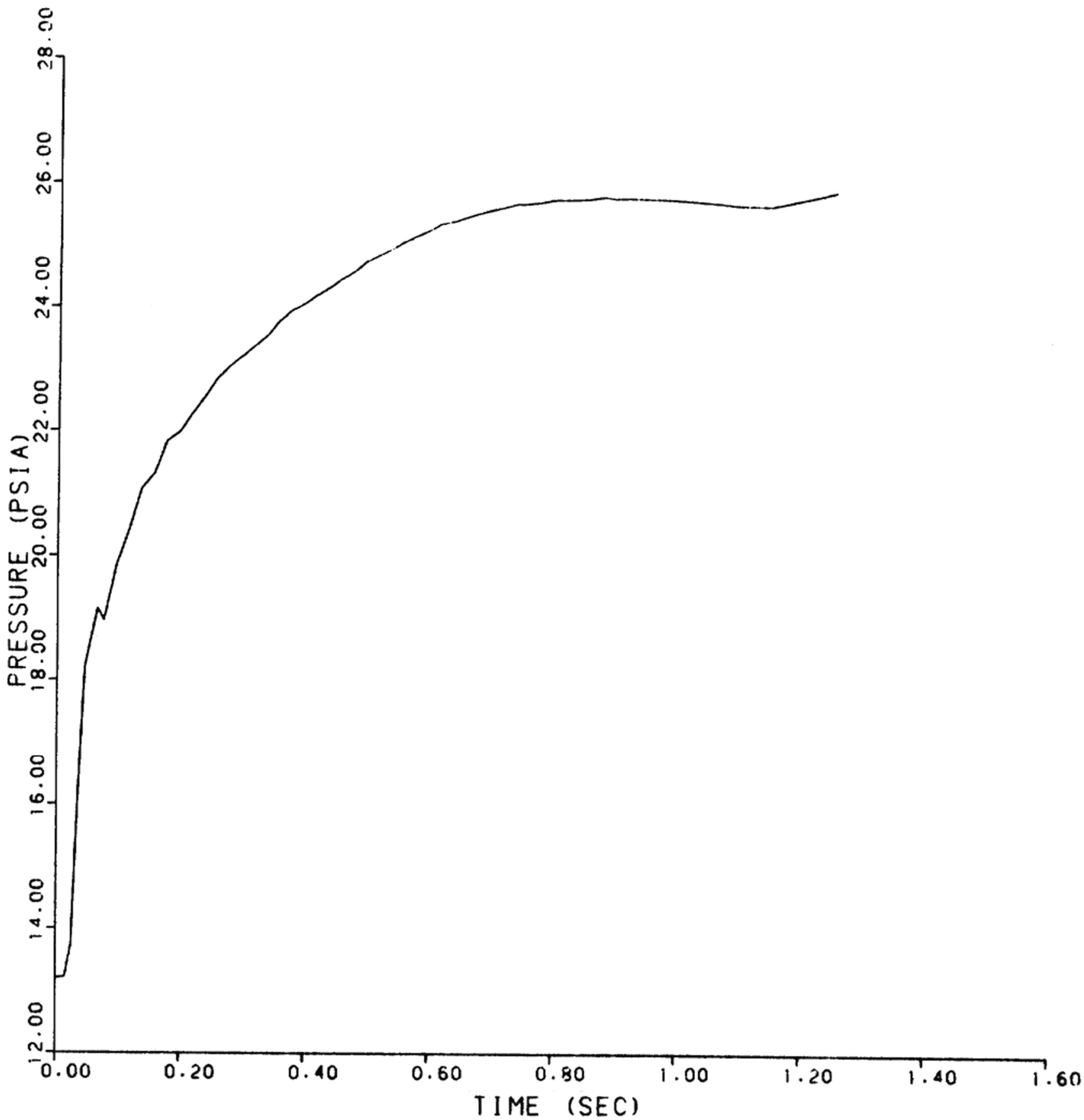
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E16
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 16 OF 74)



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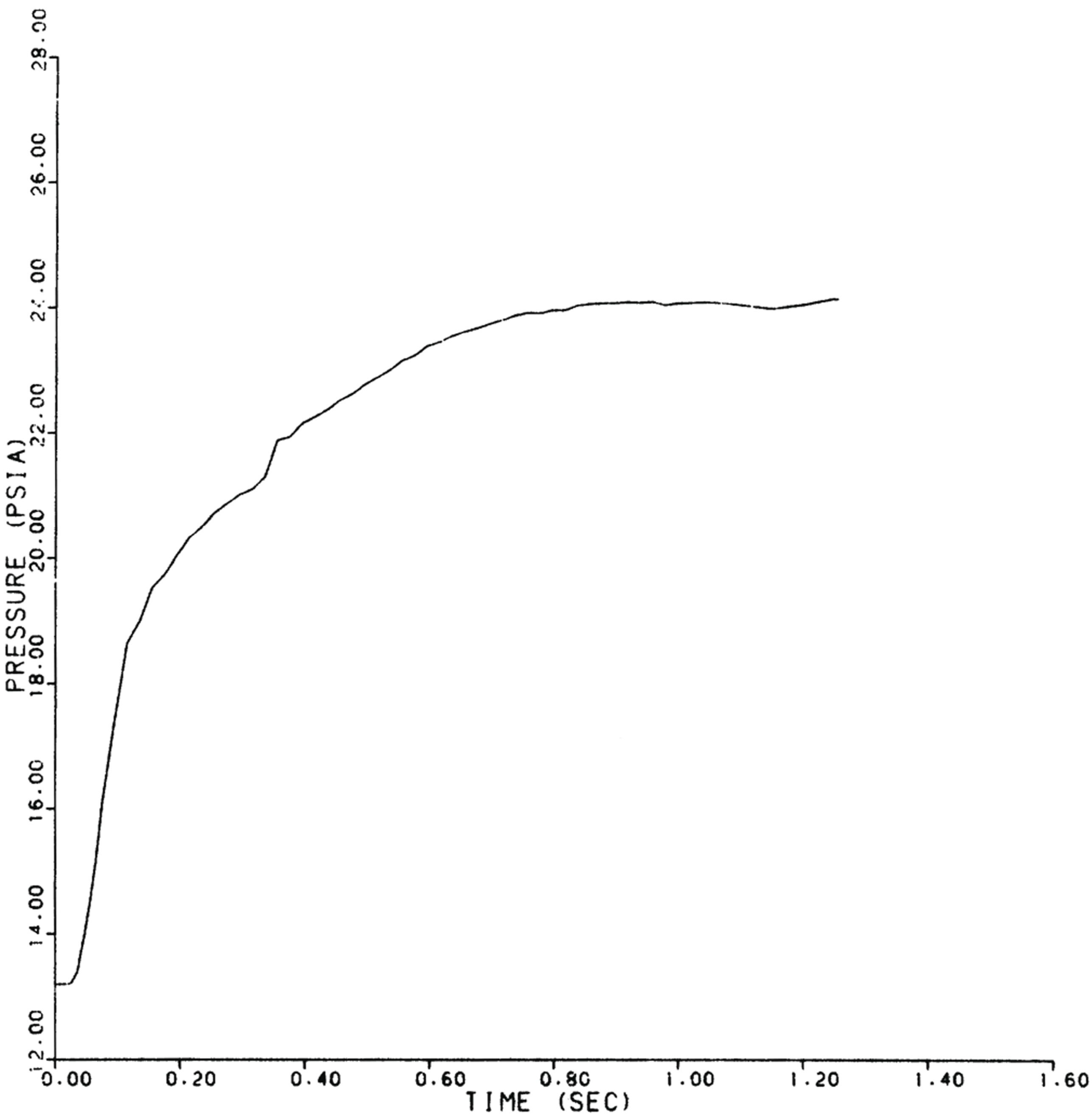
SOUTHERN COMPANY Energy to Serve Your World® VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	LOOP CLOSURE WELD NODE E17 (336–in.^{2} BREAK AREA)
	FIGURE 6.2.1–23 (SHEET 17 OF 74)



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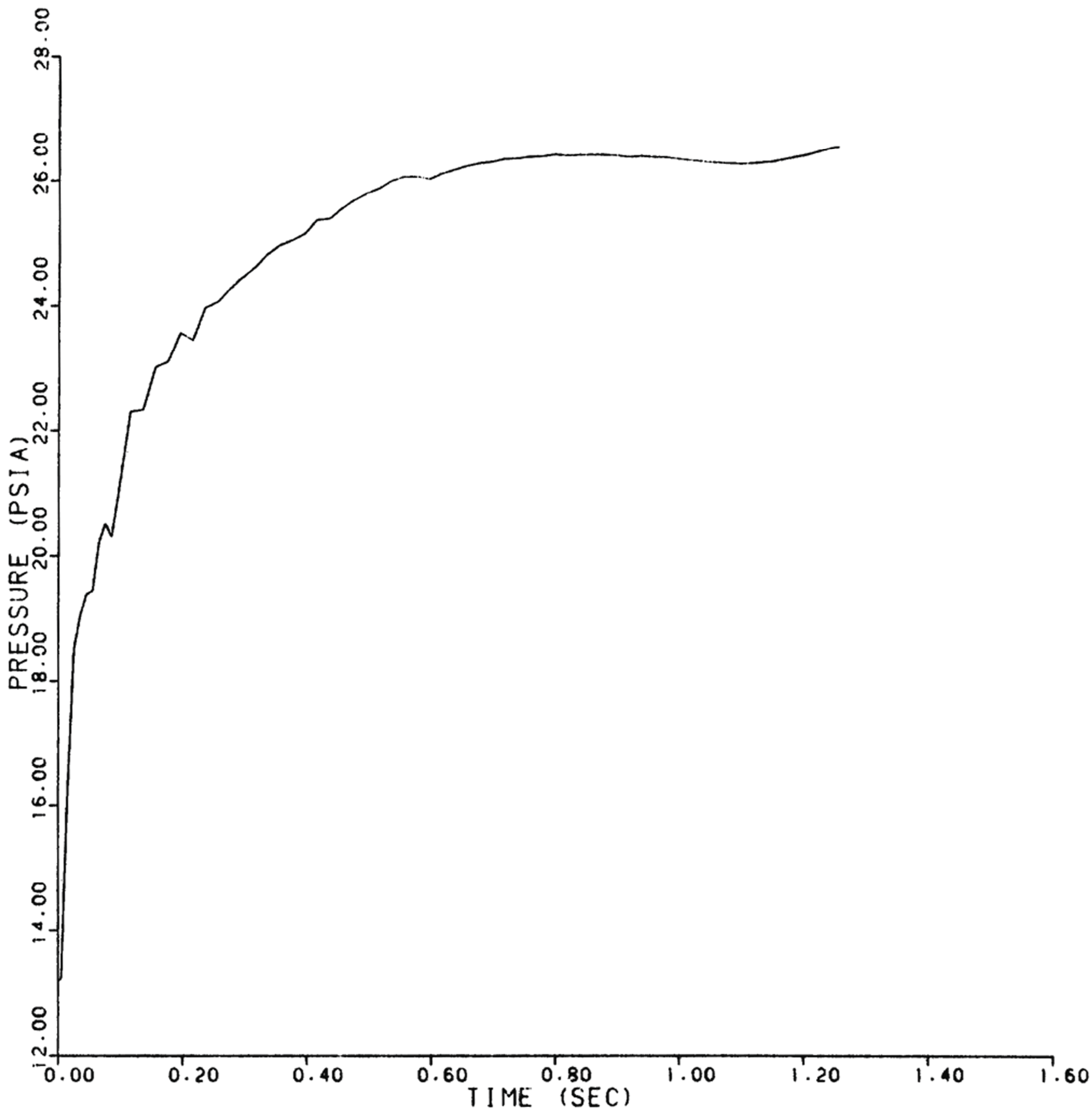
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E18
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 18 OF 74)



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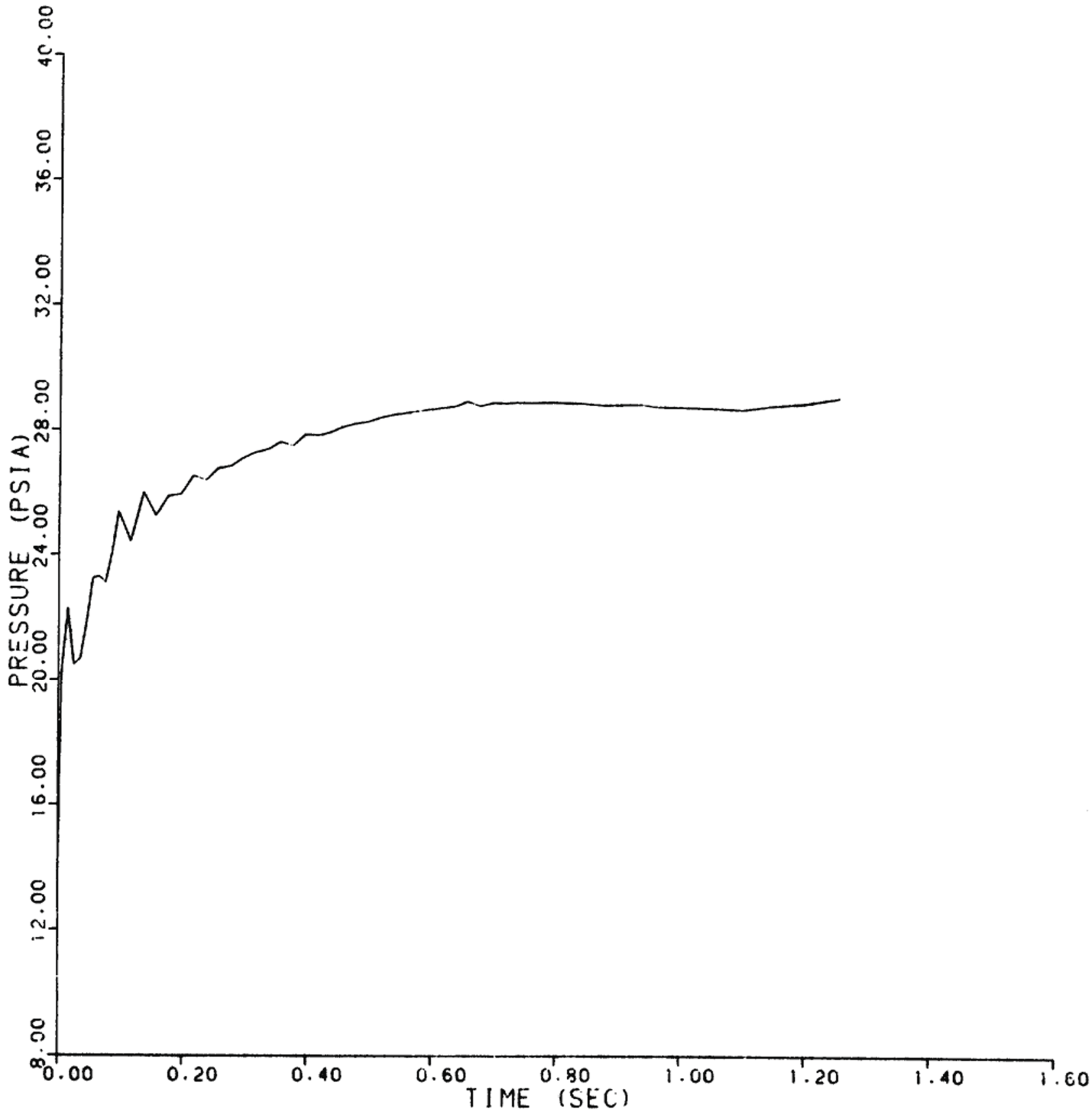
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E19
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 19 OF 74)



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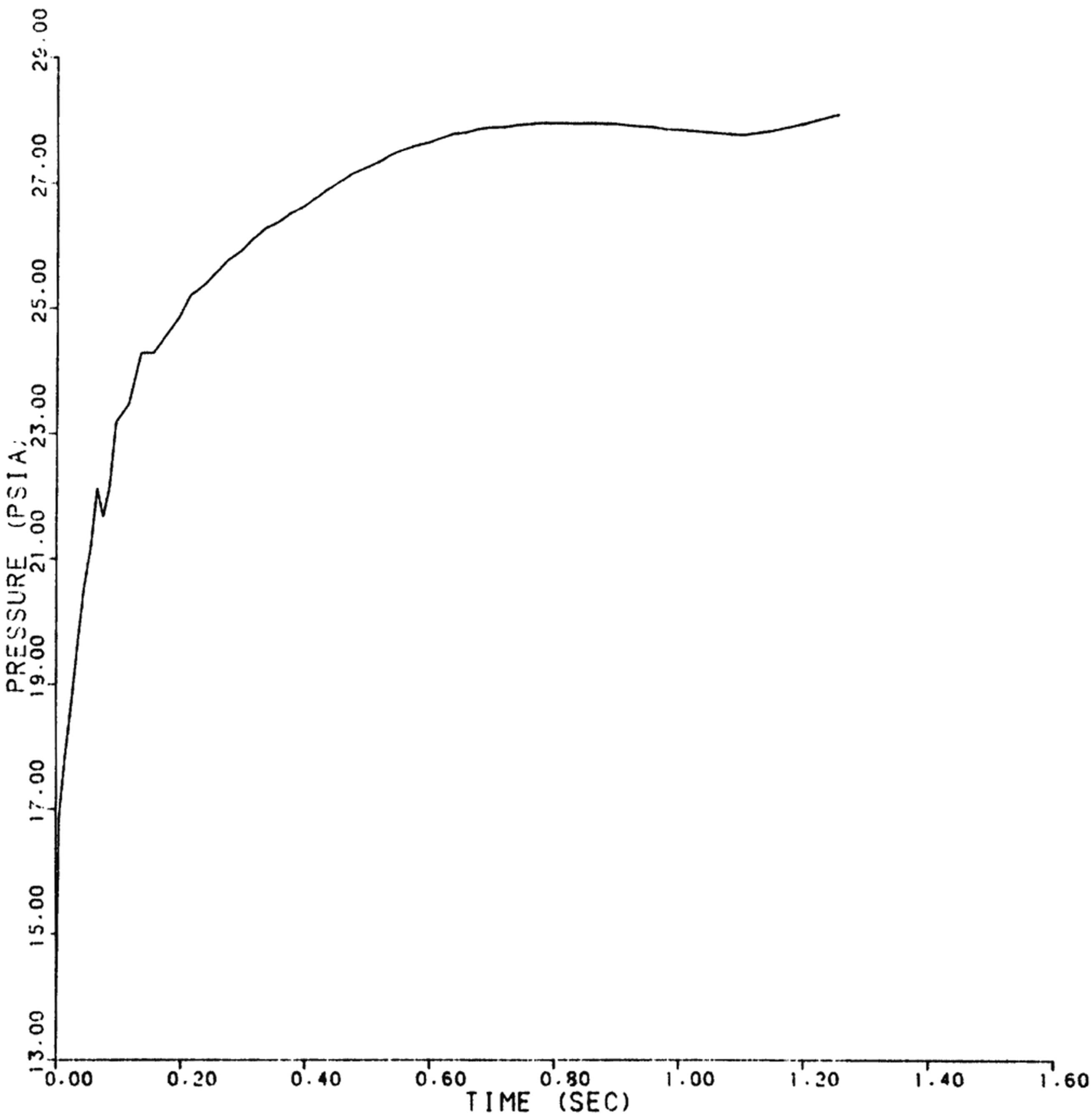
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E20
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 20 OF 74)



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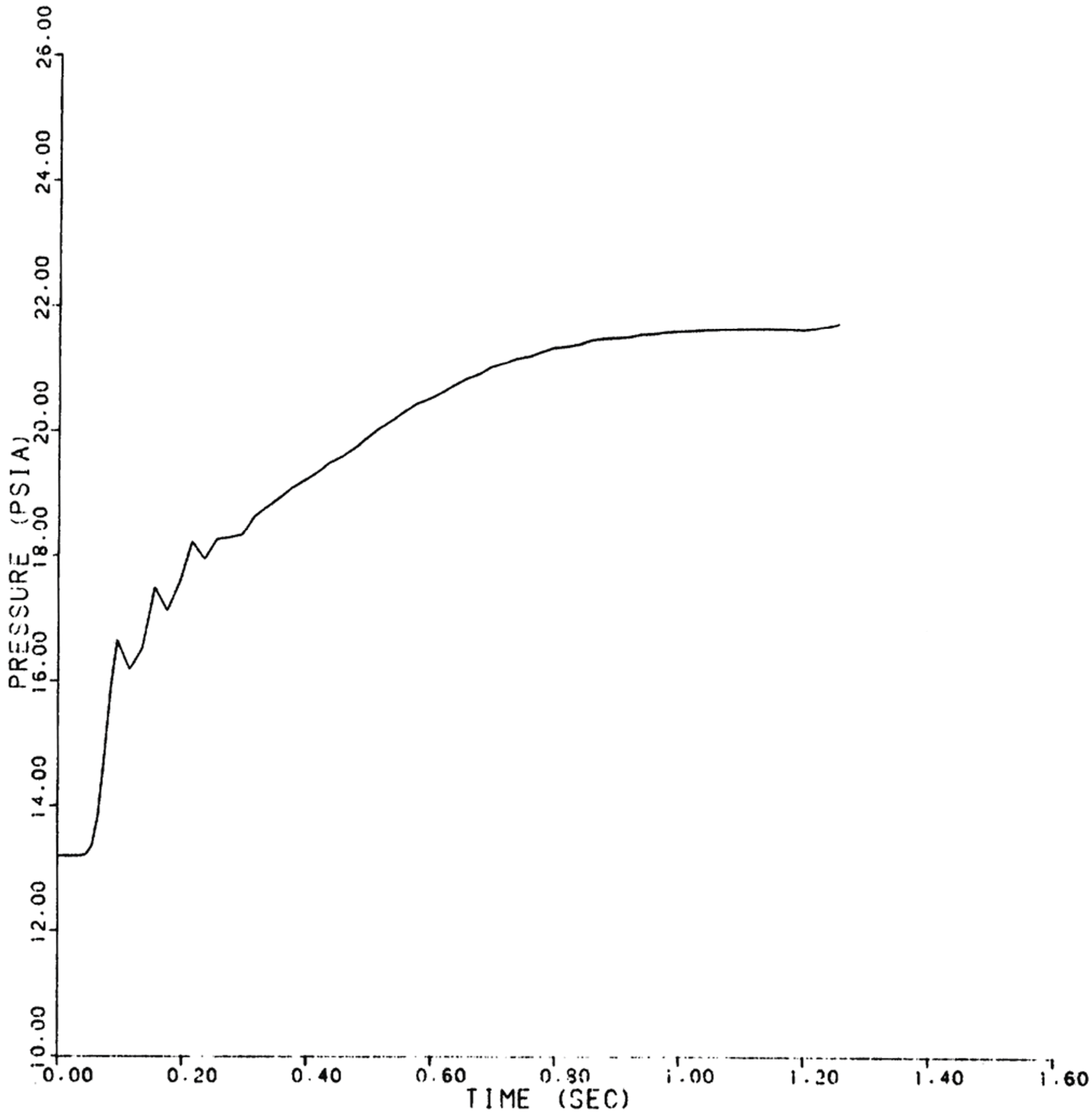
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E21
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 21 OF 74)



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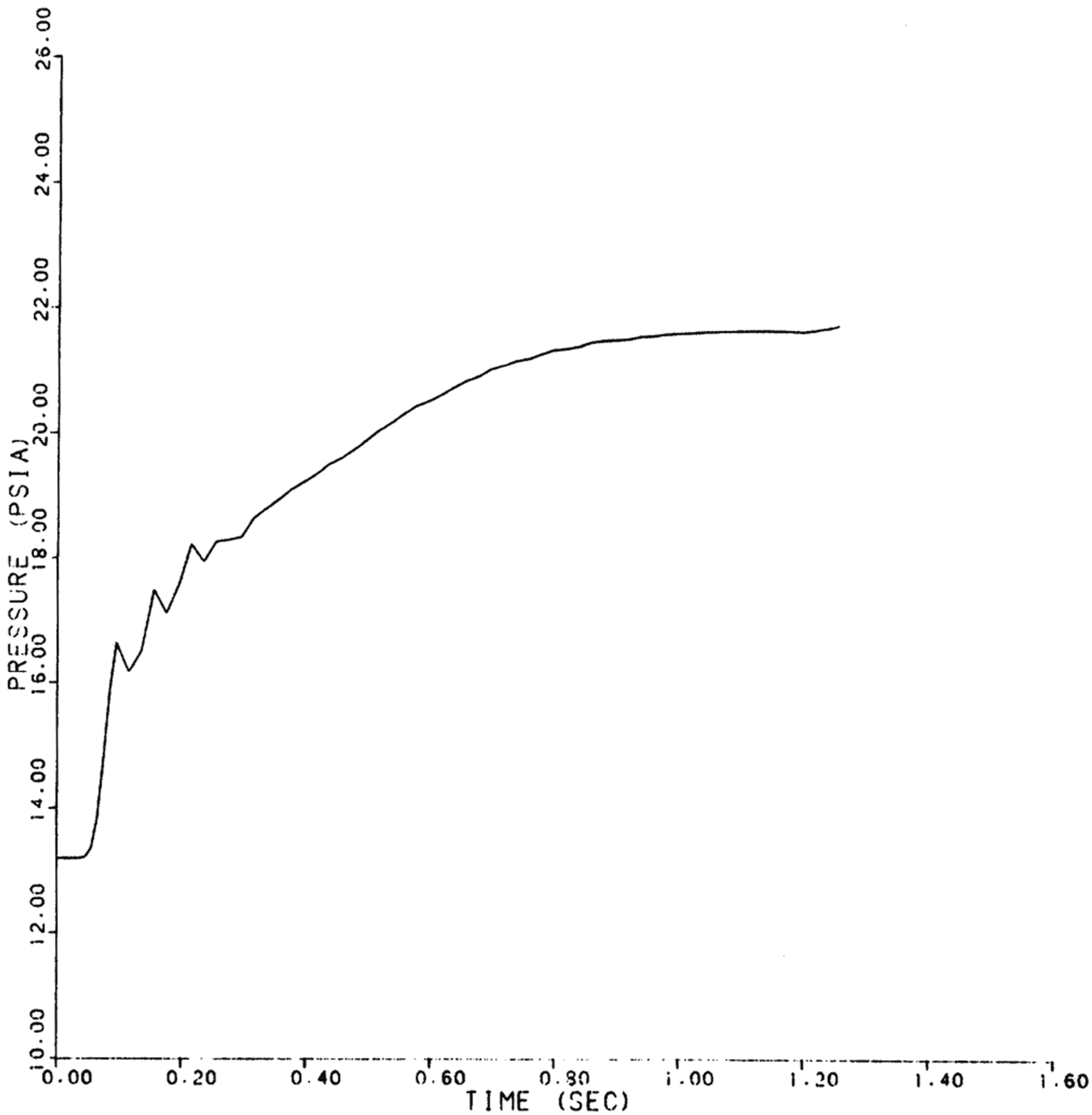
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E22
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 22 OF 74)



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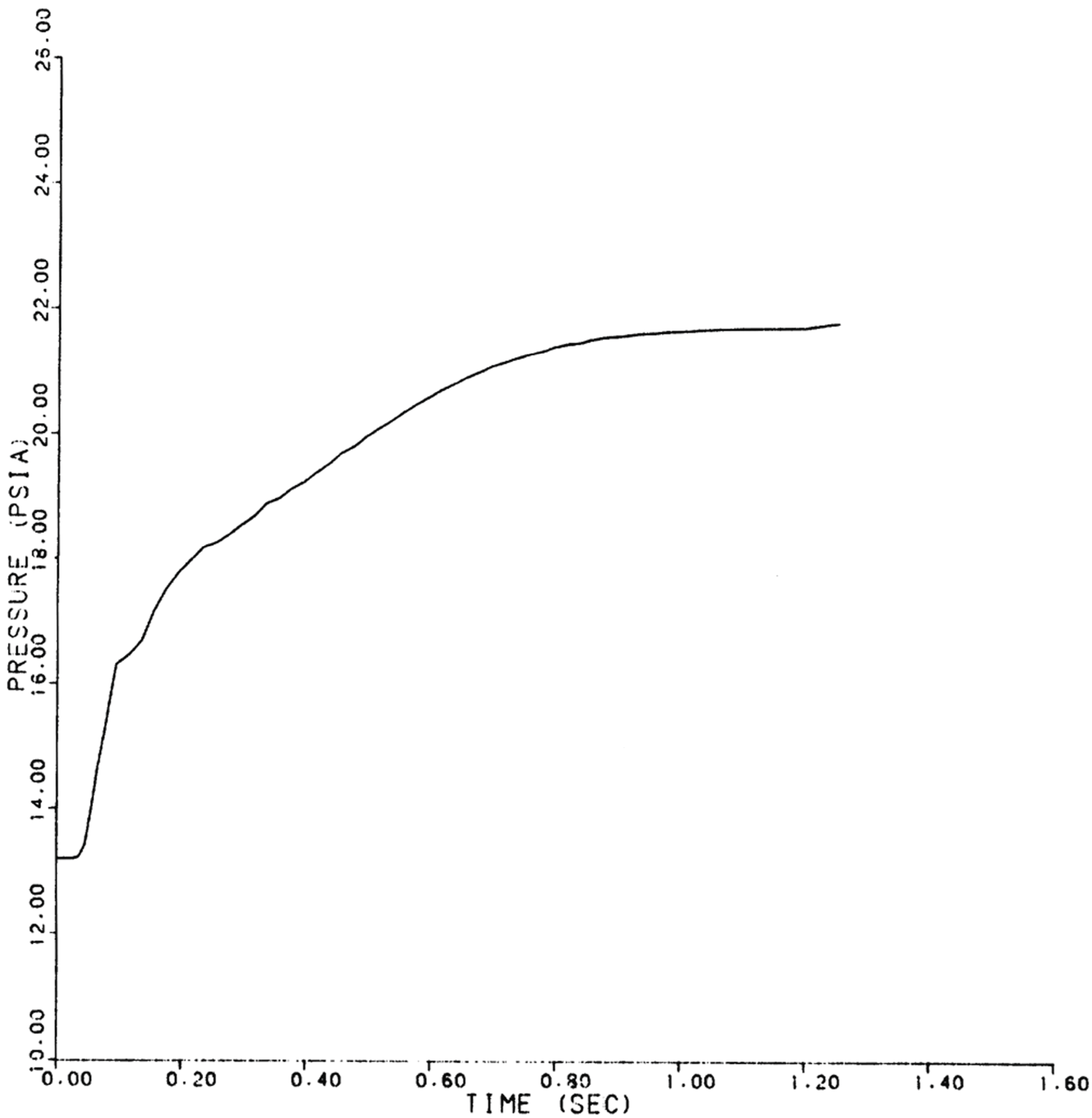
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E23
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 23 OF 74)



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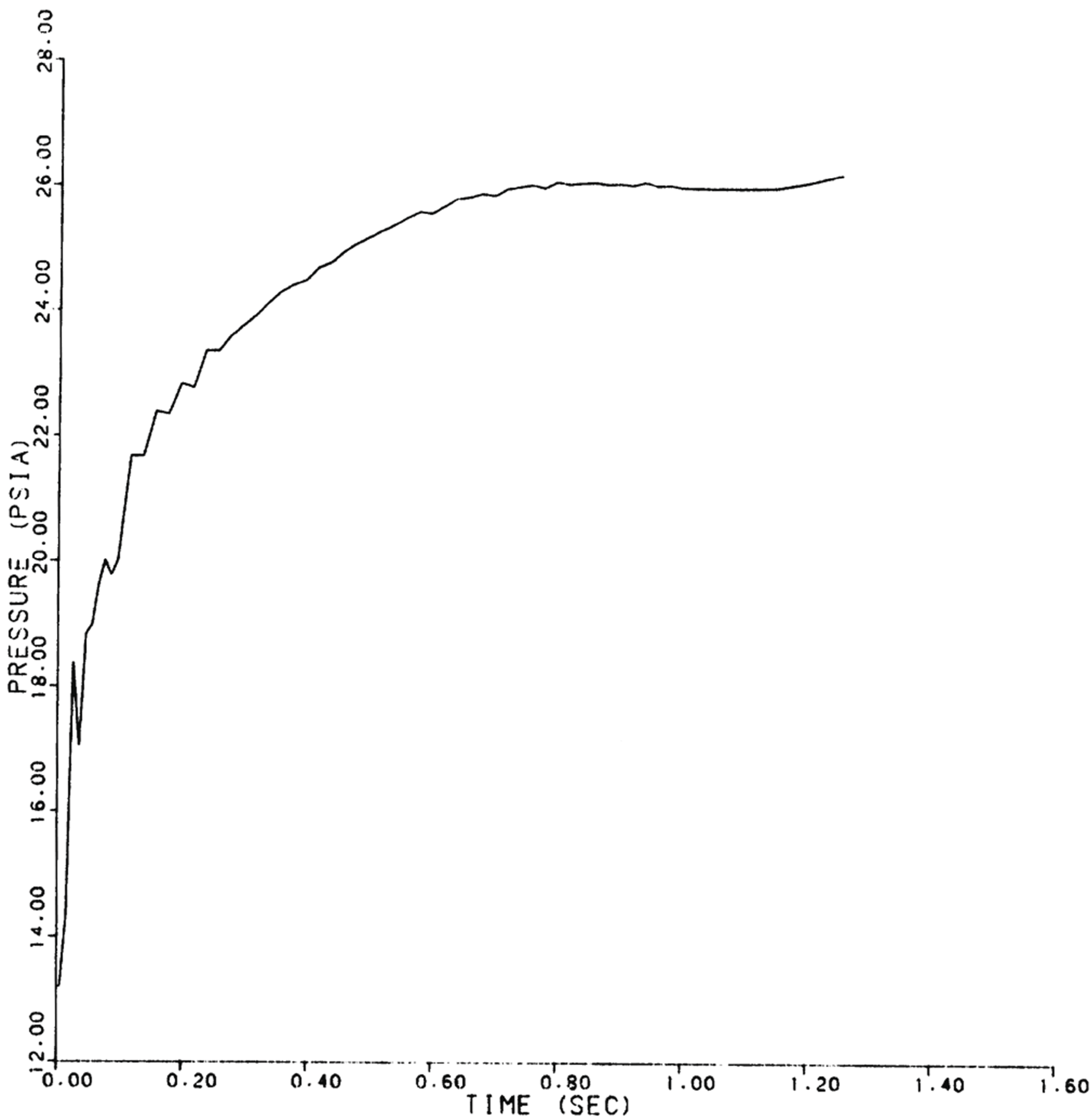
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E24
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 24 OF 74)



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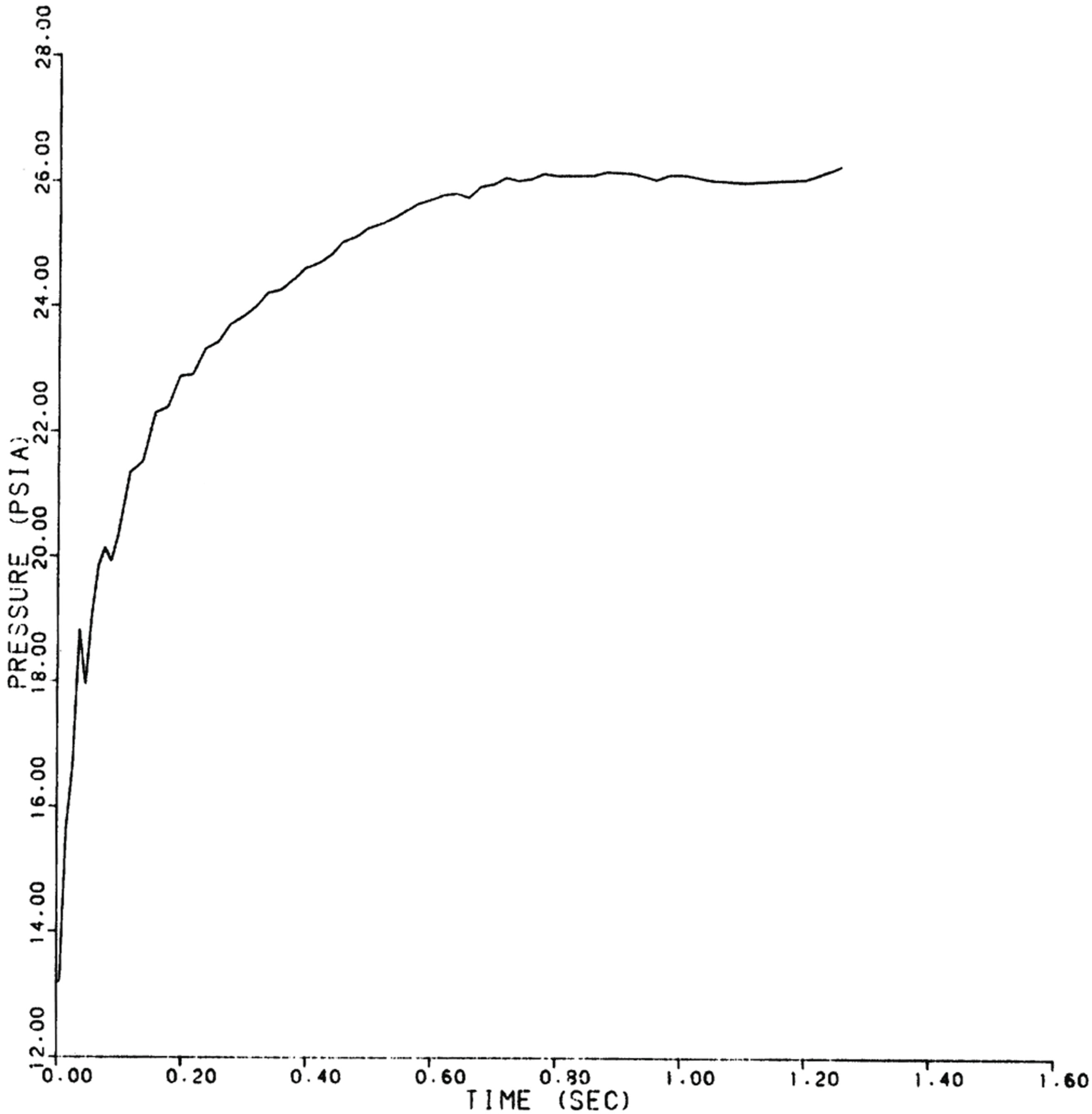
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E25
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 25 OF 74)



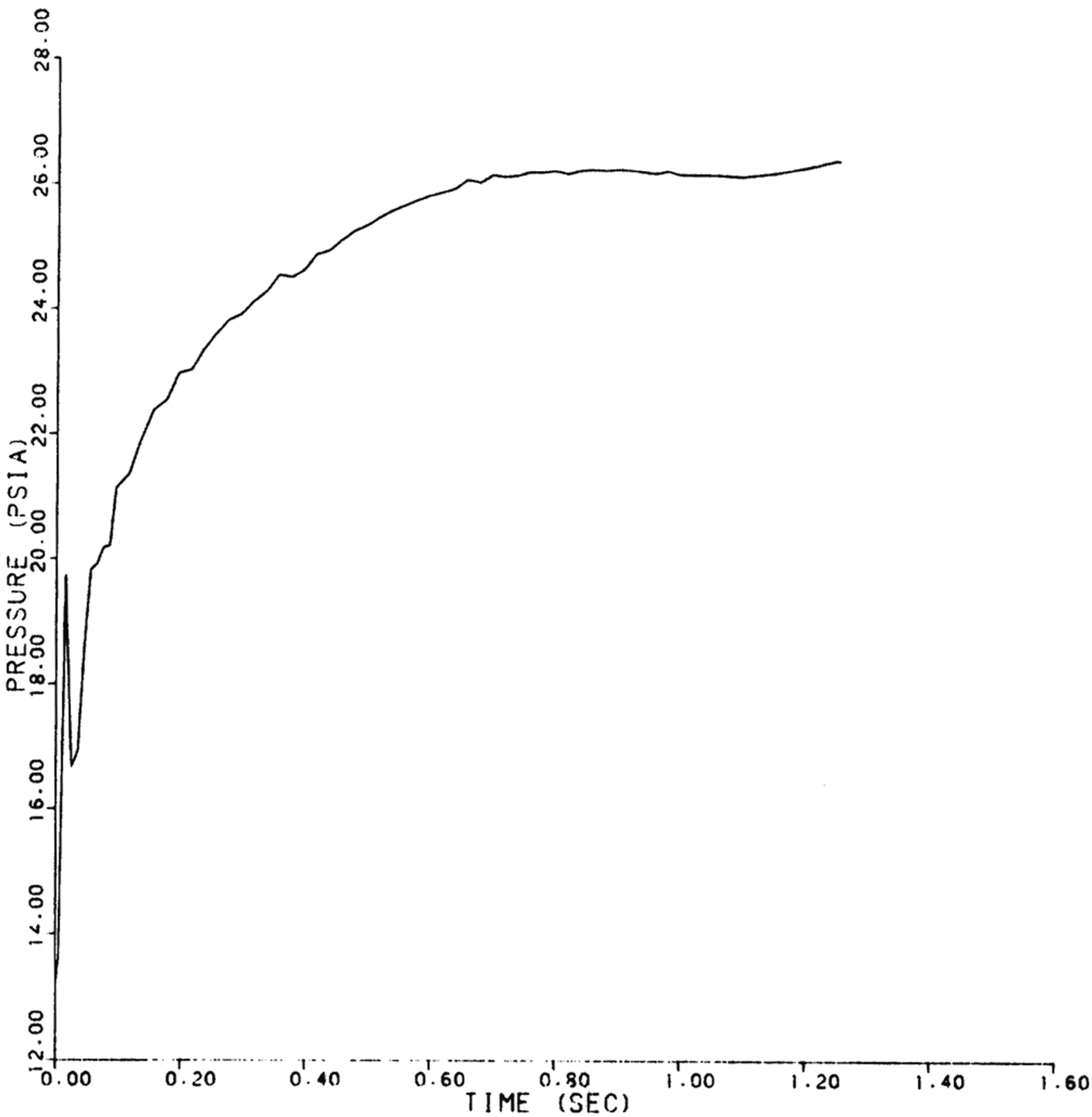
REV 13 4/06

SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

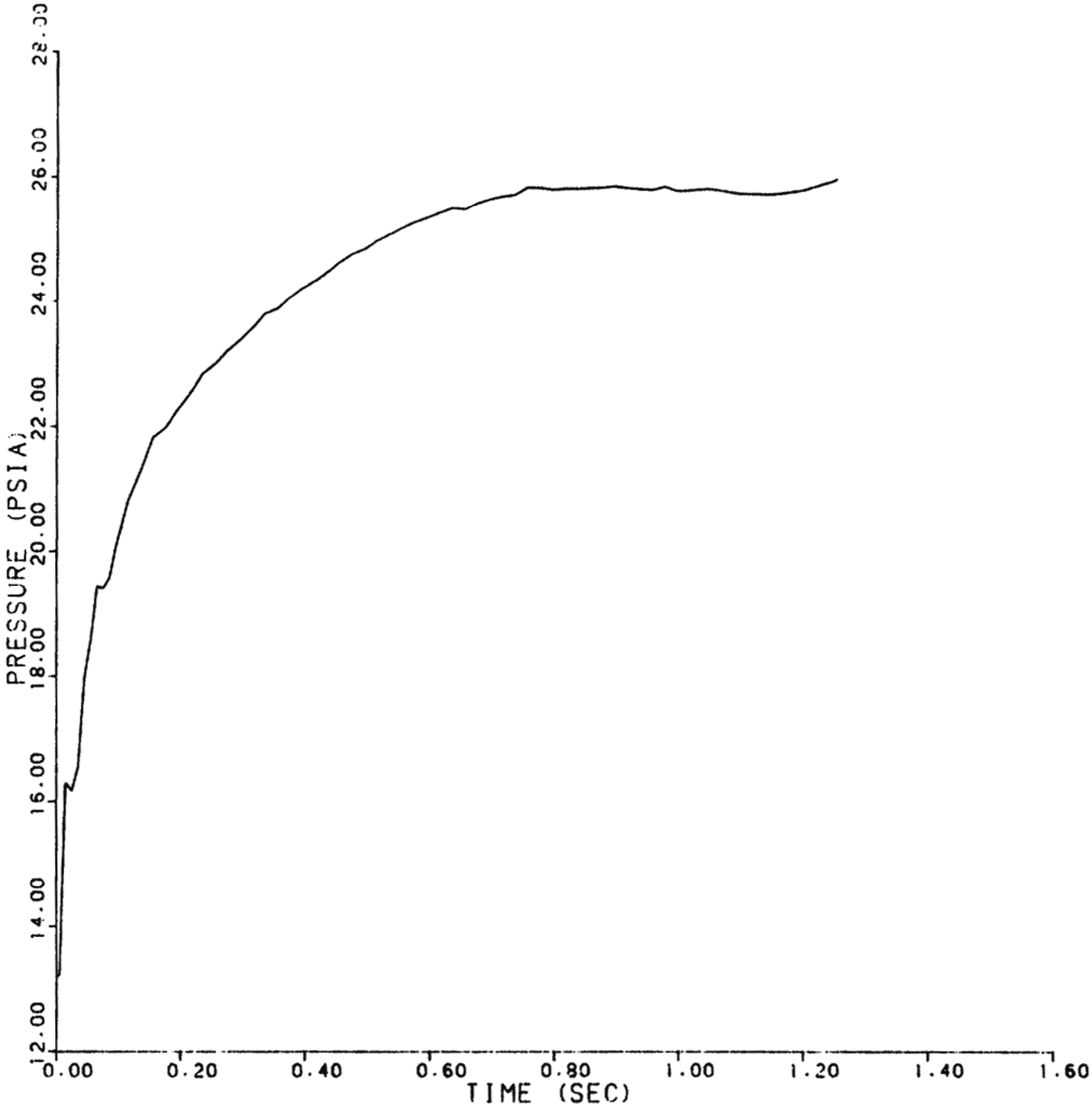
LOOP CLOSURE WELD
NODE E26
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 26 OF 74)



REV 13 4/06

SOUTHERN COMPANY *Energy to Serve Your World®*	VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	LOOP CLOSURE WELD NODE E27 (336–in.^{2} BREAK AREA)
		FIGURE 6.2.1–23 (SHEET 27 OF 74)



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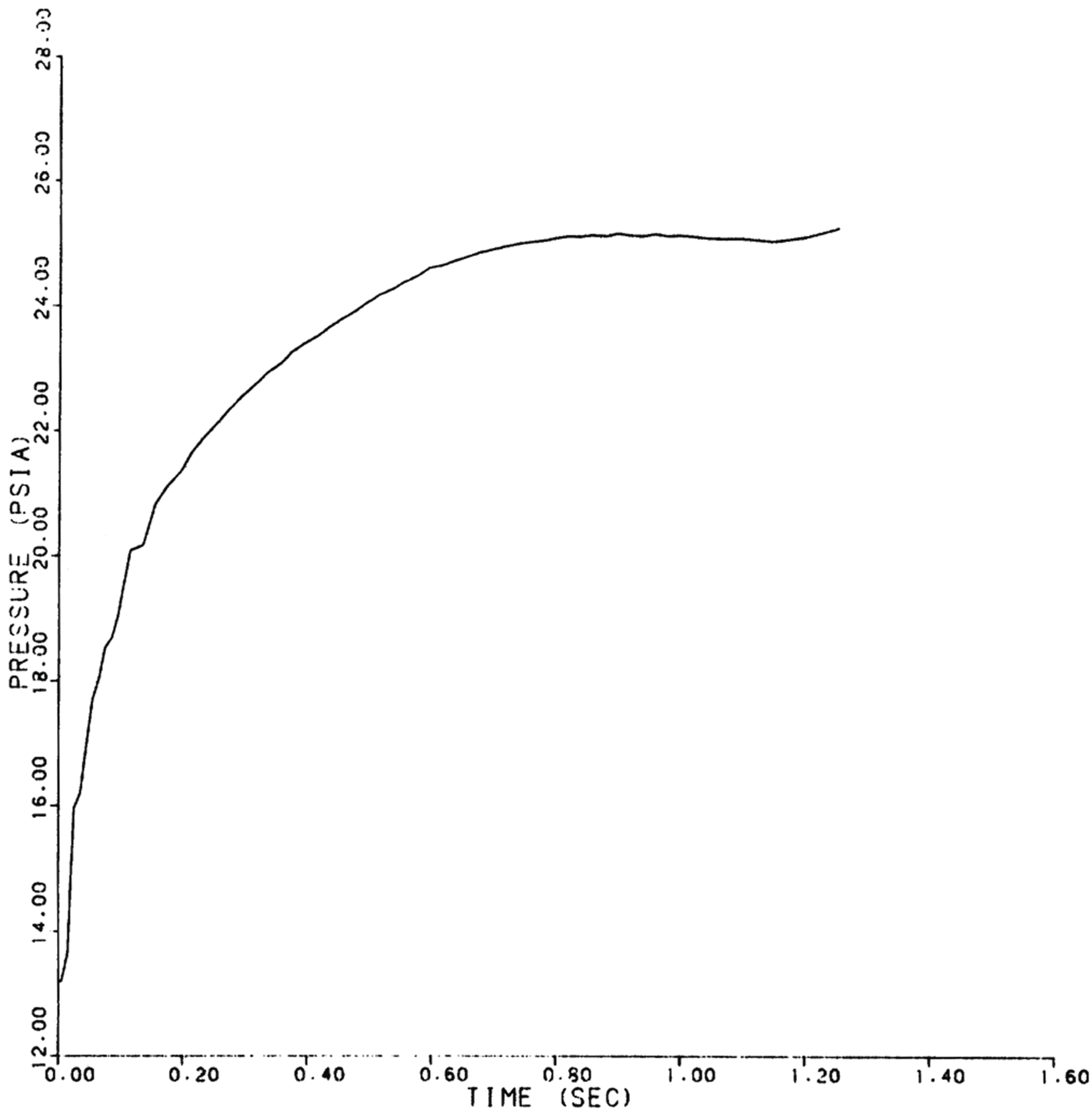
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E28
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 28 OF 74)



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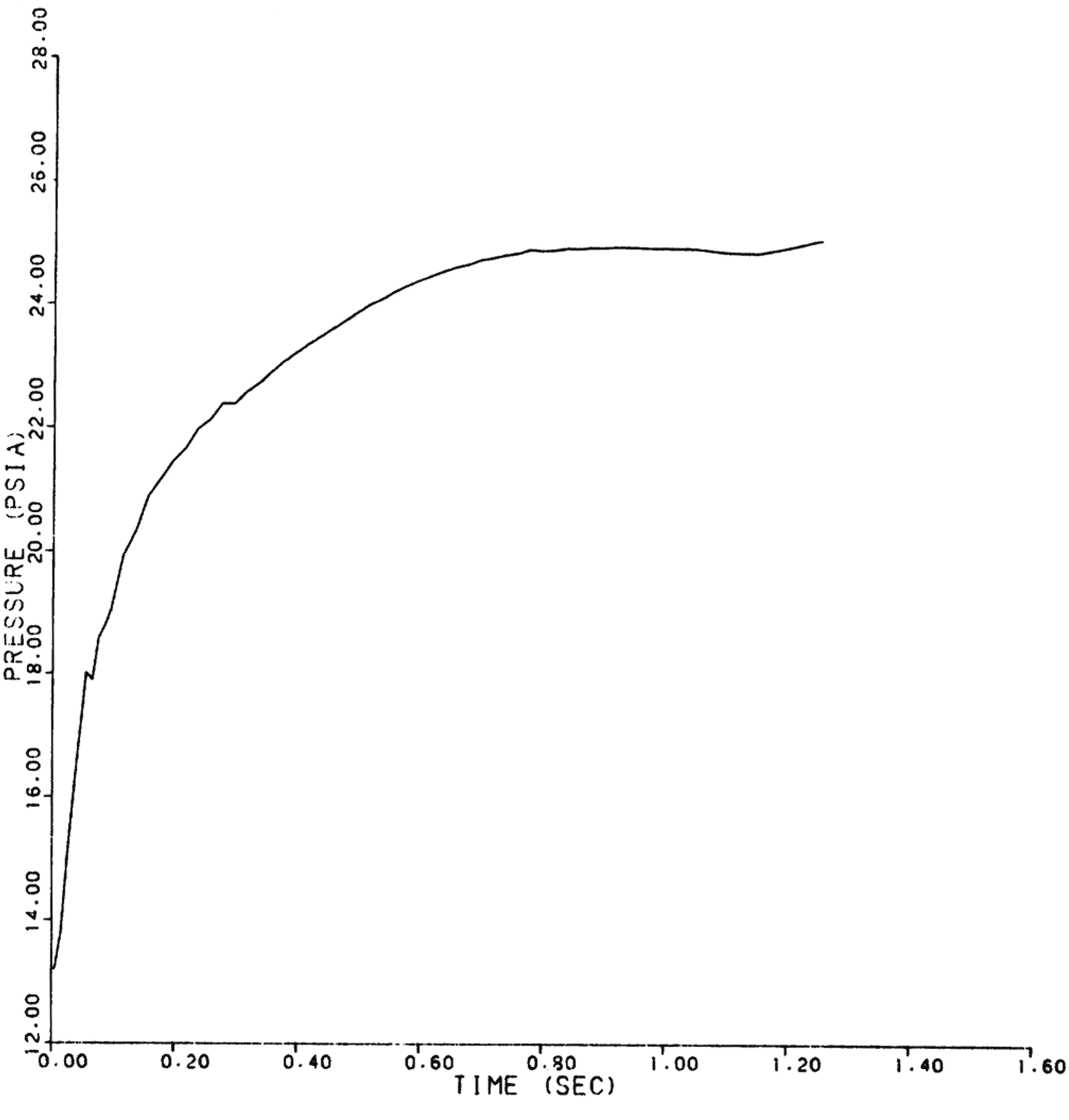
SOUTHERN COMPANY *Energy to Serve Your World®*	**VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2**	LOOP CLOSURE WELD NODE E29 (336–in.^{2} BREAK AREA)
		FIGURE 6.2.1–23 (SHEET 29 OF 74)



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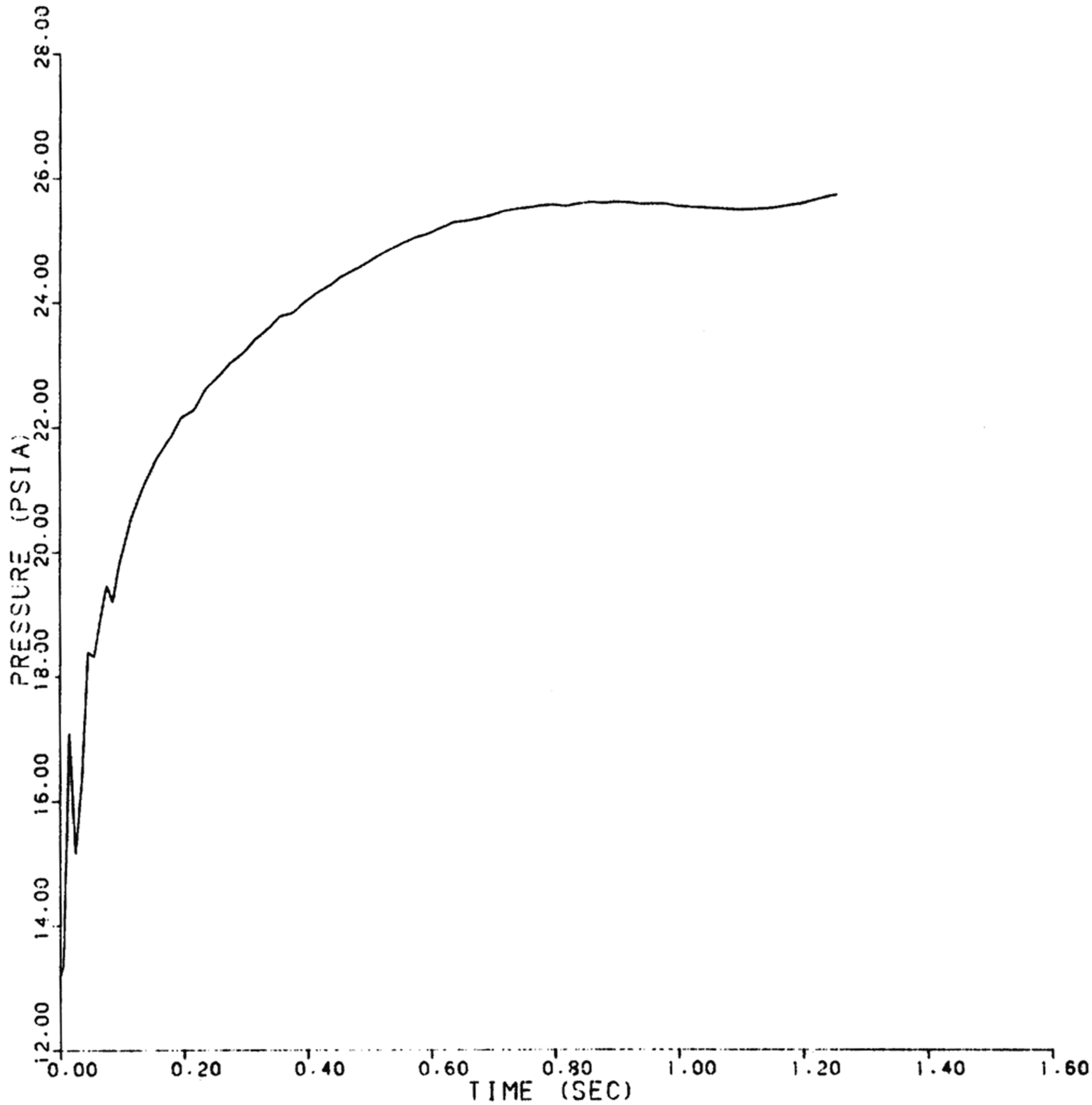
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E30
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 30 OF 74)



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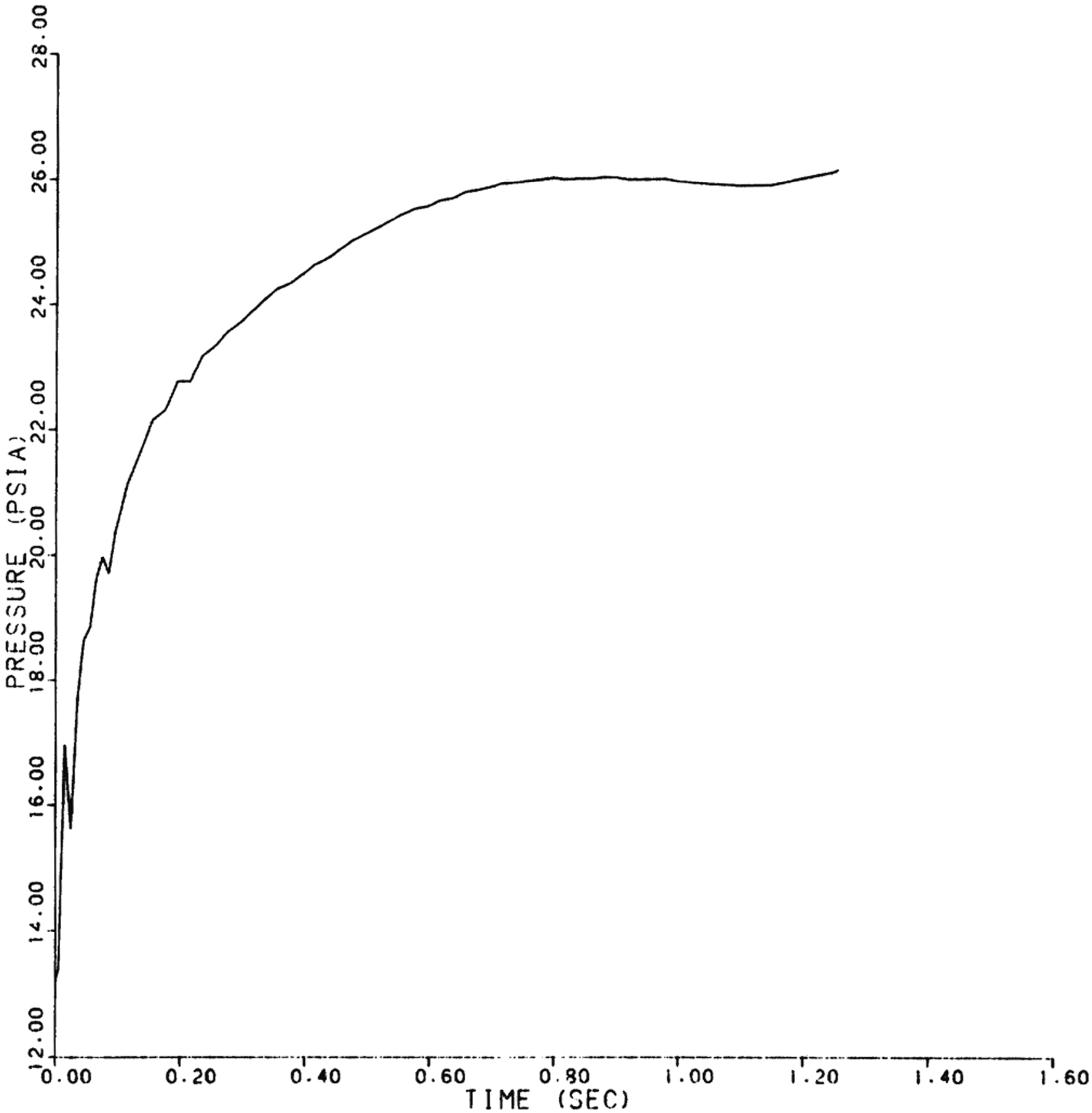
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E31
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 31 OF 74)



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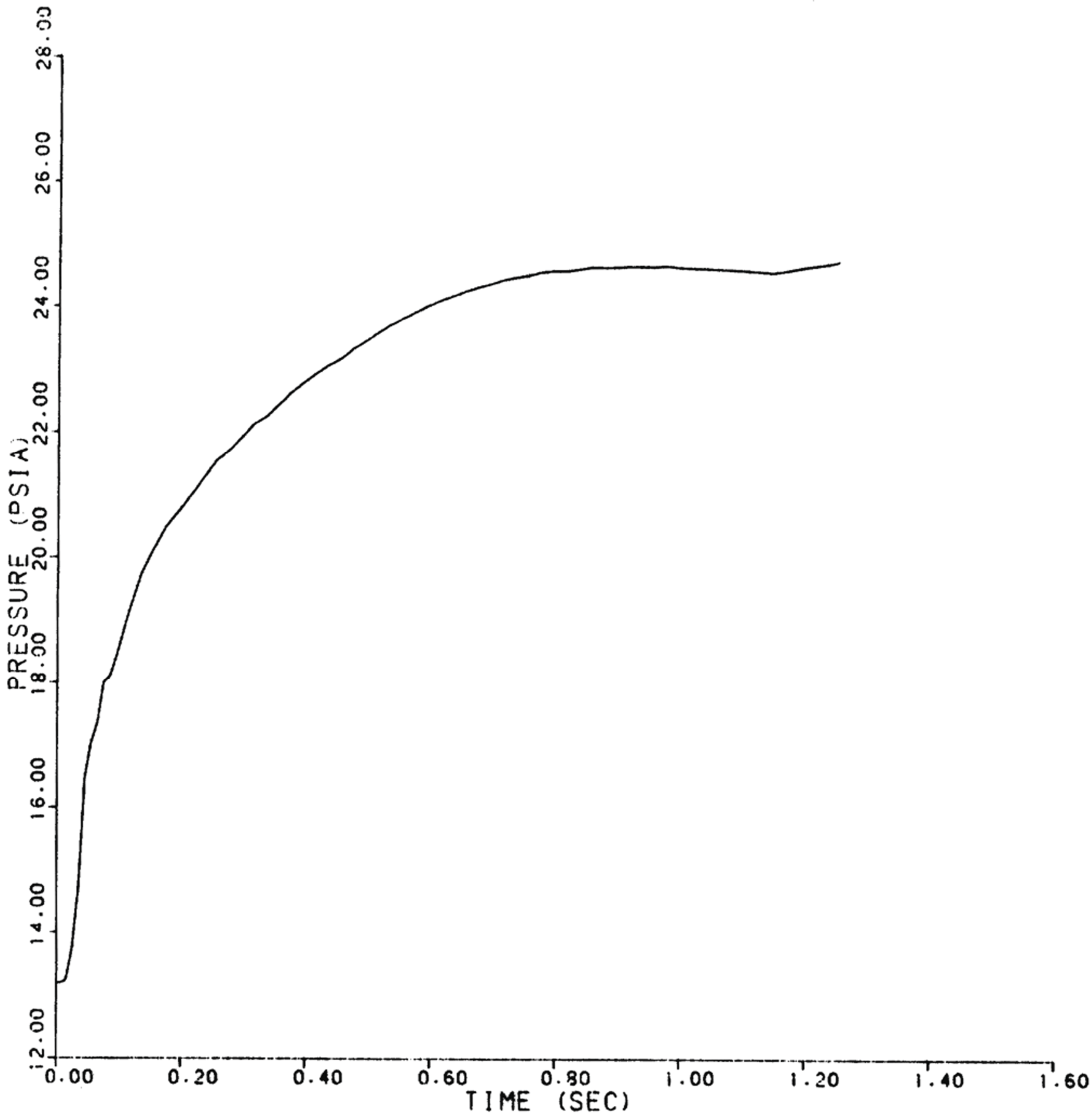
SOUTHERN COMPANY *Energy to Serve Your World®* VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	LOOP CLOSURE WELD NODE E32 (336–in.^{2} BREAK AREA)
	FIGURE 6.2.1–23 (SHEET 32 OF 74)



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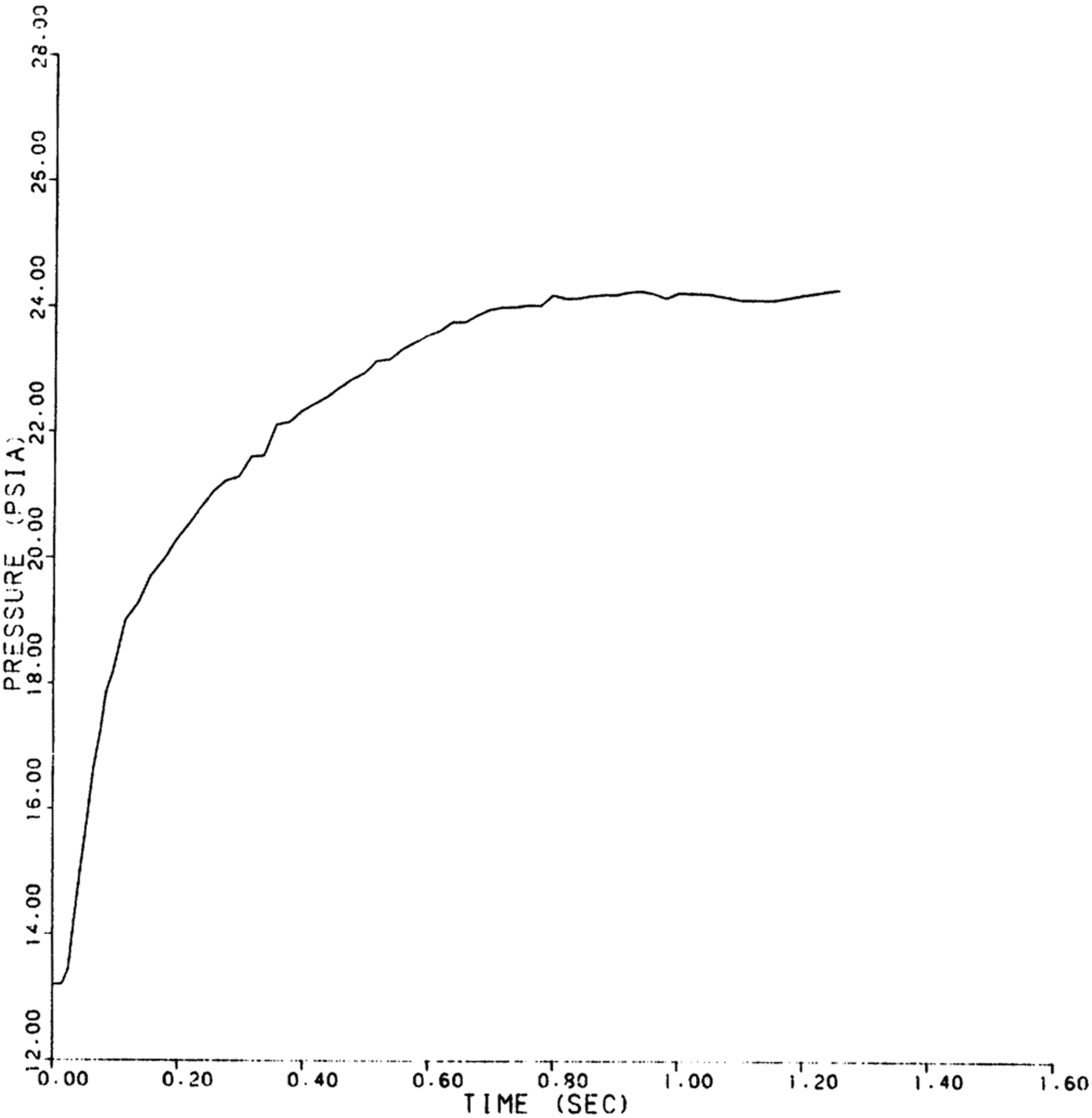
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E33
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 33 OF 74)



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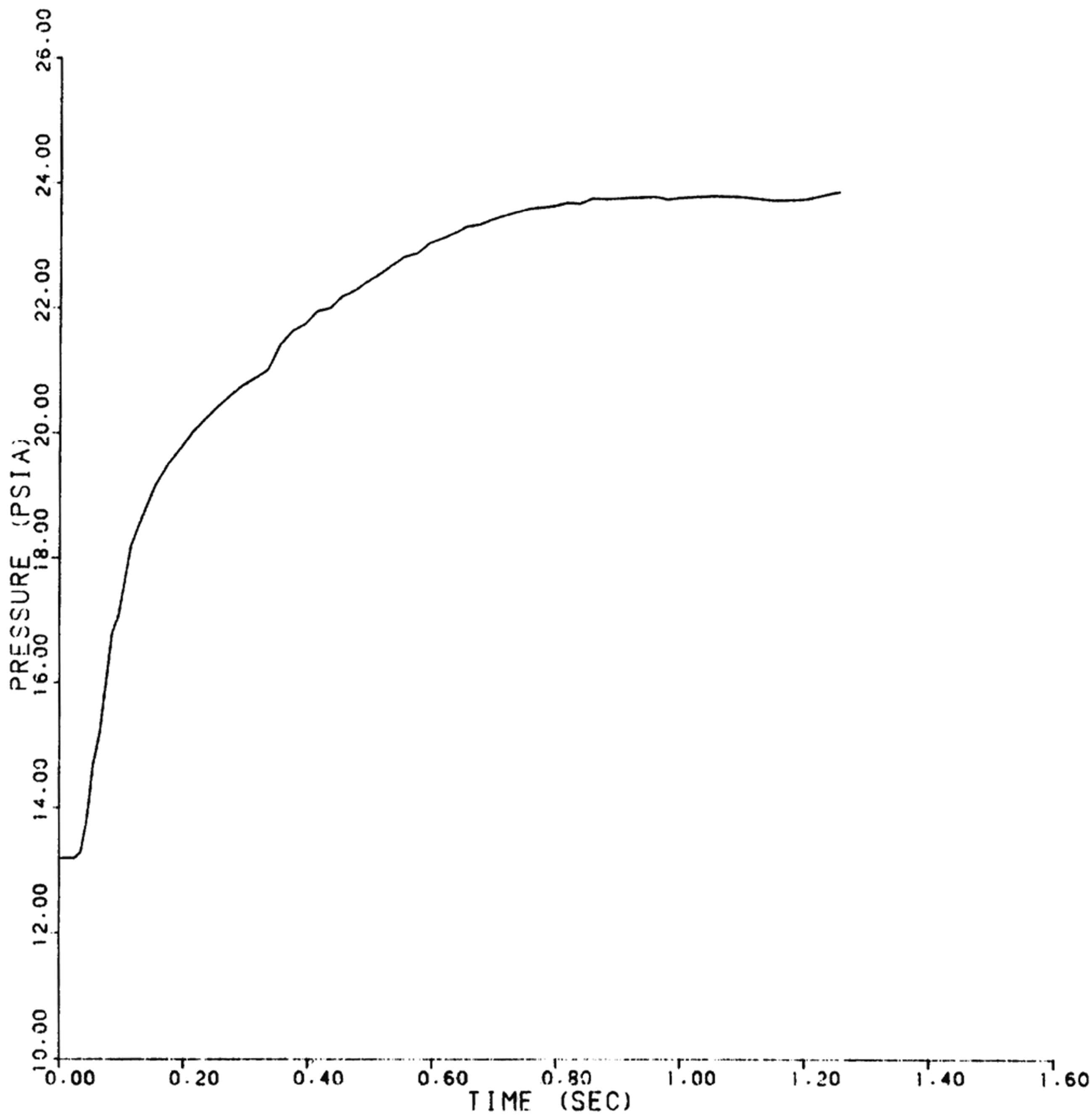
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E34
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 34 OF 74)



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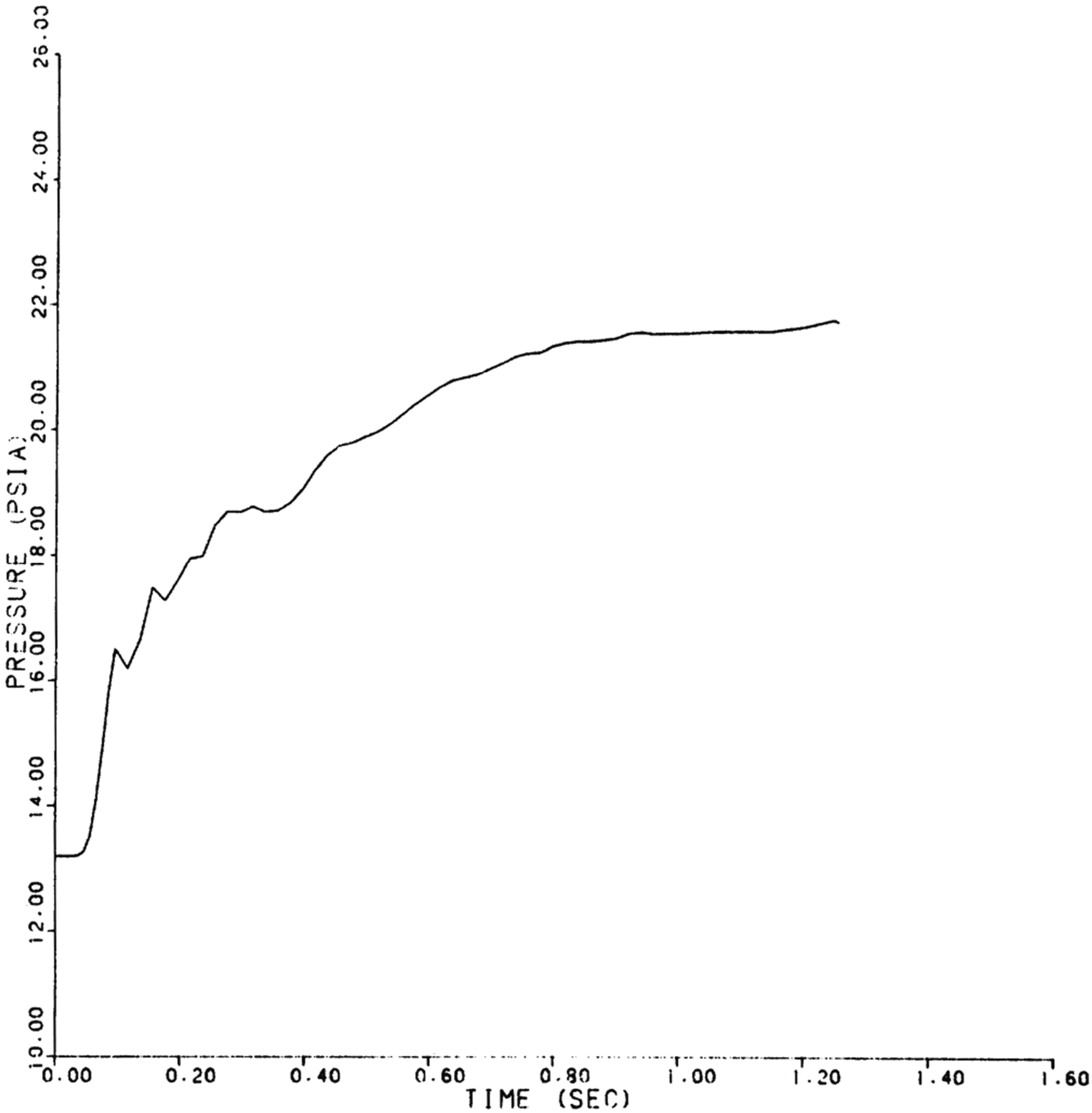
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E35
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 35 OF 74)



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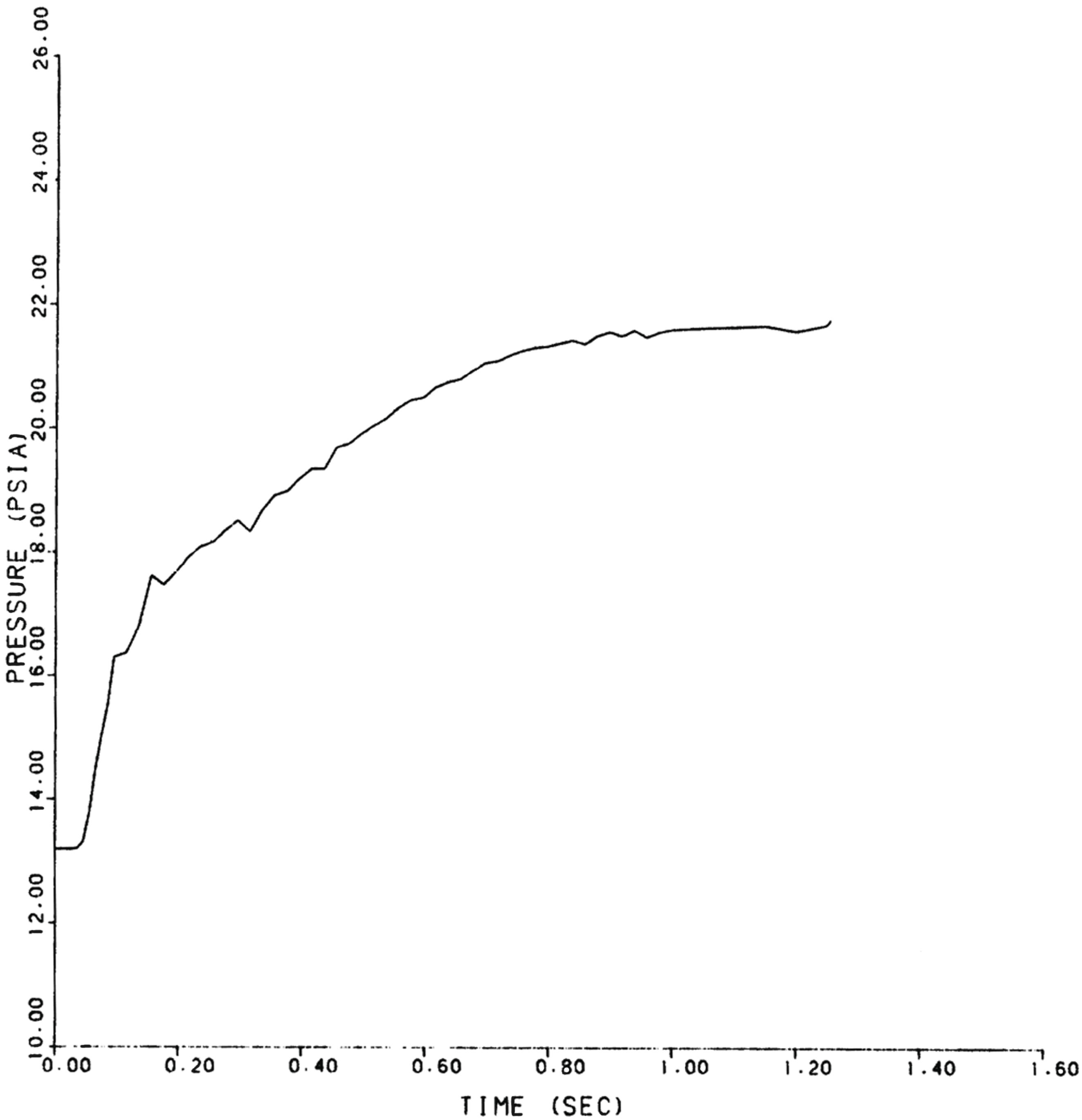
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E36
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 36 OF 74)



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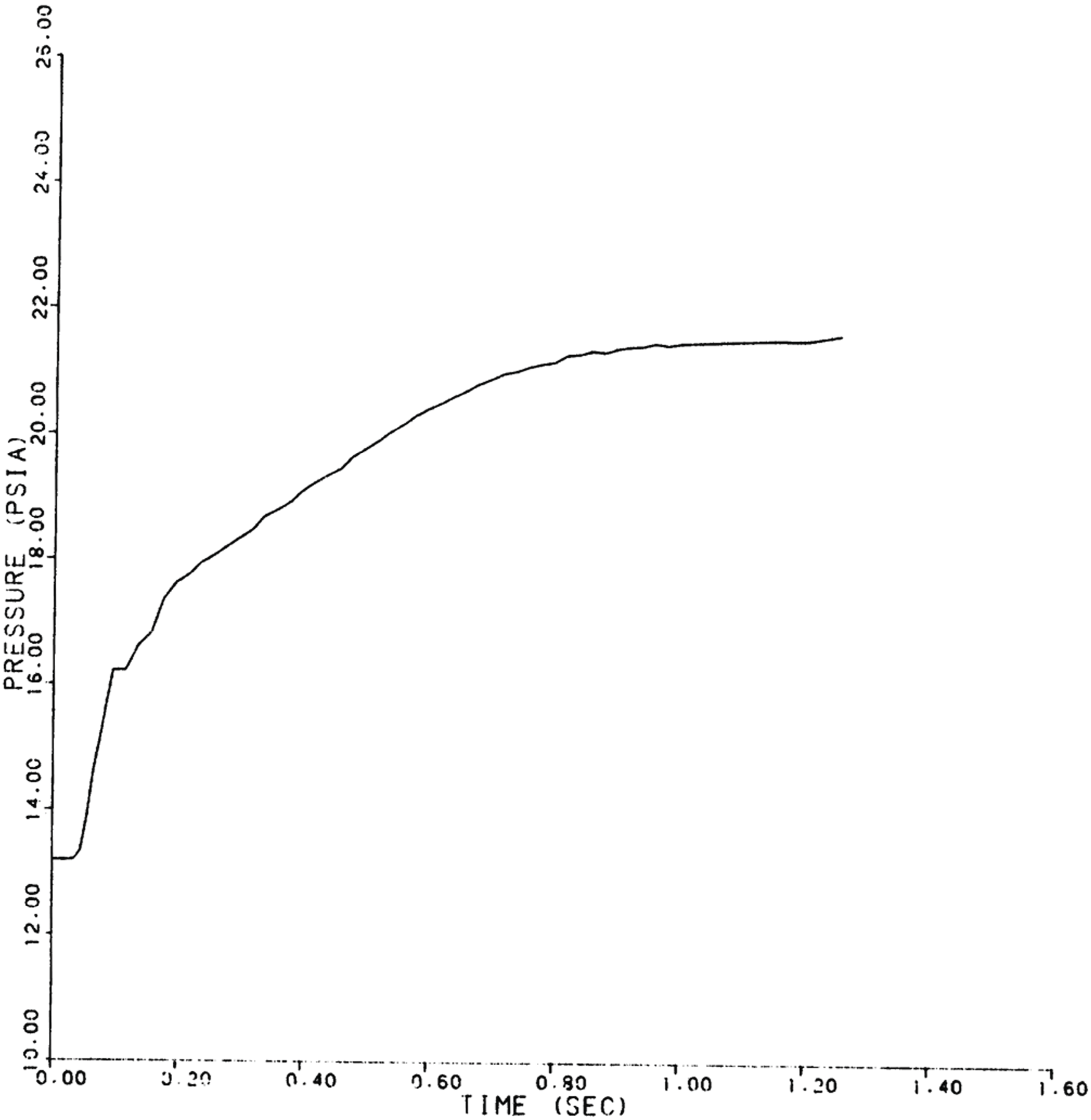
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E37
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 37 OF 74)



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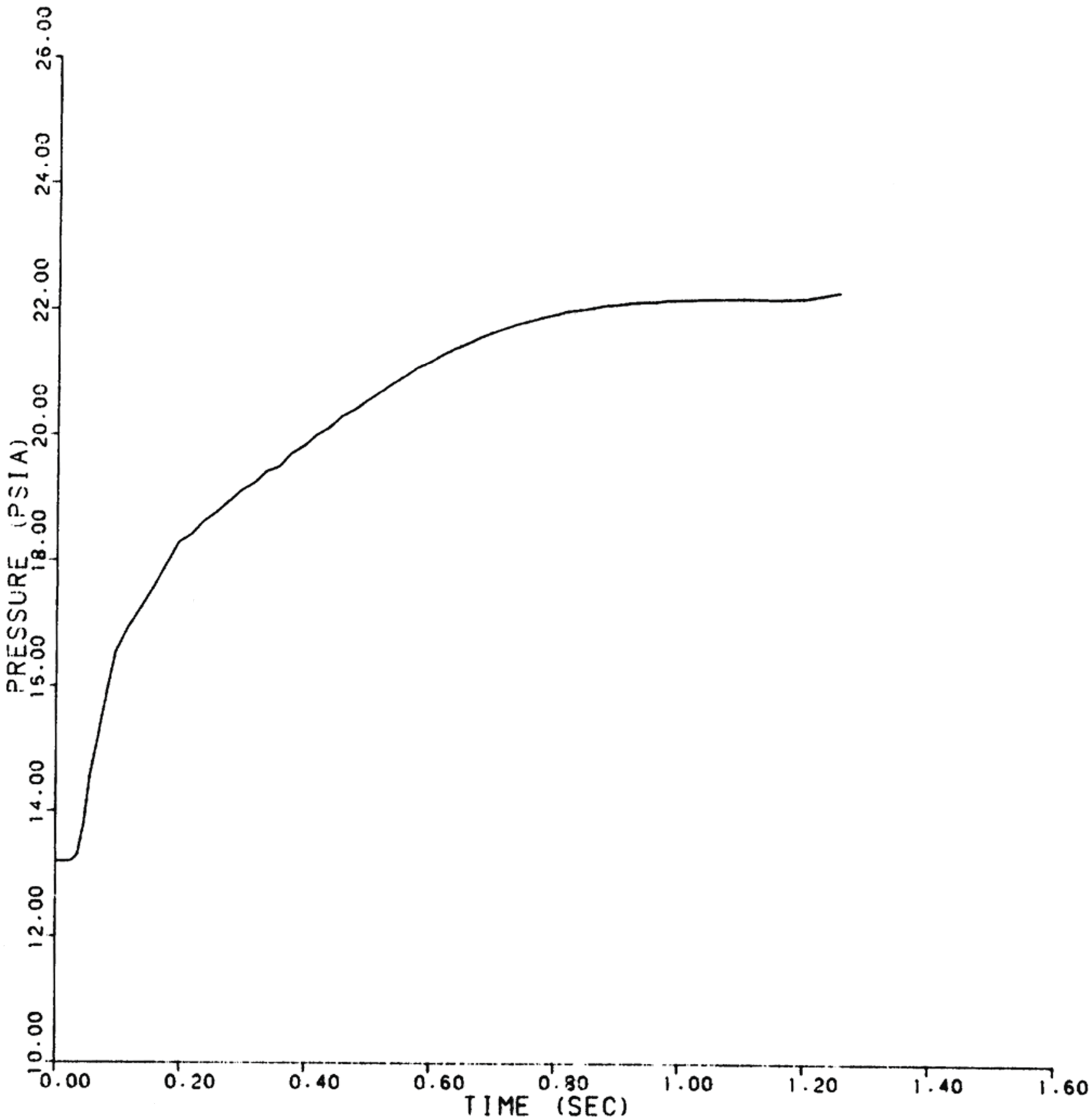
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E38
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 38 OF 74)



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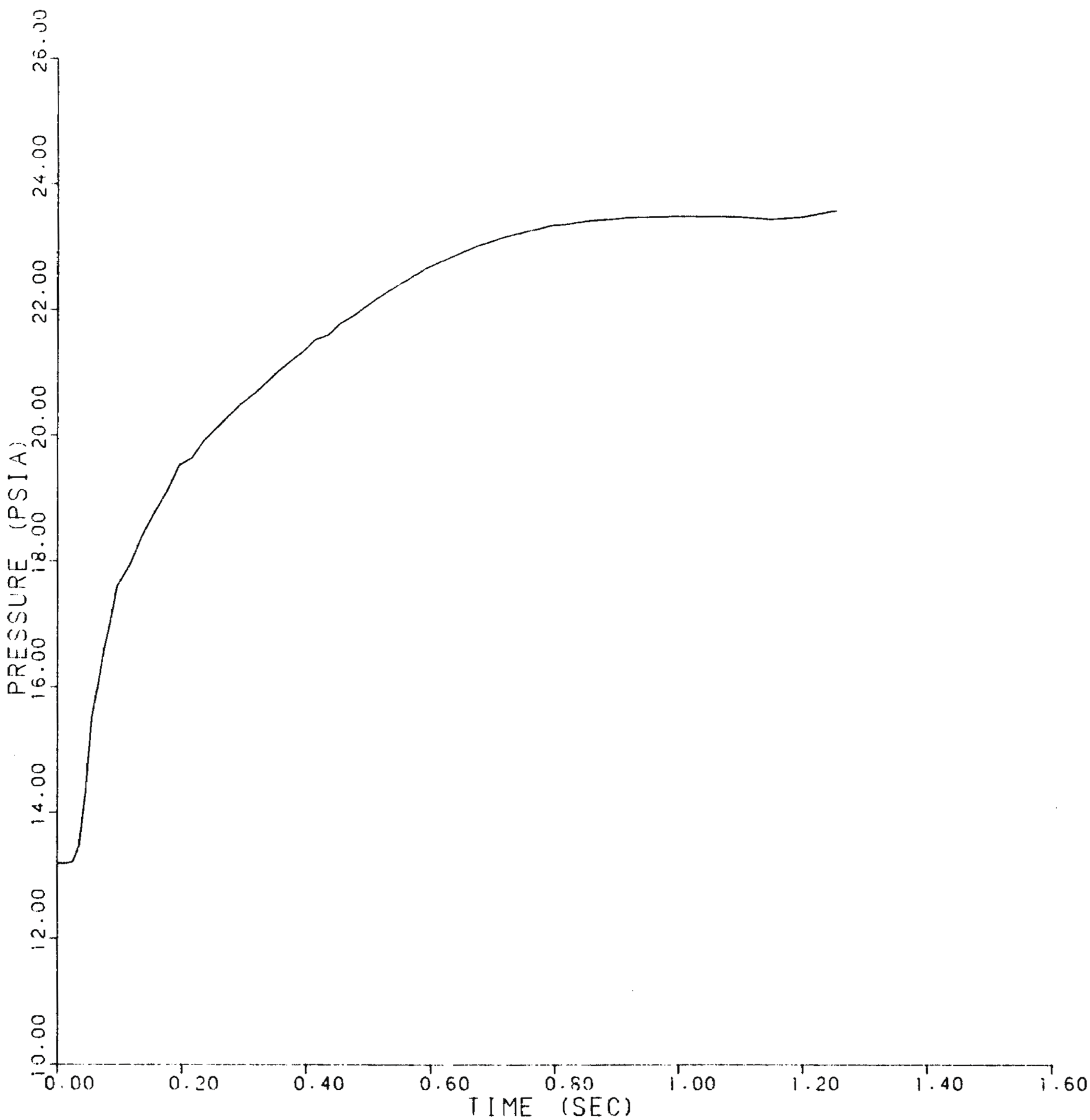
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E39
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 39 OF 74)



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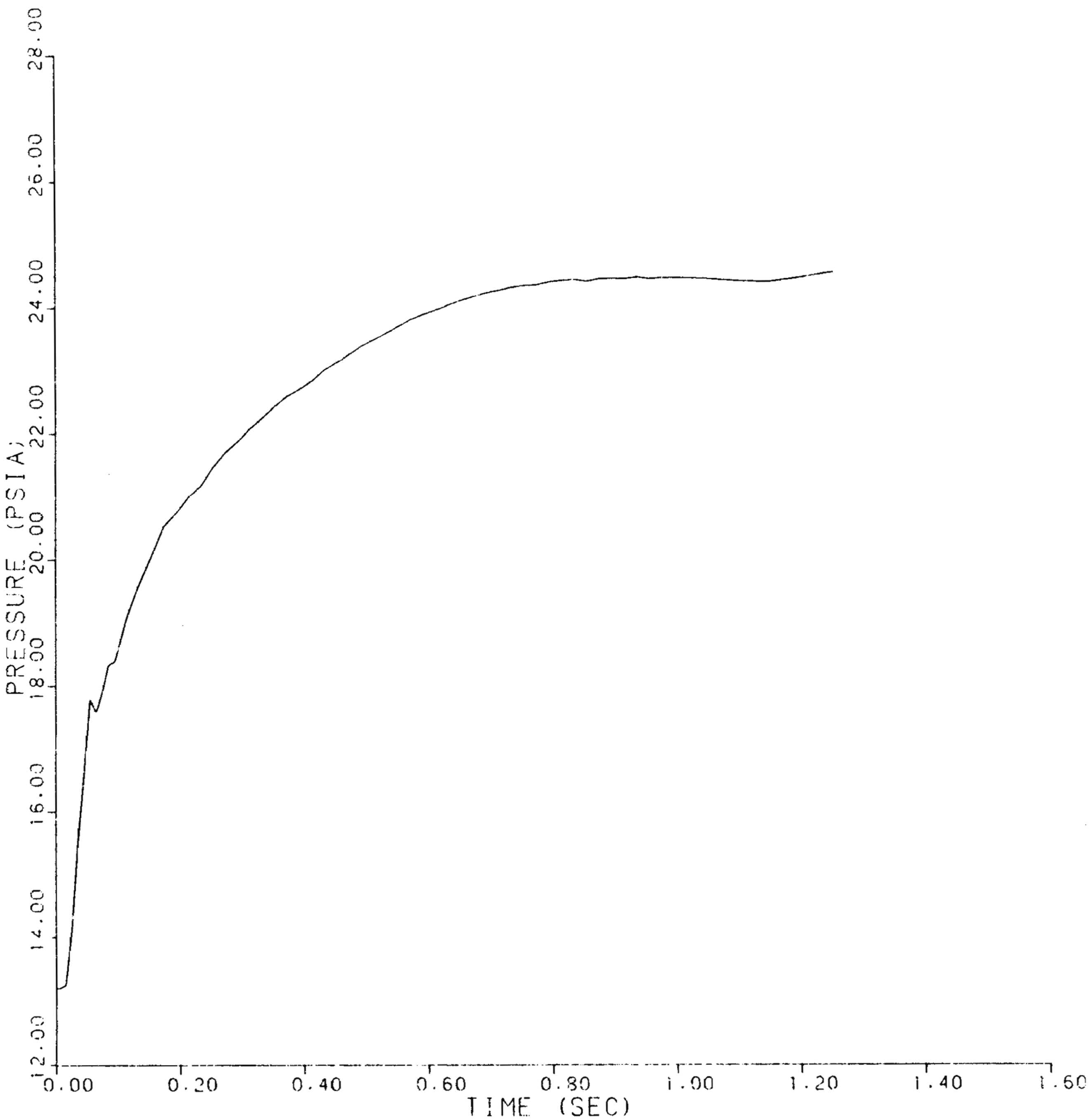
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E40
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 40 OF 74)



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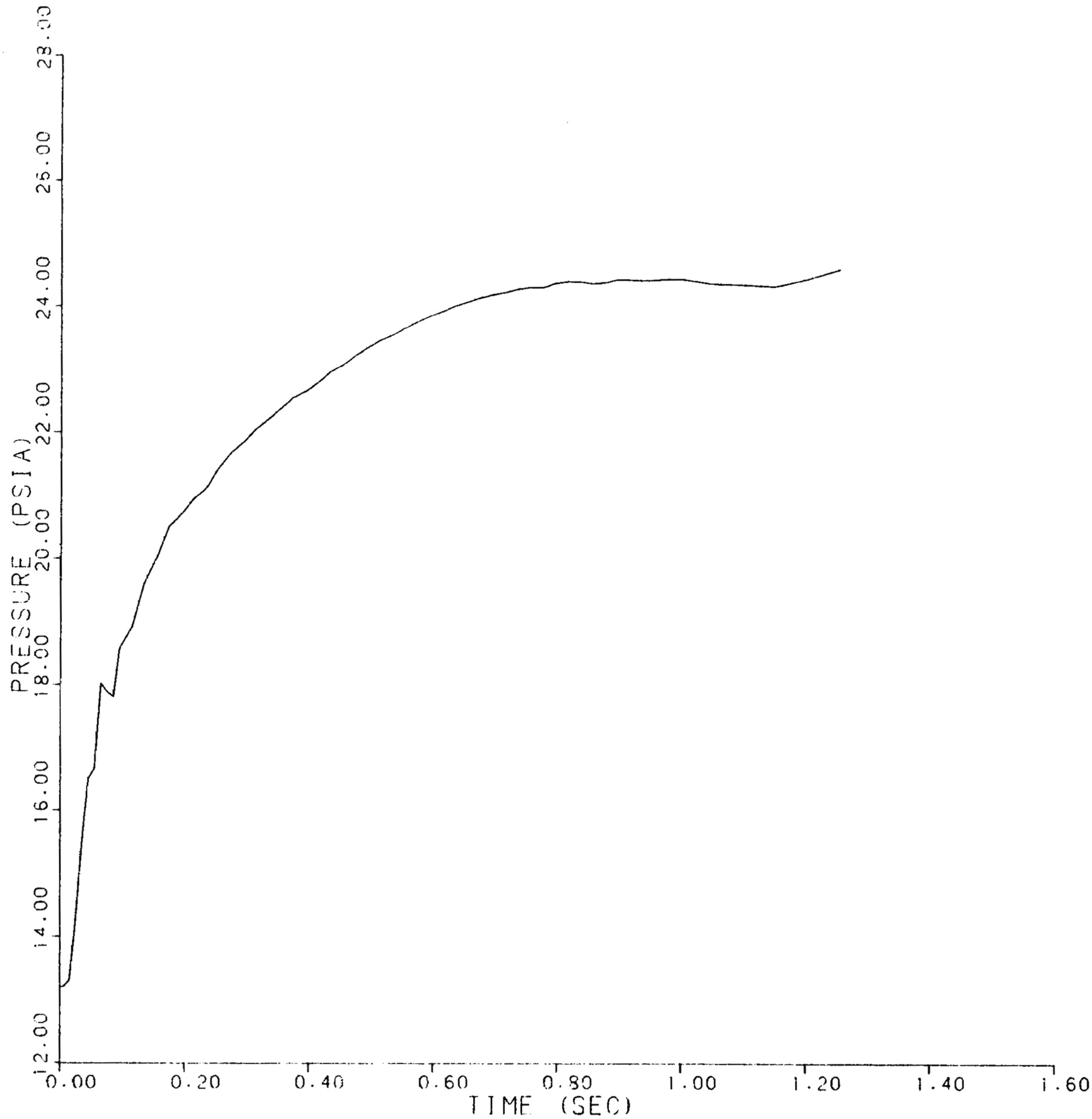
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E41
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 41 OF 74)



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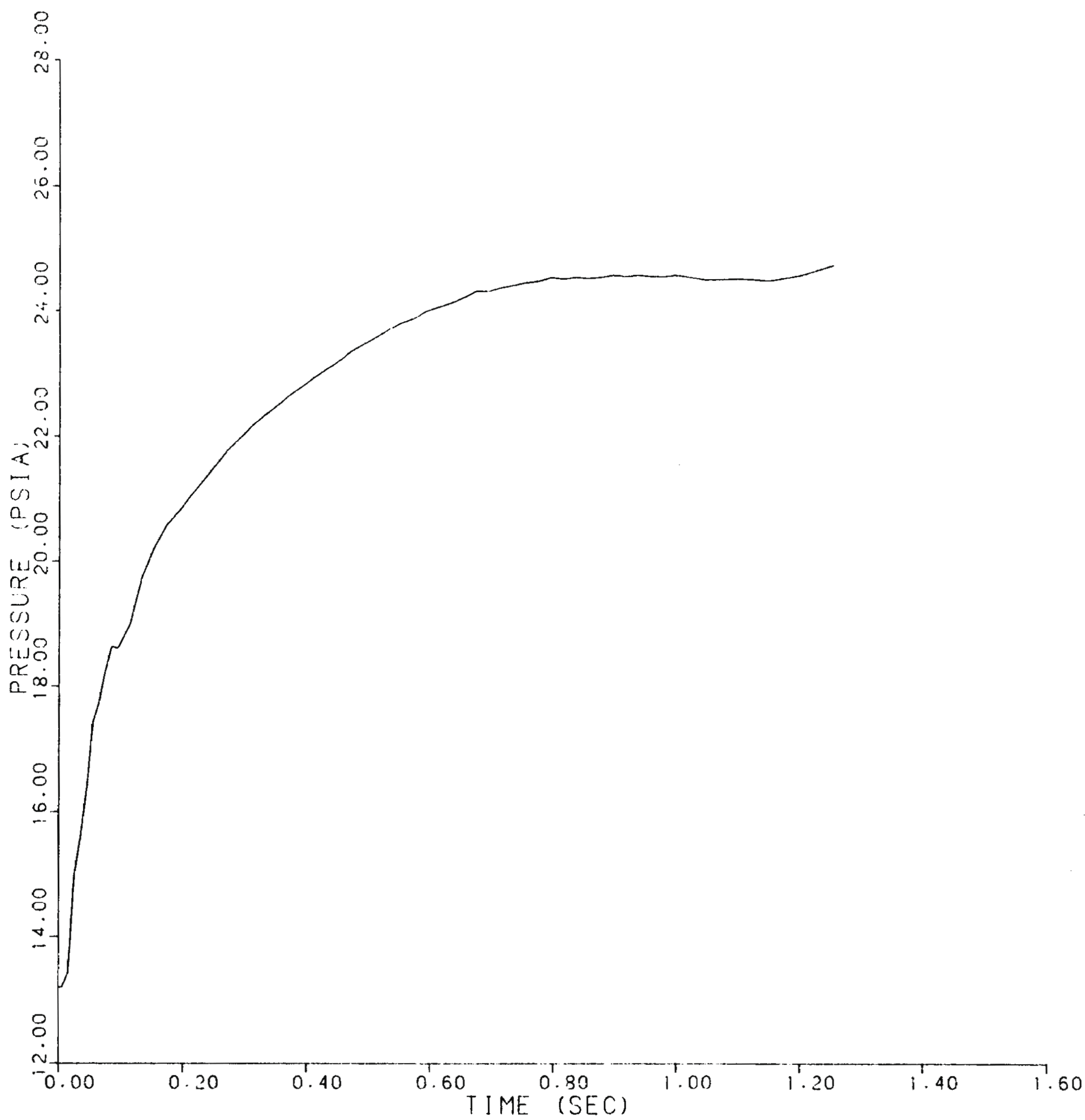
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E42
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 42 OF 74)



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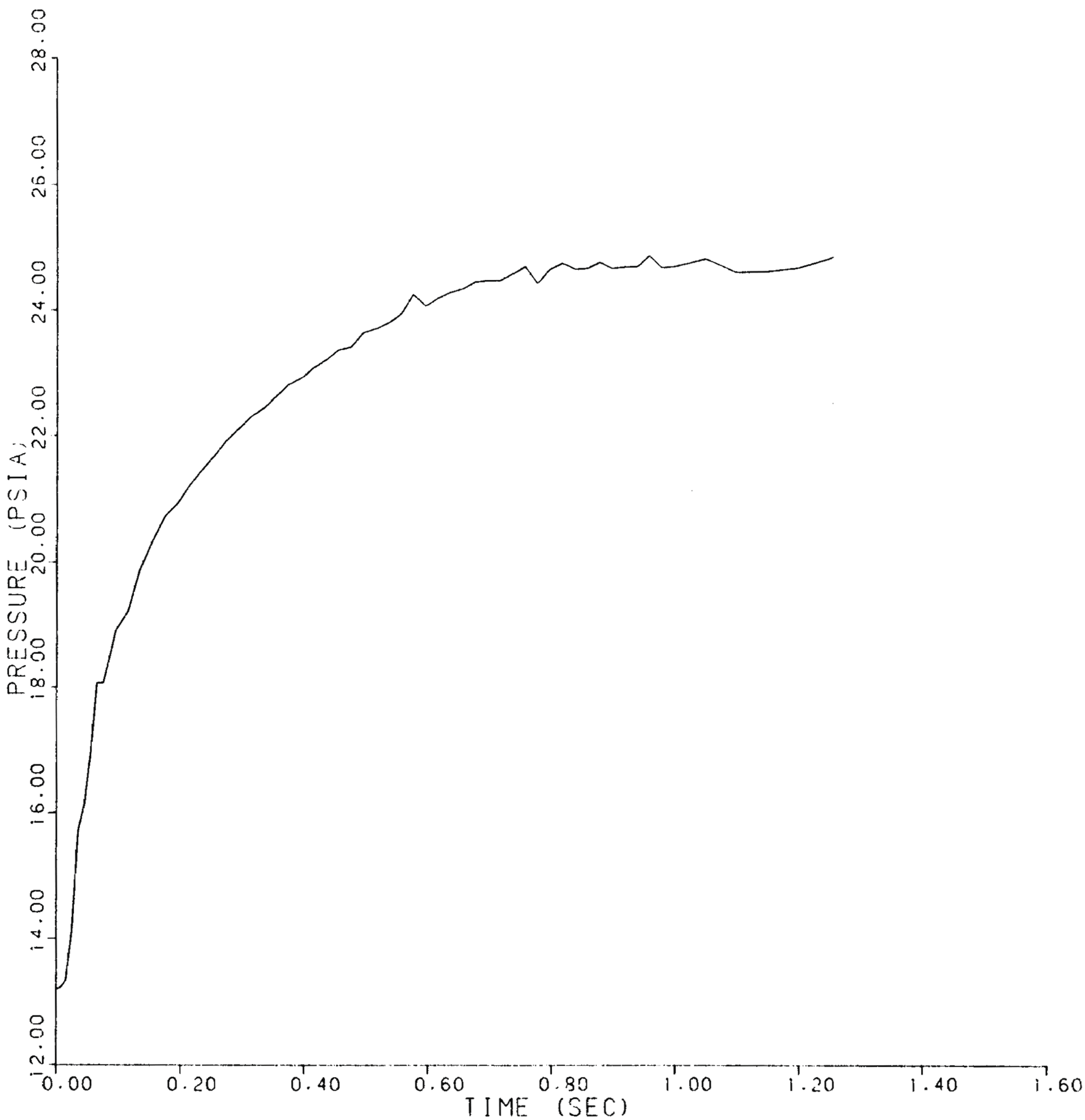
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E43
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 43 OF 74)



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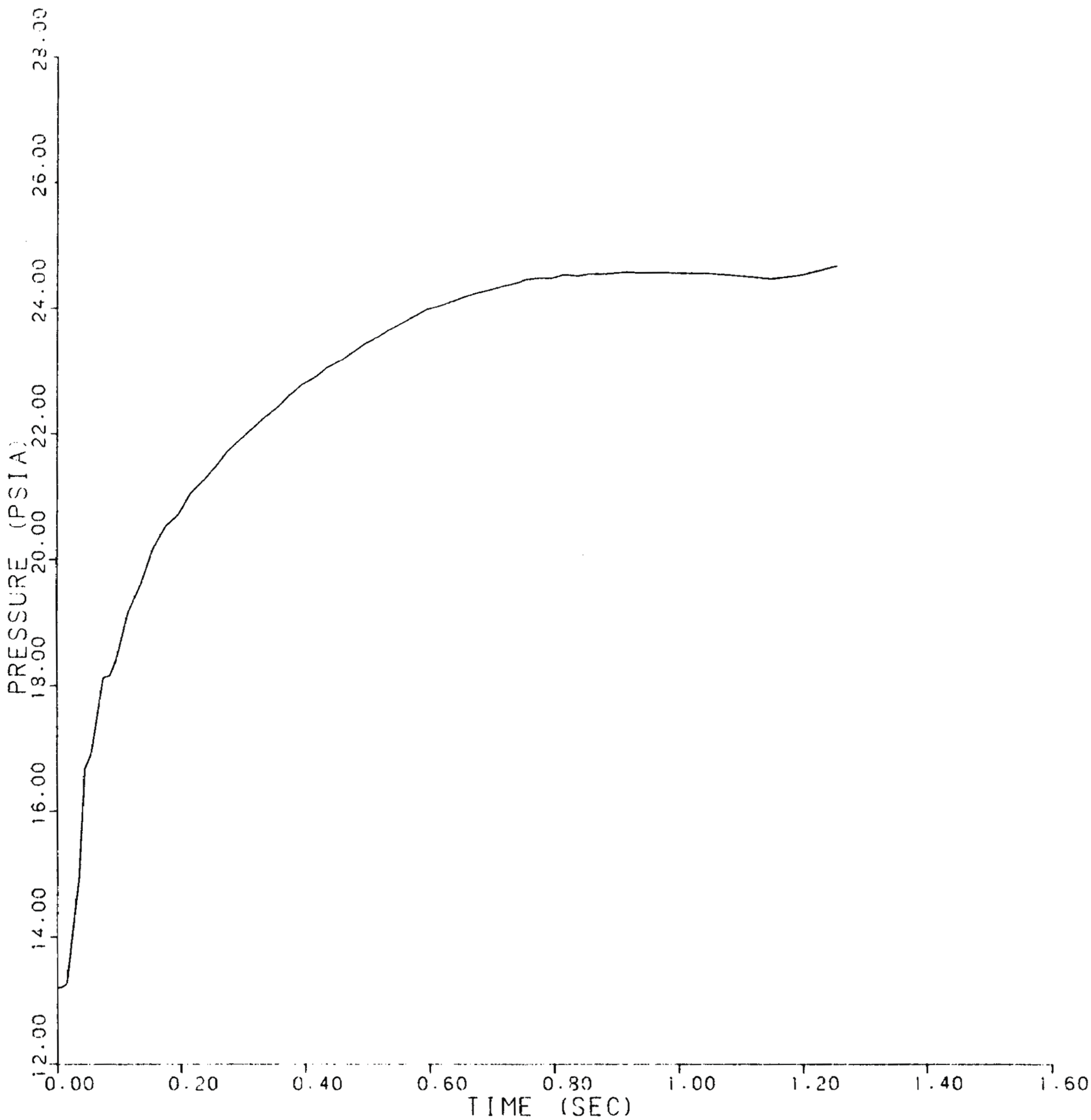
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

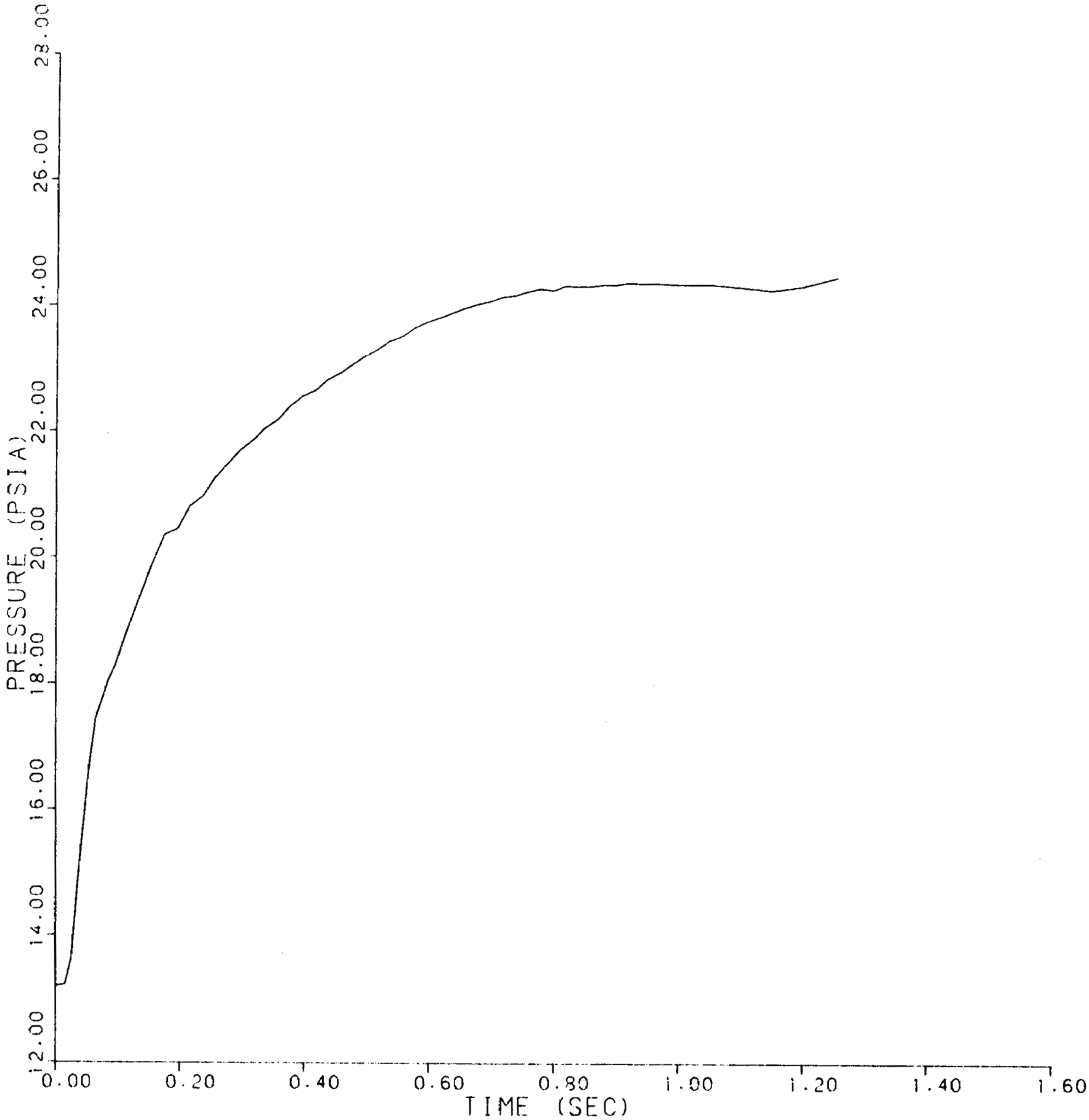
LOOP CLOSURE WELD
NODE E44
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 44 OF 74)



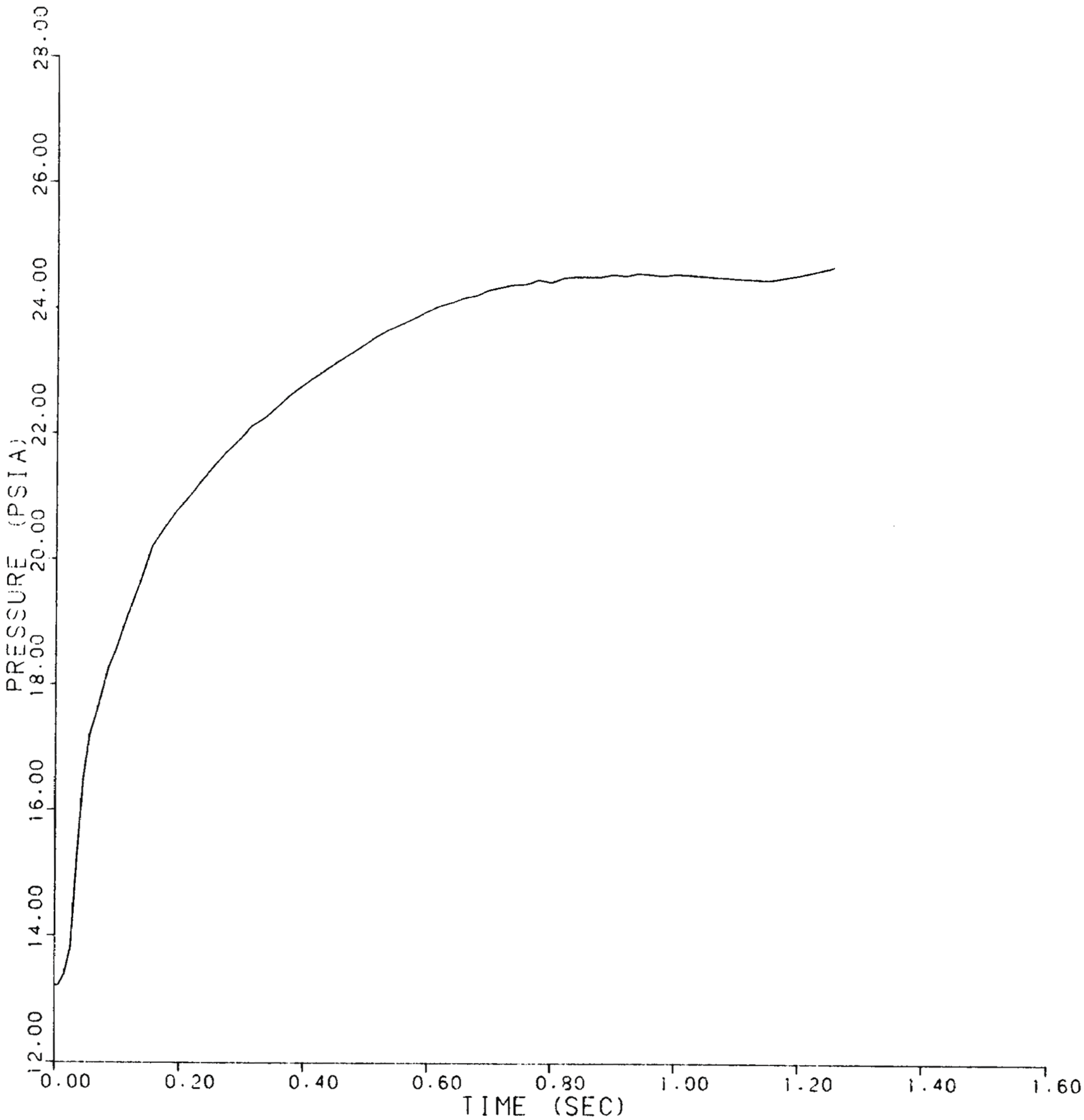
REV 13 4/06

SOUTHERN COMPANY *Energy to Serve Your World®*	VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	LOOP CLOSURE WELD NODE E45 (336–in.^{2} BREAK AREA)
		FIGURE 6.2.1–23 (SHEET 45 OF 74)



REV 13 4/06

SOUTHERN COMPANY *Energy to Serve Your World®*	**VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2**	LOOP CLOSURE WELD NODE E46 (336–in.^{2} BREAK AREA)
		FIGURE 6.2.1–23 (SHEET 46 OF 74)



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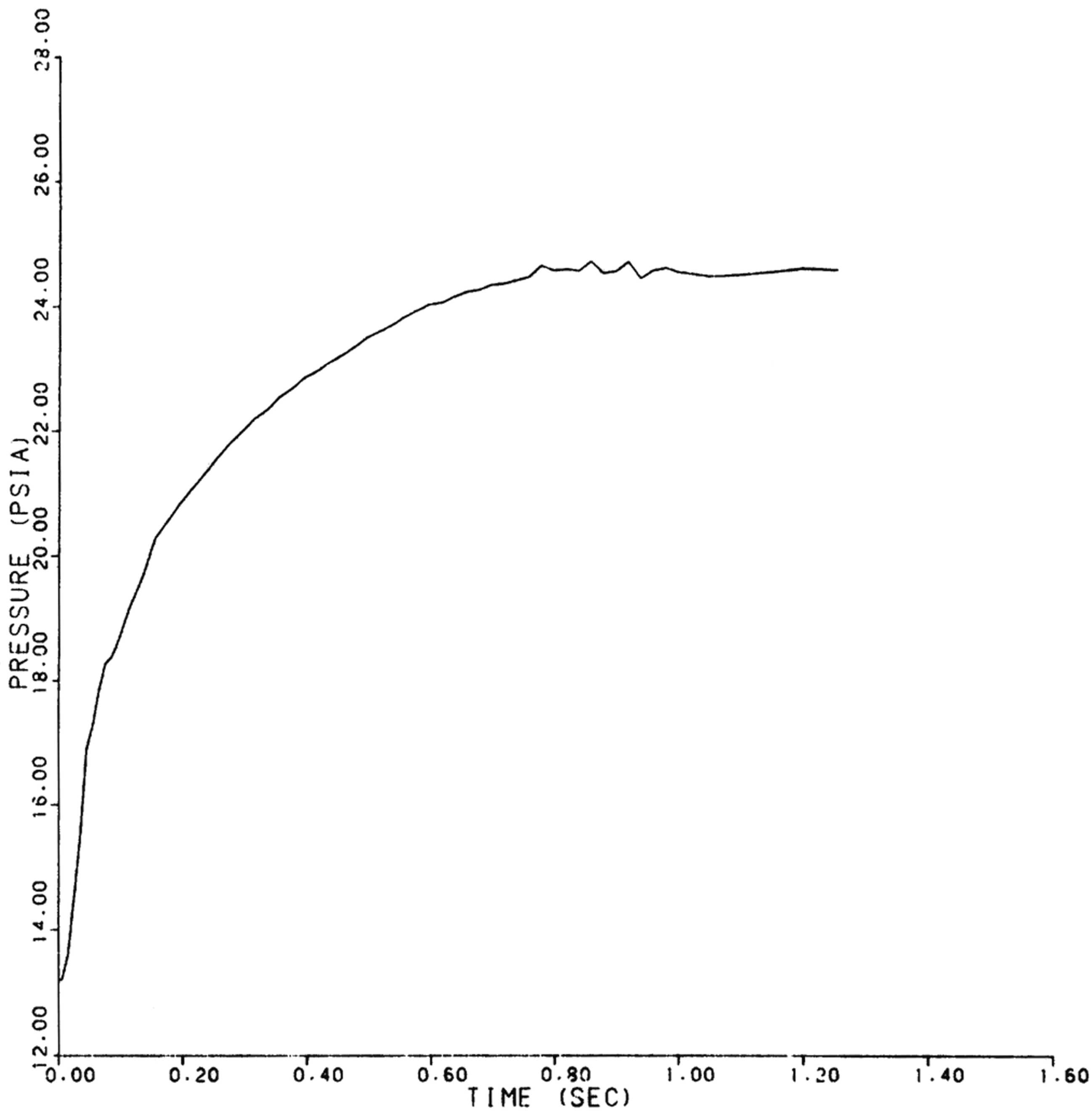
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E47
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 47 OF 74)



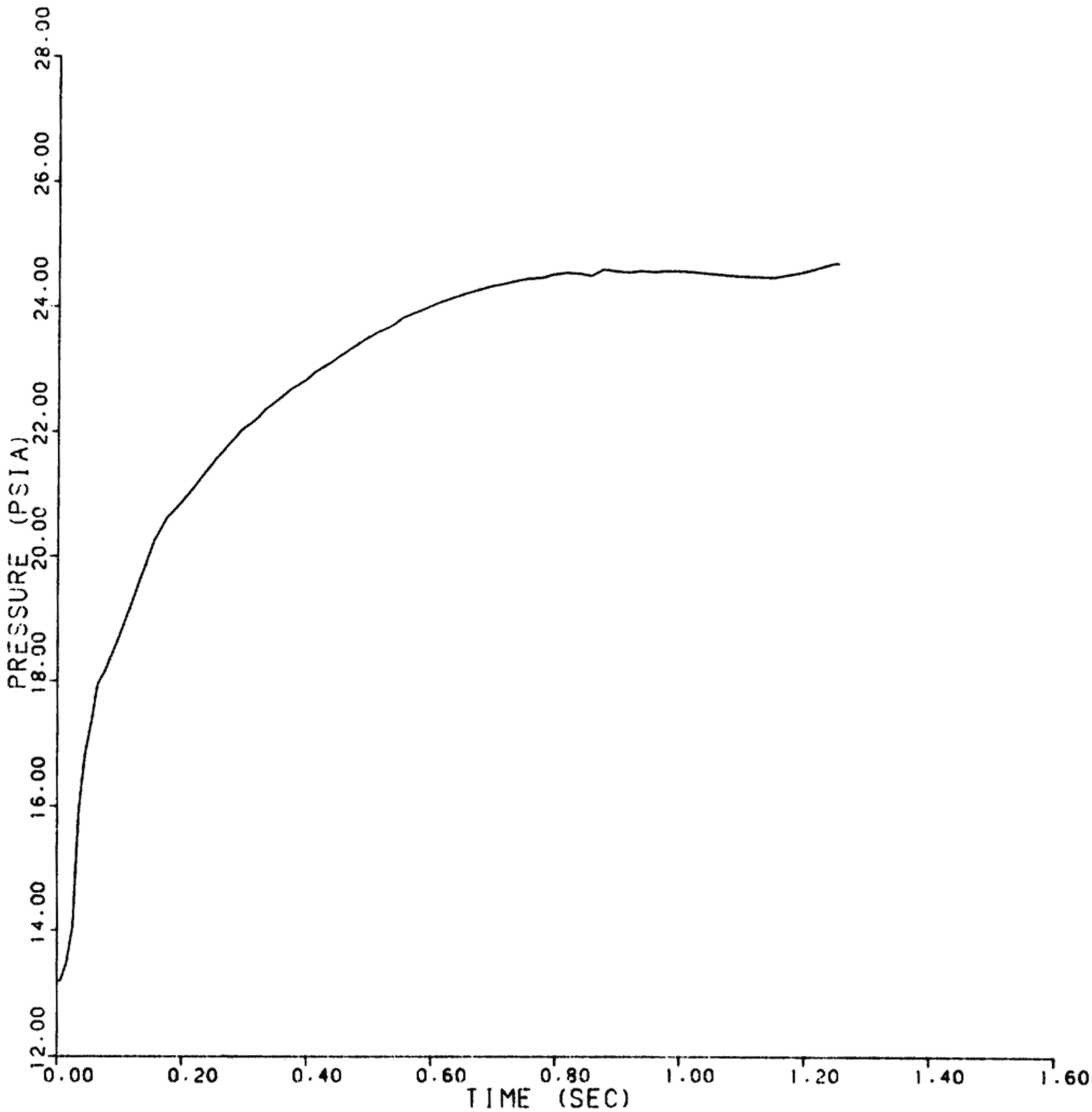
REV 13 4/06

SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E48
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 48 OF 74)



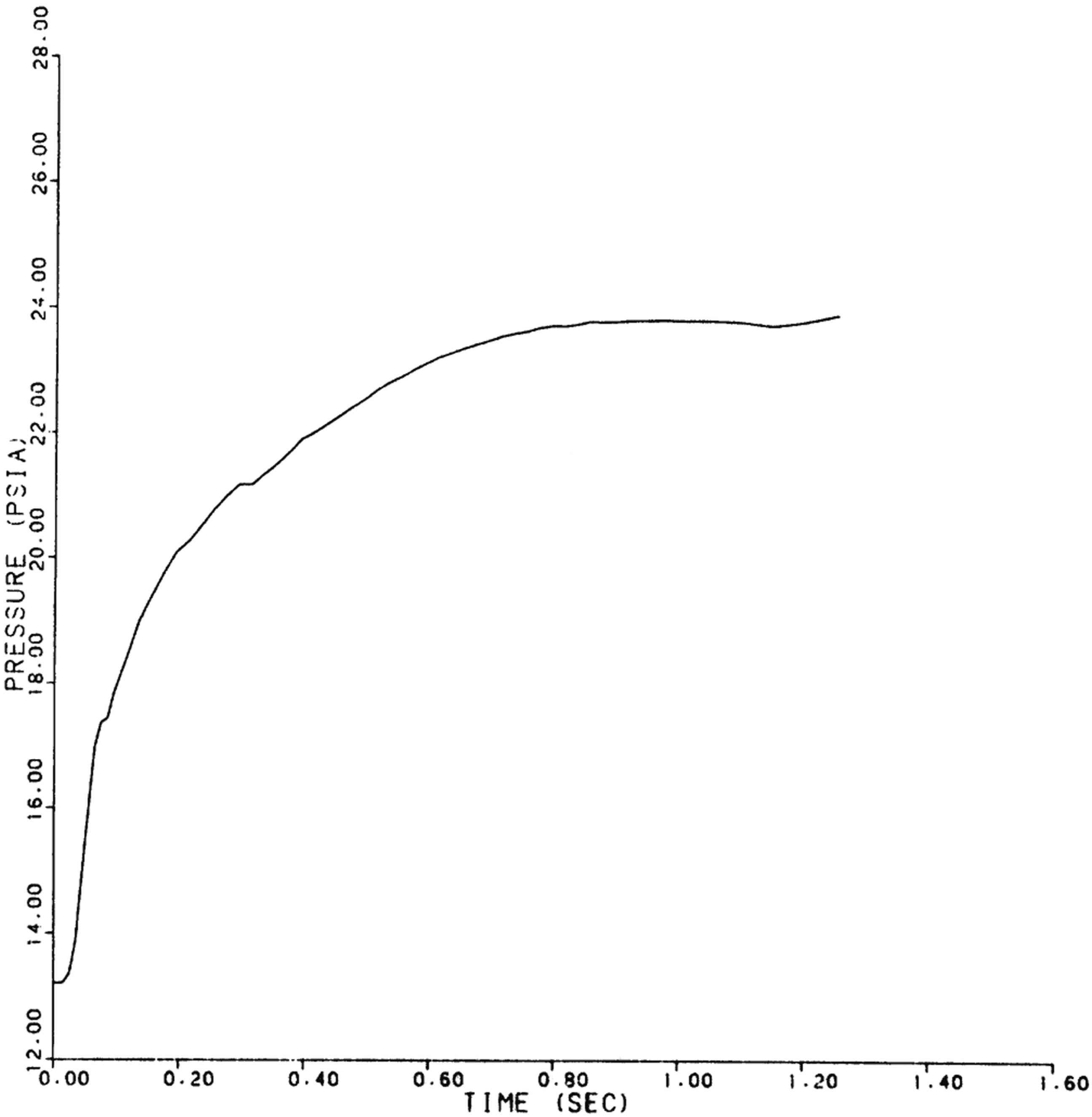
REV 13 4/06

SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E49
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 49 OF 74)



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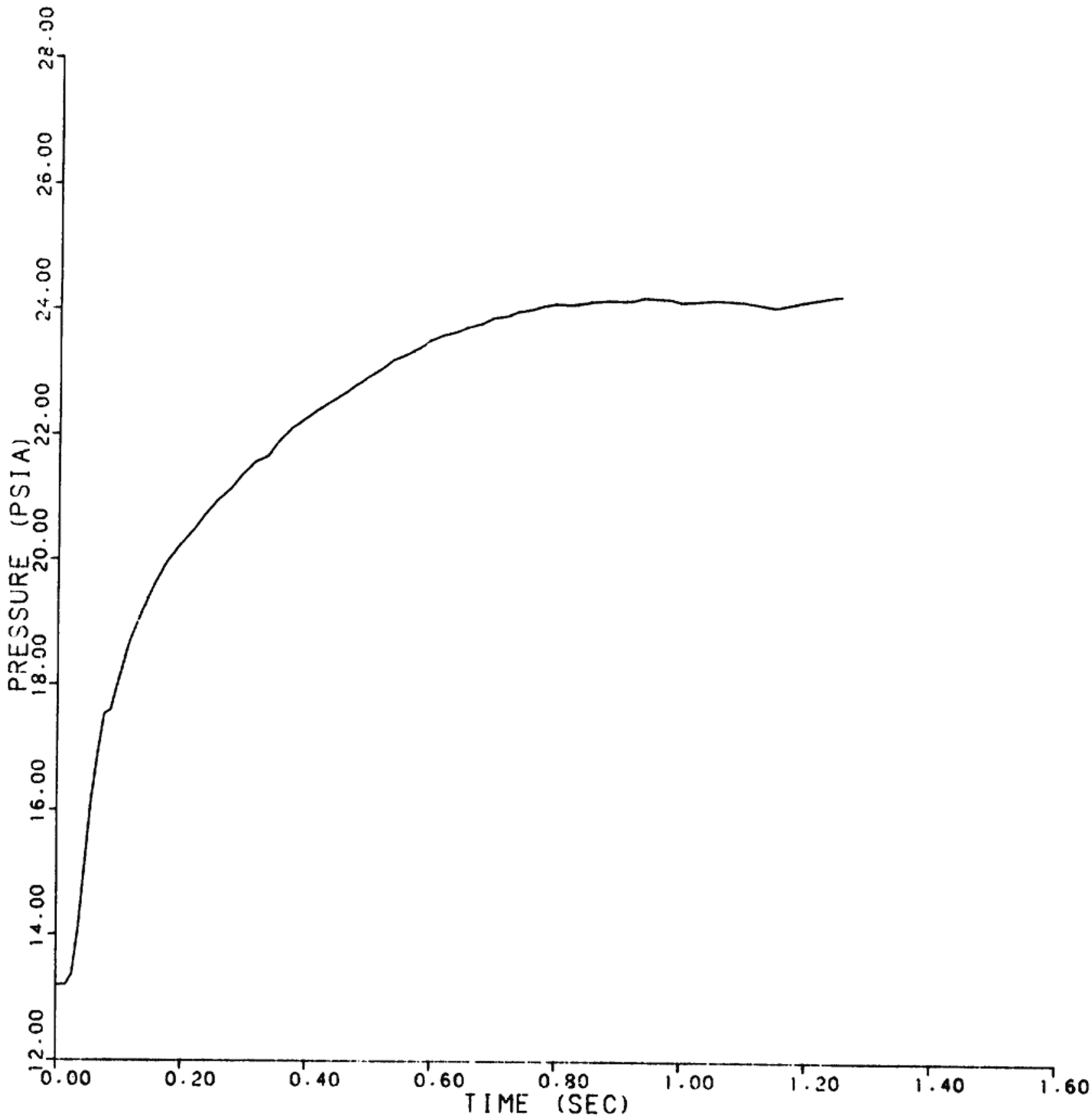
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E50
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 50 OF 74)



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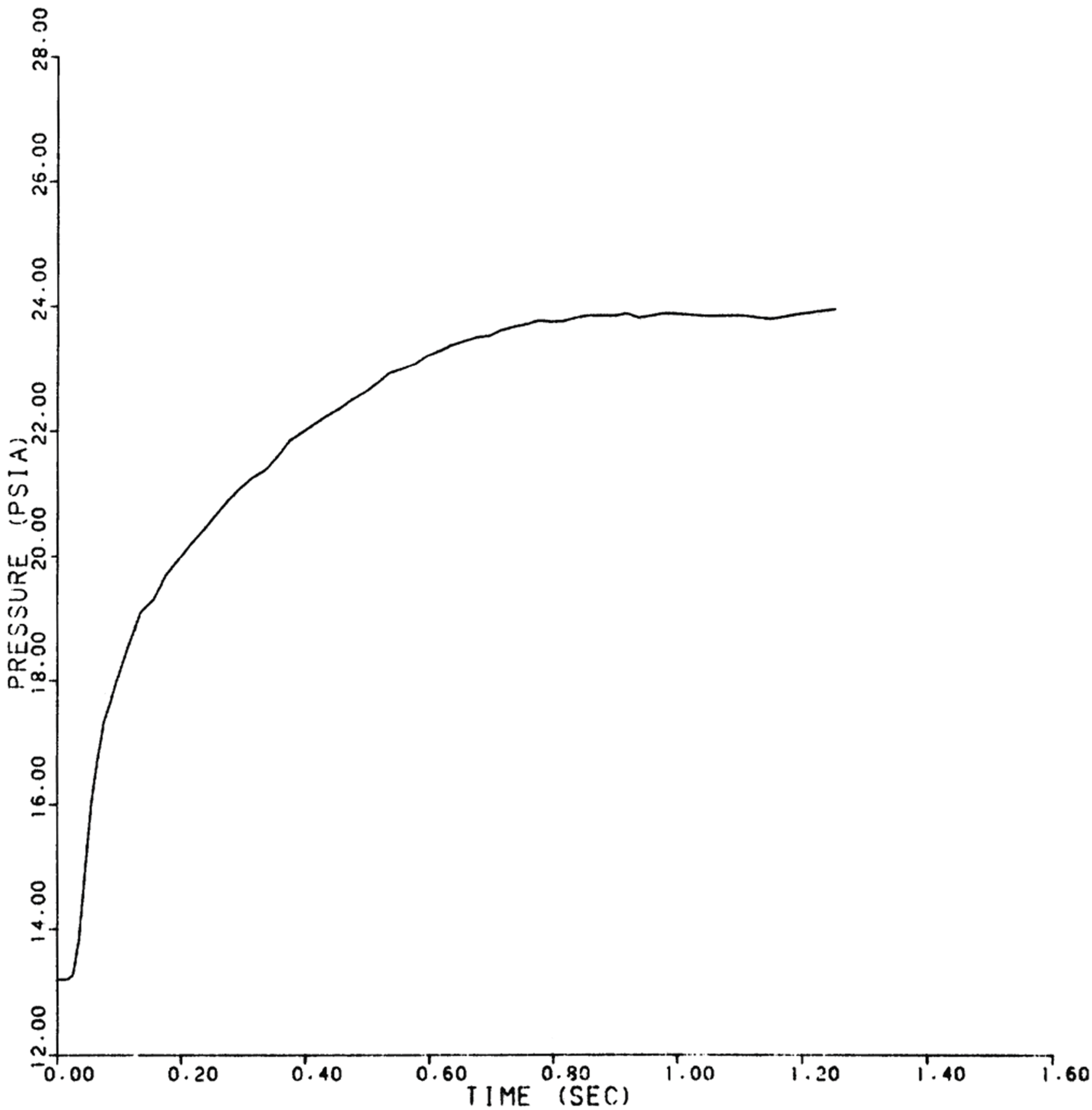
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E51
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 51 OF 74)



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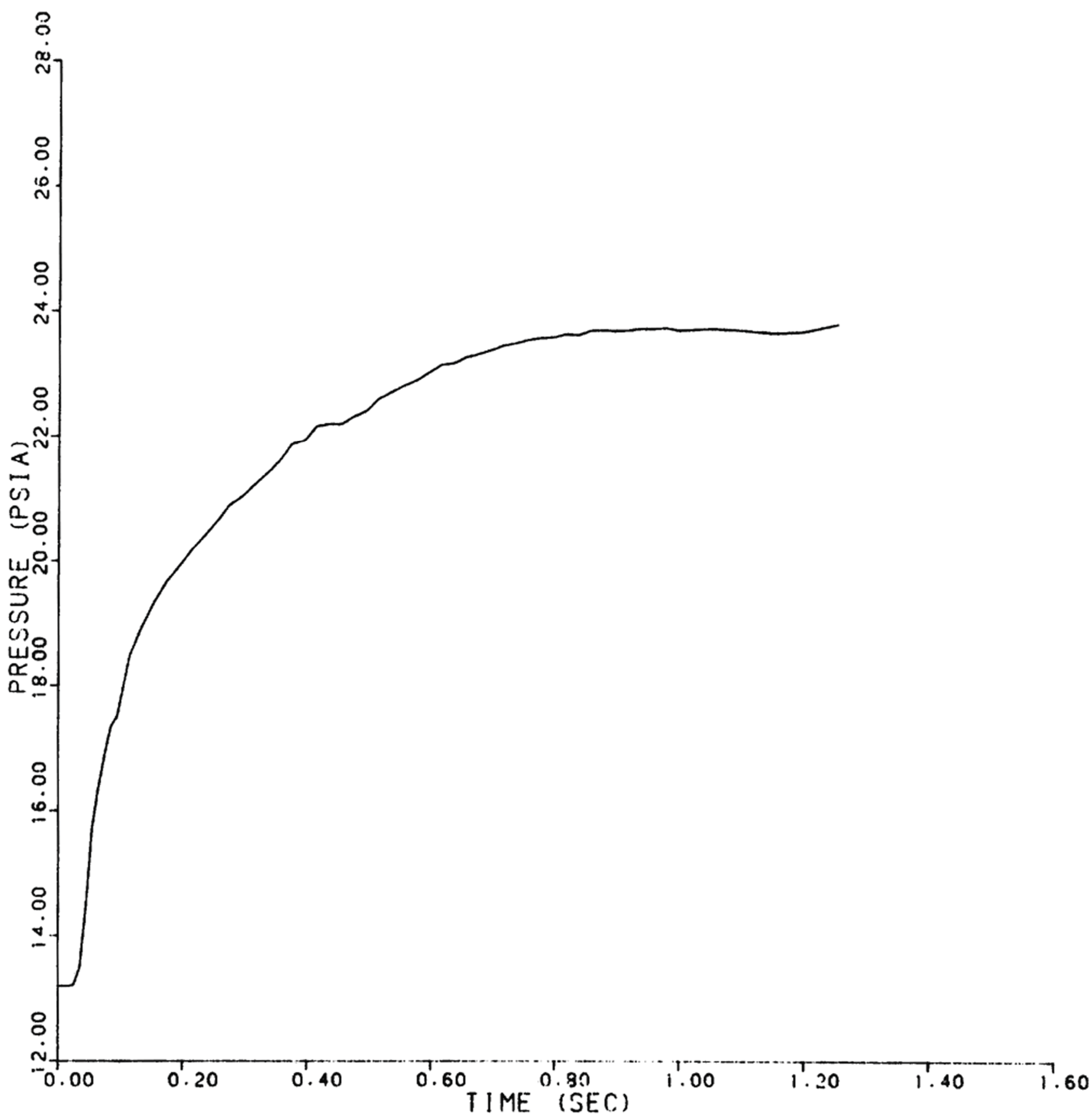
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E52
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 52 OF 74)



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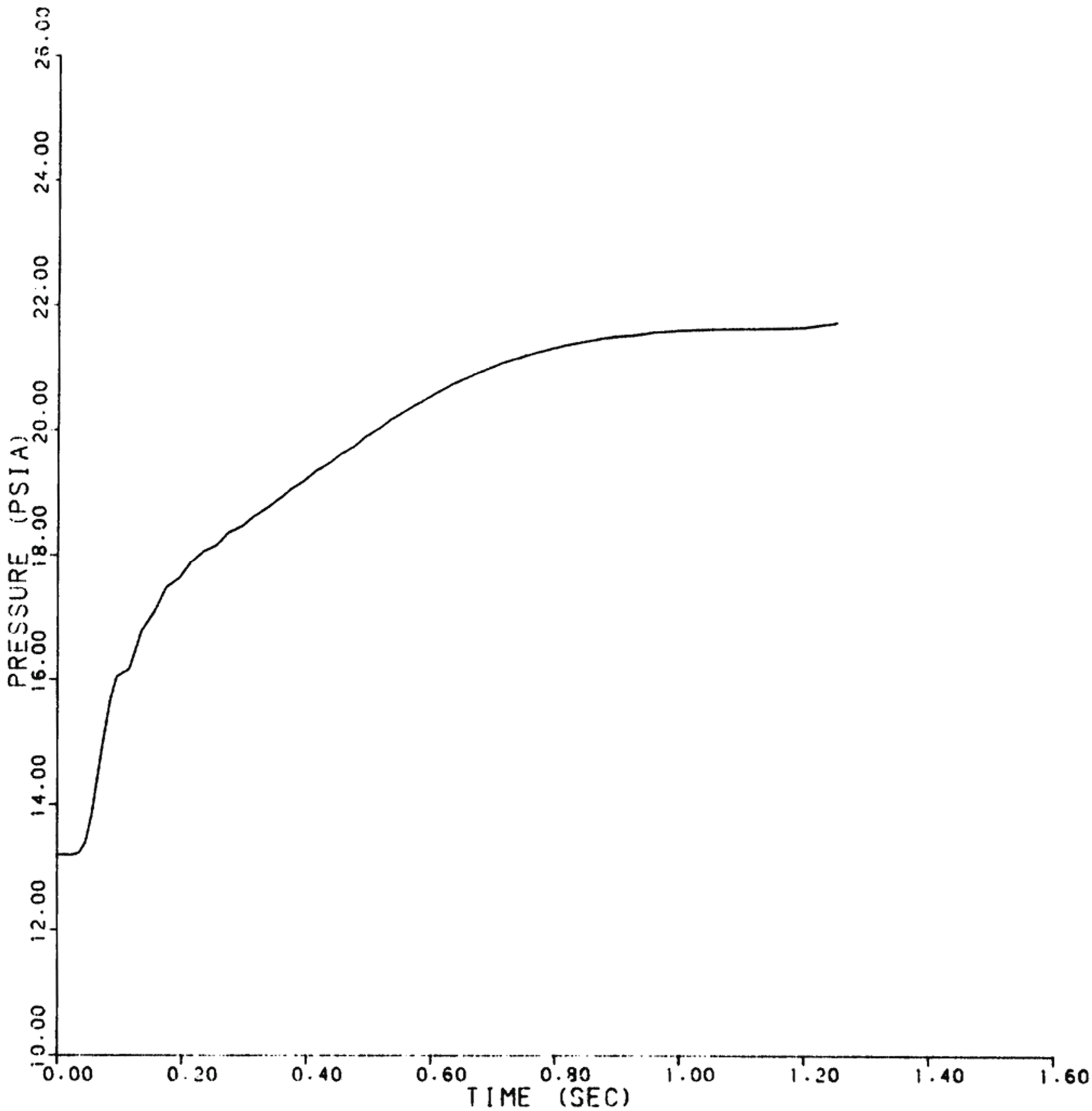
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E53
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 53 OF 74)



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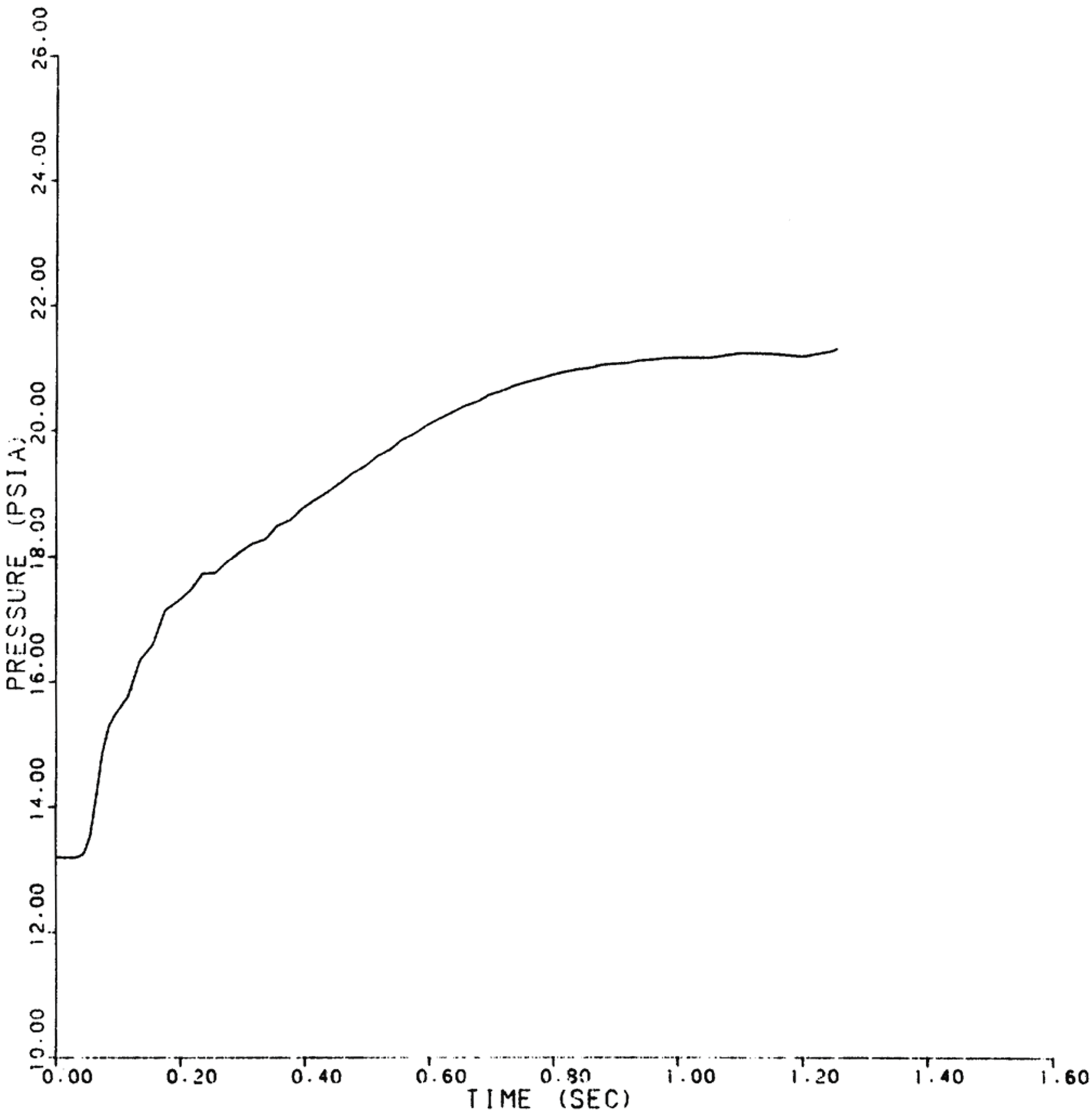
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E54
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 54 OF 74)



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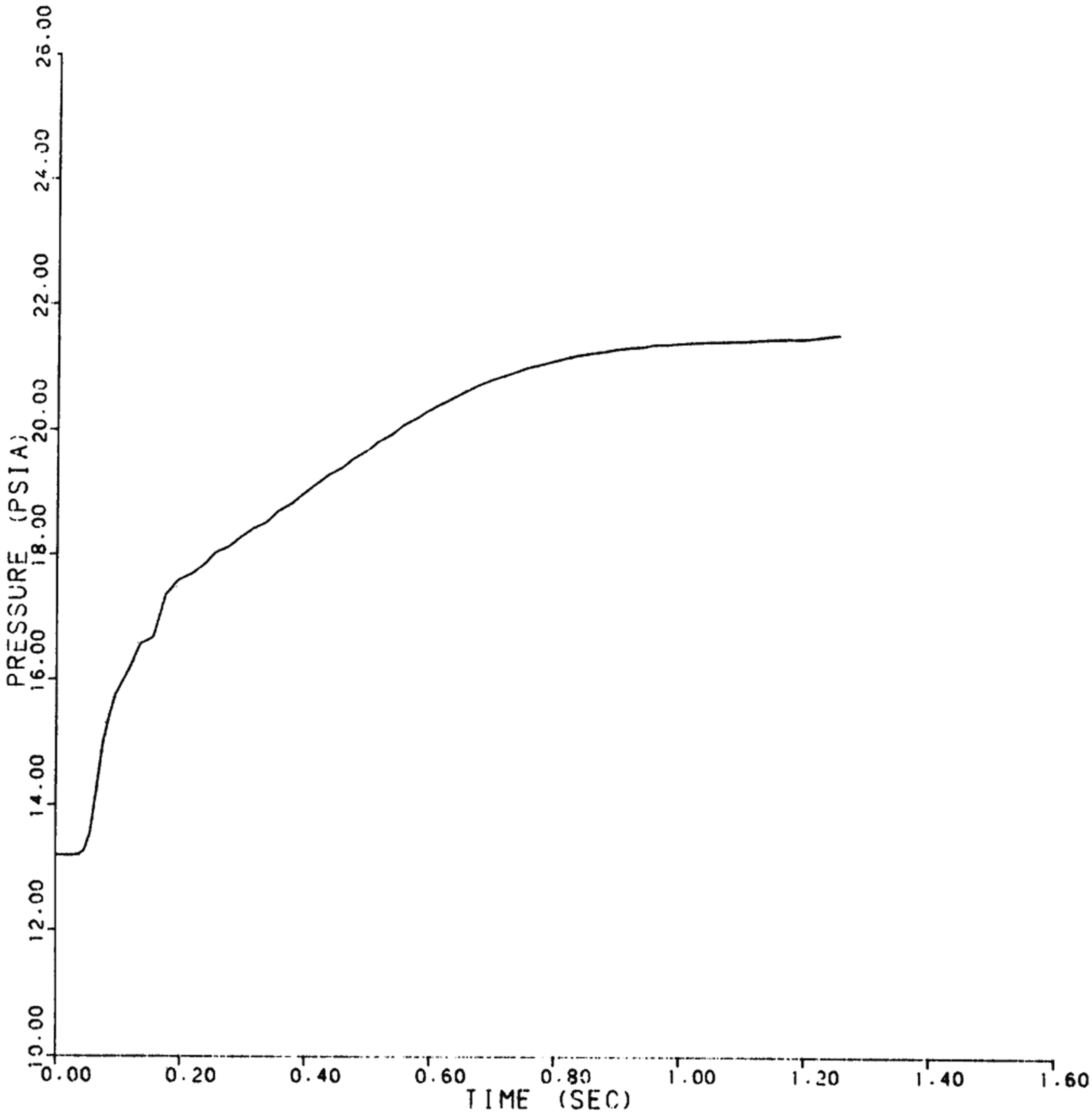
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E55
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 55 OF 74)



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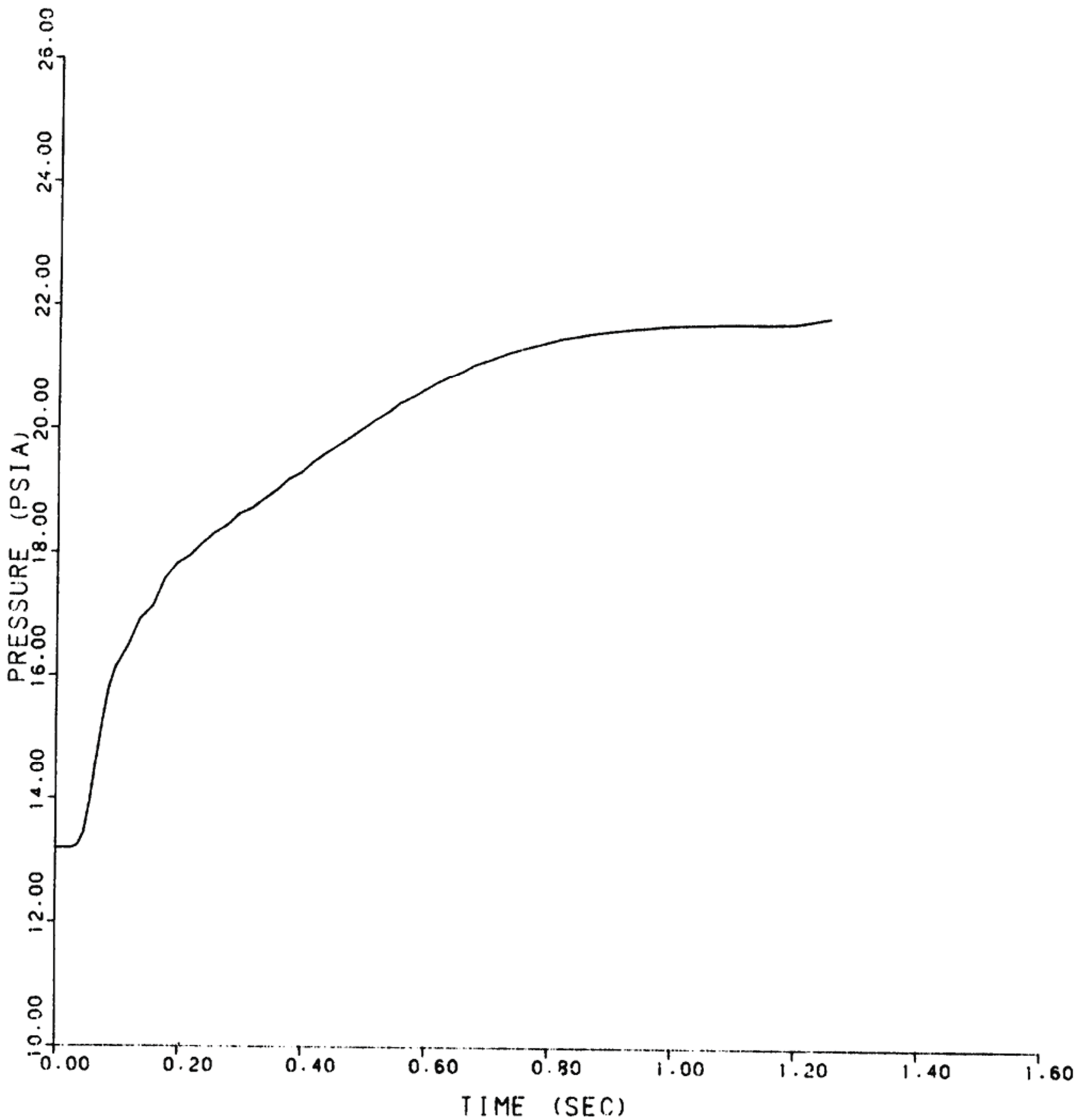
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E56
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 56 OF 74)



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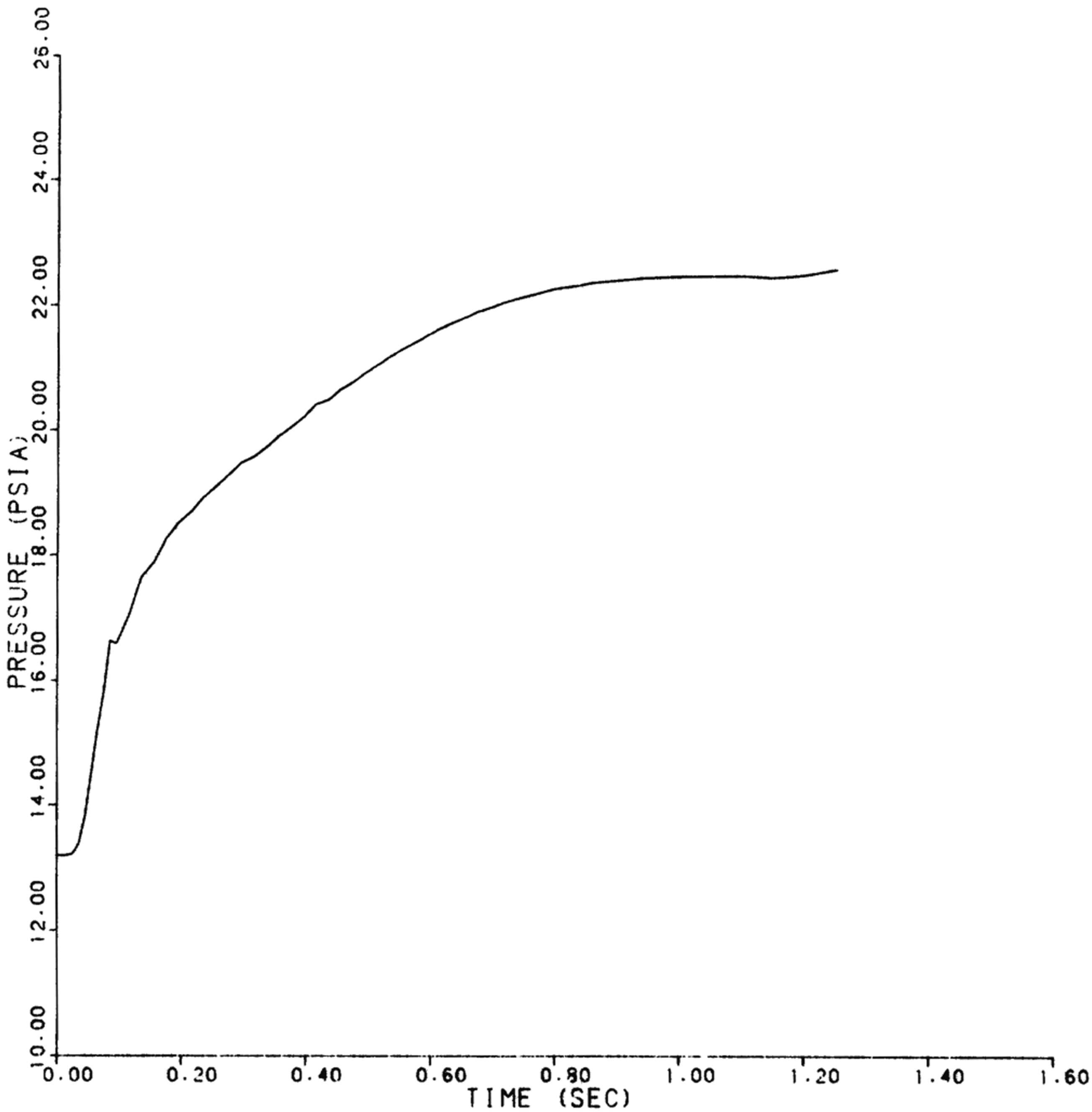
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E57
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 57 OF 74)



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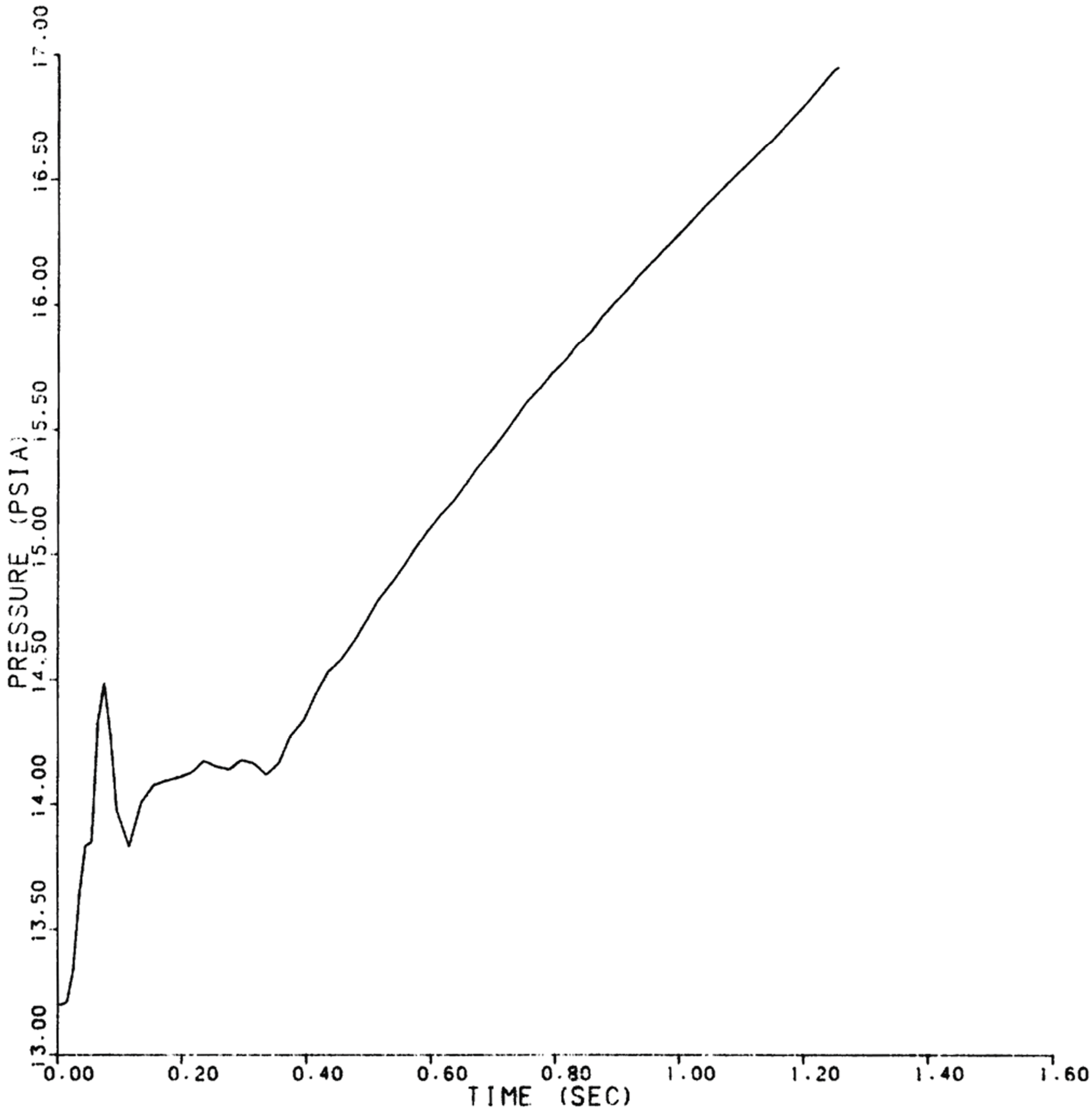
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E58
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 58 OF 74)



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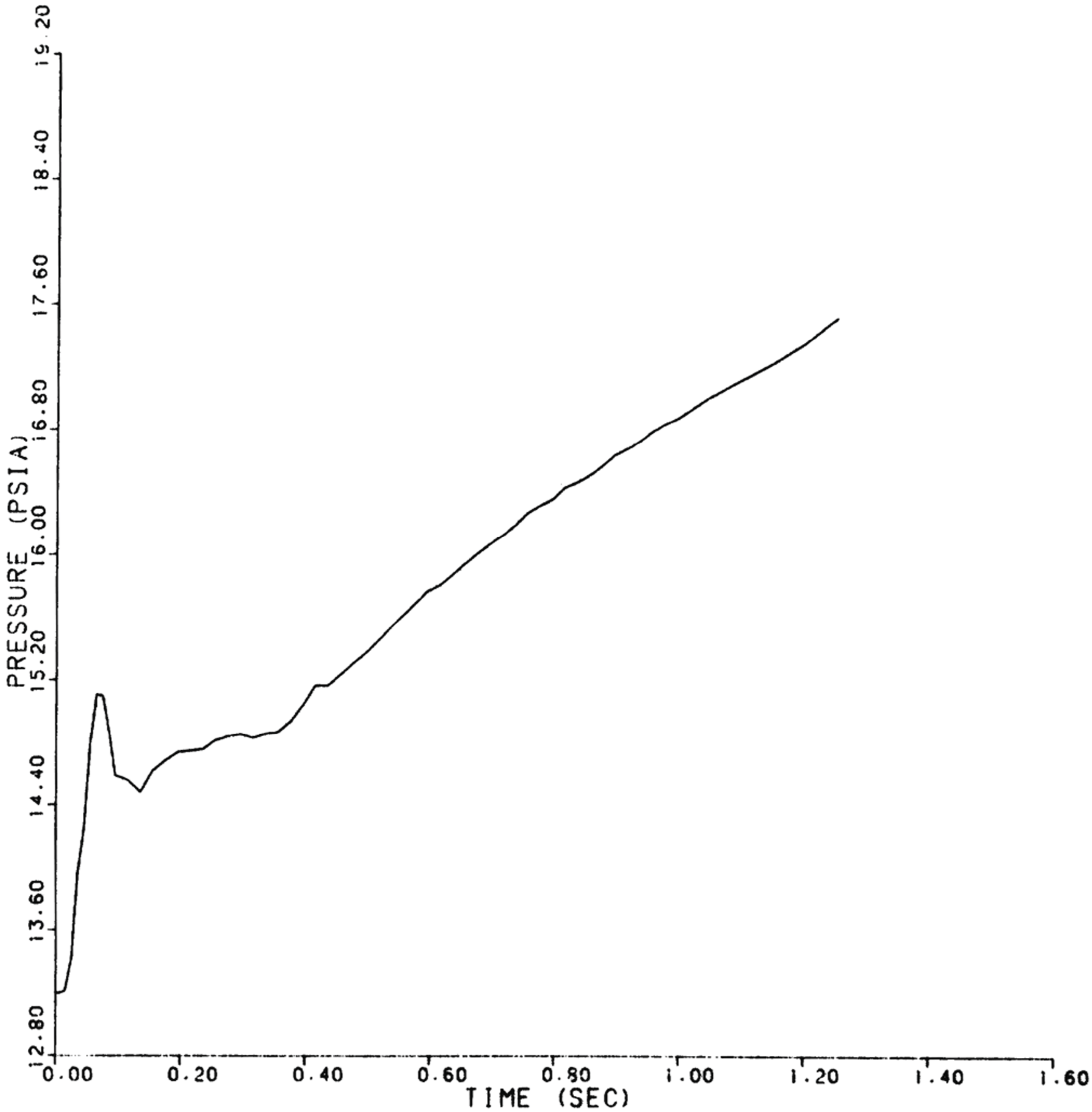
LOOP CLOSURE WELD
NODE E59
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 59 OF 74)



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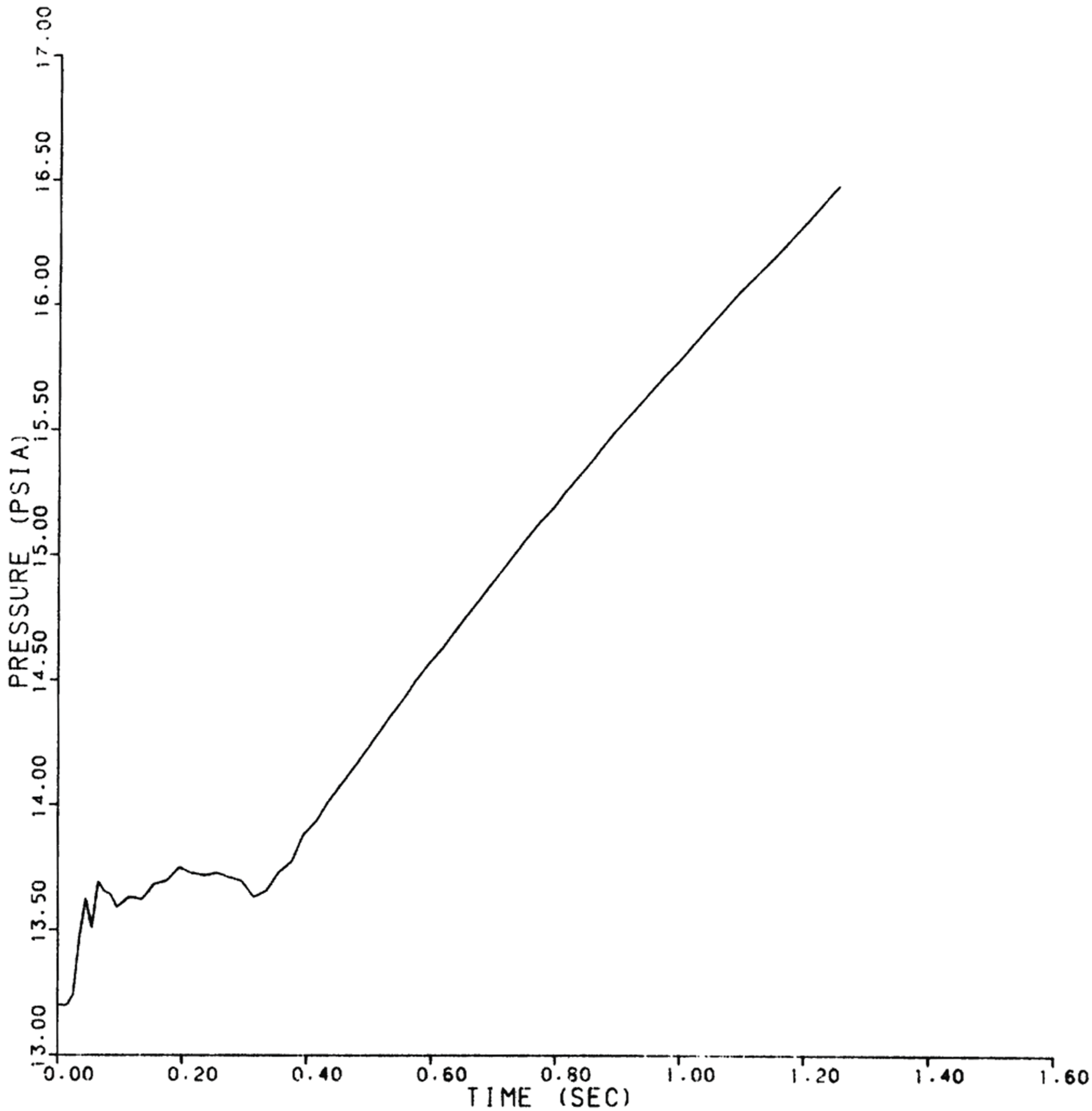
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E60
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 60 OF 74)



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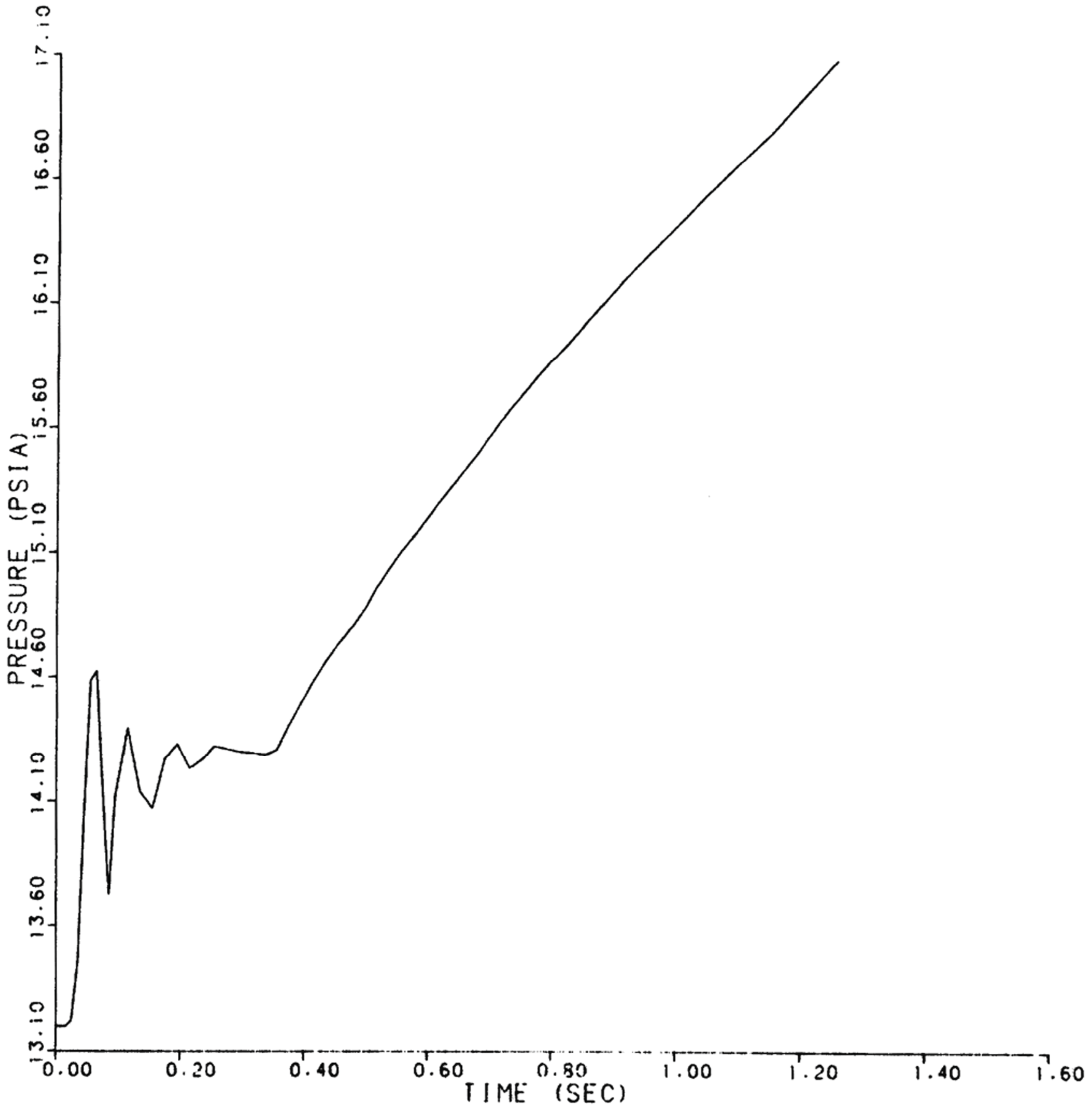
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E61
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 61 OF 74)



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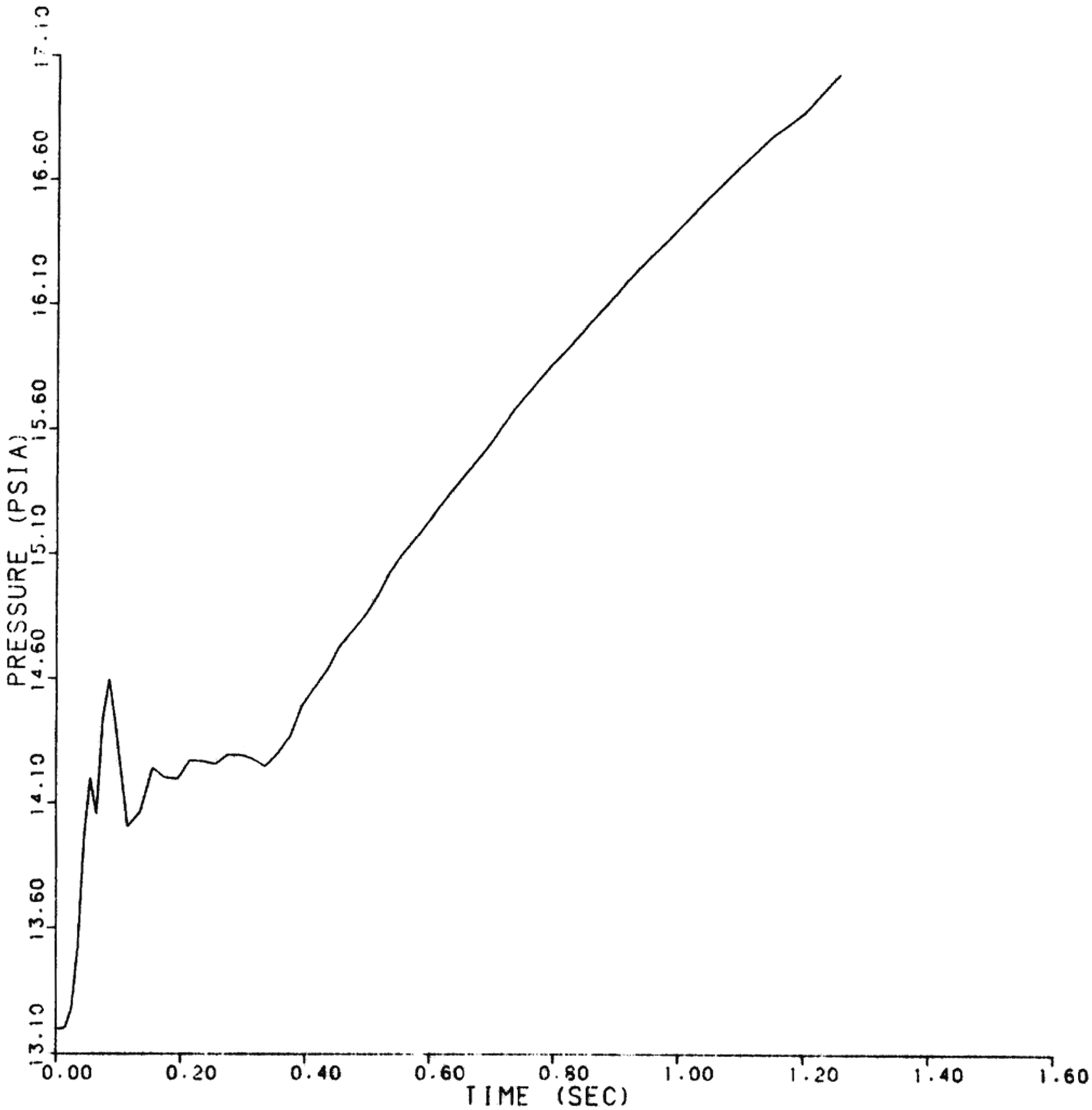
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E62
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 62 OF 74)



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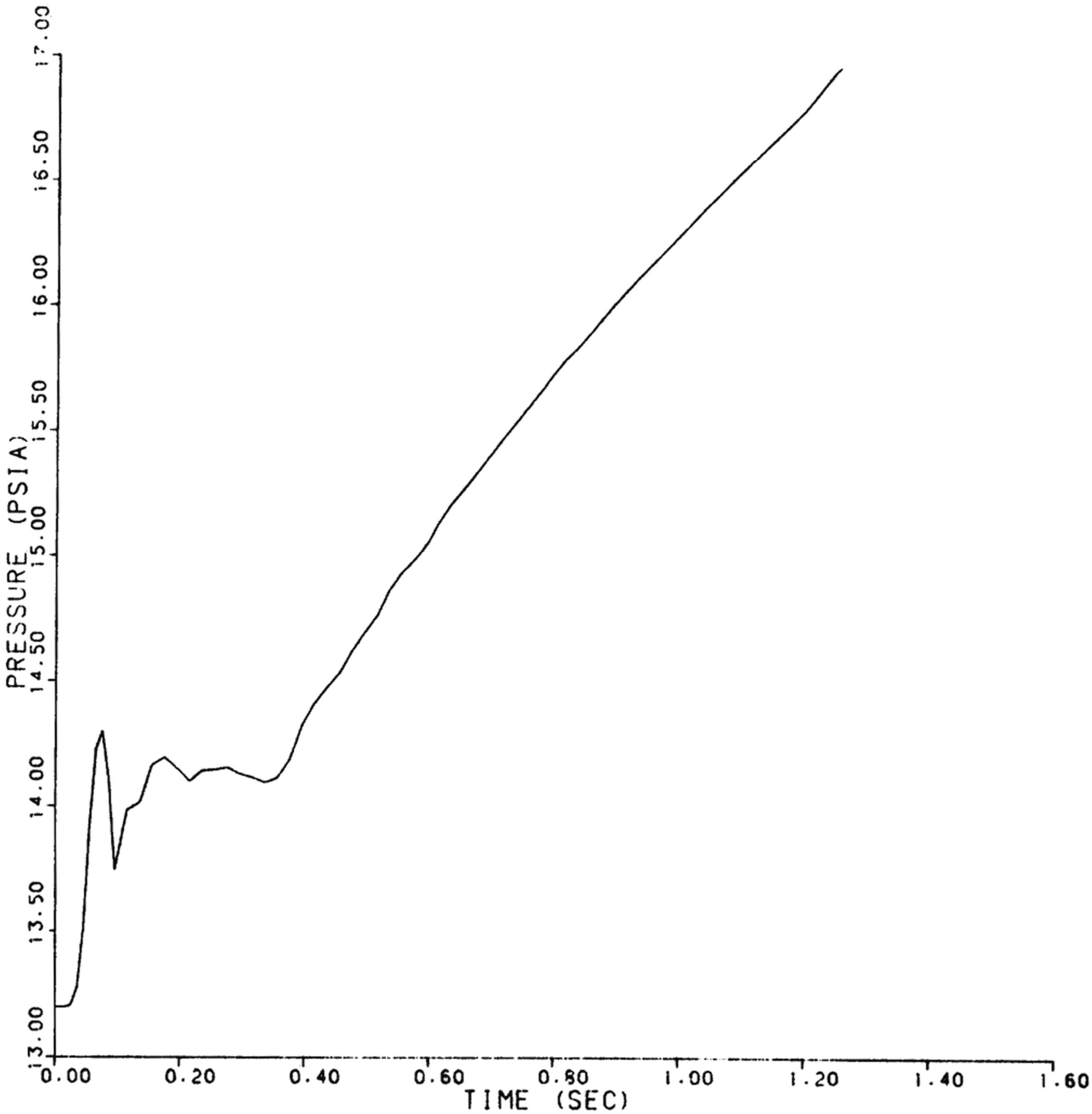
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E63
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 63 OF 74)



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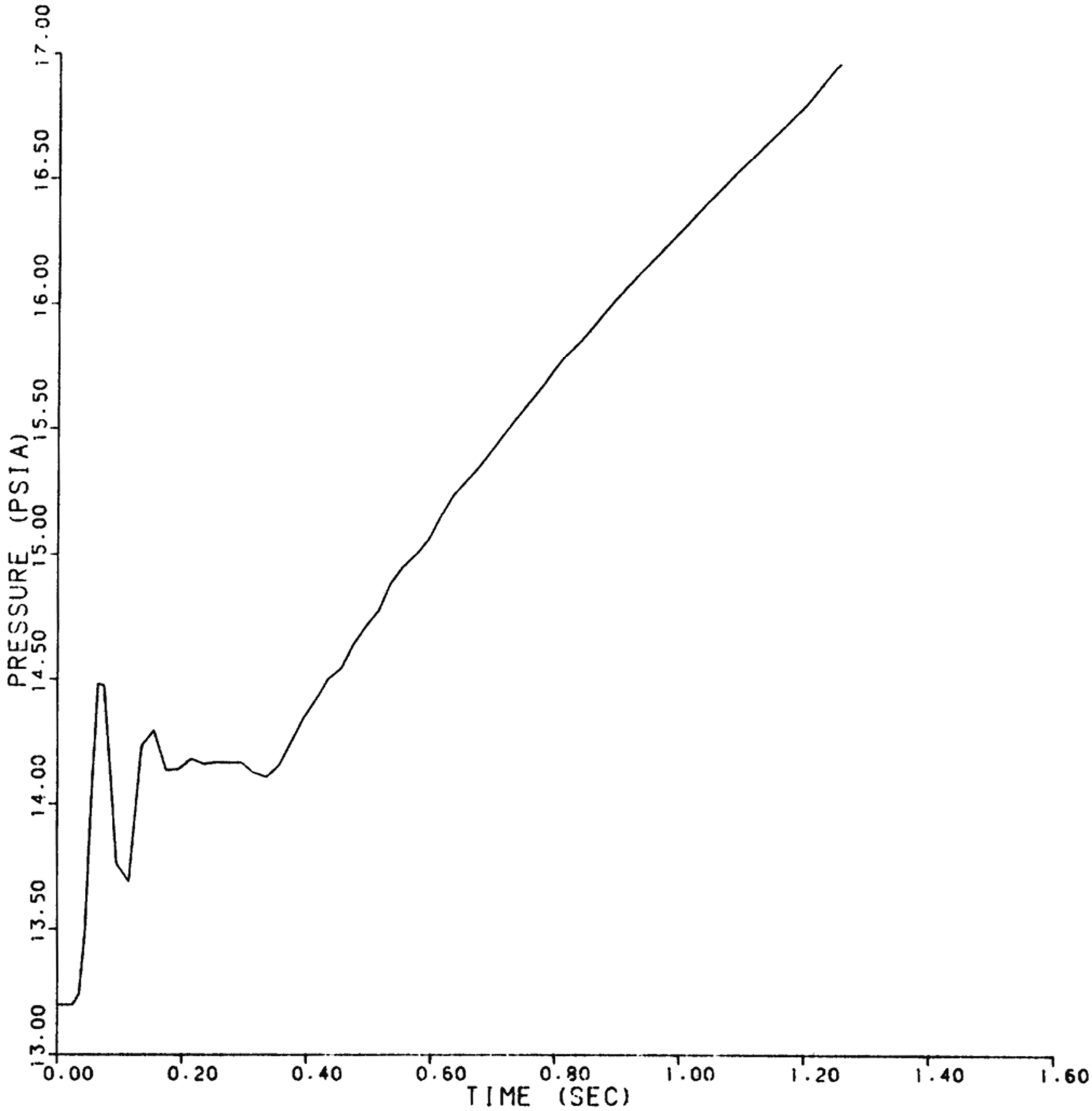
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E64
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 64 OF 74)



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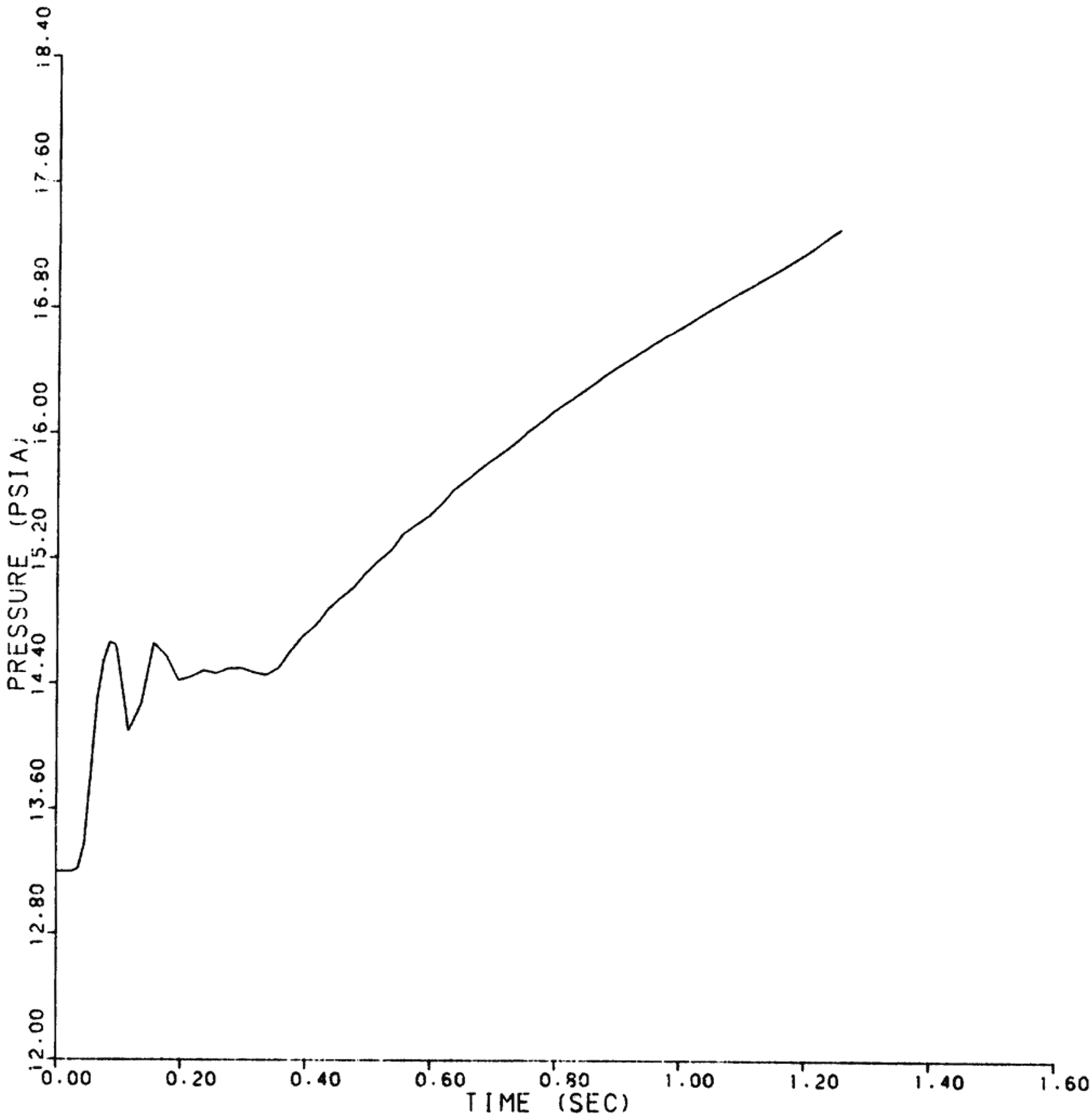
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E65
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 65 OF 74)



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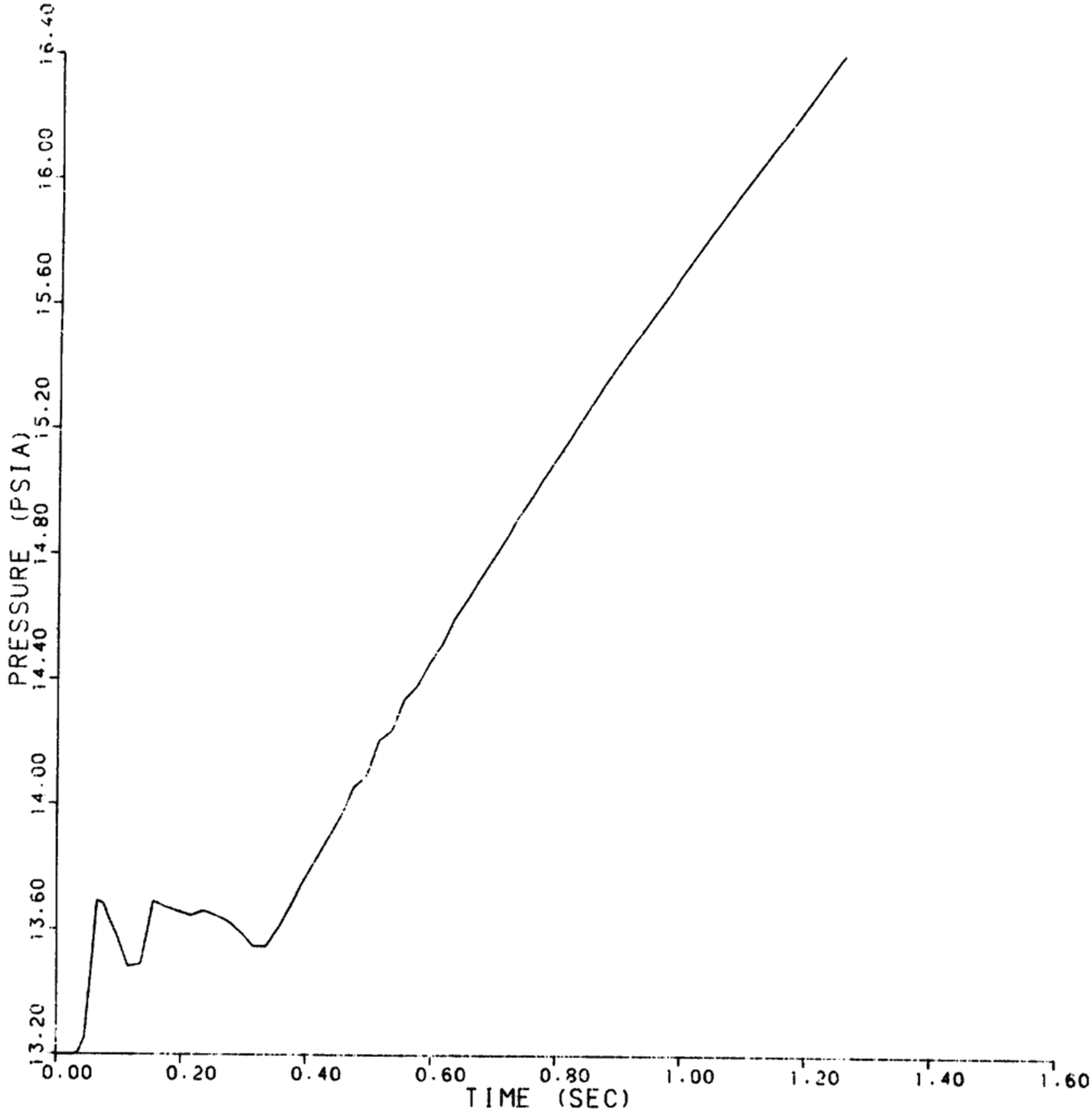
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E66
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 66 OF 74)



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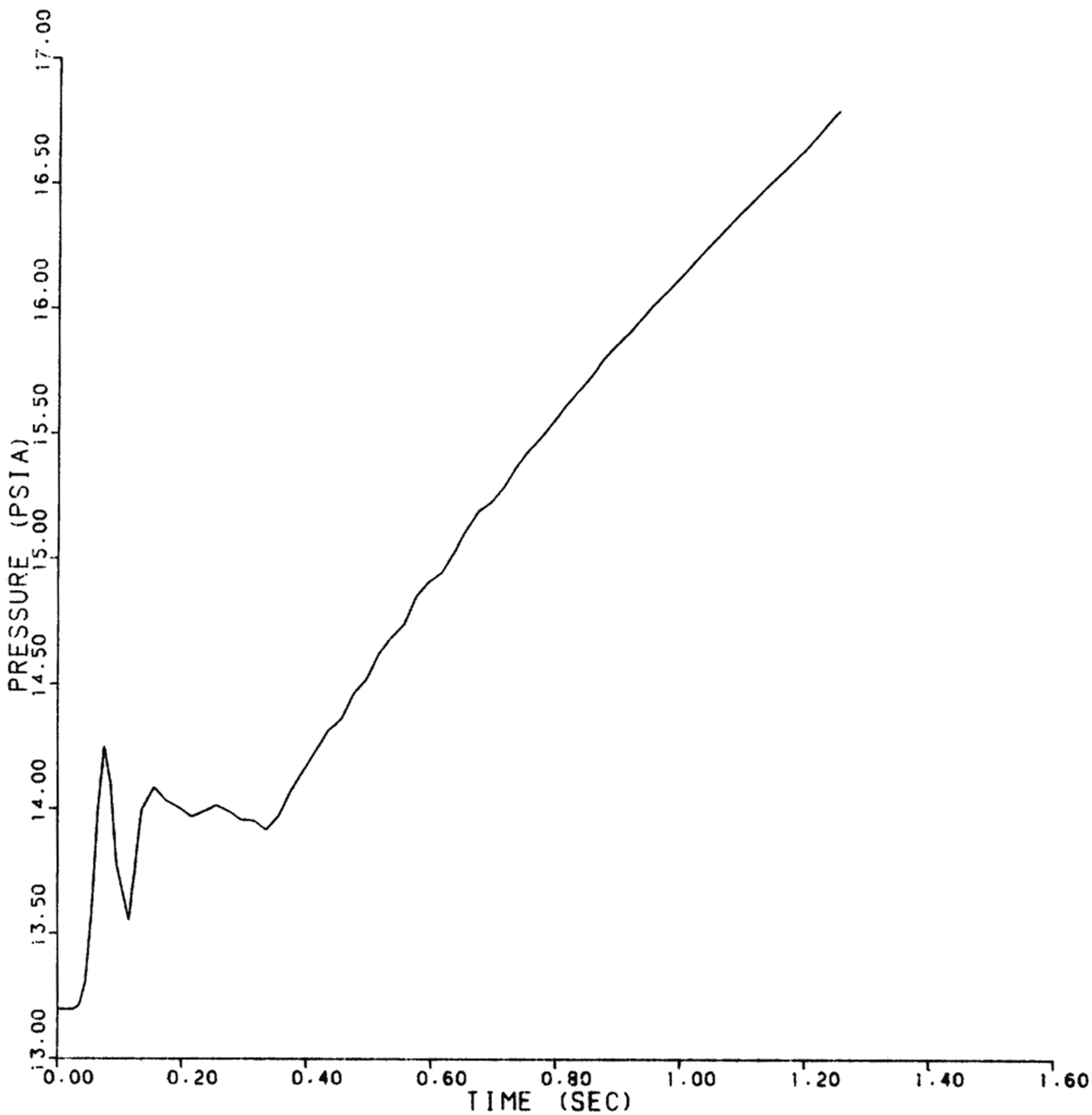
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E67
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 67 OF 74)



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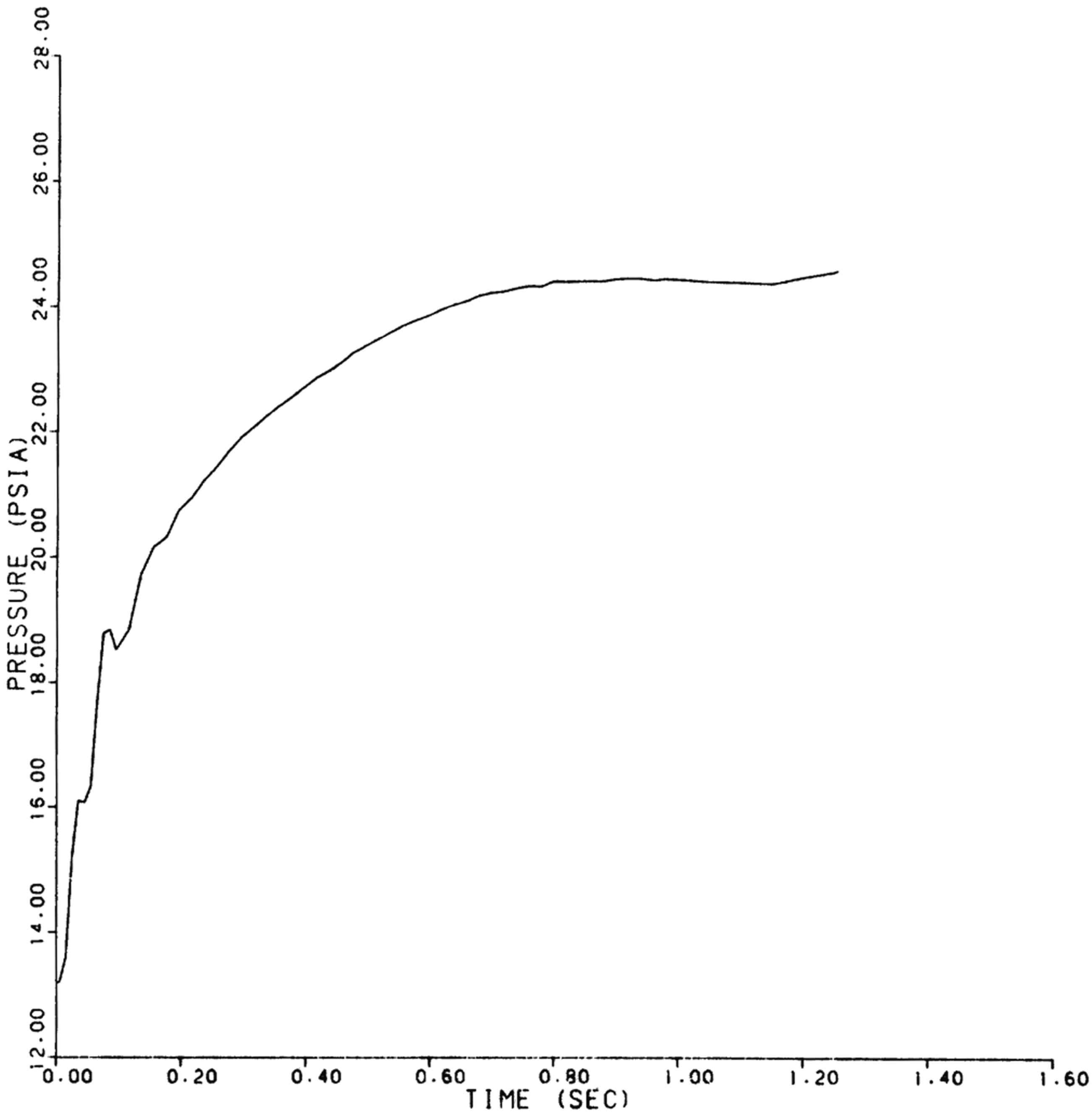
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E68
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 68 OF 74)



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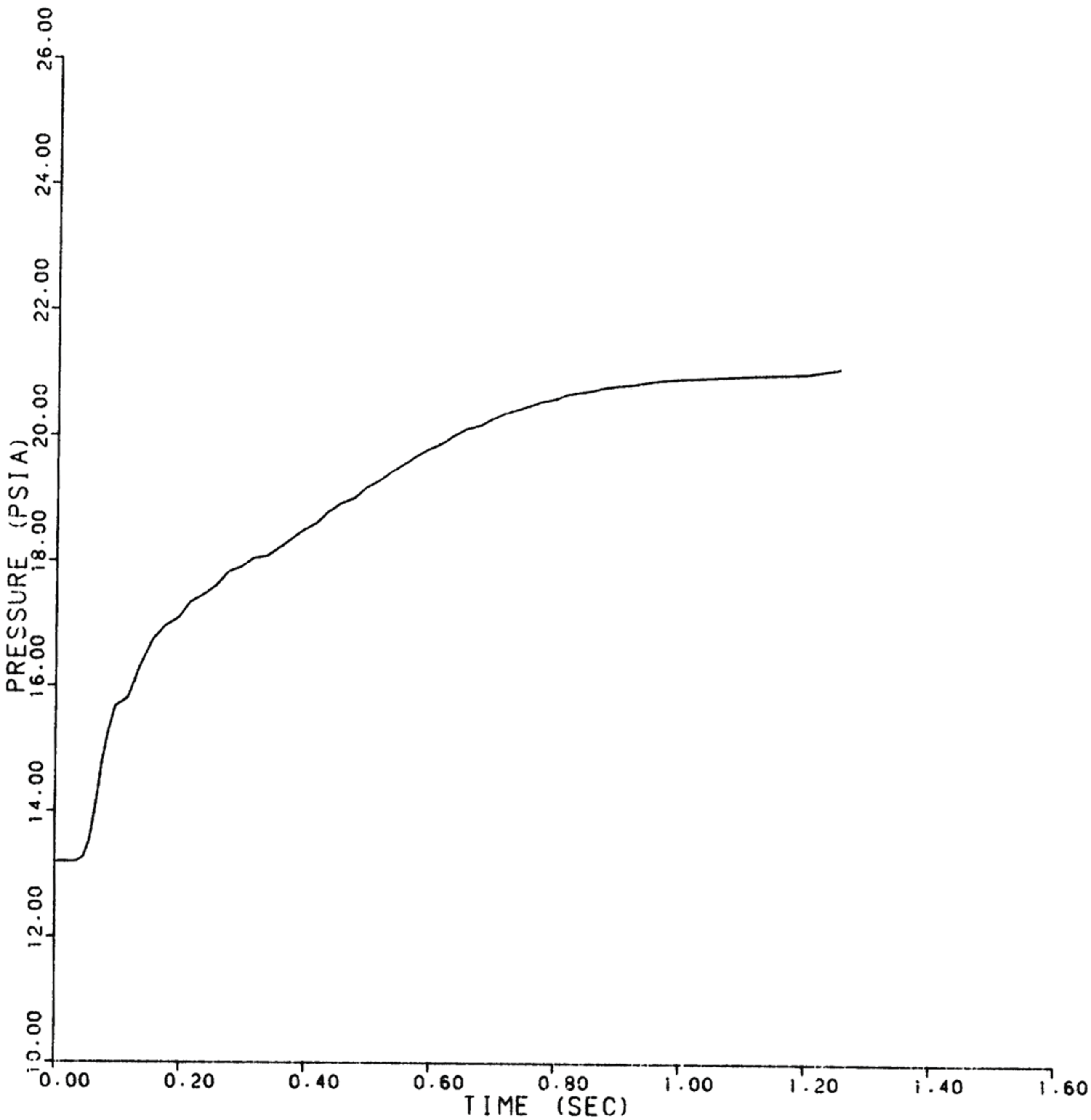
SOUTHERN COMPANY *Energy to Serve Your World®*	**VOGTLE** **ELECTRIC GENERATING PLANT** **UNIT 1 AND UNIT 2**	LOOP CLOSURE WELD NODE E69 (336–in.^{2} BREAK AREA)
		FIGURE 6.2.1–23 (SHEET 69 OF 74)



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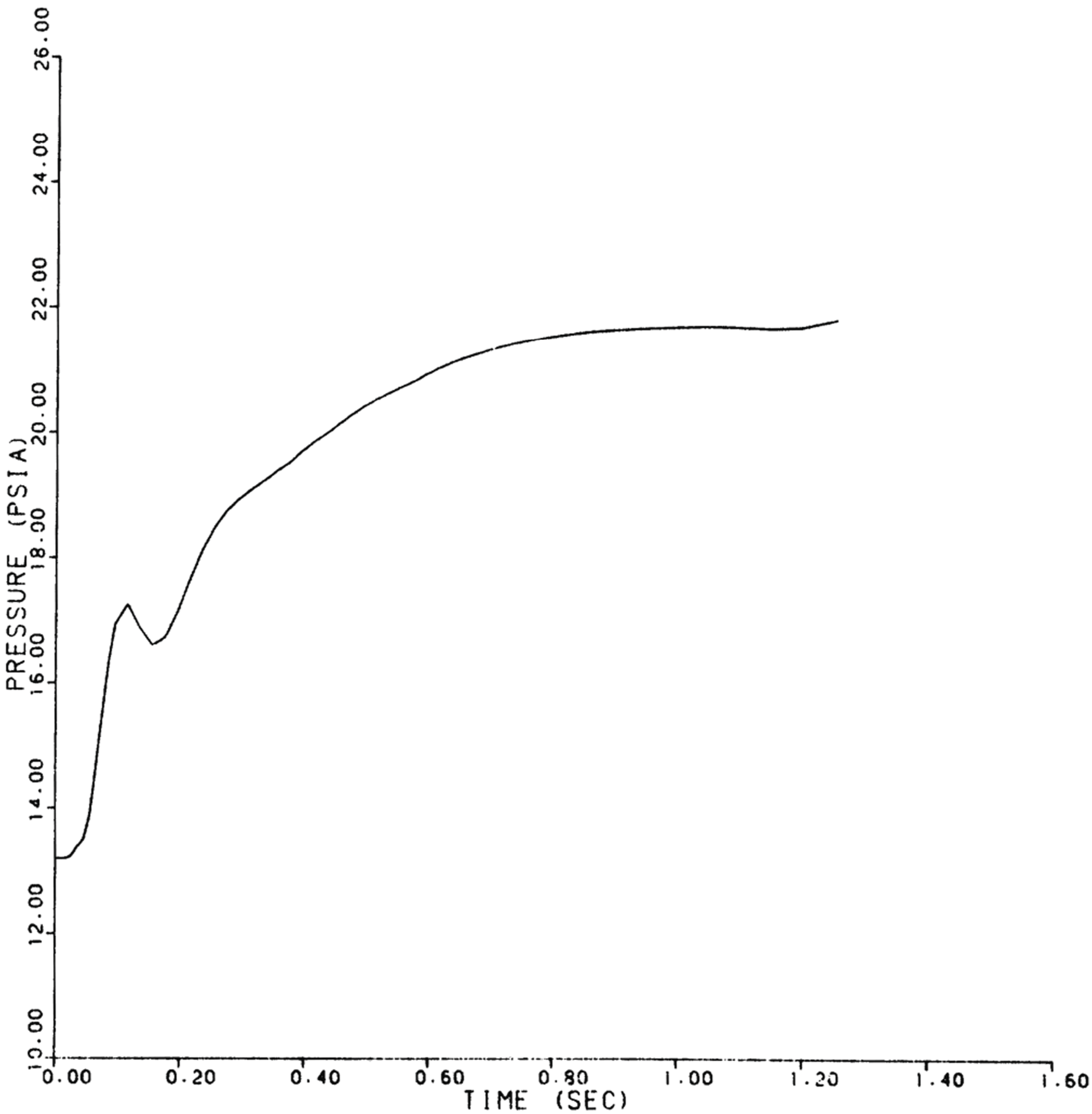
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E70
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 70 OF 74)



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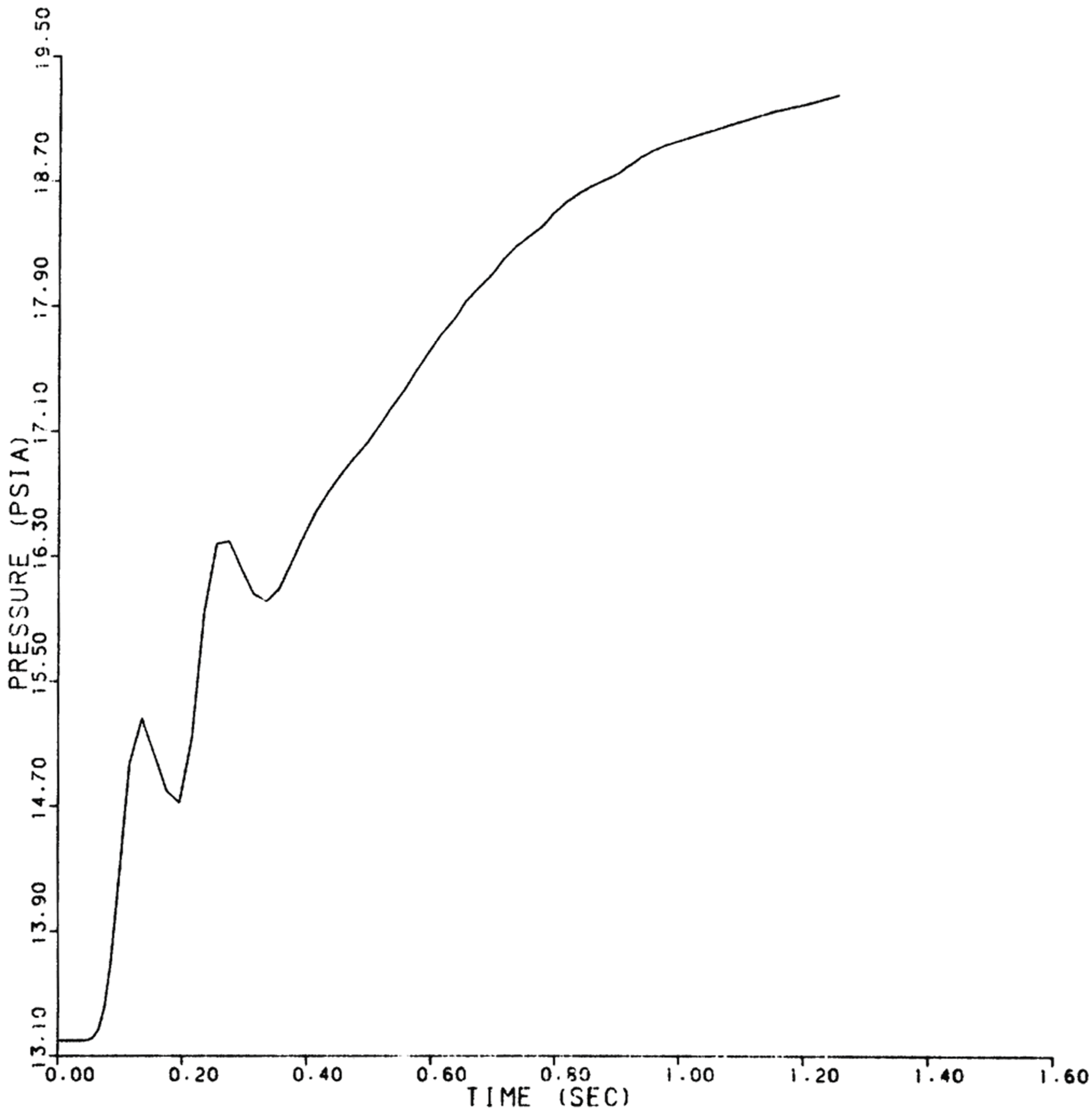
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E71
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 71 OF 74)



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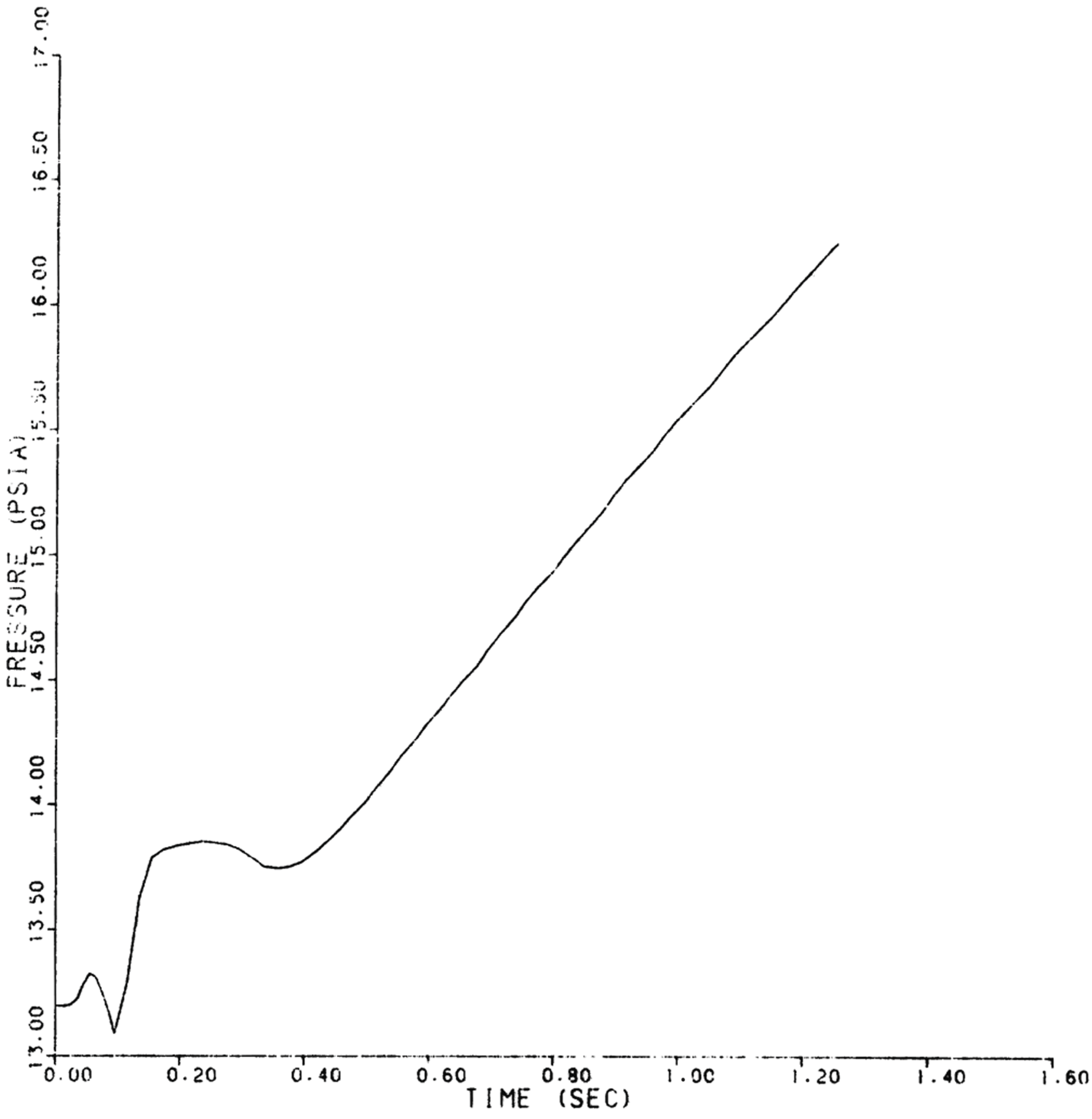
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E72
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 72 OF 74)



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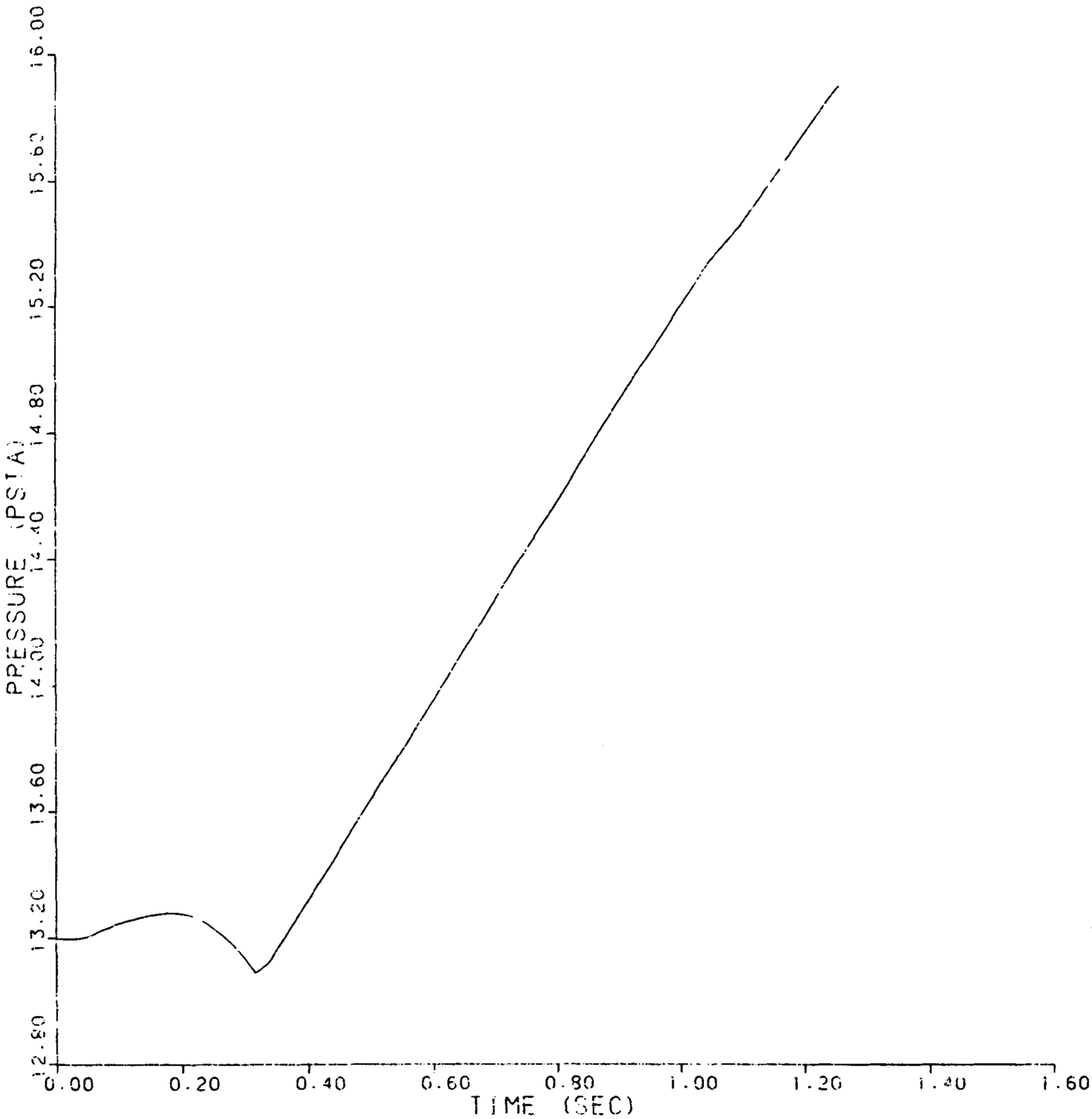
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E73
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 73 OF 74)



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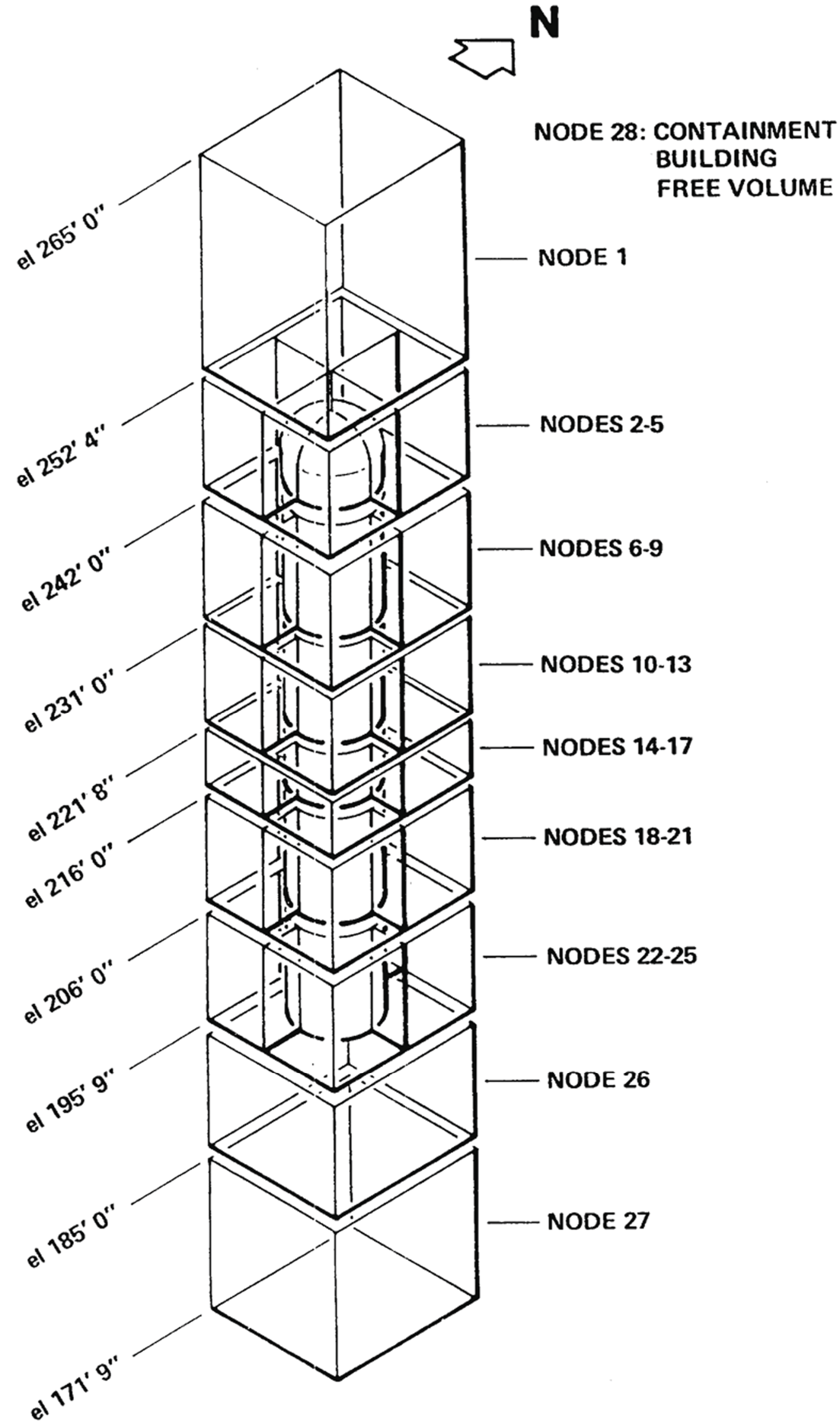
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOOP CLOSURE WELD
NODE E74
(336–in.^{2} BREAK AREA)

FIGURE 6.2.1–23 (SHEET 74 OF 74)



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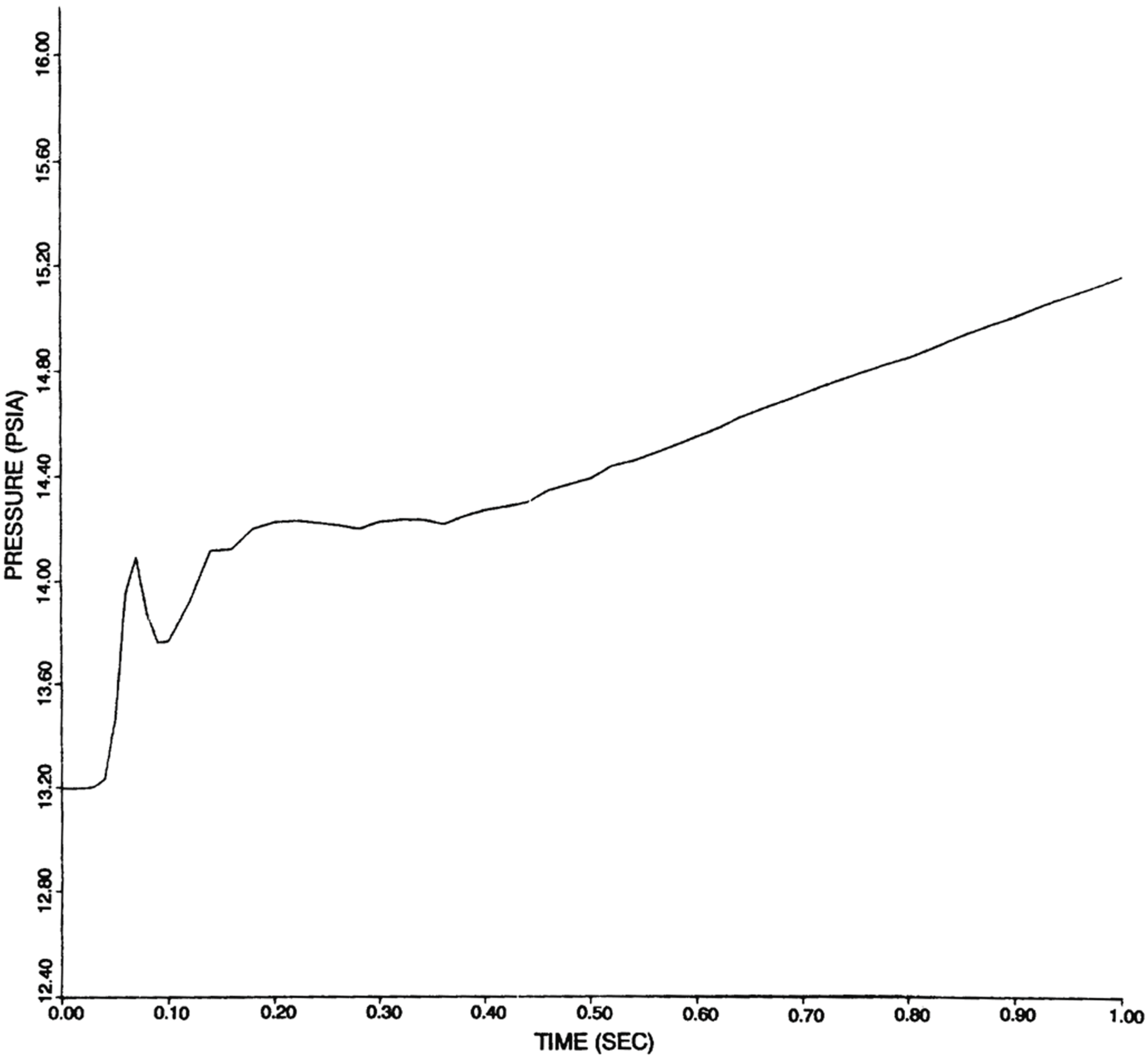
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

PRESSURIZER MODEL

FIGURE 6.2.1–24



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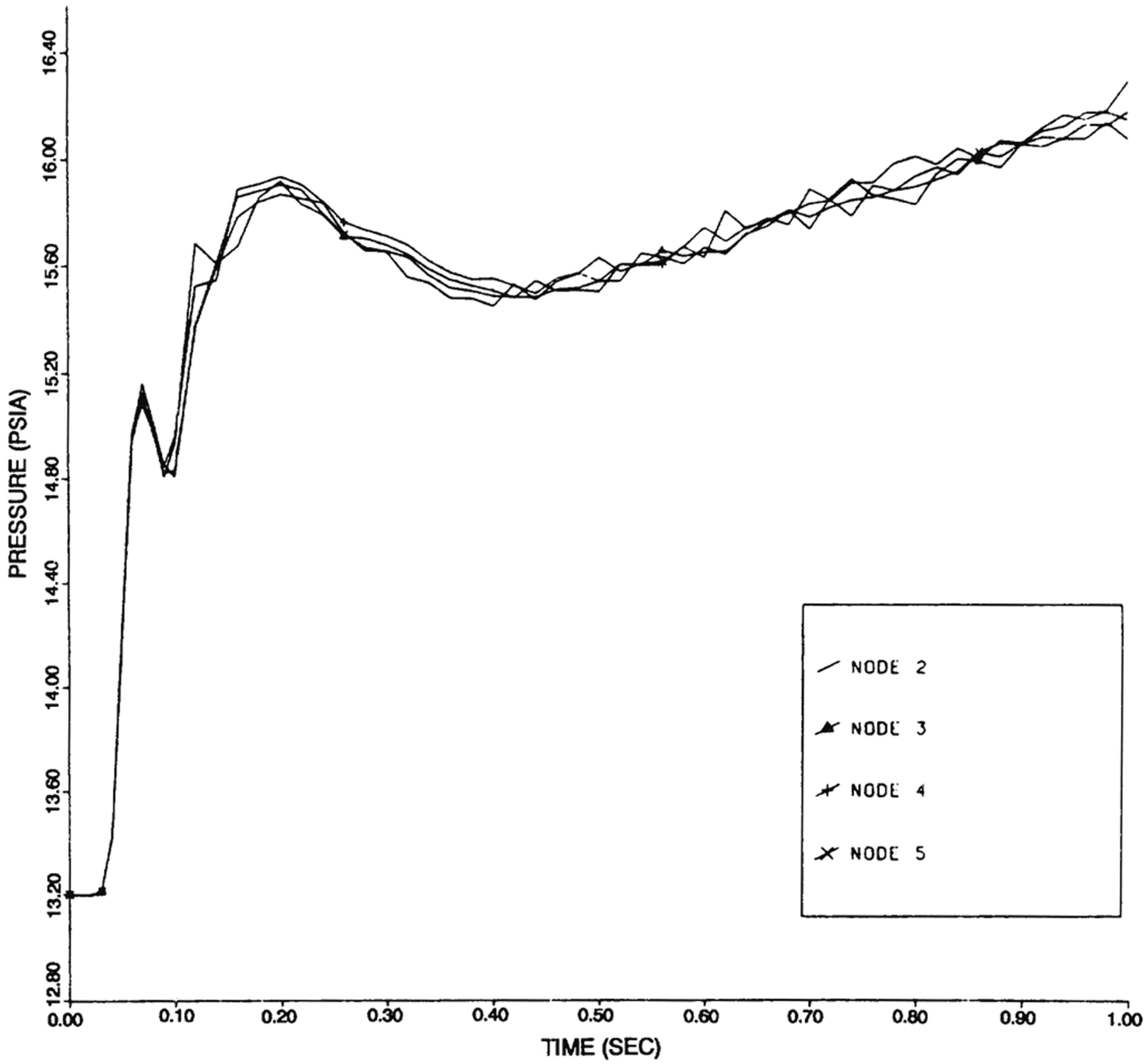
SOUTHERN COMPANY *Energy to Serve Your World®* VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	PRESSURIZER COMPARTMENT PRESSURE RESPONSE – NODE 1 SURGE LINE BREAK (308–in^2 BREAK AREA)
	FIGURE 6.2.1–25 (SHEET 1 OF 8)



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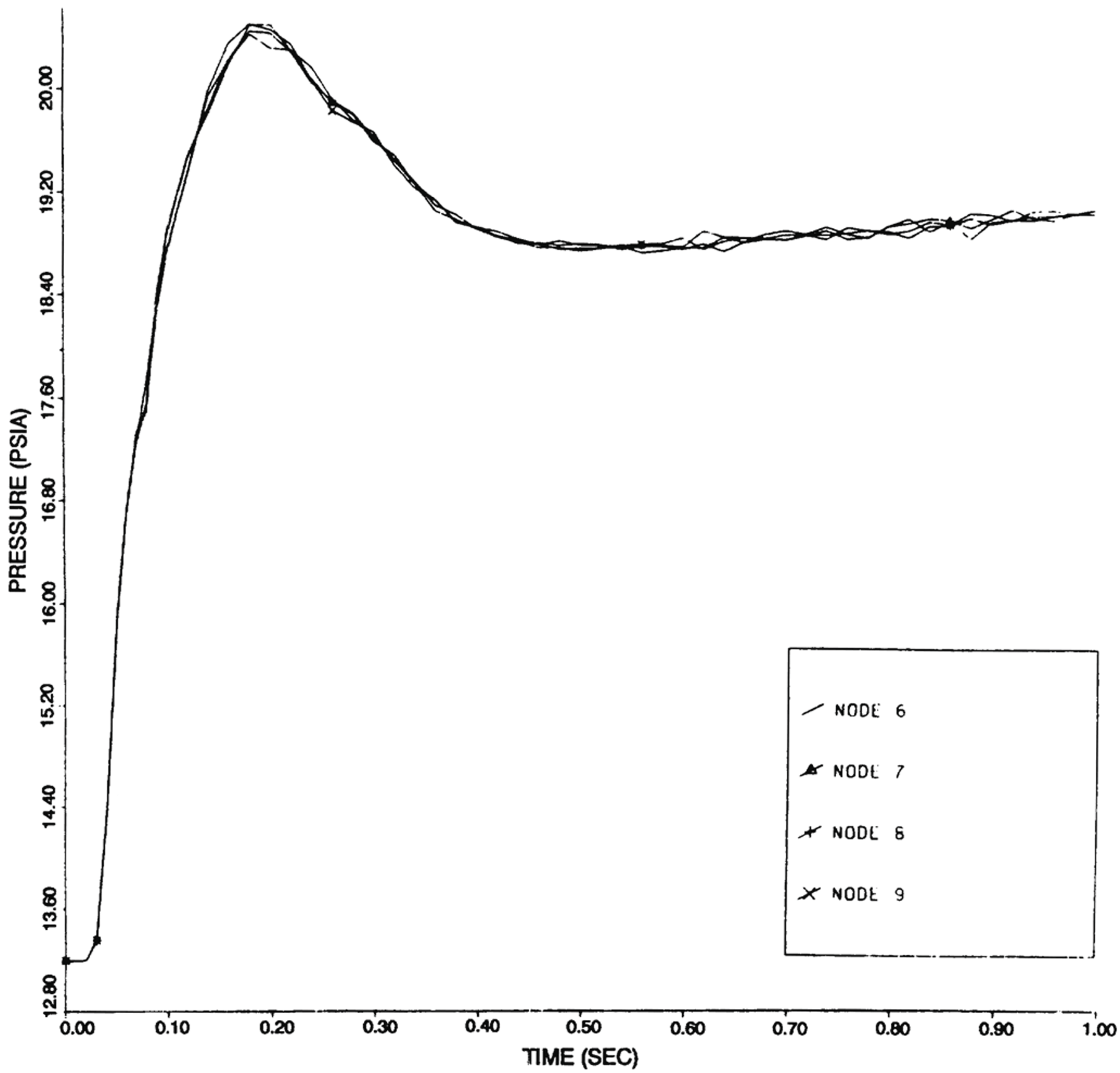
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

PRESSURIZER COMPARTMENT
PRESSURE RESPONSE – NODE 2, 3, 4, 5
SURGE LINE BREAK
(308–in^2 BREAK AREA)

FIGURE 6.2.1–25 (SHEET 2 OF 8)



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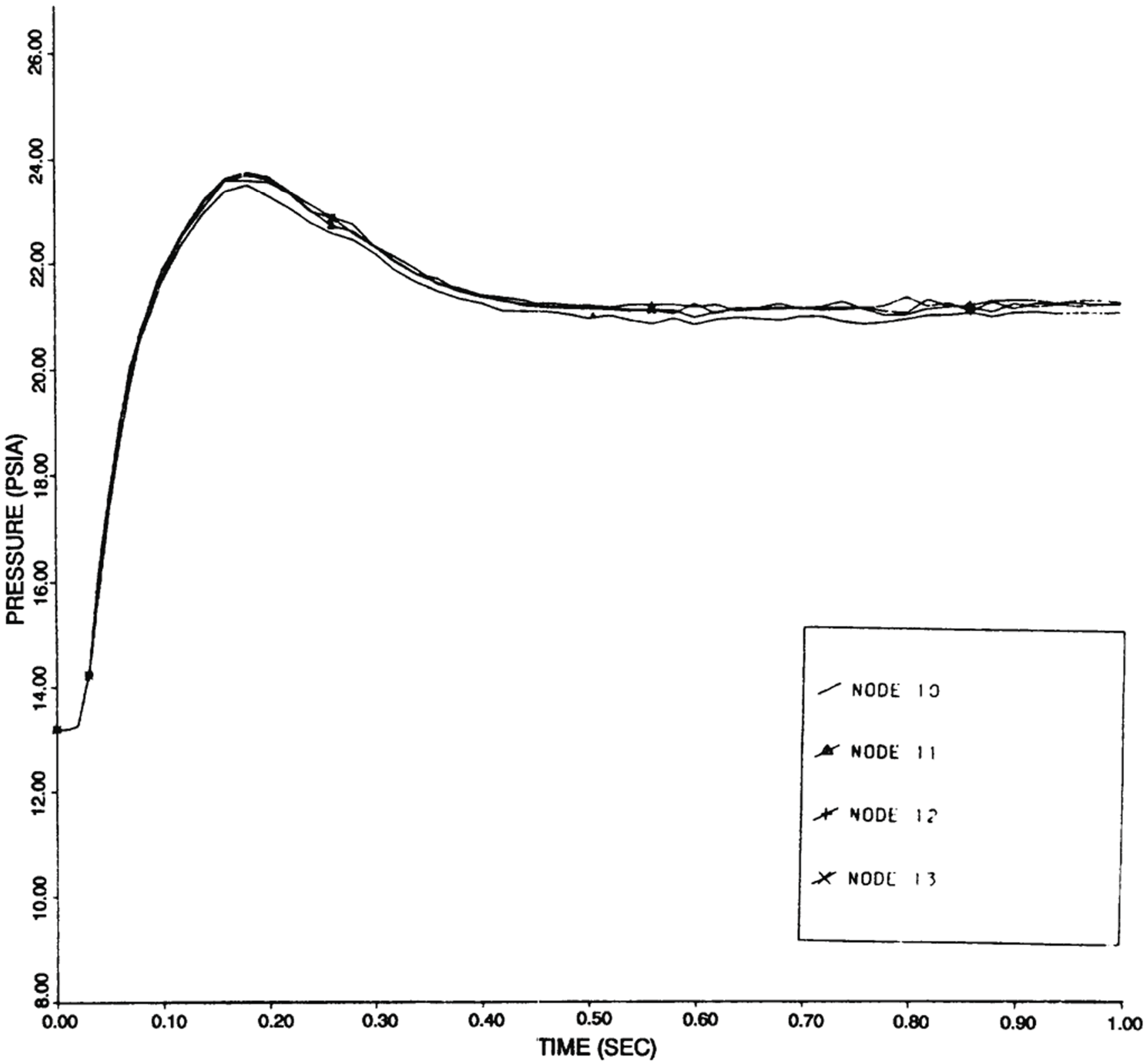
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

PRESSURIZER COMPARTMENT
PRESSURE RESPONSE – NODE 6, 7, 8, 9
SURGE LINE BREAK
(308–in^2 BREAK AREA)

FIGURE 6.2.1–25 (SHEET 3 OF 8)



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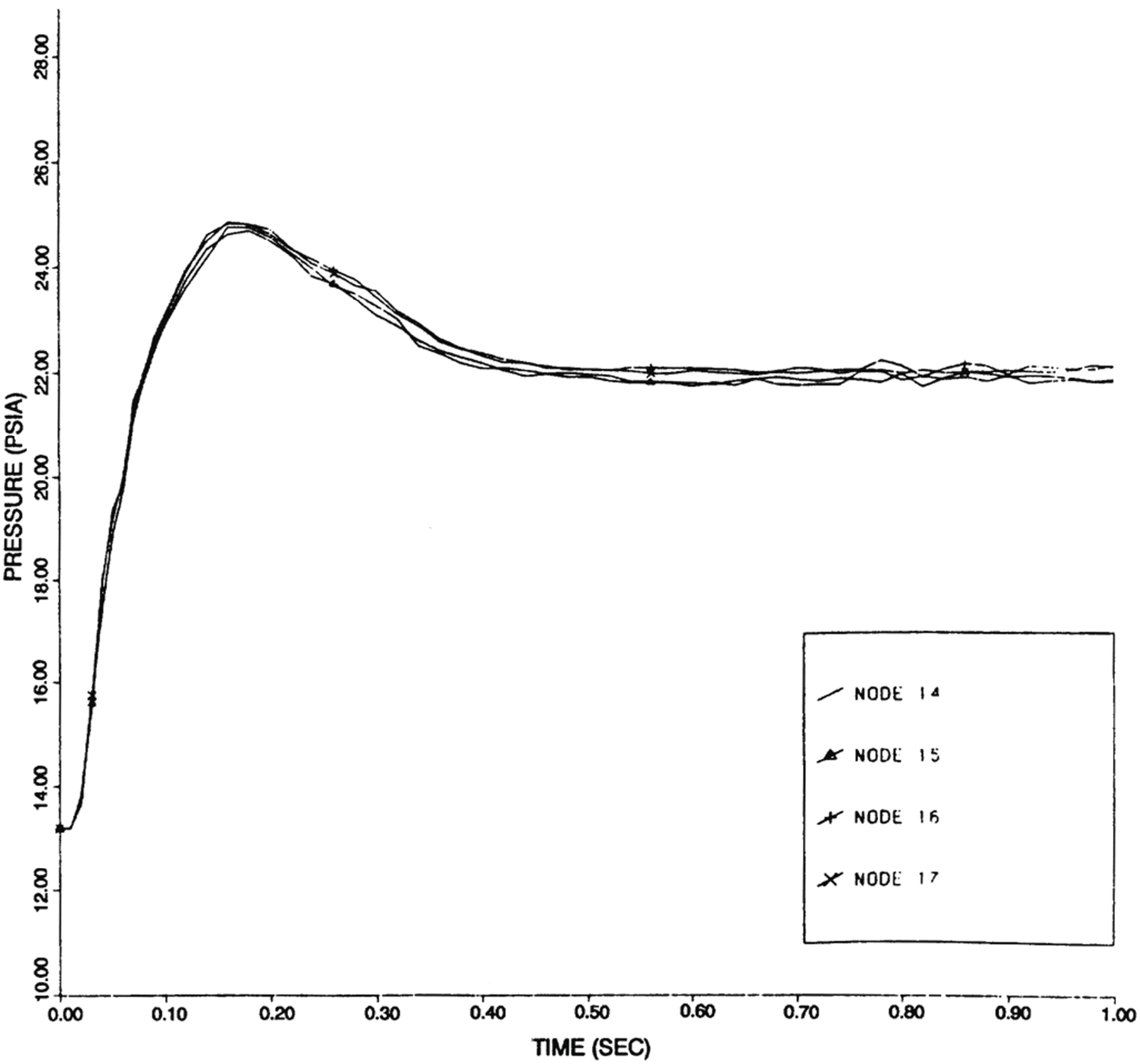
UNIT 1 AND UNIT 2

PRESSURIZER COMPARTMENT
PRESSURE RESPONSE – NODE 10, 11, 12, 13
SURGE LINE BREAK
(308–in^2 BREAK AREA)

FIGURE 6.2.1–25 (SHEET 4 OF 8)



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PRESSURIZER COMPARTMENT
PRESSURE RESPONSE – NODE 14, 15, 16, 17
SURGE LINE BREAK
(308–in^2 BREAK AREA)

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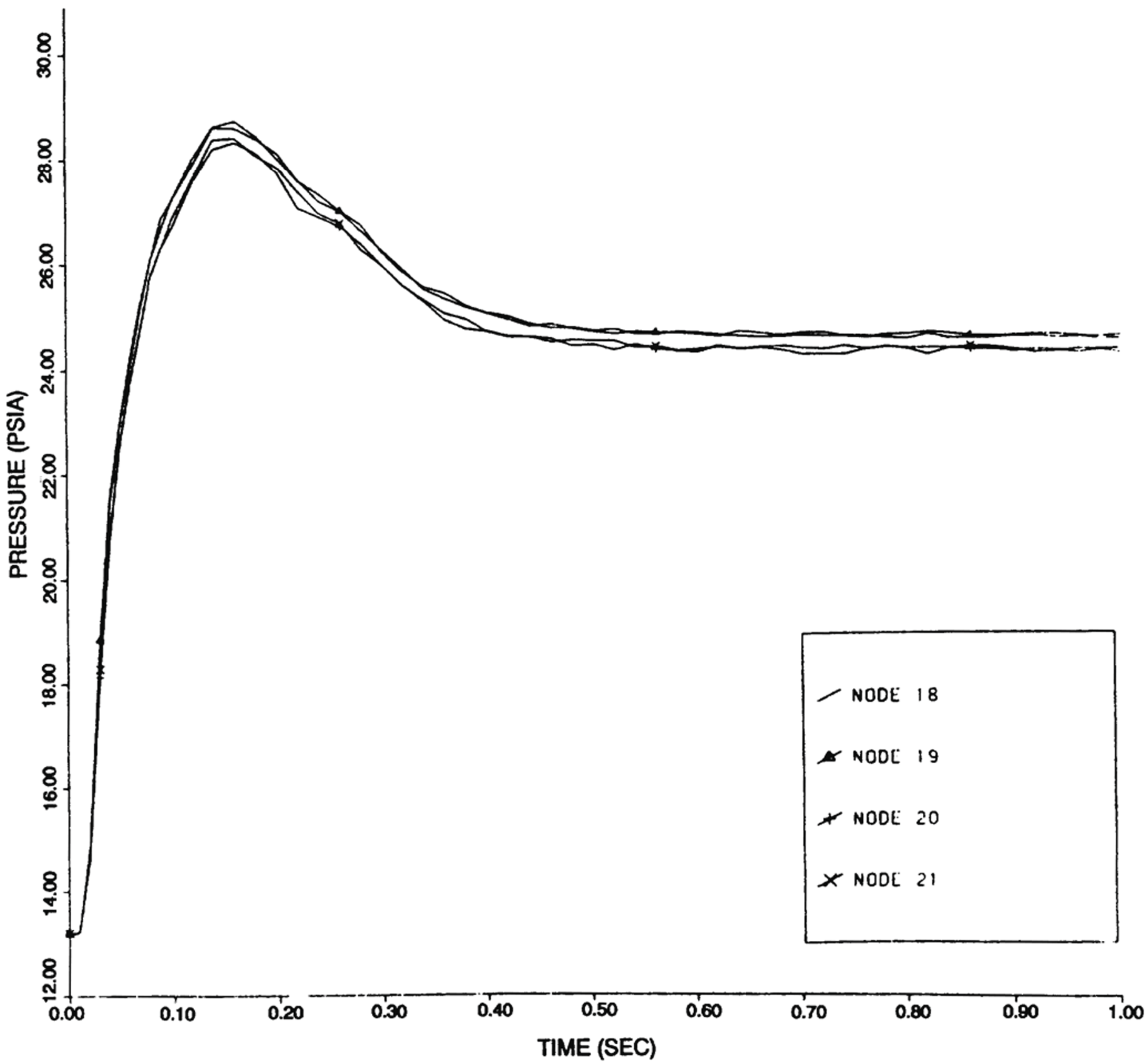
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

FIGURE 6.2.1–25 (SHEET 5 OF 8)



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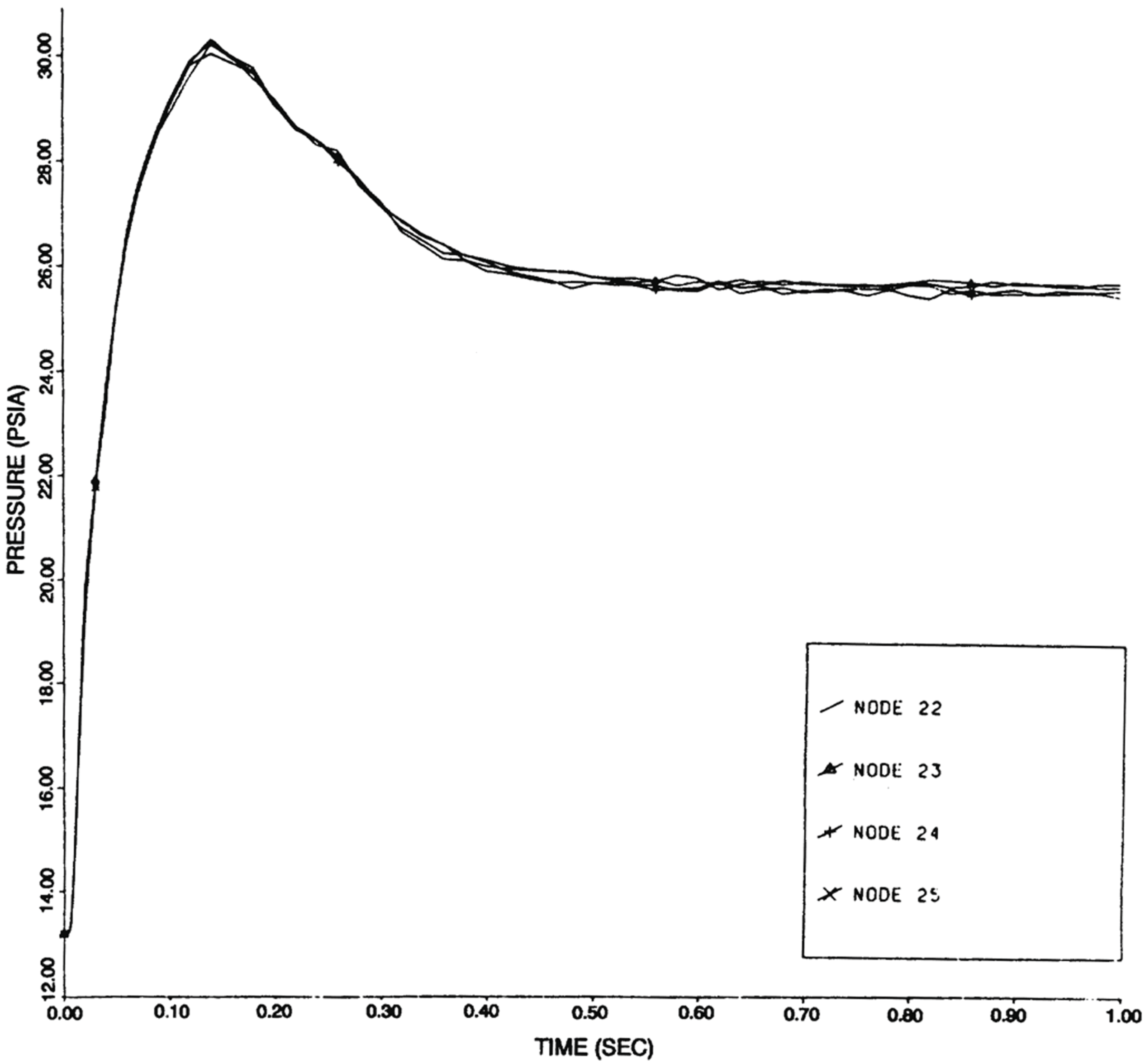
SOUTHERN COMPANY Energy to Serve Your World® **VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2**	PRESSURIZER COMPARTMENT PRESSURE RESPONSE – NODE 18, 19, 20, 21 SURGE LINE BREAK (308–in^2 BREAK AREA)
	FIGURE 6.2.1–25 (SHEET 6 OF 8)



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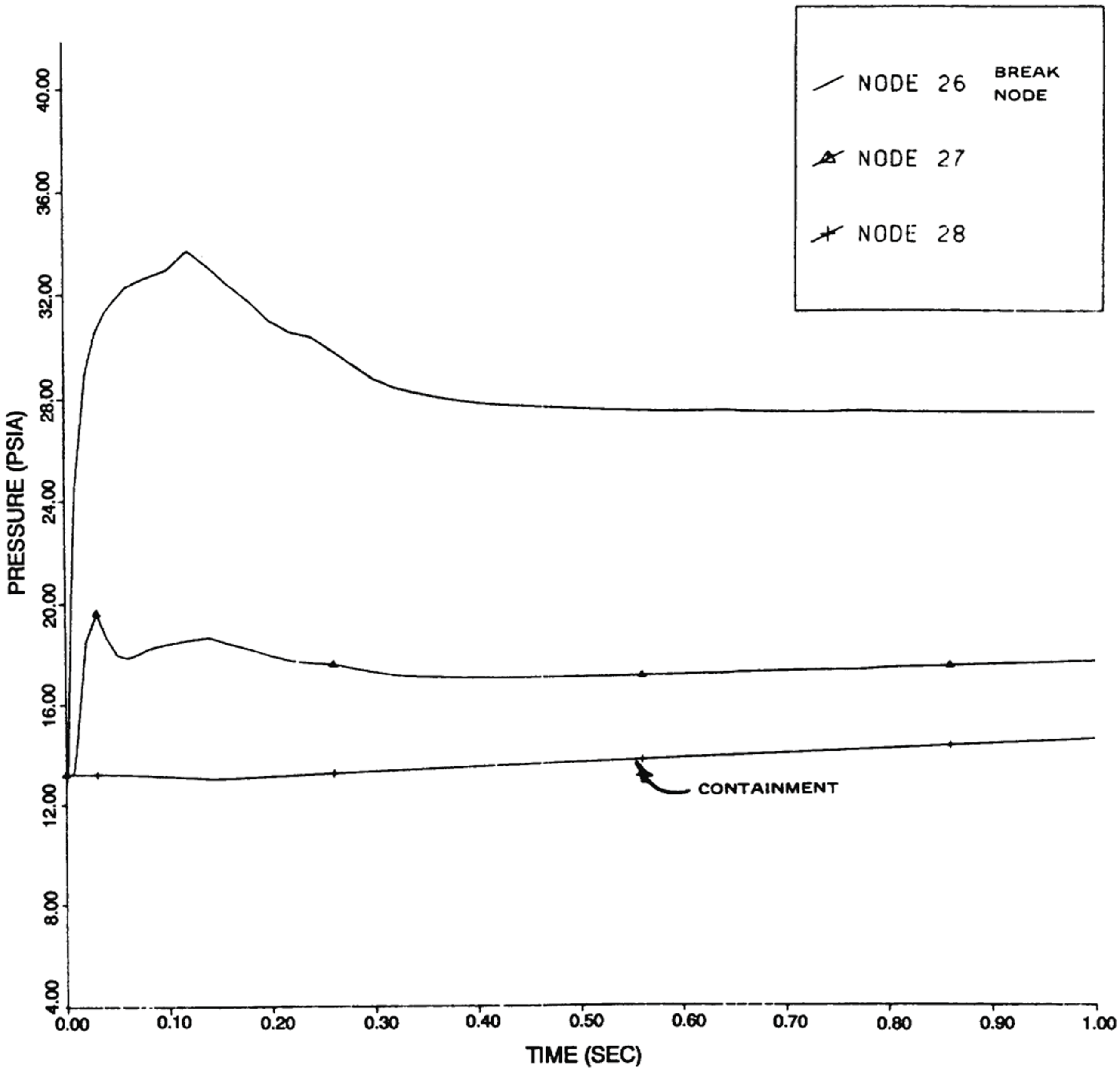
UNIT 1 AND UNIT 2

PRESSURIZER COMPARTMENT
PRESSURE RESPONSE – NODE 22, 23, 24, 25
SURGE LINE BREAK
(308–in^2 BREAK AREA)

FIGURE 6.2.1–25 (SHEET 7 OF 8)



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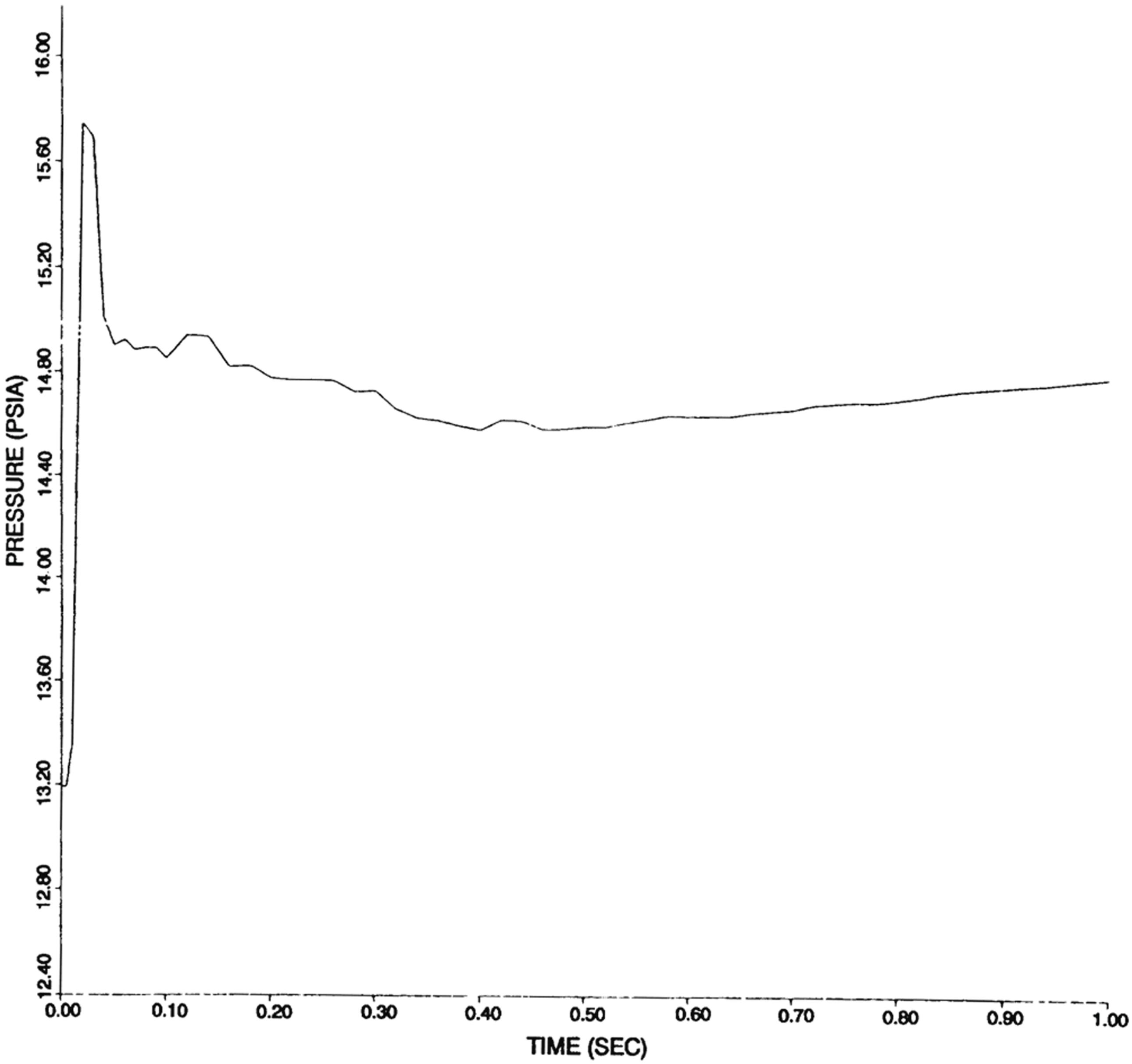
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

PRESSURIZER COMPARTMENT
PRESSURE RESPONSE – NODE 26, 27, 28
SURGE LINE BREAK
($308–in^2$ BREAK AREA)

FIGURE 6.2.1–25 (SHEET 8 OF 8)



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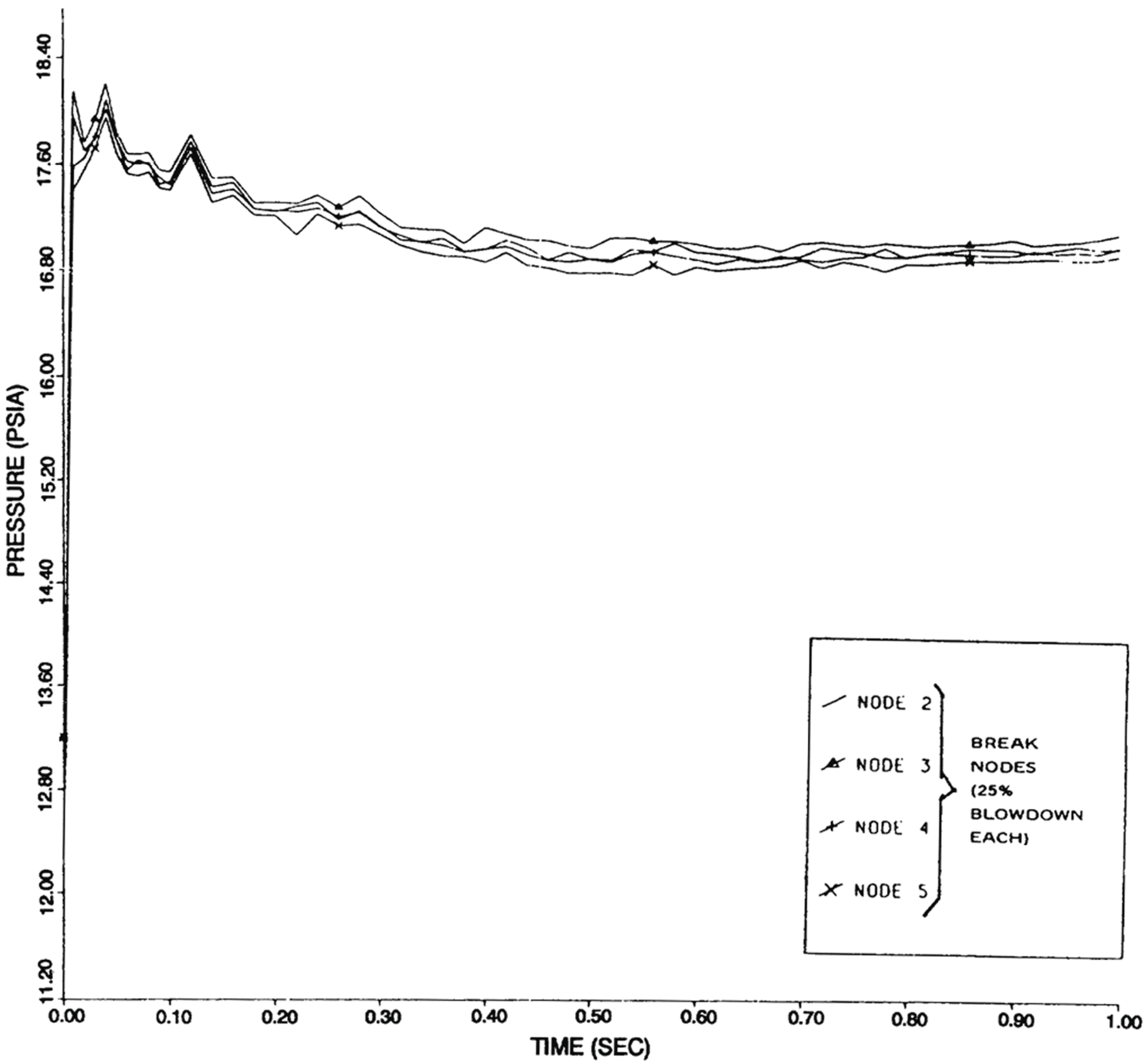
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

PRESSURIZER COMPARTMENT
PRESSURE RESPONSE – NODE 1
SPRAY LINE BREAK AT TOP OF PRESSURIZER

FIGURE 6.2.1–25a (SHEET 1 OF 8)



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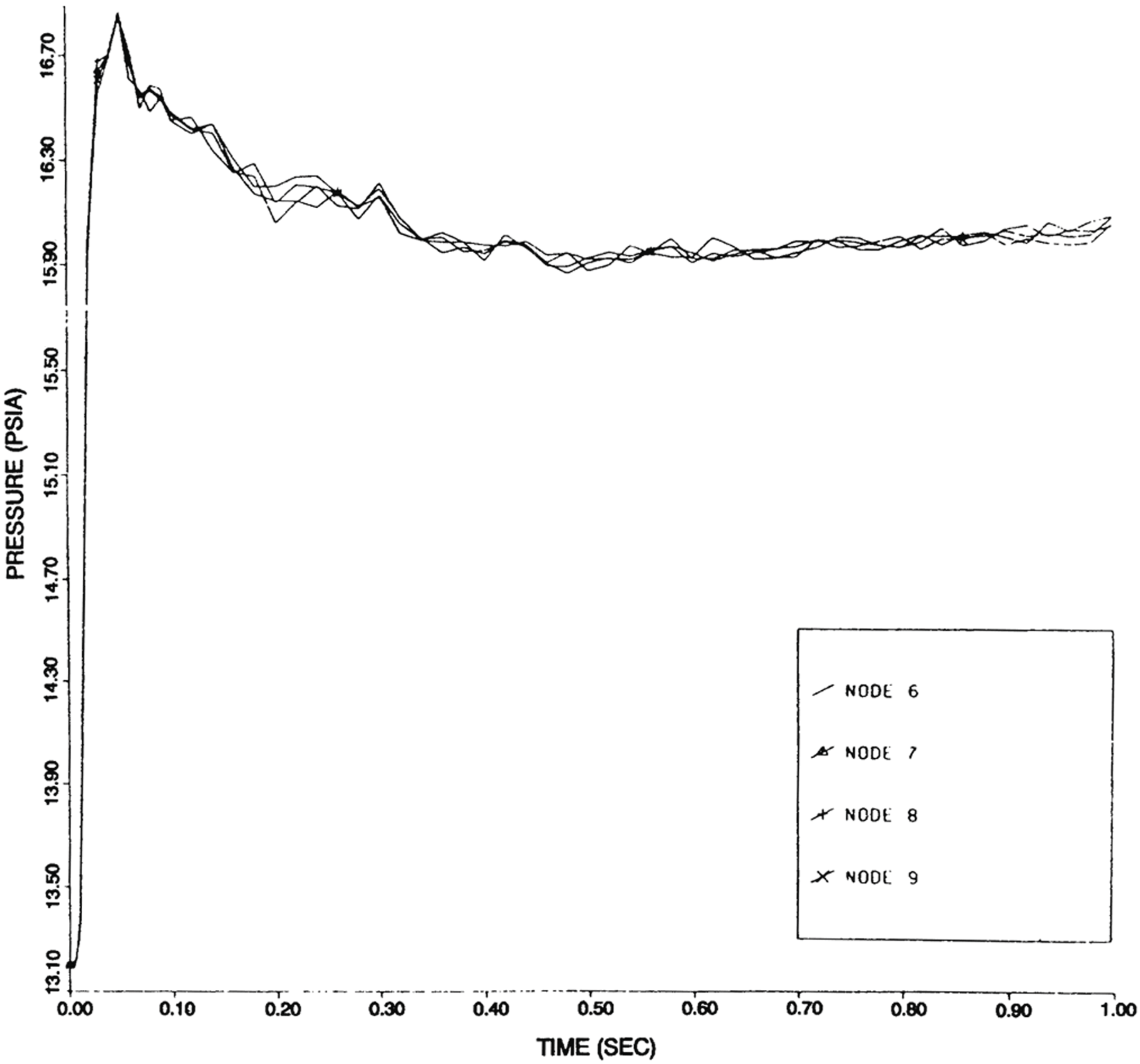
SOUTHERN COMPANY Energy to Serve Your World®	VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	PRESSURIZER COMPARTMENT PRESSURE RESPONSE – NODE 2, 3, 4, 5 SPRAY LINE BREAK AT TOP OF PRESSURIZER
		FIGURE 6.2.1–25a (SHEET 2 OF 8)



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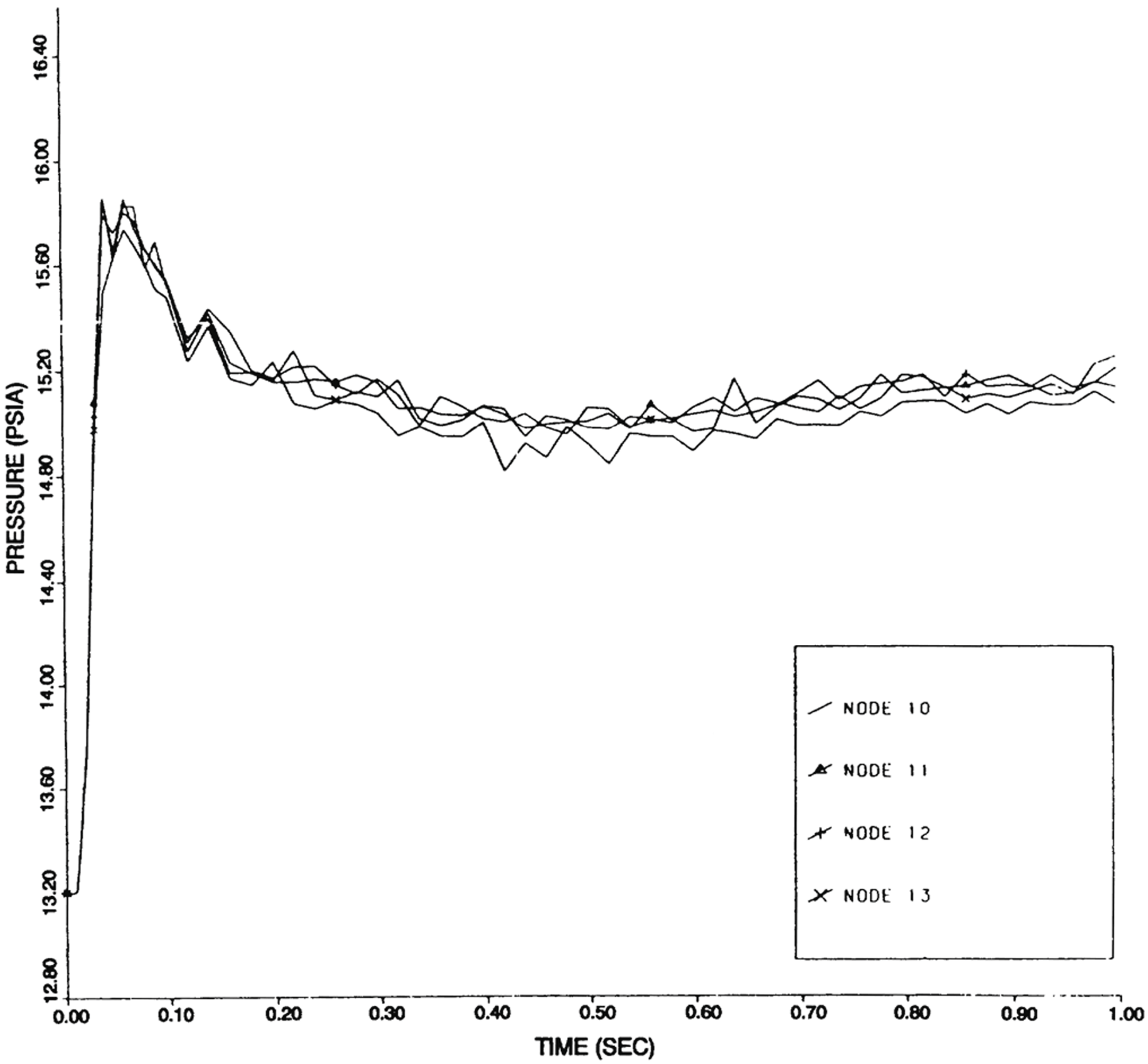
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

PRESSURIZER COMPARTMENT
PRESSURE RESPONSE – NODE 6, 7, 8, 9 SPRAY
LINE BREAK AT TOP OF PRESSURIZER

FIGURE 6.2.1–25a (SHEET 3 OF 8)



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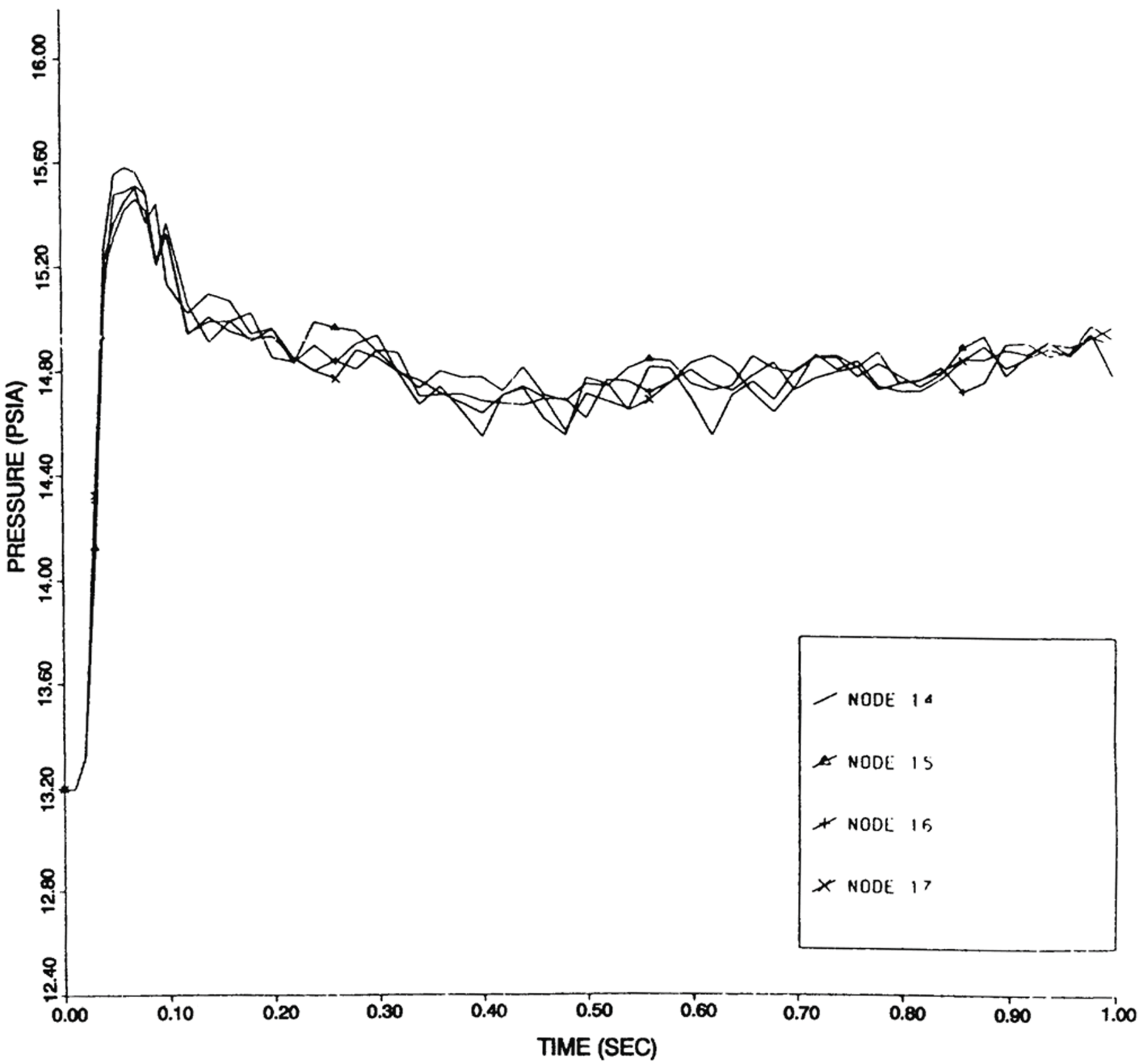
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

PRESSURIZER COMPARTMENT
PRESSURE RESPONSE – NODE 10, 11, 12, 13
SPRAY LINE BREAK AT TOP OF PRESSURIZER

FIGURE 6.2.1–25a (SHEET 4 OF 8)



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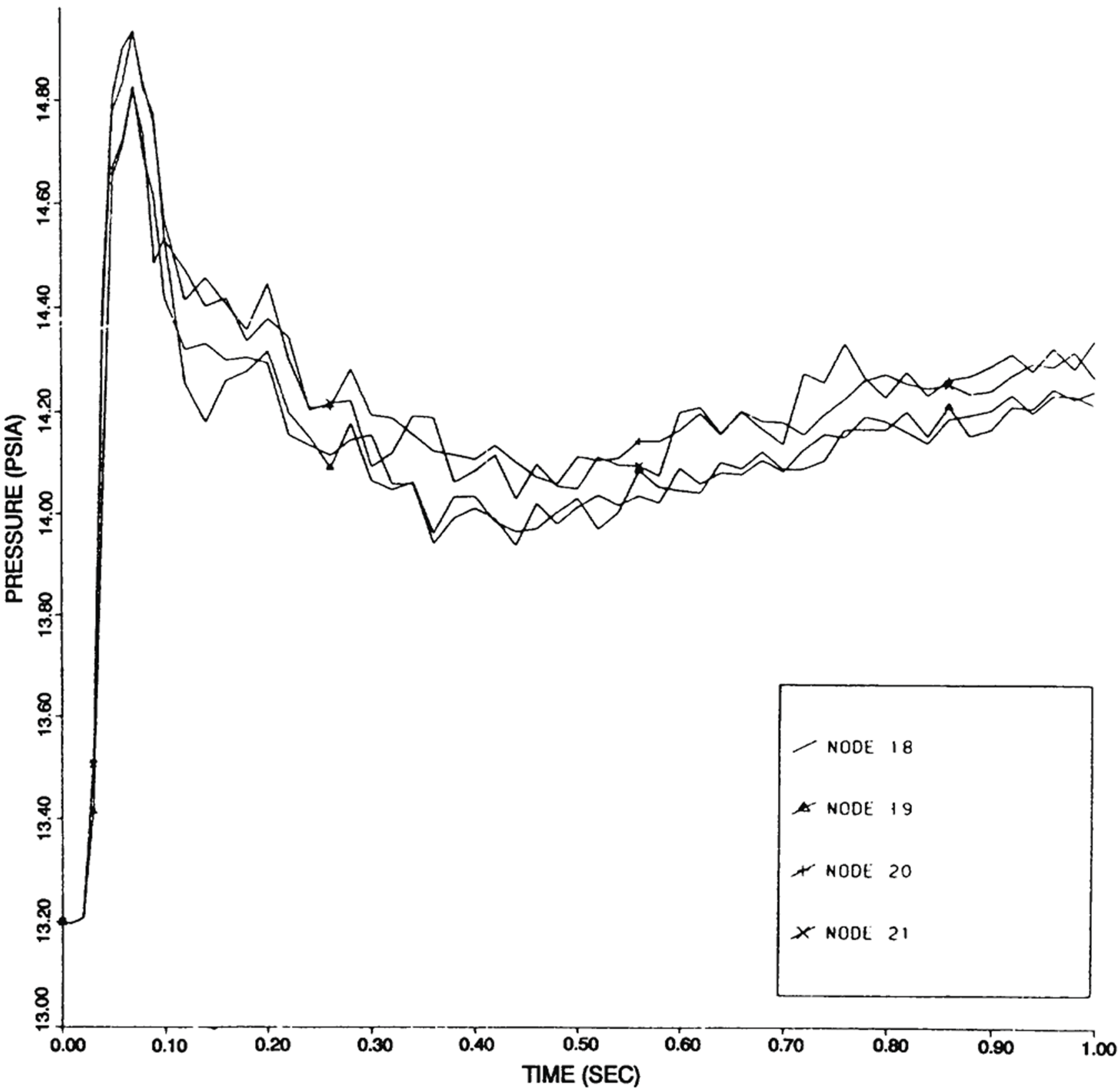
UNIT 1 AND UNIT 2

PRESSURIZER COMPARTMENT
PRESSURE RESPONSE – NODE 14, 15, 16, 17
SPRAY LINE BREAK AT TOP OF PRESSURIZER

FIGURE 6.2.1–25a (SHEET 5 OF 8)



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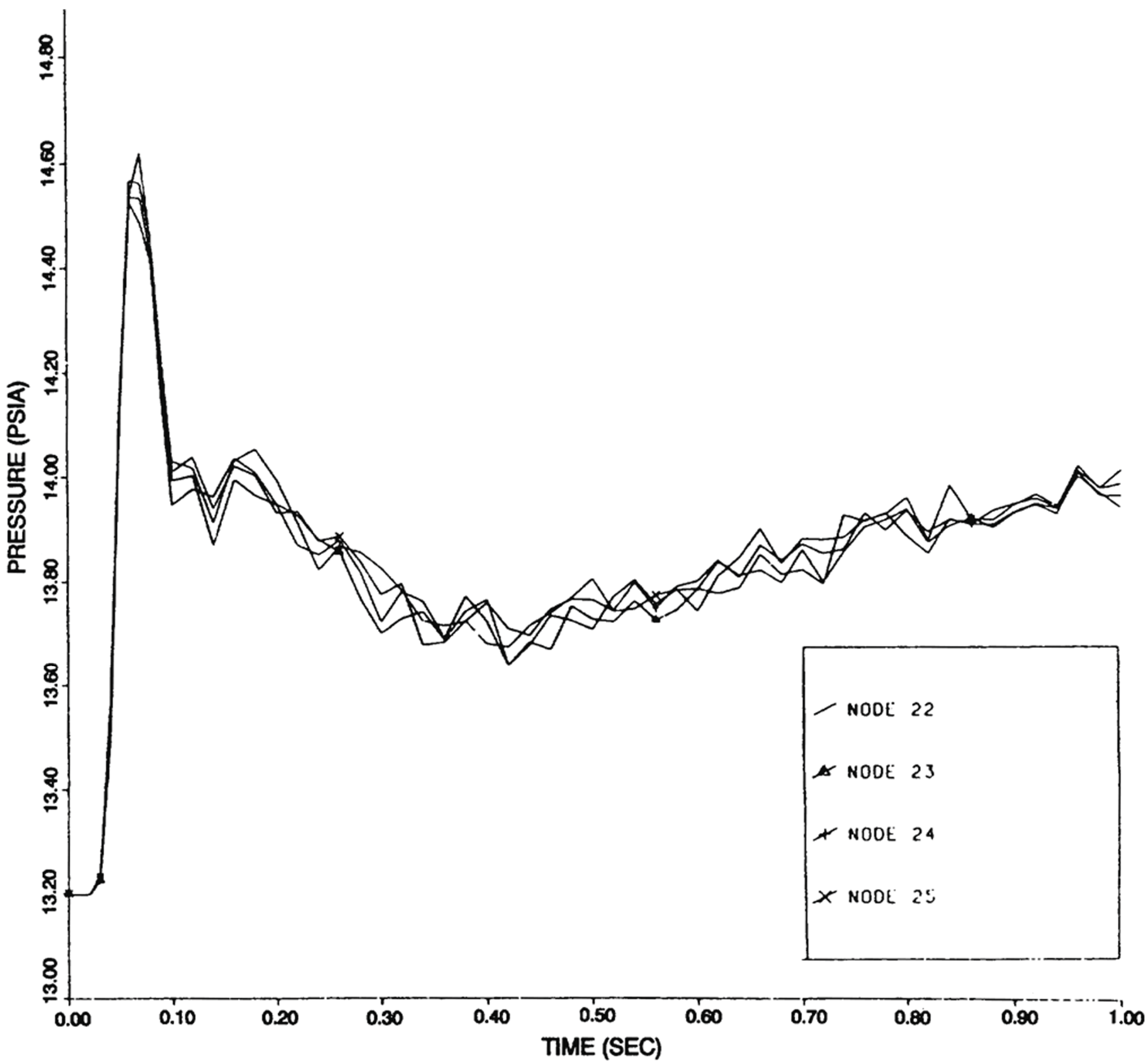
UNIT 1 AND UNIT 2

PRESSURIZER COMPARTMENT
PRESSURE RESPONSE – NODE 18, 19, 20, 21
SPRAY LINE BREAK AT TOP OF PRESSURIZER

FIGURE 6.2.1–25a (SHEET 6 OF 8)



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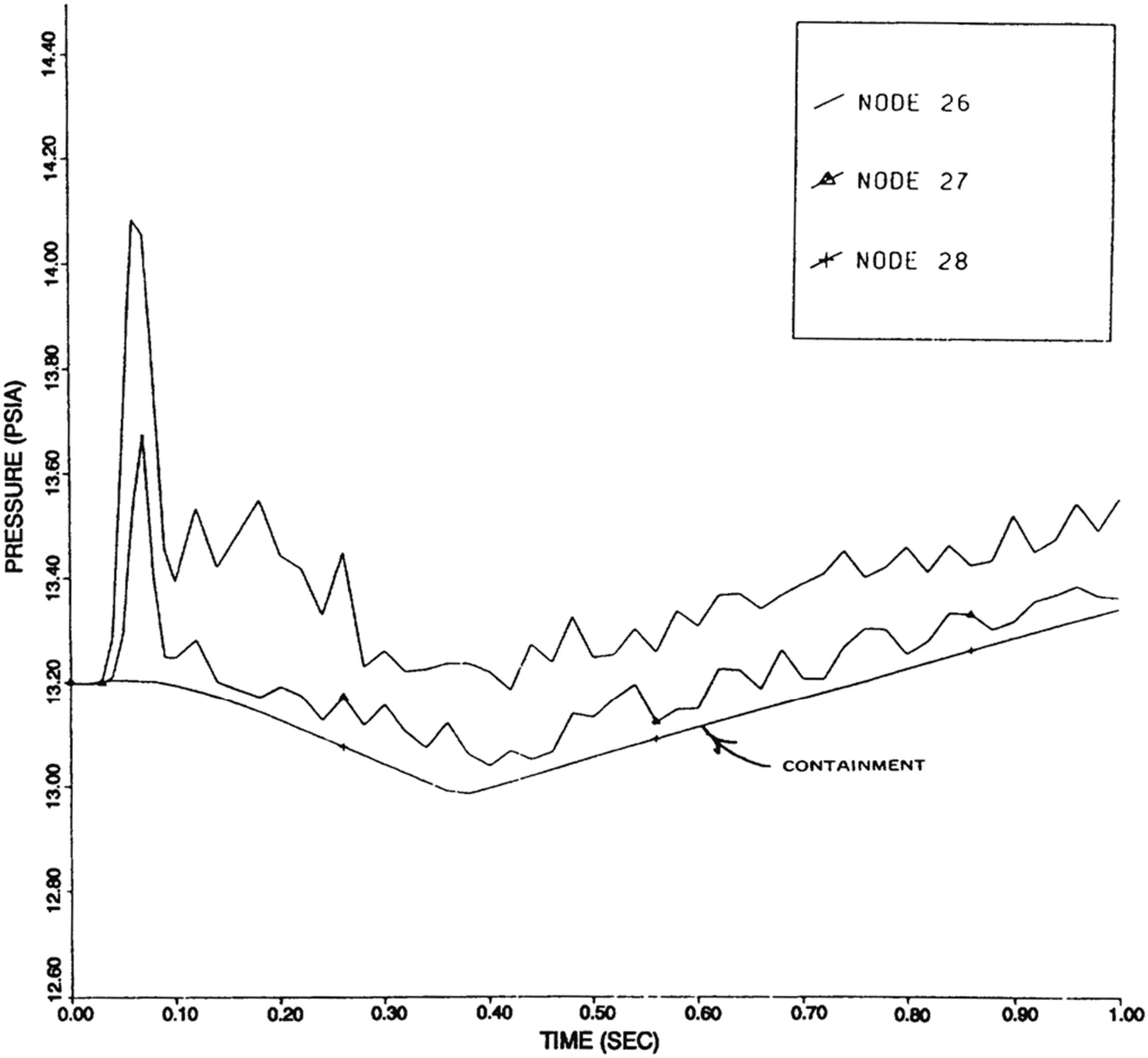
SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

PRESSURIZER COMPARTMENT
PRESSURE RESPONSE – NODE 22, 23, 24, 25
SPRAY LINE BREAK AT TOP OF PRESSURIZER

FIGURE 6.2.1–25a (SHEET 7 OF 8)



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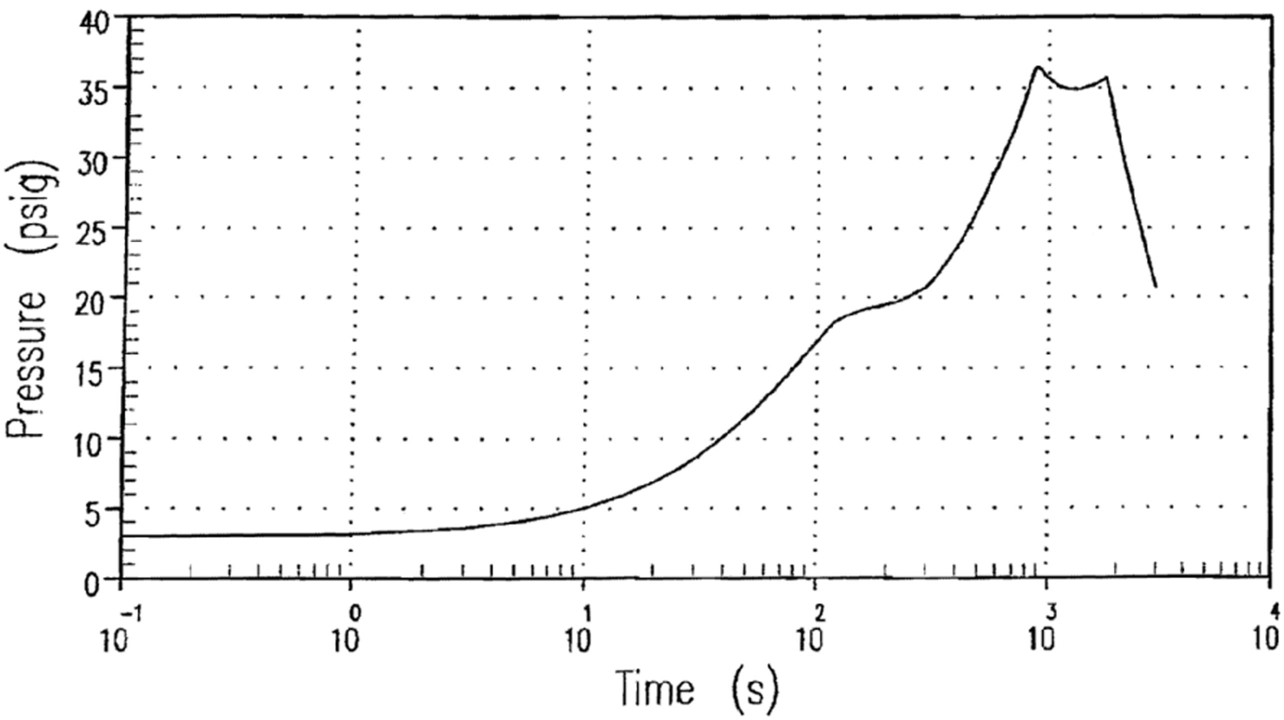
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

PRESSURIZER COMPARTMENT
PRESSURE RESPONSE – NODE 26, 27, 28
SPRAY LINE BREAK AT TOP OF PRESSURIZER

FIGURE 6.2.1–25a (SHEET 8 OF 8)



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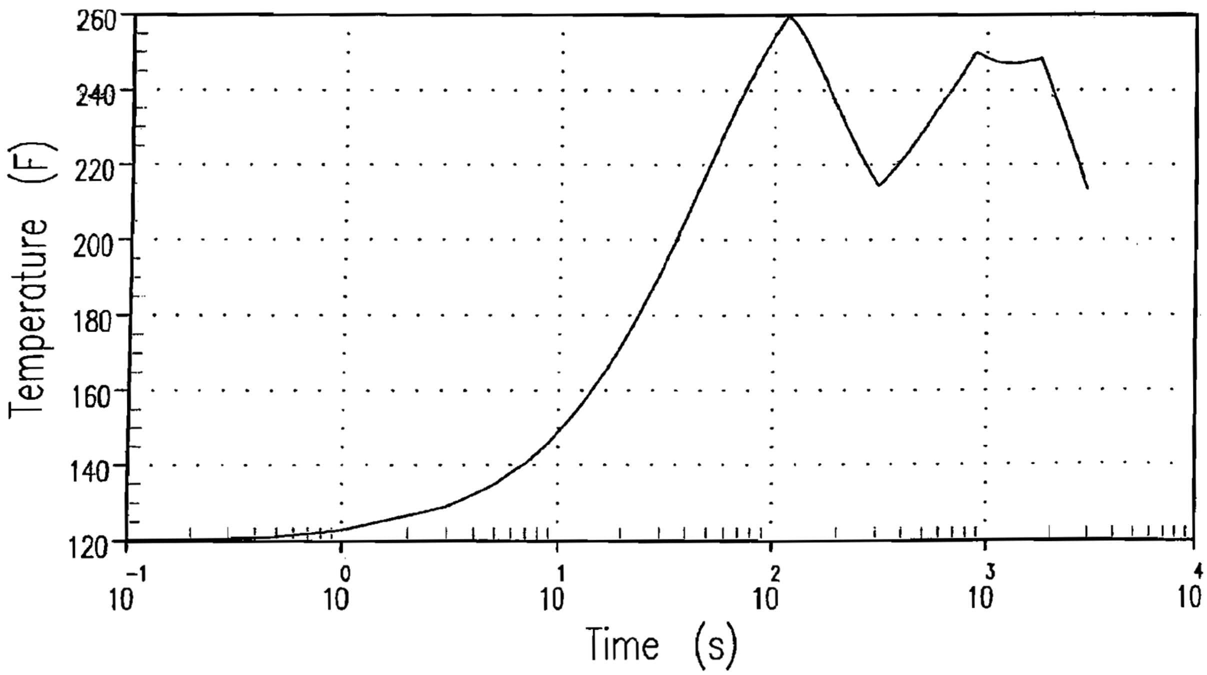
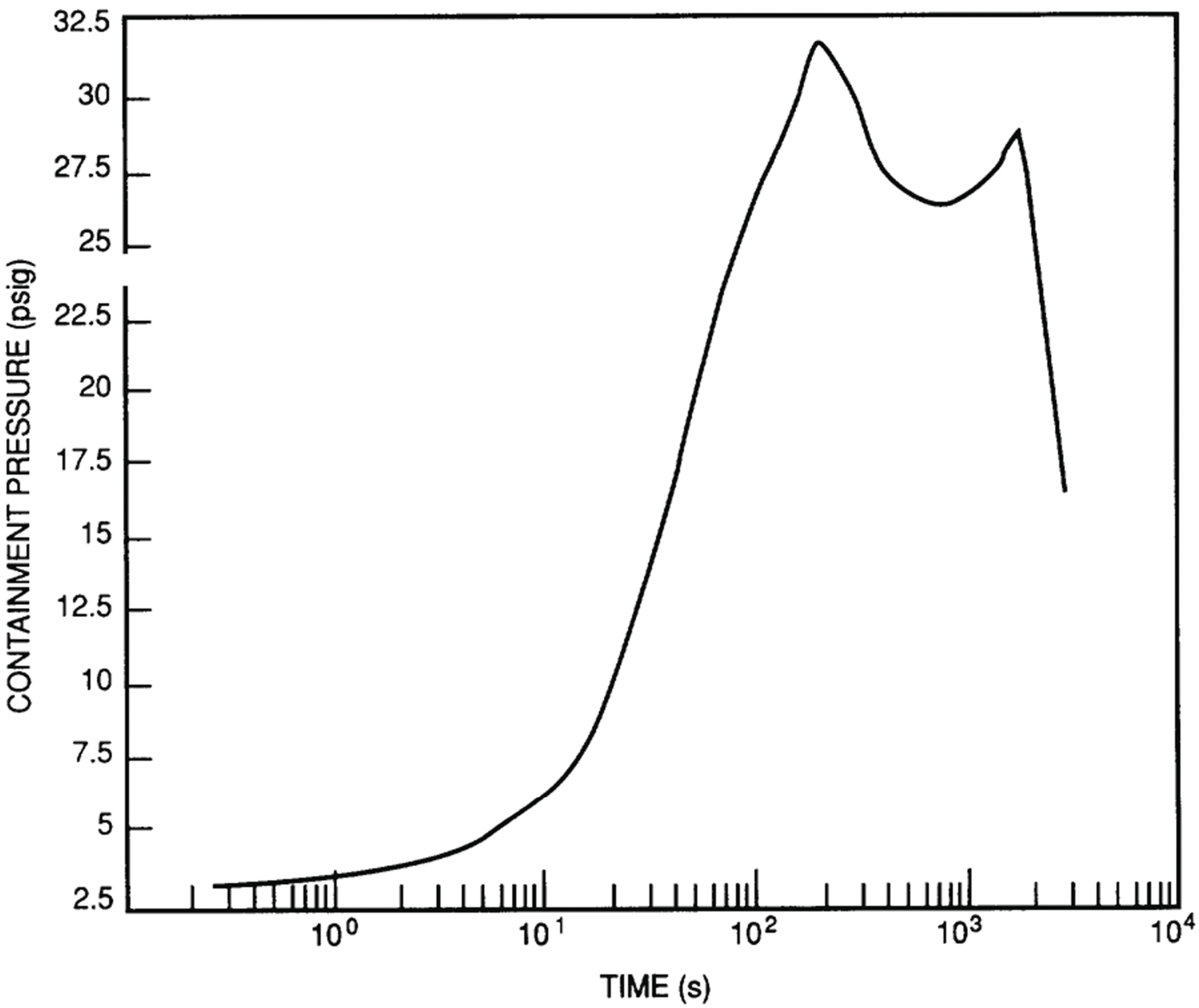
SOUTHERN COMPANY *Energy to Serve Your World®*	**VOGTLE** **ELECTRIC GENERATING PLANT** **UNIT 1 AND UNIT 2**	CONTAINMENT PRESSURE TRANSIENT MSLB – 0.4 ft^2 SPLIT RUPTURE– 0% POWER CASE 16
		FIGURE 6.2.1–26



REV 15 4/09

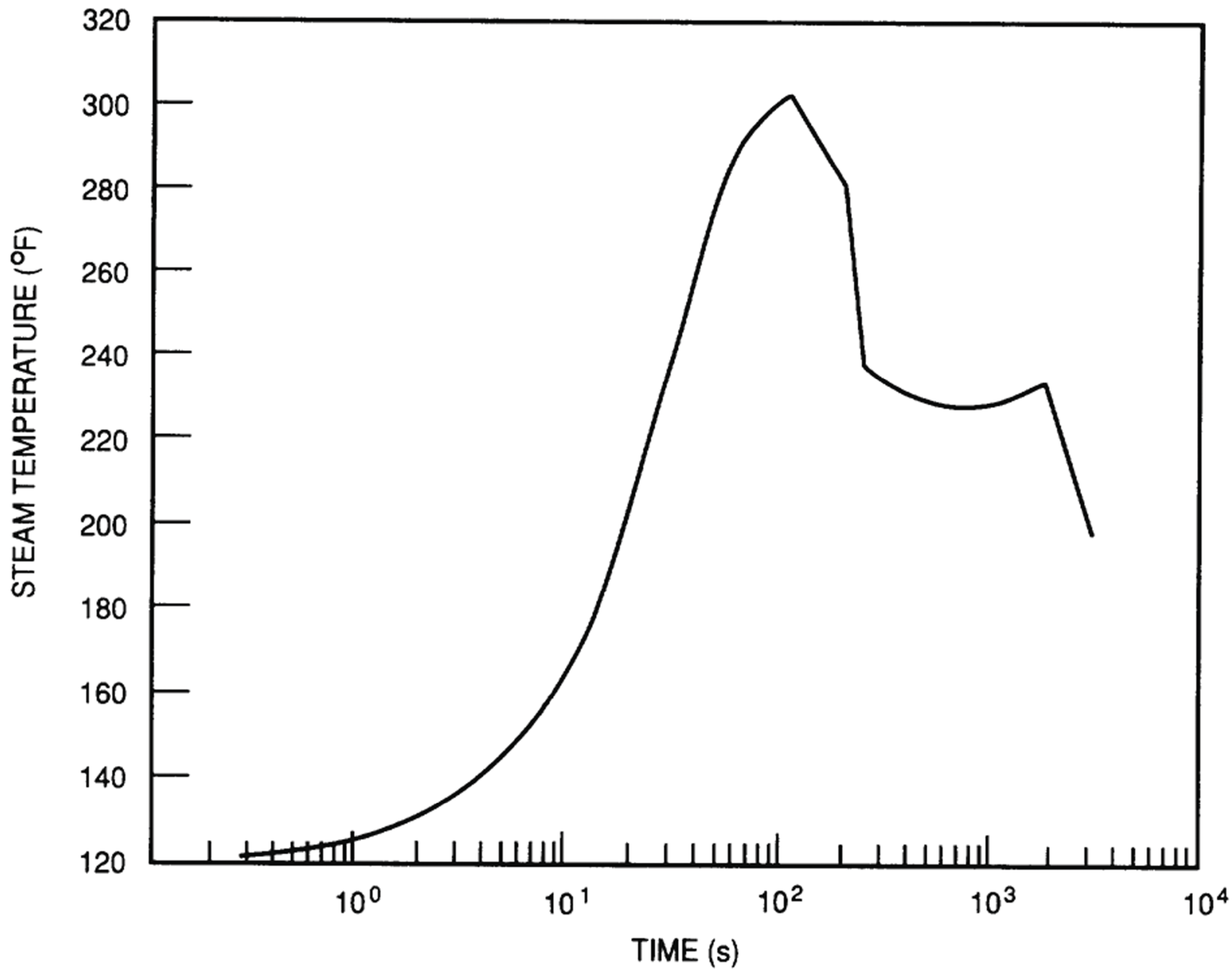
CONTAINMENT TEMPERATURE TRANSIENT
MSLB – 0.4 ft^2 SPLIT RUPTURE– 0% POWER
CASE 16

FIGURE 6.2.1–27



REV 13 4/06

SOUTHERN COMPANY *Energy to Serve Your World®*	**VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2**	CONTAINMENT PRESSURE TRANSIENT MSLB – 0.86 ft^2 SPLIT RUPTURE – 102% POWER CASE 13
		FIGURE 6.2.1–28



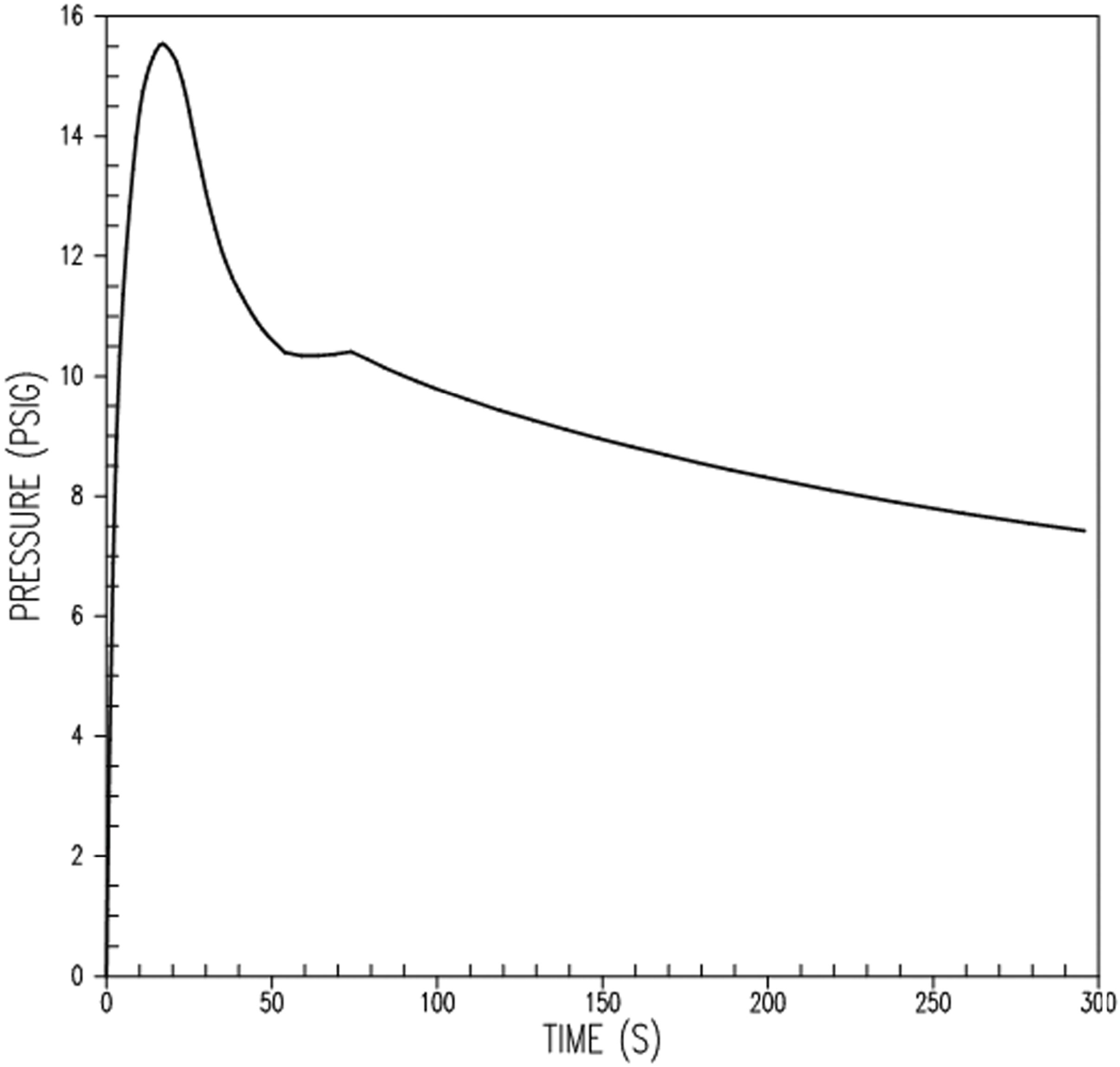
REV 18 9/13

SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CONTAINMENT TEMPERATURE TRANSIENT
MSLB – 0.86 ft^2 SPLIT RUPTURE – 102% POWER
CASE 13

FIGURE 6.2.1–29



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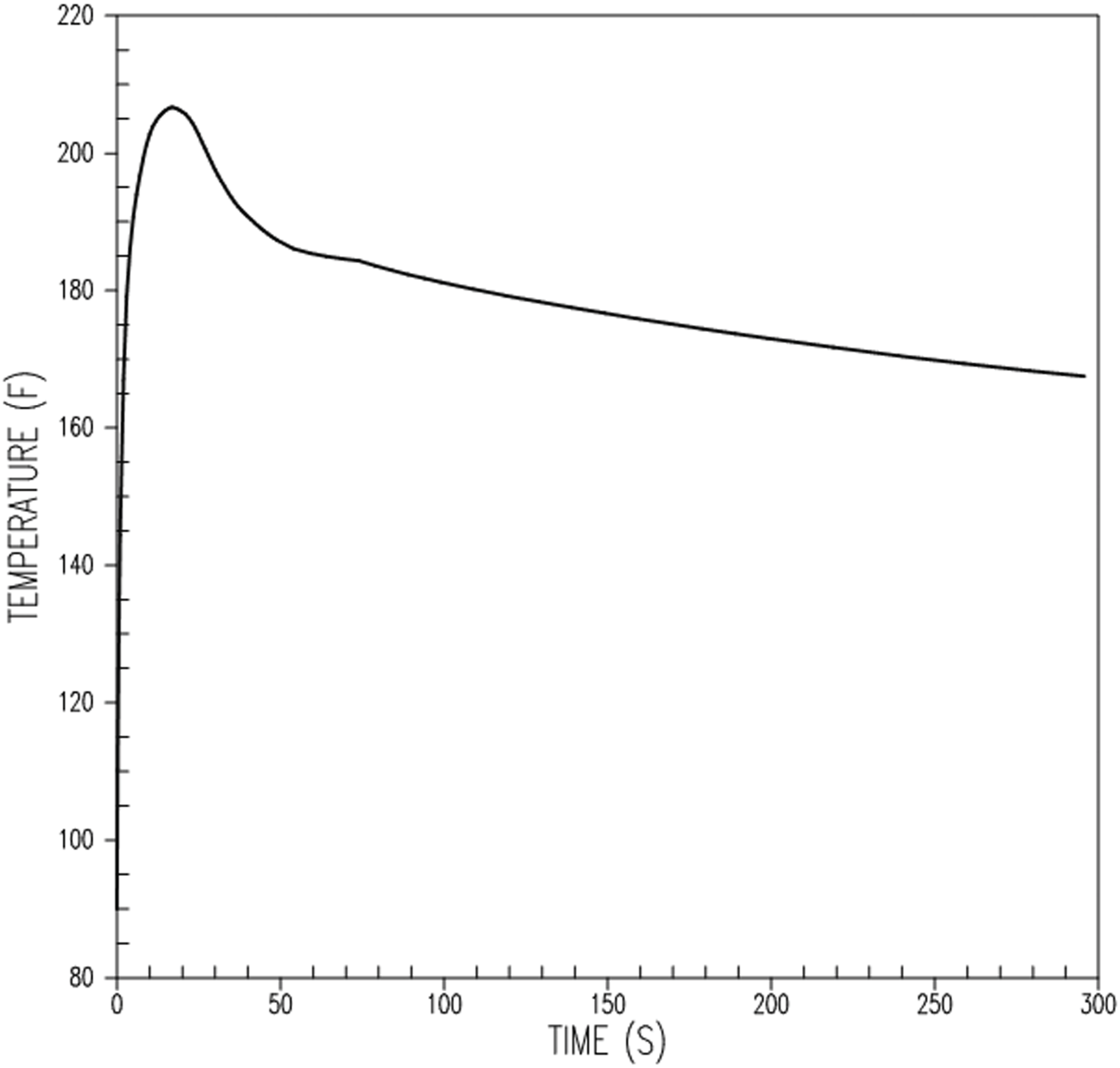
SOUTHERN COMPANY *Energy to Serve Your World®* **VOGTLE** **ELECTRIC GENERATING PLANT** **UNIT 1 AND UNIT 2**	CONTAINMENT PRESSURE DECLG (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE) FIGURE 6.2.1–30



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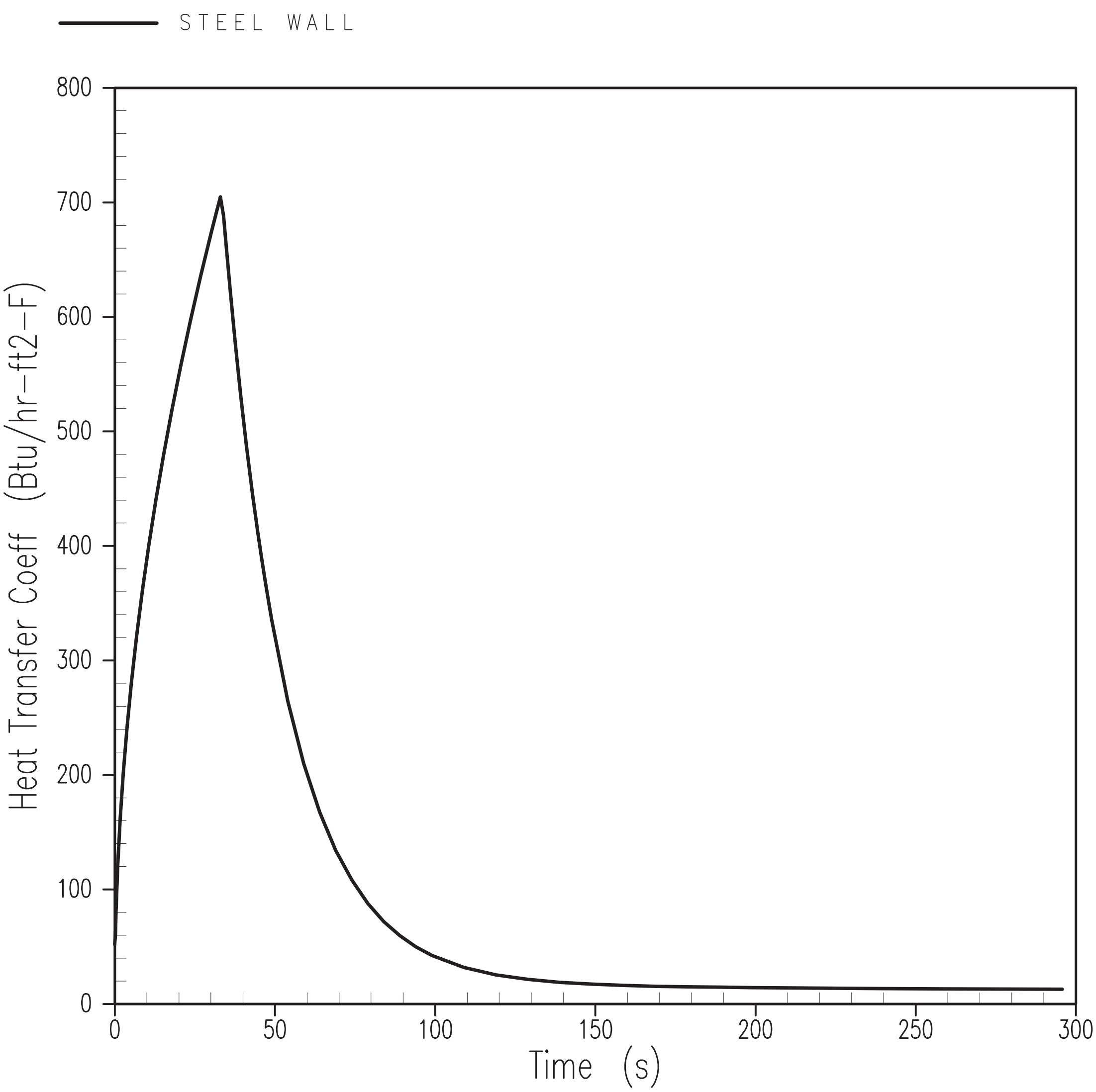
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CONTAINMENT TEMPERATURE DECLG
(C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE)

FIGURE 6.2.1–31



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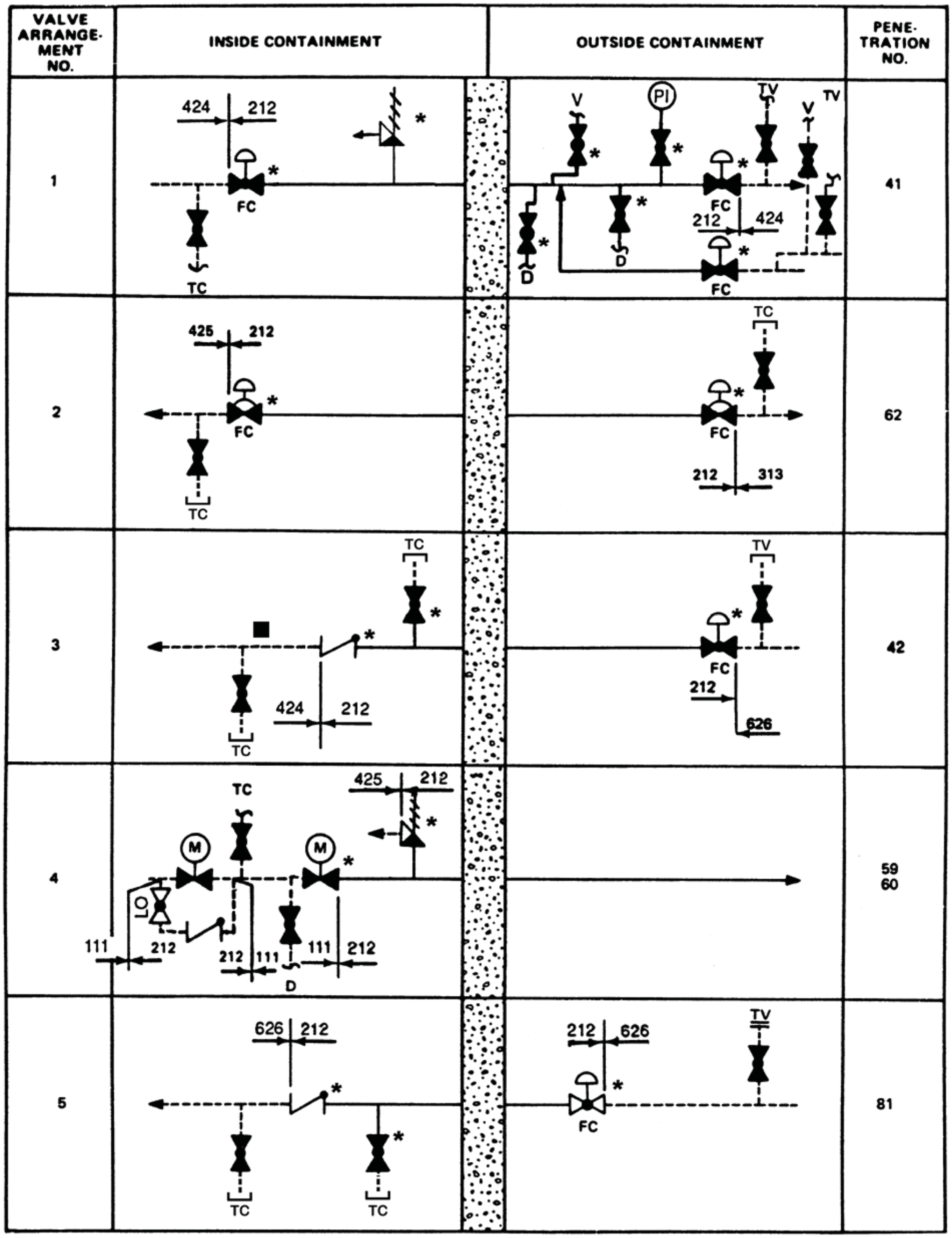
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CONTAINMENT WALL CONDENSATION
HEAT TRANSFER COEFFICIENT DECLG
(C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE)

FIGURE 6.2.1–32



* Valve listed on table 6.2.4-1.

** Bypass line (includes globe & check valve) Unit 1, Loops 1 & 4; Unit 2, Loop 4 only.

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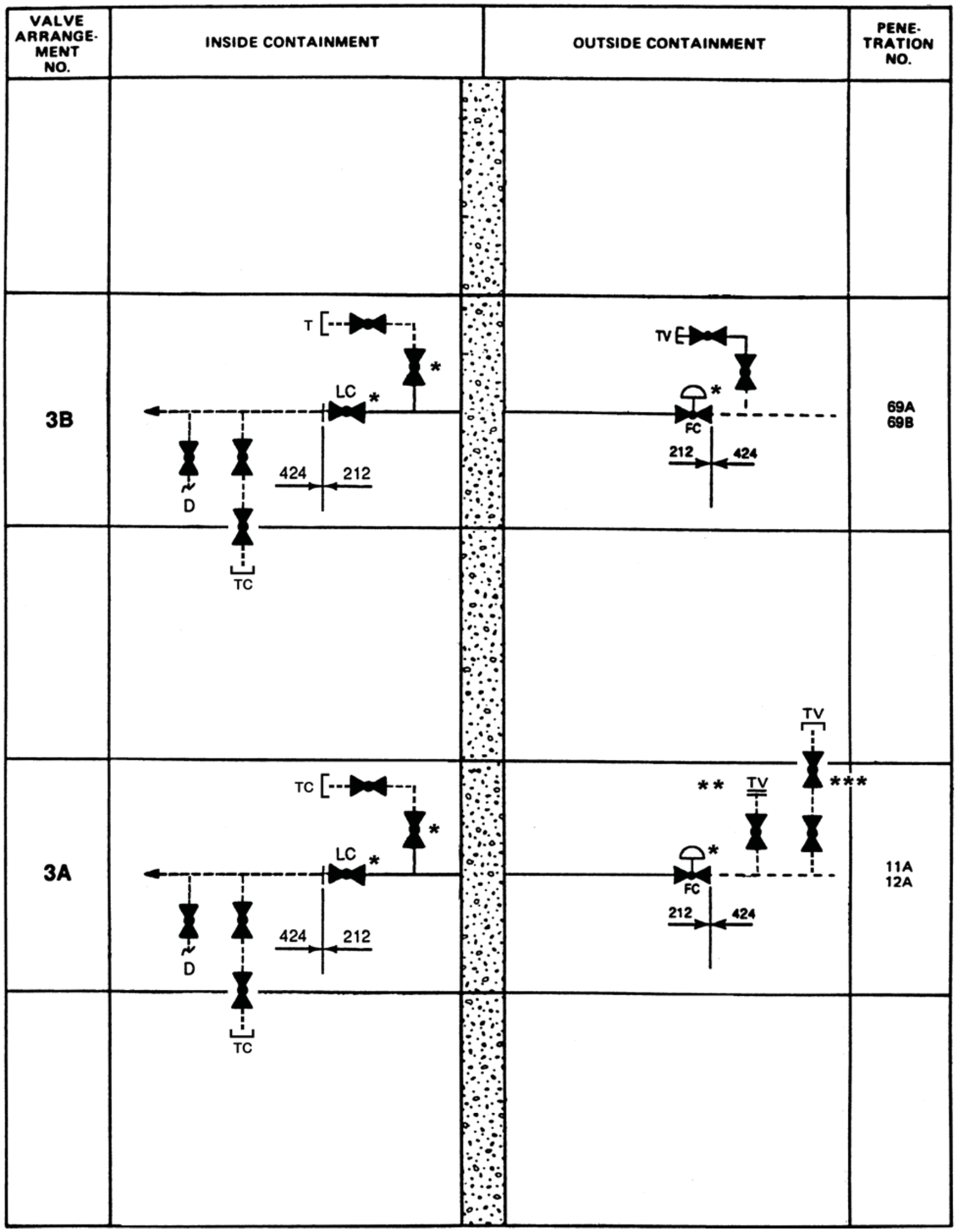
SOUTHERN COMPANY *Energy to Serve Your World®*	VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	VALVE ARRANGEMENT
		FIGURE 6.2.4-1 (SHEET 1 OF 13)



* Valve listed on table 6.2.4-1
** Applicable Unit 1 only
*** Applicable Unit 2 only

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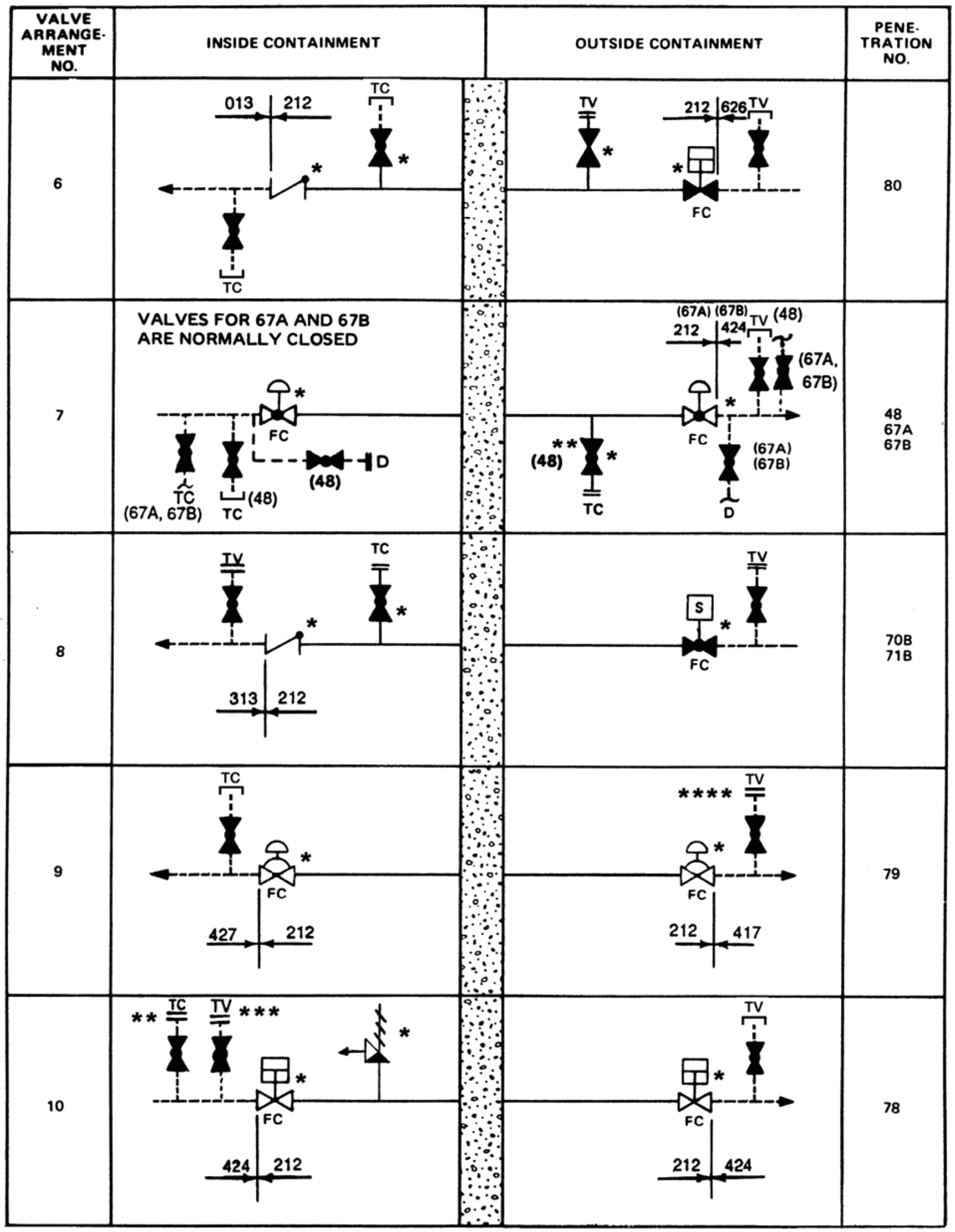
SOUTHERN COMPANY *Energy to Serve Your World®*	VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	VALVE ARRANGEMENT FIGURE 6.2.4-1 (SHEET 2 OF 13)



* Valve listed on table 6.2.4-1
** Applicable Unit 1 only
*** Applicable Unit 2 only
**** Blind flange applies to Unit 2 only

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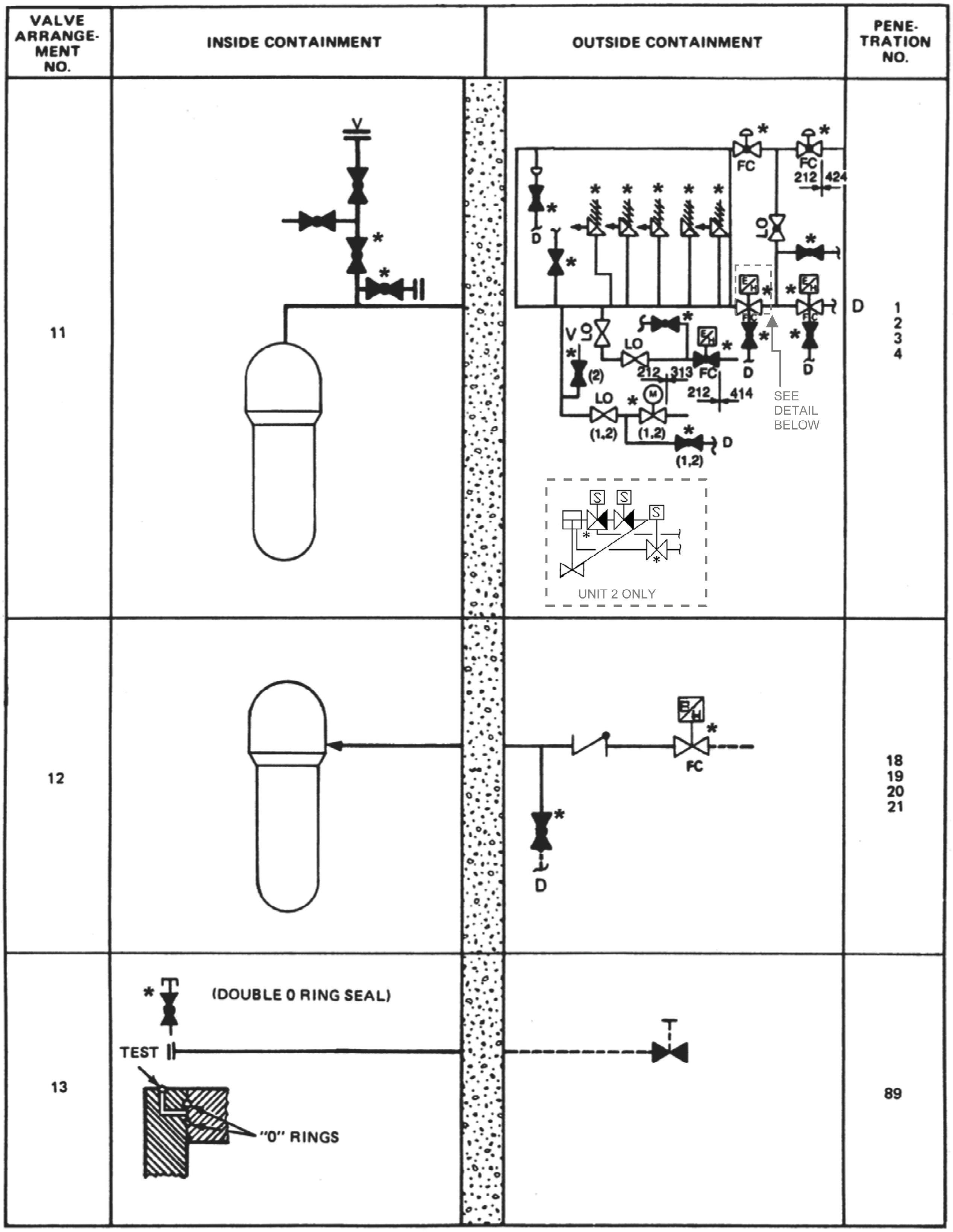
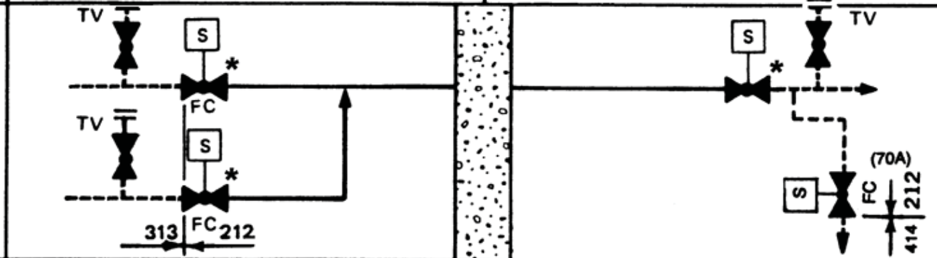
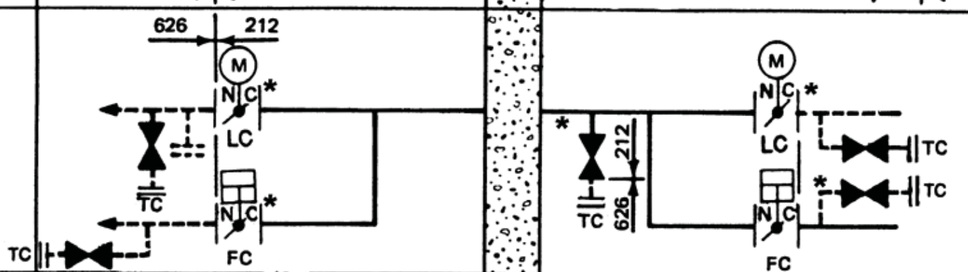
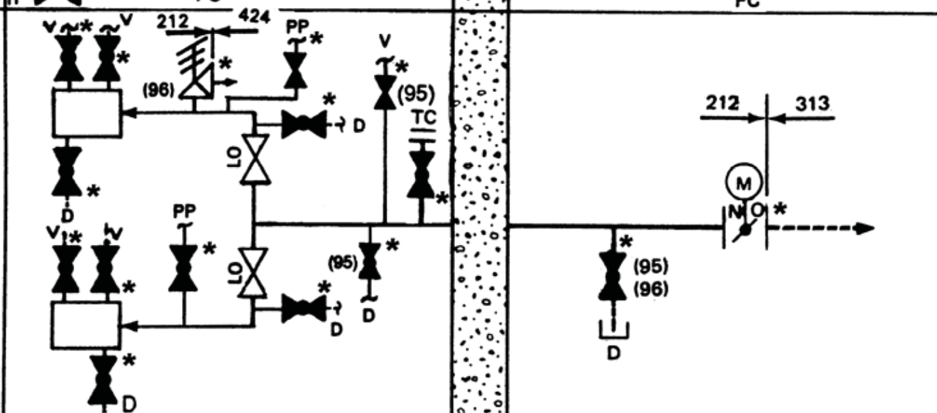
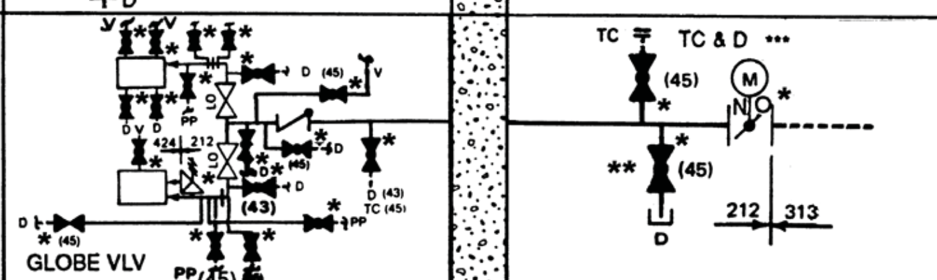
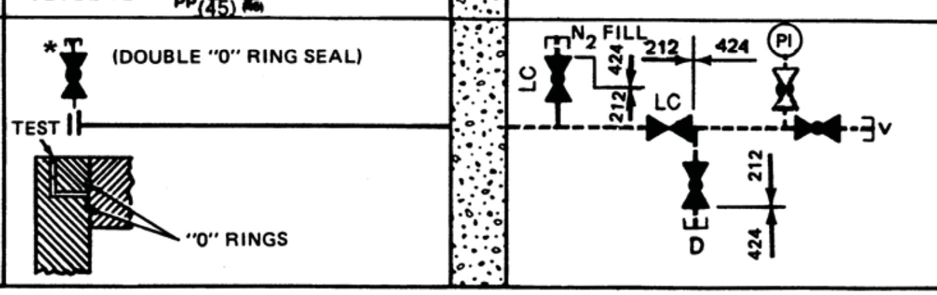


* Valve listed on table 6.2.4-1

REV 24 10/22

VALVE ARRANGEMENT NO.	INSIDE CONTAINMENT / OUTSIDE CONTAINMENT	PENETRATION NO.
14		70A 71A
15		83
16		95 96 97 98
17		43 45
18		68 87

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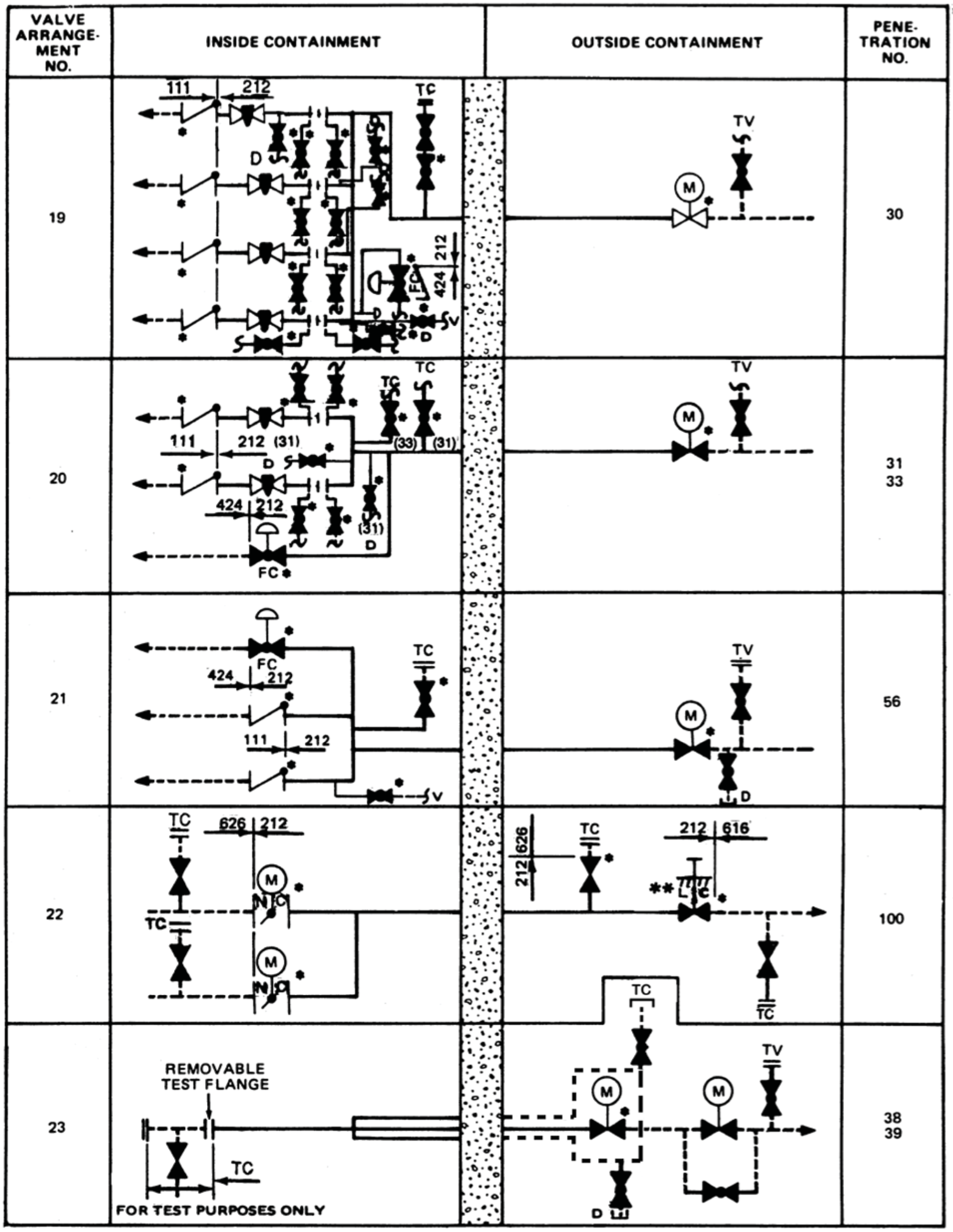

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ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

VALVE ARRANGEMENT

FIGURE 6.2.4-1 (SHEET 6 OF 13)

<table>
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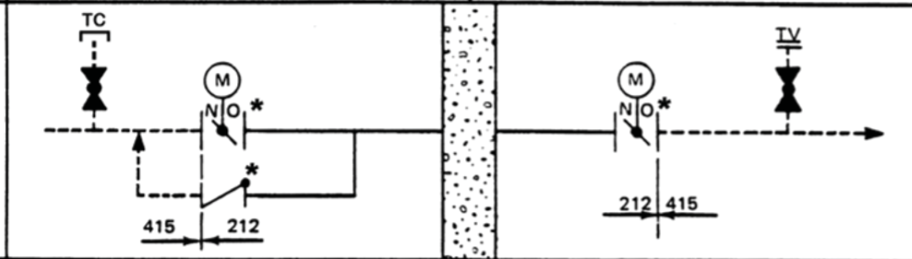
<tr><td>24</td><td colspan="2">
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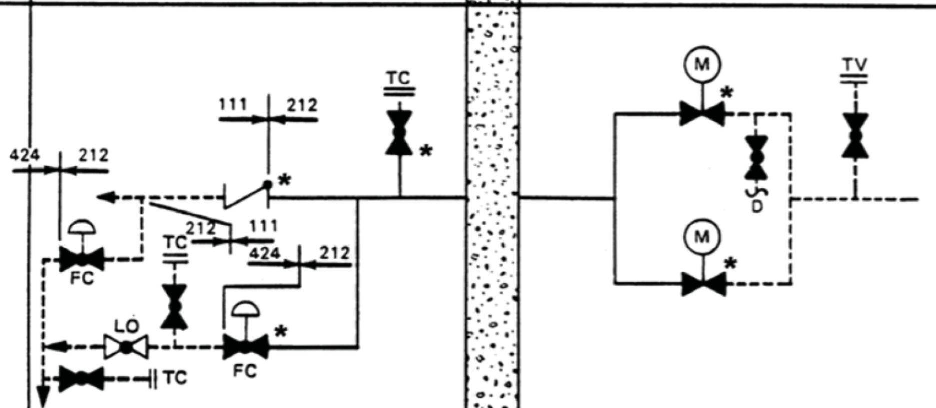
<tr><td>25</td><td colspan="2">
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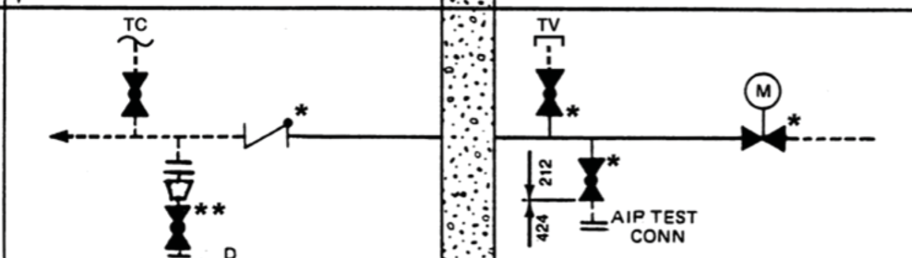
<tr><td>26</td><td colspan="2">
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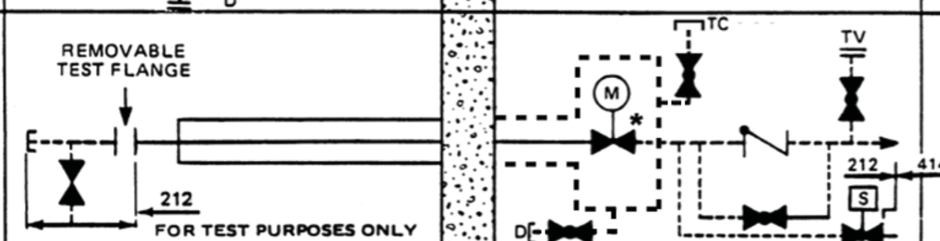
<tr><td>27</td><td colspan="2">
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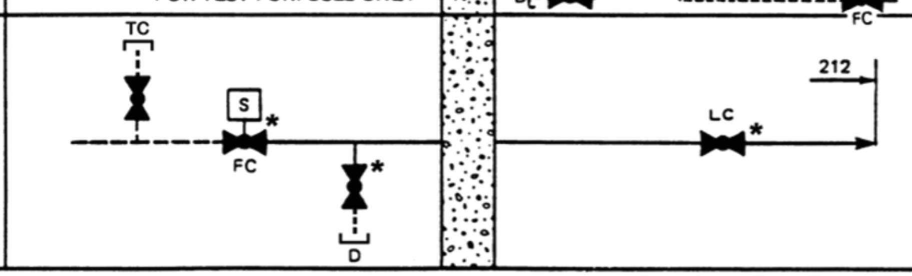
<tr><td>28</td><td colspan="2">
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73B</td></tr>
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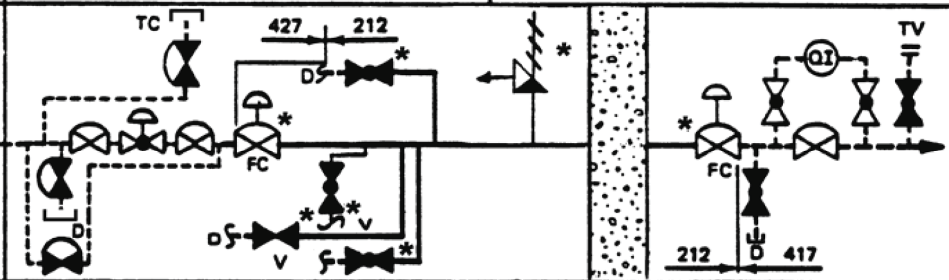
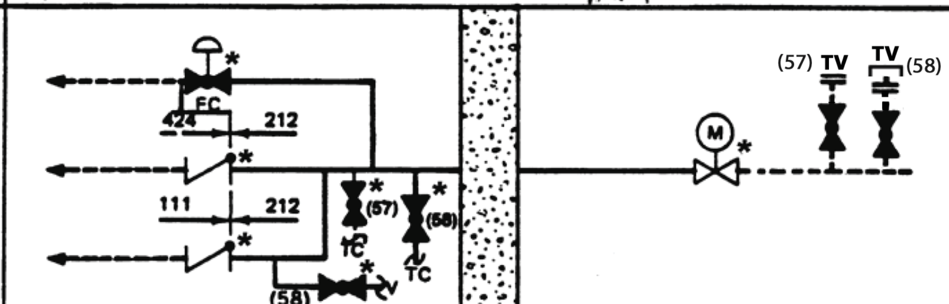
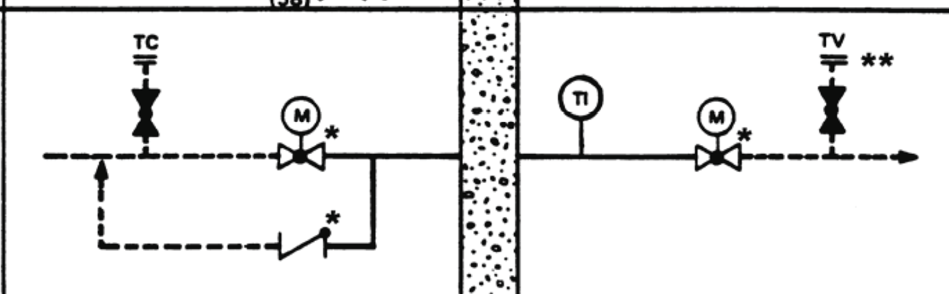
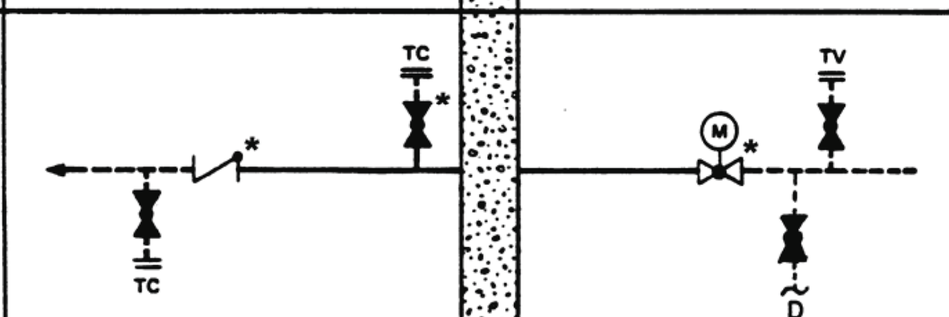
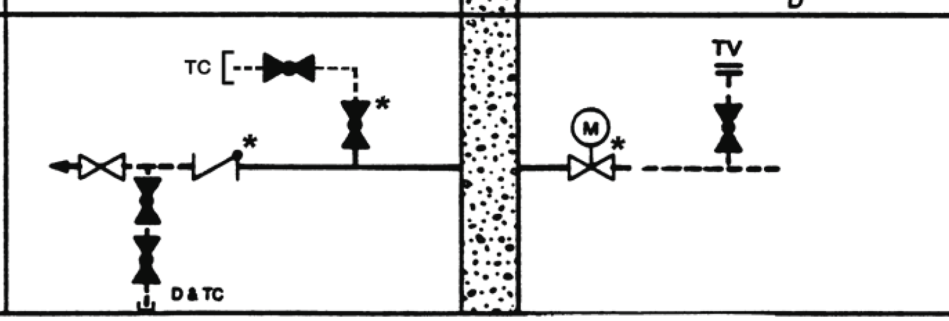
VALVE ARRANGEMENT NO.	INSIDE CONTAINMENT	OUTSIDE CONTAINMENT	PENETRATION NO.
29			77
30			57 58
31			49
32			51 52 53 54
33			50

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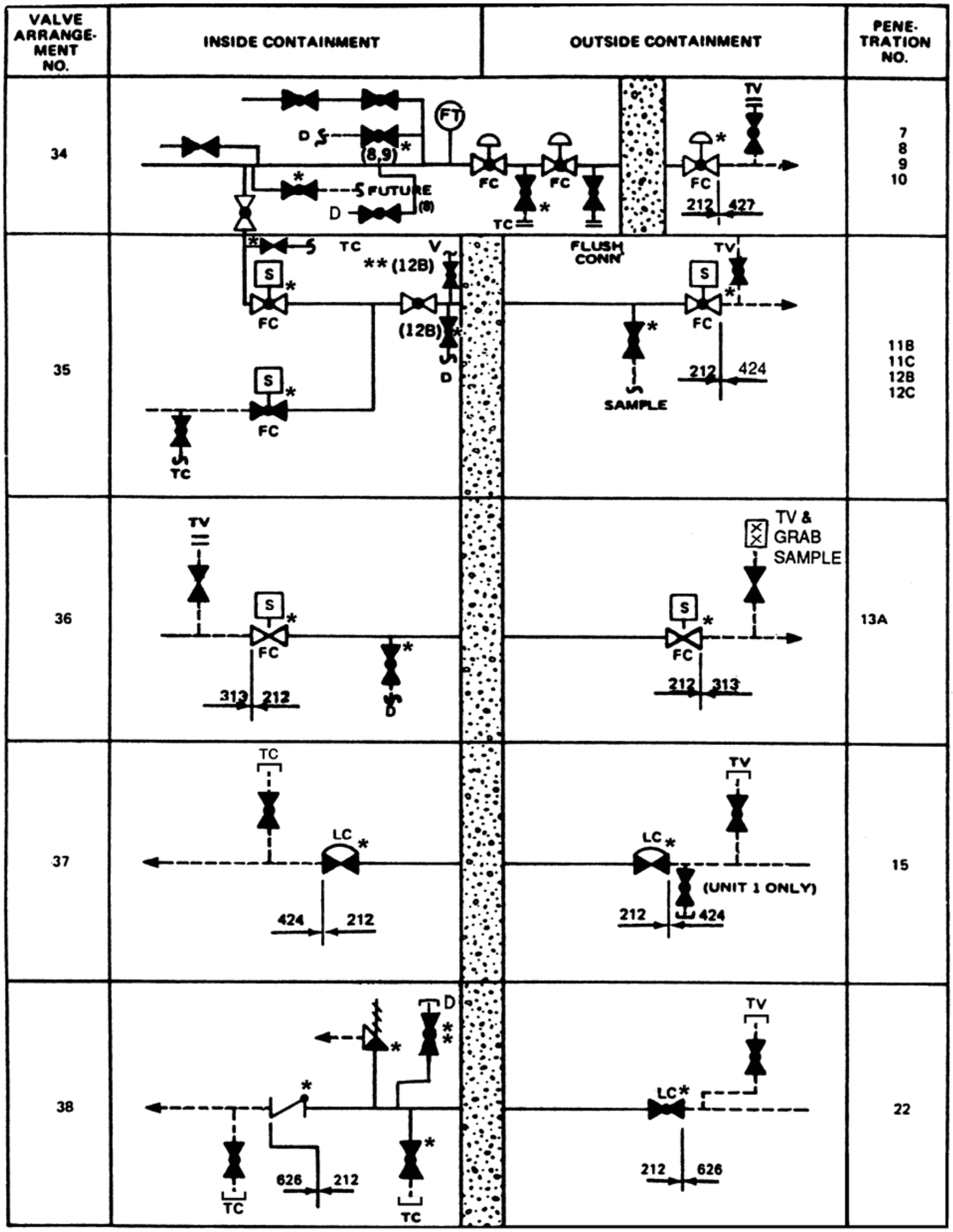
UNIT 1 AND UNIT 2

VALVE ARRANGEMENT

FIGURE 6.2.4-1 (SHEET 8 OF 13)



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ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

VALVE ARRANGEMENT

FIGURE 6.2.4-1 (SHEET 9 OF 13)

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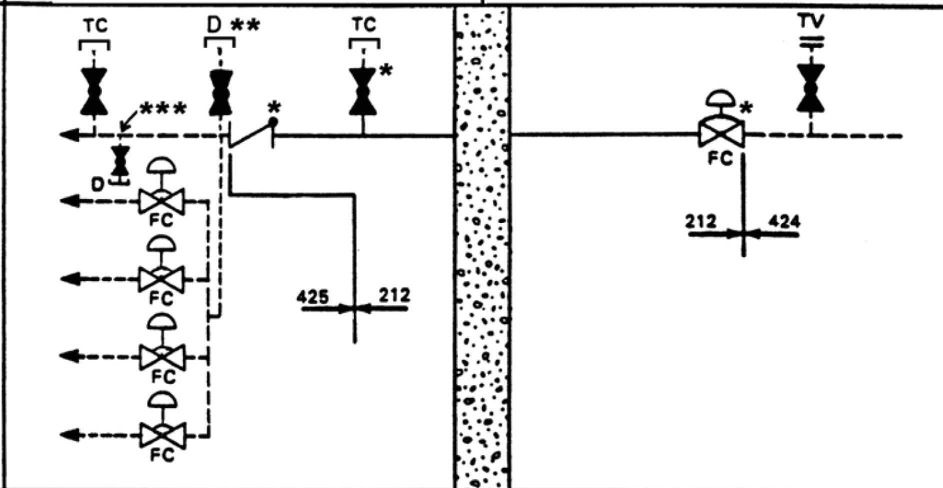
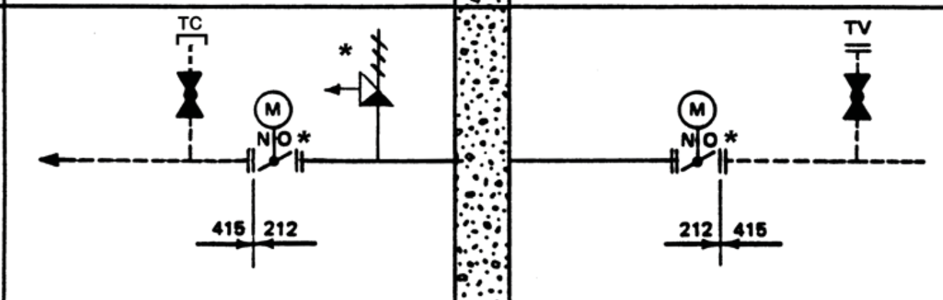
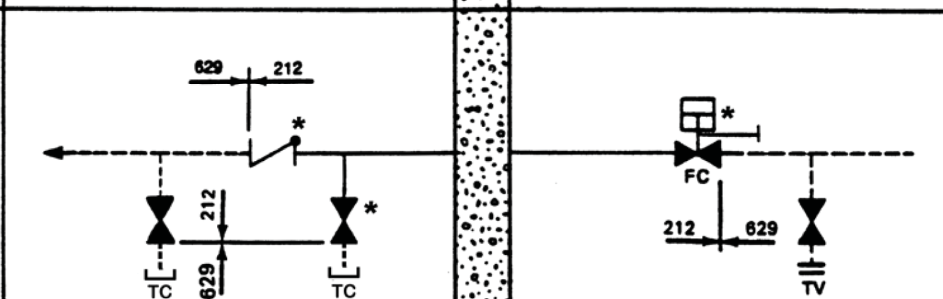
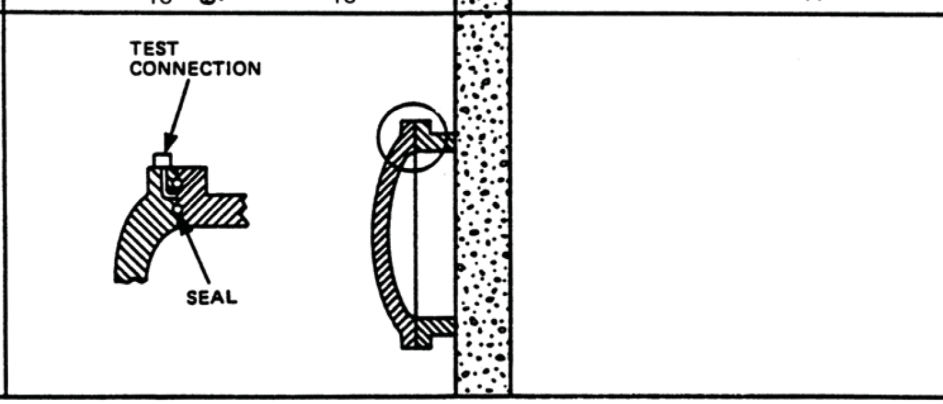
39		63
40		28
41		40
42		

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VALVE ARRANGEMENT

FIGURE 6.2.4-1 (SHEET 10 OF 13)

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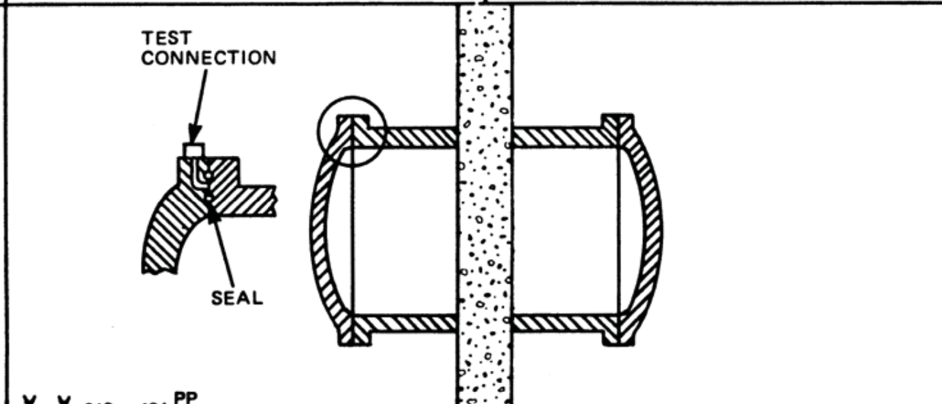
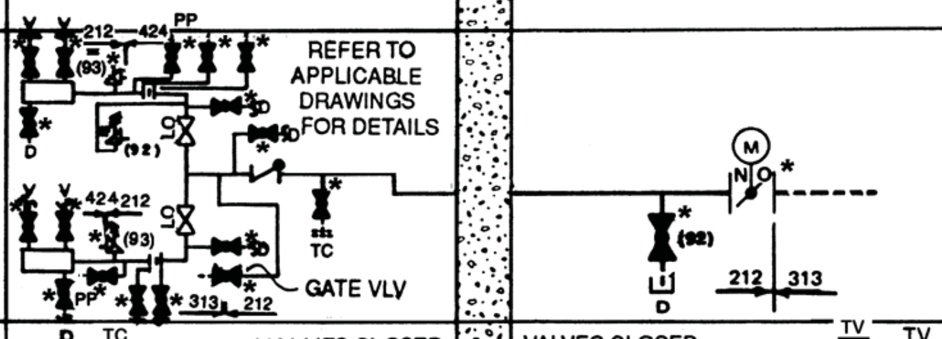
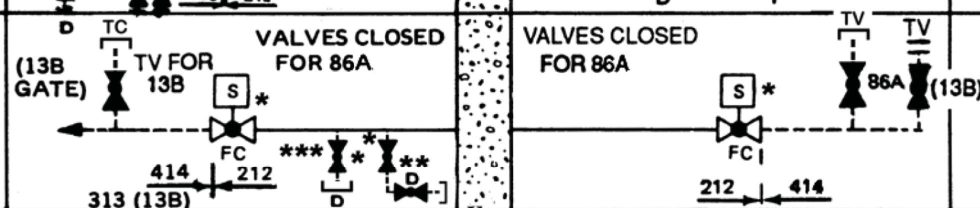
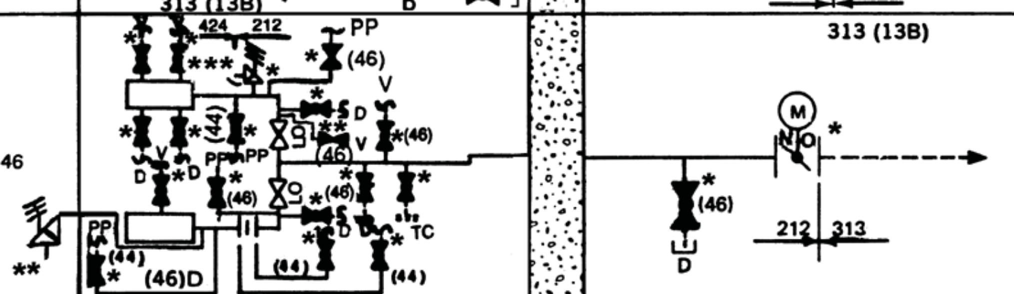
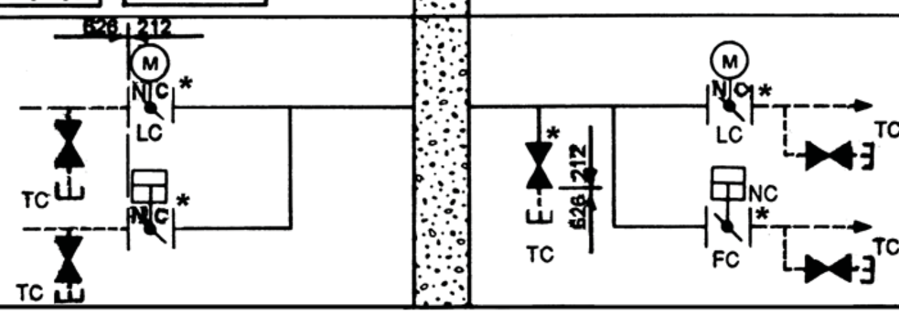
43		
44		92 93
45		13B 86A
46		44 46
47		84

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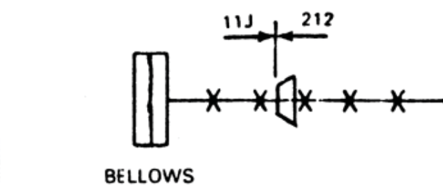
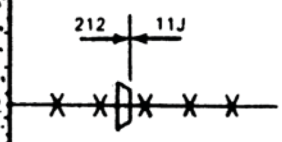
<tr><td>48</td><td>
</td><td>
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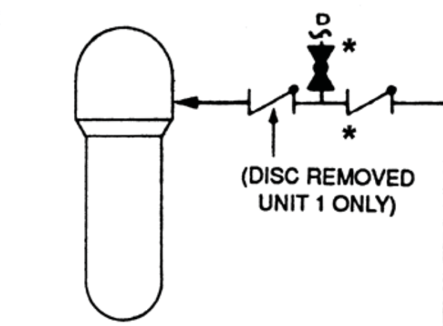
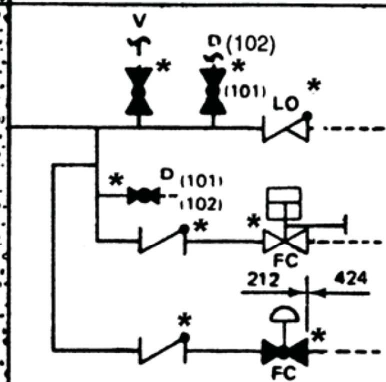
<tr><td>49</td><td>
</td><td>
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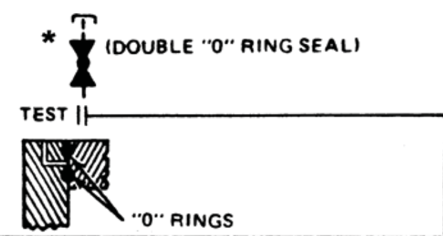
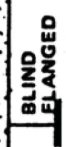
<tr><td>51</td><td>
</td><td>
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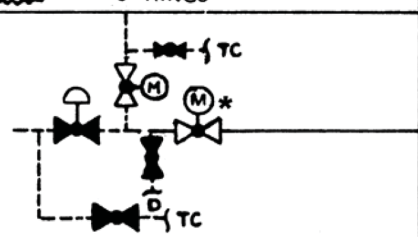
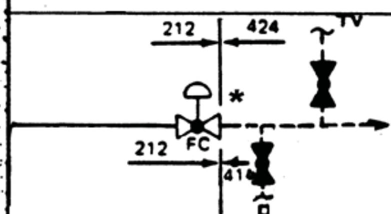
<tr><td>52</td><td>
</td><td>
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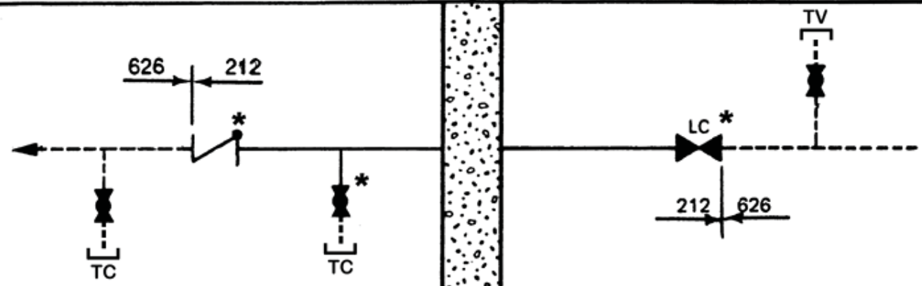
<tr><td>53</td><td colspan="2">
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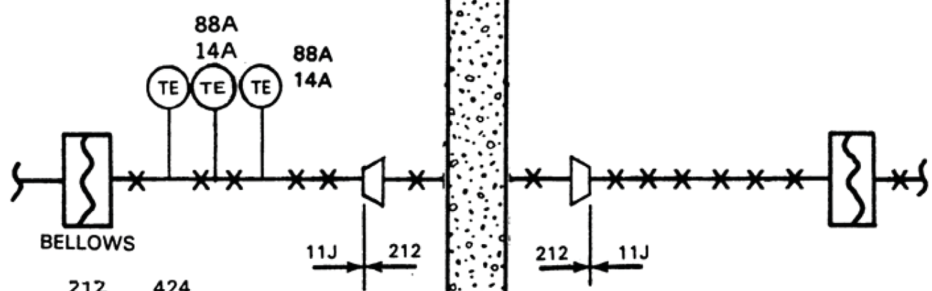
<tr><td>54</td><td colspan="2">
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14C
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88B
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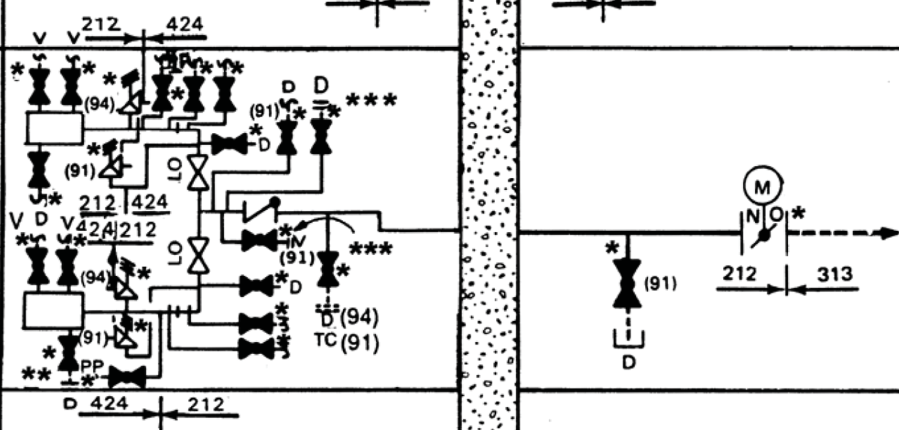
<tr><td>55</td><td colspan="2">
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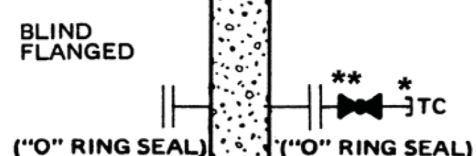
<tr><td>56</td><td colspan="2">

** UNIT 2 PEN 55 IS A GATE VALVE.</td><td>5
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90</td></tr>
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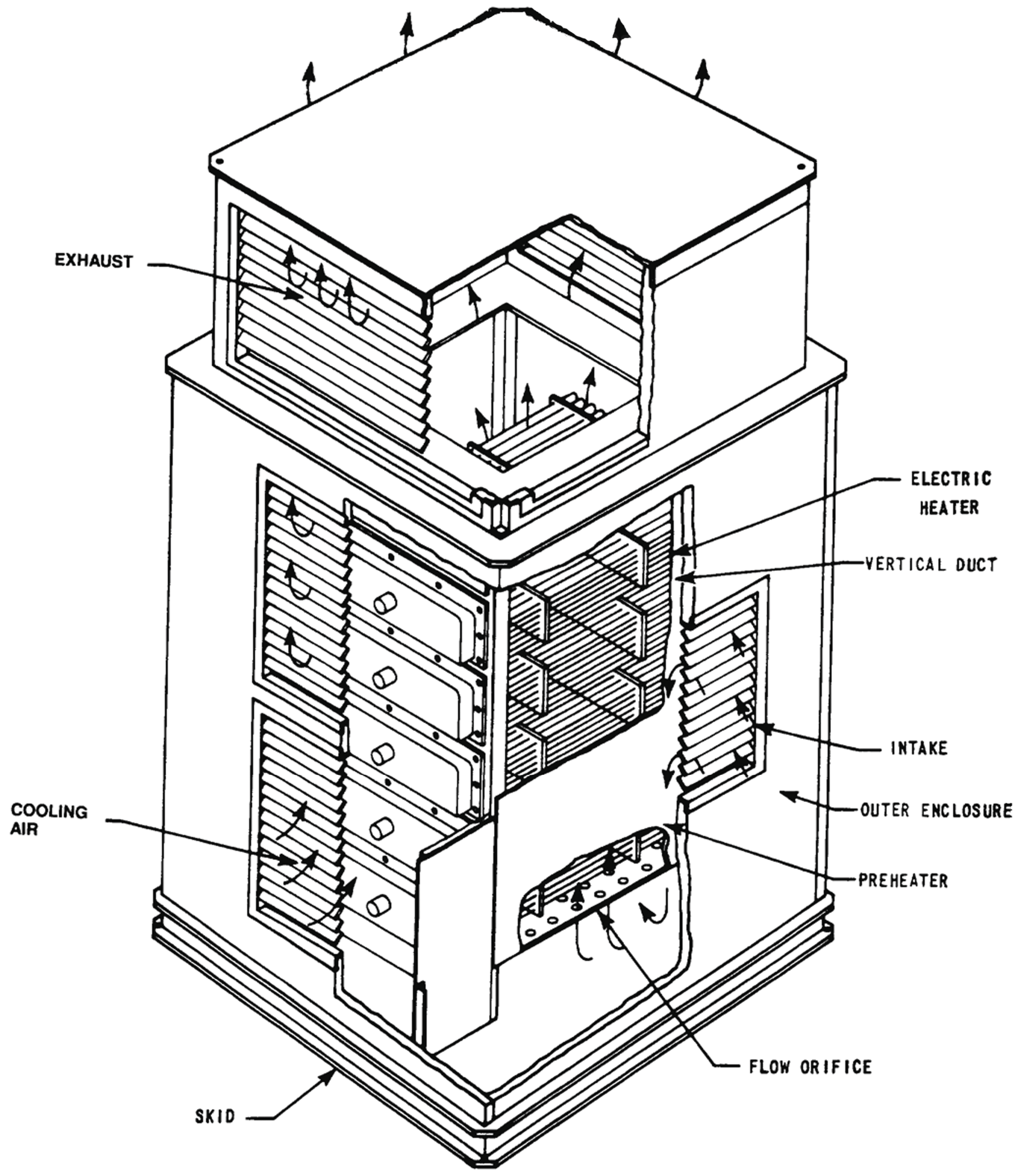

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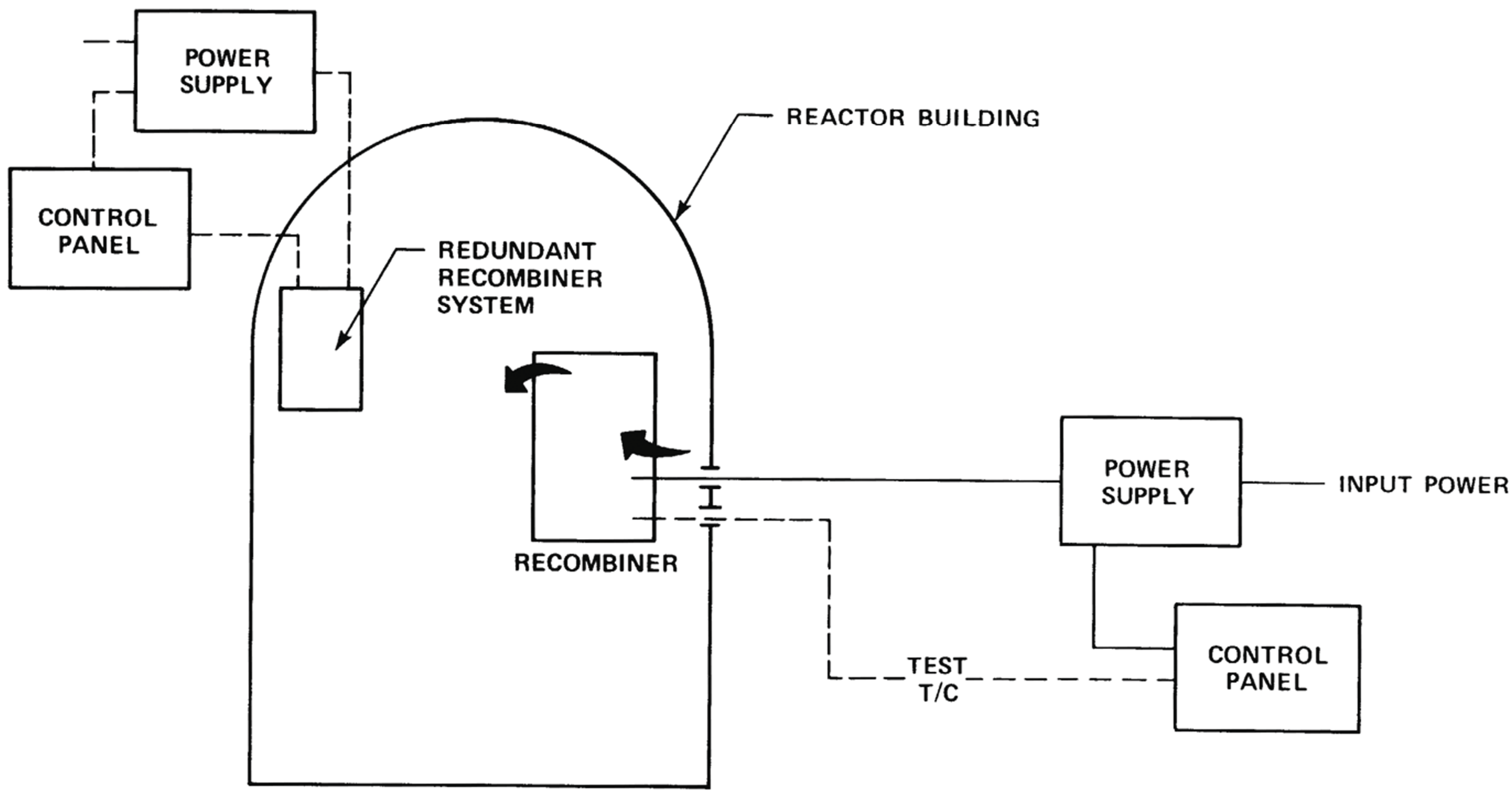
UNIT 1 AND UNIT 2

ELECTRIC HRYDROGEN RECOMBINER
(TYPICAL)

FIGURE 6.2.5–1



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ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

ELECTRIC HYDROGEN RECOMBINER
SYSTEM SCHEMATIC

FIGURE 6.2.5–2

DELETED

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ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

COMPARISON OF ANS 5.1 DECAY ENERGY CURVE AT 650 DAYS IRRADIATION + 20% TO DECAY ENERGY VALUES USED FOR H_2 PRODUCTION CALCULATION

FIGURE 6.2.5–3

DELETED

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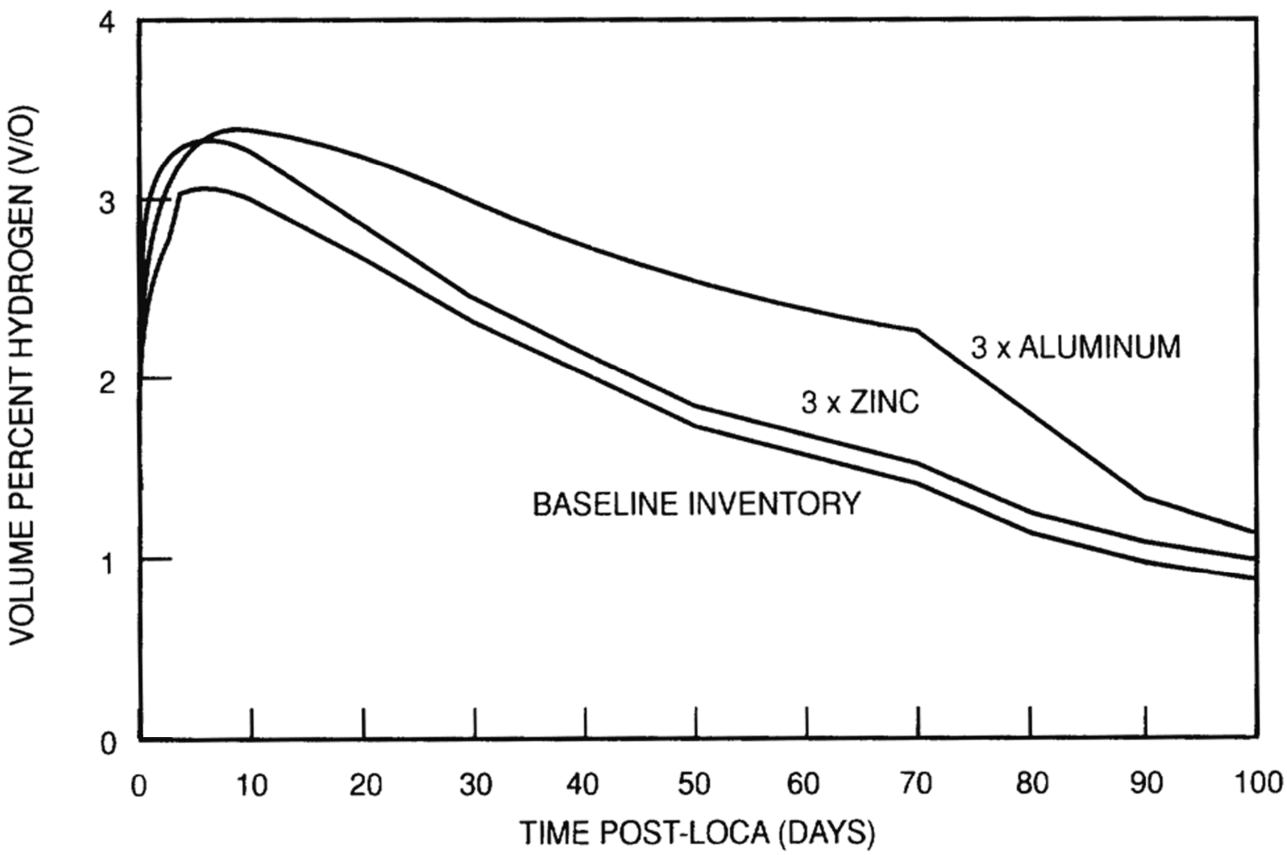
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

ALUMINUM AND ZINC CORROSION
RATE DESIGN CURVES

FIGURE 6.2.5–4



THIS FIGURE REPRESENTS THE CONCENTRATION OF HYDROGEN CONTRIBUTED FROM ALL SOURCES.

REV 13 4/06

SOUTHERN COMPANY *Energy to Serve Your World®*	**VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2**	CONTAINMENT HYDROGEN CONCENTRATION (ONE RECOMBINER ON AT 3.0 V/O)
		FIGURE 6.2.5–5

DELETED

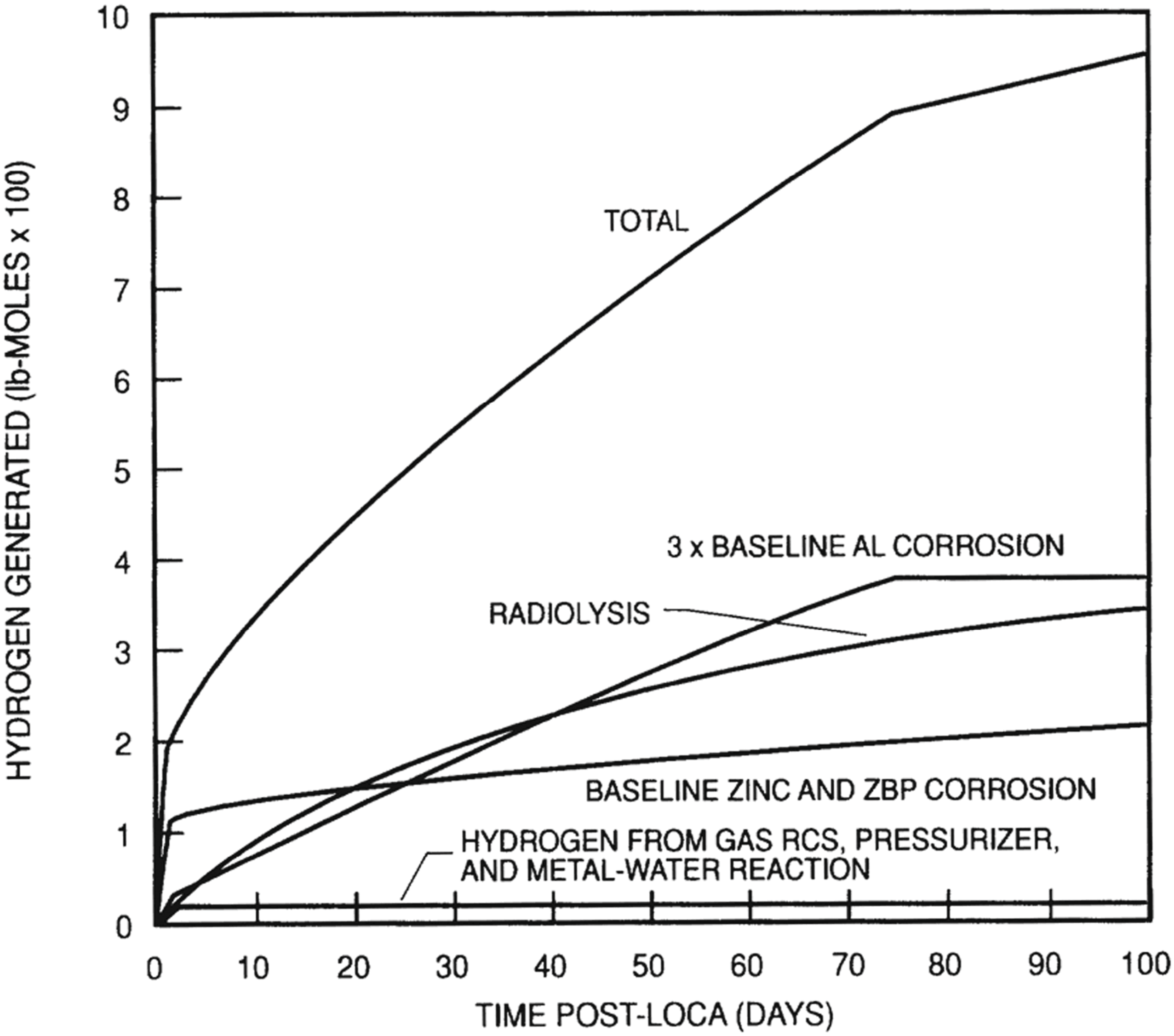
REV 13 4/06

SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

HYDROGEN PRODUCTION FROM ALL SOURCES

FIGURE 6.2.5–6



This curve bounds 3x baseline zinc case or an equivalent combination of zinc and aluminum.

Note: Total hydrogen generation curve remains bounding for MUR power uprate conditions. Individual curves showing contributions of the four individual hydrogen generation sources were not updated as part of the MUR power uprate.

REV 15 4/09

SOUTHERN COMPANY *Energy to Serve Your World®*	**VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2**	HYDROGEN ACCUMULATION FROM ALL SOURCES (FOR 3 X BASELINE ALUMINUM SURFACE AREA) FIGURE 6.2.5–7

6.3 EMERGENCY CORE COOLING SYSTEM

6.3.1 DESIGN BASES

The emergency core cooling system (ECCS) is a Seismic Category 1 safety-related system. It consists of the centrifugal charging pumps, safety injection pumps, residual heat removal pumps, accumulators, boron injection tank (Unit 1 only), residual heat removal heat exchangers, refueling water storage tank (RWST), and the associated piping, valves, instrumentation, and other related equipment. Nuclear plants employing the same ECCS design as VEGP are given in section 1.3.

The primary function of the ECCS following an accident is to remove the stored and fission product decay heat from the reactor core such that fuel rod damage, to the extent that it would impair effective cooling of the core, is prevented.

The ECCS is designed to cool the reactor core and to provide additional shutdown capability following initiation of the following accident conditions:

A. Loss-of-coolant accident (LOCA) including a pipe break or a spurious relief or safety valve opening in the reactor coolant system (RCS) which would result in a discharge larger than that which could be made up by the normal makeup system.

B. Loss-of-secondary-coolant accident including a pipe break or a spurious relief or safety valve opening in the secondary steam system which would result in an uncontrolled steam release or a pipe break in the secondary feedwater system.

C. A steam generator tube rupture accident.

The acceptance criteria for the consequences of each of these accidents are described in chapter 15 in the respective accident analyses sections.

The bases used in design and for selection of ECCS functional requirements are derived from 10 CFR 50, Appendix K, limits for fuel cladding temperature, etc., following any of the above accidents as delineated in 10 CFR 50.46. The subsystem functional parameters are selected so that, when integrated, the Appendix K requirements are met over the range of anticipated accidents and single failure assumptions.

The design basis for the ECCS with regard to the effects of debris on the emergency sump strainers, to the extent that the strainers support the ECCS element of the core cooling function, is a risk-informed analysis that shows there is a high probability that the ECCS can perform its design basis functions.

The conclusion that ECCS will perform its design basis functions with high probability is based on plant-specific testing using assumptions that provide safety margin and defense-in-depth. The risk from breaks that do not meet one (or more) of the GSI-191 acceptance criteria is very small and acceptable in accordance with the guidelines of RG 1.174.

Details of the design basis for the effects of debris on the function of the emergency sump strainers are provided in FSAR Appendix 6A.

Portions of the ECCS also operate in conjunction with the other systems of the cold shutdown design. The primary function of the ECCS during a safety grade cold shutdown is to ensure a means for injecting and throttling boration and makeup flow. Details of the cold shutdown design bases are discussed in subsection 5.4.7.

The primary function of the safety injection system (SIS) is to provide emergency core cooling in the event of a LOCA resulting from a break in the primary RCS or to provide emergency boration in the event of a steam line or feed line break accident resulting from a break in the secondary system.

Emergency core cooling following a LOCA is divided into three phases:

A. Short-Term Core Cooling/Cold Leg Injection Phase

The cold leg injection phase is defined as that period during which borated water is delivered from the RWST and accumulators to the RCS cold legs.

B. Long-Term Core Cooling/Cold Leg Recirculation

The cold leg recirculation phase is that period during which borated water is recirculated from the containment emergency sump to the RCS cold legs.

C. Long-Term Core Cooling/Hot Leg Recirculation Phase

The hot leg recirculation phase is that period during which borated water is recirculated from the containment emergency sump to both the RCS hot legs and RCS cold legs.

The emergency boration following a steam break accident would occur only during the injection phase. The function of the SIS during this phase would be to inject borated water into the RCS with sufficient shutdown reactivity to compensate for the change in RCS volume and to counteract any reactivity increase caused by the resulting cooldown. The SIS would continue to inject borated water from the RWST until the RCS conditions have stabilized, the accident has been identified as a steam break, and the criteria for safety injection termination are satisfied.

The reliability of the ECCS has been considered in selection of the functional requirements, selection of the particular components and location of components, and connected piping. Redundant components are provided where the loss of one component would impair reliability. Valves are provided in series where isolation is desired and in parallel when flow paths are to be established for ECCS performance. Redundant sources of the safety injection actuation signal are available so that the proper and timely operation of the ECCS is ensured. Sufficient instrumentation is available so that failure of an instrument will not impair readiness of the system. The active components of the ECCS are normally powered from separate buses which are energized from offsite power supplies. In addition, redundant sources of emergency onsite power are available through the use of the emergency diesel generators to ensure adequate power for all ECCS requirements. Each diesel generator is capable of driving all pumps, valves, and necessary instruments associated with one train of the ECCS.

All valves required to be actuated during ECCS operation are located to prevent vulnerability to flooding. Repositioning of valves due to spurious actuation coincident with an accident has been analyzed and is not considered credible as a design basis.

To address the Three Mile Island requirements of II.K.1.5, operations surveillance procedures (OSP) have controls which address the manipulation of valves during testing. The procedures are written to ensure positive control over all valve movements and to independently verify that each valve is returned to its original position, i.e., safeguards position.

After extended outages systems are aligned by their individual procedures which include safety-related systems. Safety-related systems are aligned again using the flow path verification surveillance procedure. This in effect provides an independent verification of flow paths for safety-related system valves.

These surveillance procedures are then performed on a periodic basis during plant operation to ensure proper alignment. Also, as mentioned earlier, if a valve position is changed during a surveillance test, it is procedurally repositioned to original position and independently verified in that position.

Using the methods described above, OSPs maintain positive control over safety system valves.

The environmental qualification of active ECCS equipment is discussed in section 3.11.

Protection of the ECCS from missiles is discussed in section 3.5. Protection of the ECCS against dynamic effects associated with rupture of piping is described in section 3.6. Protection from flooding is also discussed in section 3.4, paragraph 3.6.1.3, and appendix 3F.

The elevated temperature of the containment emergency sump solution during recirculation is well within the design temperature of all ECCS components. In addition, consideration has been given to the potential for corrosion of various types of metals exposed to the fluid conditions prevalent immediately after the accident or during long-term recirculation operations.

6.3.2 SYSTEM DESIGN

The emergency core cooling system (ECCS) components are designed such that a minimum of three accumulators, one charging pump, one safety injection (SI) pump, one residual heat removal (RHR) pump, and one RHR heat exchanger, together with their associated valves and piping, will ensure adequate core cooling in the event of a design basis accident (DBA). The redundant onsite emergency diesels ensure adequate emergency power to at least one train of electrically operated components in the event that a loss of offsite power occurs simultaneously with an accident, even assuming a single failure in the emergency power system.

6.3.2.1 Schematic Piping and Instrumentation Diagrams

Piping and instrumentation diagrams of the ECCS are shown in drawings 1X4DB116-1, 2X4DB116-1, 1X4DB116-2, 2X4DB116-2, 1X4DB119, 2X4DB119, 1X4DB120, 2X4DB120, 1X4DB121, 2X4DB121, 1X4DB122 and 2X4DB122. Process flow diagrams of the ECCS are shown in figure 6.3.2-1. Pertinent design and operating parameters for the components of the ECCS are given in table 6.3.2-1. The codes and standards to which the individual components of the ECCS are designed are listed in table 3.2.2-1.

Process flow diagrams (figure 6.3.2-1) are developed for illustrative purposes only and are not intended to represent the flowrates and temperatures used in the various accident analyses. For the cold leg injection mode, they illustrate best estimate system performance based on maximum ECCS safeguards (both trains of ECCS components) operating. The system operation conditions presented are based on the assumption that the reactor coolant system (RCS) is fully depressurized and is in equilibrium with the containment at 0 psig.

Flowrates to the RCS are provided in chapter 15, where appropriate, for the accident analyses. The accident analyses flowrates are developed from certified pump performance curves and calculated system resistances based on plant piping layouts. Minimum ECCS safeguards flowrates are determined by degrading the minimum composite pump performance curves by an amount representing design margins of the pumps and also by uniformly degrading those resulting curves by 5 percent (reference 1) and, to maximize the spill, the injection line with the lowest resistance is assumed to spill to either the containment or to the RCS. Refer to paragraph 15.6.5.2 for details.

The component interlocks used in different modes of system operation are listed below.

A. The SI signal is interlocked with the following components and initiates the indicated action:

	Component	Action
1.	Centrifugal charging pumps	Start
2.	Refueling water storage tank (RWST) suction valves to charging pumps	Open
3.	Discharge header (parallel) valves for Unit 1 boron injection tank (BIT) and Unit 2 CVCS charging pumps high head cold leg injection valves.	Open
4.	Normal charging path valves	Close
5.	Charging pump miniflow valves	Close
6.	Charging pump alternate miniflow valves	Open[a]
7.	SI pumps	Start
8.	RHR pumps	Start
9.	Any closed accumulator isolation valve	Open
10.	Volume control tank outlet isolation valves	Close

B. Switchover from injection mode to recirculation involves the following interlocks:

1. The RHR suction valves from the containment emergency sumps open when two out of four RWST level transmitters indicate a low-low level in conjunction with an SI signal.
2. The SI pump and charging pump suction isolation valves from the RHR pump discharge can be opened provided that the SI pump miniflow and charging pump alternate miniflow isolation valves have been closed.

6.3.2.2 Equipment and Component Descriptions

The component design and operating conditions are specified as the most severe conditions to which each respective component is exposed during either normal plant operation or during operation of the ECCS. For each component these conditions are considered in relation to the code to which it is designed. By designing the components in accordance with applicable codes

[a] Valves are enabled by the SI signal and will open or close based on centrifugal charging pump discharge pressure.

and with due consideration for the design and operating conditions, the fundamental assurance of structural integrity of the ECCS components is maintained. Components of the ECCS are designed to withstand the appropriate seismic loadings in accordance with their safety class as given in table 3.2.2-1. Specific equipment parameters are given in table 6.3.2-1.

A gas accumulation monitoring and trending process for the Vogtle Unit 1 and 2 ECCS and containment spray systems has been established to meet the requirements of NRC Generic Letter 2008-01.

A discussion of the major mechanical components of the ECCS follows.

6.3.2.2.1 Accumulators

The accumulators are pressure vessels partially filled with borated water and pressurized with nitrogen gas. During normal operation each accumulator is isolated from the RCS by two check valves in series. Should the RCS pressure fall below the accumulator pressure, the check valves open and borated water is forced into the RCS. One accumulator is attached to each of the cold legs of the RCS. Mechanical operation of the swing-disc check valves is the only action required to open the injection path from the accumulators to the core via the cold legs.

Connections are provided for remotely adjusting the level and boron concentration of the borated water in each accumulator during normal plant operation as required. Accumulator water level may be adjusted either by draining to the RWST or by pumping borated water from the RWST to the accumulator. Samples of the solution in the accumulators are taken periodically to check boron concentration.

Accumulator pressure is provided by a supply of nitrogen gas and can be adjusted as required during normal plant operation. However, the accumulators are normally isolated from this nitrogen supply. Gas relief valves on the accumulators protect them from pressures in excess of design pressure. The redundant capability to vent the accumulators is described in paragraph 5.4.7.2.3.

The accumulators are located within the containment but outside the secondary shield wall which protects them from missiles.

Accumulator level and pressure are monitored by indicators and alarms. The operator can take action as required to maintain plant operation within the requirements of the technical specification covering accumulator operability.

6.3.2.2.2 Boron Injection Tank (Unit 1 only)

The BIT will contain anywhere from 0 to 2600 ppm borated water solution (the upper limit being the same as the borated water solution in the refueling water storage tank (RWST) and is connected to the discharge of the centrifugal charging pumps. Upon actuation of the SI signal, the charging pumps provide the pressure to inject the borated water solution from the RWST into the RCS when the isolation valves associated with the BIT discharge path open automatically.

6.3.2.2.3 Deleted

6.3.2.2.4 Residual Heat Removal Pumps

In the event of an accident, the RHR pumps are started automatically on receipt of an SI signal. The RHR pumps take suction from the RWST during the injection phase and are automatically realigned to the containment emergency sump during the recirculation phase, although manual action is required to close the suction path from the RWST. Each RHR pump is a single-stage, vertical position, centrifugal pump.

A minimum flow bypass line is provided on each pump discharge to recirculate and return the pump discharge fluid to the pump suction should these pumps be started with the RCS pressure above their shutoff head. Once flow is established to the RCS, each pump bypass line automatically closes. The minimum flow bypass lines prevent deadheading of the pumps and permit pump testing during normal operation.

The RHR pumps are discussed further in subsection 5.4.7. A pump performance curve is given in figure 6.3.2-2.

The net positive suction head (NPSH) of the RHR pumps was evaluated for normal plant cooldown operation and for both the injection and recirculation modes of operation for the DBA.

The recirculation mode of operation at -0.3 psig containment pressure and 211°F sump temperature results in the limiting NPSH.

The adequacy of the available NPSH was evaluated as described in Appendix 6A.

6.3.2.2.5 Centrifugal Charging Pumps

In the event of an accident, the centrifugal charging pumps are started automatically on receipt of an SI signal and are automatically aligned to take suction from the RWST during the injection phase. During recirculation, suction is provided from the RHR pump discharge.

These high-head pumps deliver flow to the RCS at the prevailing RCS pressure. Each centrifugal charging pump is a multistage diffuser design, barrel-type casing with vertical suction and discharge nozzles.

A minimum flow bypass line is provided on each pump discharge to prevent pump deadheading and to permit pump testing during power operations. Each minimum flow bypass line contains an isolation valve that closes automatically upon receipt of an SI signal. A third isolation valve is provided in the common header downstream of the two individual pump minimum flow lines. An alternate minimum flow line is provided for each pump to prevent pump deadheading should RCS pressure rise following isolation of the normal minimum flow lines. An isolation valve in each of these lines is enabled by the SI signal and opens upon receipt of a high pressure signal from a pressure switch connected to the centrifugal charging pump discharge. When the isolation valve opens, flow will be discharged to the RWST. Both isolation valves in each alternate minimum flow line are closed from the control room as part of the ECCS realignment from the injection to the recirculation mode.

A pump performance curve for the centrifugal charging pumps is given in figure 6.3.2-3.

6.3.2.2.6 Safety Injection Pumps

Two SI pumps are provided. Each pump is a multistage, diffuser design, split-case centrifugal pump with side suction and side discharge.

In the event of an accident, the SI pumps are started automatically on receipt of an SI signal.

These pumps deliver water to the RCS from the RWST during the injection phase and from the containment emergency sump via the RHR pumps during the recirculation phase.

A minimum flow bypass line is provided on each pump discharge to recirculate flow to the RWST in the event that the pumps are started with the RCS pressure above pump shutoff head. This line also permits pump testing during normal plant operation. Two parallel valves in series, with a third downstream in a common header, are provided for isolation of the minimum flow lines.

These valves are manually closed from the control room as part of the ECCS realignment from the injection to the recirculation mode. A pump performance curve is presented in figure 6.3.2-4.

The NPSH for the SI and charging pumps was evaluated for both the injection and recirculation modes of operation for the DBA. The end of the injection mode of operation gives the limiting NPSH available (minimum static head). The NPSH available was determined from the elevation head and vapor pressure of the water in the RWST, which is at atmospheric pressure, and from the pressure drop in the suction piping from the tank to the pumps.

The NPSH evaluation for the charging and SI pumps from the RWST was based on all safeguards pumps operating, with the pump being analyzed at its runout flowrate.

When a predetermined low RWST level is reached, the SI and charging pumps are manually aligned to take suction from the RHR pump discharge headers. The NPSH requirements of these pumps are therefore satisfied by the discharge head of the RHR pumps during the recirculation mode of system operation.

6.3.2.2.7 Deleted

6.3.2.2.8 Residual Heat Removal Heat Exchangers

The RHR heat exchangers are conventional shell and U-tube type units. During normal cooldown operation, the RHR pumps recirculate reactor coolant through the tube side while component cooling water flows through the shell side. During ECCS recirculation operation, water from the containment emergency sump flows through the tube side. The tubes are seal welded to the tube sheet.

The RHR heat exchangers are discussed further in subsection 5.4.7.

6.3.2.2.9 Refueling Water Storage Tank

The RWST provides a source of water for the SI, containment spray, centrifugal charging, and RHR pumps following an accident. The tank volume is sufficiently large to supply the injection phase water requirements. The RWST is a cylindrical, reinforced concrete tank with a stainless steel liner. The walls and roof slab are sufficiently thick to protect the tank against tornado-generated missiles. The tank is designed to Seismic Category 1 requirements. The tank outlet is designed to prevent vortex propagation to the pump suction lines. The outlet is also screened to prevent the passage of particles larger than 1/8 in. in diameter. A recirculation heater is provided to maintain a minimum water temperature of 50°F, and external connections to the tank are heat traced to ensure their operability. The RWST provides a sufficient volume of water to adequately account for instrument error, working allowance, transfer allowance, single failure, and unusable volume. RWST sizing is shown in figure 6.3.2-5.

The discussion which follows addresses the adequacy of the RWST volume, including the shortest times available for ECCS injection and switchover.

6.3.2.2.9.1 Injection Mode Allowance. The SI mode of ECCS operation consists of the ECCS pumps (charging pumps, SI pumps, and RHR pumps) and the containment spray pumps taking suction from the RWST and delivering to the RCS and containment, respectively. In order to analyze the shortest time available for injection mode operation, the following conservative bases are established:

A. The RWST volume available for injection mode operation is approximately 455,635 gal.

B. Containment and RCS pressures are conservatively assumed to be 0 psig to maximize flow out of the RWST.

C. Flow out of the RWST during the injection mode includes conservative allowances for two pumps of each type operating at the following flowrates:

SI pump	450 gal/min per pump
Charging pump	450 gal/min per pump
RHR pump	3700 gal/min per pump
Spray pump	3200 gal/min per pump

Total RWST outflow during injection mode operation is 15,600 gal/min.

Based on a minimum available RWST volume of 435,522 gal for injection mode operation, and the maximum total flowrate out of the RWST, the shortest injection mode operation time is approximately 28 min.

6.3.2.2.9.2 Transfer Allowance. During the injection mode of ECCS operation, the operator monitors the RWST level and containment emergency sump level in anticipation of switchover. Upon receipt of the RWST low-low level alarm, the operator is required to initiate the manual operations to complete switchover in a timely manner in preparation for the empty level alarm, after which ECCS switchover can be completed.

The switchover from injection to cold leg recirculation is initiated automatically upon receipt of the RWST low-low level trip signal and is completed via timely operator action at the main control board after receipt of the empty level alarm. Switchover is initiated via automatic opening of the containment emergency sump isolation valves (HV-8811 A and B). This automatic action aligns the suction of the RHR pumps to the containment emergency sump to ensure continued availability of a suction source. Manual actions of table 6.3.2-7 must be performed following switchover initiation prior to loss of the RWST transfer allowance to ensure that all pumps are protected with suction flow available from the containment emergency sump. The manual actions required to complete switchover are shown in table 6.3.2-7. The switchover procedure is structured so that the operator simultaneously switches both trains from injection to recirculation, repositioning functionally similar switches as part of the same procedural steps.

The time available for switchover is dependent on the flowrate out of the RWST as the switchover manual actions are performed. As valves are repositioned, the flowrate out of the RWST is reduced in magnitude. In order to analyze the shortest time available for switchover, the following conservative bases are established:

A. The RWST transfer allowance, for completing most of the manual actions for switchover, is approximately 135,000 gal (between low-low and empty levels). The RWST transfer allowance for the manual actions for both ECCS and containment spray (CS) switchover after reaching the empty level is approximately 48,000 gal.

B. Approximately 34,000 gal between the bottom of the RWST and the level at which ECCS and CS switchover occur is provided for vortex prevention and is not included in the above volumes.

C. Containment and RCS pressures for large break conditions are conservatively assumed to be 0 psig. Thus, no credit is taken for the reduction in RWST outflow that results with higher containment and RCS pressures following a large break.

   The same conservative assumption is made for the small break conditions (except that RCS pressure is assumed to be greater than RHR pump shutoff head resulting in no RHR pump flow to the RCS for small break conditions).

D. Pumped flowrates are assumed to be constant during switchover and include the following conservative flowrate allowances assuming two pumps of each type are operating:

SI pump	450 gal/min per pump
Charging pump	450 gal/min per pump
RHR pump	3700 gal/min per pump
Spray pump	3200 gal/min per pump

E. Flowrate out of the RWST for the worst ECCS single failure condition is determined assuming one of the RWST isolation valves (HV-8812 A or B) fails to close on demand. This single failure maximizes RWST outflow during switchover. Flowrates out of the RWST assume no operator corrective action to mitigate the single failure; i.e., stop the affected RHR pump and close the appropriate sump isolation valves.

6.3.2.2.10 Valves

Design features employed to minimize valve leakage include:

A. Where possible, packless valves are used.

B. Other valves which are normally open, except check valves and those which perform a control function, are provided with backseats to limit stem leakage.

C. Normally closed globe valves are installed with recirculation fluid pressure under the seat to prevent stem leakage of recirculated (radioactive) water.

D. Relief valves are enclosed; i.e., they are provided with a closed bonnet.

E. Live-load packing is used on some valves including valves equipped with valve stem leakoff connections to maintain a constant force on the gland follower as the packing ages and compresses.

6.3.2.2.11 Motor-Operated Valves

Design parameters for motor-operated valves used in the ECCS are given in table 6.3.2-1.

The seating design of all motor-operated valves is of the Crane flexible wedge design. This design releases the mechanical holding force during the first increment of travel so that the motor operator works only against the frictional component of the hydraulic unbalance on the disc and the packing box friction. The disc is guided throughout the full disc travel to prevent chattering and to provide ease of gate movement. The seating surfaces are hard faced to prevent galling and to reduce wear.

Where a gasket is employed for the body to bonnet joint, it is either a fully trapped, controlled compression, spiral wound gasket with provisions for seal welding or it is of the pressure seal design with provisions for seal welding. The valve stuffing boxes are designed with a reduced packing configuration and the deletion of the valve stem leakoff line, or lantern ring leakoff connection with a set of packing below and above the lantern ring.

6.3.2.2.12 Manual Globe, Gate, and Check Valves

Gate valves employ a wedge design and are straight through. The wedge is either split or solid. All gate valves have backseat and outside screw and yoke.

Globe valves, "T" and "Y" style, are full ported with outside screw and yoke construction.

Check valves are spring-loaded lift piston types for sizes 2 in. and smaller, swing type for sizes 2 1/2 in. to 4 in., and tilting disc type for sizes 4 in. and larger.

Stainless steel check valves have no penetration welds other than the inlet, outlet, and bonnet. The check hinge is serviced through the bonnet.

The stem packing and gasket of the stainless steel manual globe and gate valves are similar to those described above for motor-operated valves. Carbon steel manual valves are employed to pass nonradioactive fluids only and, therefore, do not contain the double packing and seal weld provisions.

6.3.2.2.13 Accumulator Check Valves (Swing-Disc)

The accumulator check valve is designed with a low-pressure drop configuration with all operating parts contained within the body.

Design considerations and analyses, which ensure that leakage across the check valves located in each accumulator injection line does not impair accumulator availability, are as follows:

A. During normal operation, the check valves are in the closed position with a nominal differential pressure across the disc of approximately 1650 psi. Since the valves remain in this position except for testing or when called upon to open following an accident and are, therefore, not subject to the abuse of flowing operation or impact loads caused by sudden flow reversal and seating, they do not experience significant wear of the moving parts and are expected to function with minimal backleakage. This backleakage can be checked via the test connection, as described in subsection 6.3.4.

B. When the RCS is being pressurized during the normal plant heatup operation, the check valves are tested for leakage at a test pressure of greater than 350 psig. This test confirms the seating of the disc and whether there has been an increase in the leakage since the last test.

C. The experience derived from the check valves employed in the emergency injection systems indicates that the system is reliable and workable. This is substantiated by the satisfactory experience obtained from operation of the Robert Emmett Ginna plant and subsequent plants where the usage of check valves is identical to VEGP.

D. The accumulators can accept some inleakage from the RCS without affecting availability. Continuous inleakage would require, however, that the accumulator water volume and boron concentration be adjusted periodically to meet Technical Specification requirements.

6.3.2.2.14 Relief Valves

Relief valves are installed in various sections of the ECCS to protect lines which have a lower design pressure than the RCS. The valve stem and spring adjustment assembly are isolated from the system fluids by a bellows seal between the valve disc and spindle. The closed bonnet provides an additional barrier for enclosure of the relief valves. Table 6.3.2-2 lists the ECCS relief valves with their capacities and setpoints.

ECCS piping has been reviewed to identify those lengths of piping which are isolated by normally closed valves and which do not have pressure relief protection in the piping section between the valves. These sections include:

1. Between valves 1205-U4-021 and 1205-U4-022 in the residual heat removal system cross-connection line to the chemical and volume control system. This piping is outside containment, is not an ECCS flowpath, and is not needed to achieve safety-grade cold shutdown.

2. Portions of ECCS test lines. This piping is inside containment, is not an ECCS accident mitigation flowpath, and is not needed to achieve safety-grade cold shutdown.

3. Containment spray system sump suction lines, between valves HV-9002A-9003A and HV-9002B-9003B. This piping is the recirculation flowpath outside of containment.

4. Between valves 1205-U6-027 and 1205-U4-226 on the RHR pump discharge to the RWST. This piping is outside the containment and is not in the ECCS flow path and is not required for safety-grade cold shutdown.

5. Piping vents, drains, test connections, etc., typically have two closed valves or one closed valve and a blind flange.

6. Check valve test lines have sections that are isolated by two normally closed valves.

The piping vents, drains, test corrections, and check valve lines have design pressure/temperature conditions compatible with the process piping to which they connect. Thus valve leakage will not function to overpressurize the isolated piping sections and pressure relief provisions are not required.

6.3.2.2.15 Butterfly Valves

Each main RHR line has an air-operated butterfly valve which is normally open and is designed to fail in the open position. The actuator is arranged such that air pressure on the diaphragm overcomes the spring force, causing the linkage to move the butterfly to the closed position. Upon loss of air pressure, the spring returns the butterfly to the open position. These valves are left in the full-open position during normal operation to maximize flow from this system to the RCS during the injection mode of the ECCS operation. These valves are used during normal RHR system operation to control cooldown flowrate.

Each RHR heat exchanger bypass line has an air-operated butterfly valve which is normally closed and is designed to fail closed. These valves are used during normal cooldown to control RCS cooldown rates.

Other air-operated valves in the ECCS along with their failure positions and position indications are provided in table 6.3.2-8.

6.3.2.2.16 Motor-Operated Valves Control

Remotely operated valves for the injection mode which are under manual control; i.e., valves which normally are in their ready position and do not receive an SI signal, have their positions indicated on a common portion of the control board. If a component is out of its proper position, its monitor light indicates this on the control panel. At any time during operation when one of these valves is not in the ready position for injection, this condition is shown visually on the board, and an audible alarm is sounded in the control room.

Spurious movement of a motor-operated valve due to an electrical fault in the motor actuation circuitry, coincident with a loss-of-coolant accident (LOCA), has been analyzed (WCAP-8966) and found to be an acceptably low probability event. In addition, power lockout in accordance with Branch Technical Position ICSB-18 is provided for those valves whose spurious movement could result in degraded ECCS performance. Power lockout is accomplished by providing a control power isolation switch for each of these valves on the main control board. Further details on power lockout are provided in paragraph 8.3.1.1.11. Table 6.3.2-3 provides a listing of the motor-operated isolation valves in the ECCS, showing interlocks, automatic features, and position indication.

Periodic visual inspection and operability testing of the motor-operated valves in the ECCS ensure that there is no potential for impairment of valve operability due to boric acid crystallization which could result from valve stem leakage.

In addition, the location of all motor-operated valves within the containment has been examined to identify any motor operators which may be submerged following a postulated LOCA. Based on a maximum post-LOCA flood level of el 181 ft 4 in., the only potentially submerged valves are the accumulator discharge valves, HV-8808 A, B, C, and D. These valves are positioned prior to startup and then have power removed from the motor operator. These valves are not required to change position after a LOCA. Therefore, the flooding of these motor operators and any resultant postulated failure does not present any problems for the short or long-term ECCS operations, containment isolation, or any other safety-related function.

6.3.2.2.17 Manual Valves

The 24-in. manually operated gate valve on the suction line from the RWST is the only manual valve which, if mispositioned, could totally interrupt ECCS flow. For this reason and in accordance with Regulatory Guide 1.47, the valve is locked open, administratively controlled, and provided with redundant system level input to the bypassed/inoperable status panel in the control room.

Manual valves are generally used as maintenance isolation valves or throttling valves. When used for these functions they are under administrative control, which requires them to be locked in the correct position. Manual valves used as maintenance isolation valves occur on the SI and RHR pump discharges. They are located so that no single valve can isolate both trains of ECCS equipment. Manual valves are also used as throttling valves in the injection branch paths of the high-head ECCS pumps.

To preclude the possibility of ECCS degradation due to valve mispositioning, branch line connections such as vent and drain lines, test connections, pressure points, flow element test points, flush connections, local sample points, and bypass lines are provided with double isolation or sealed barriers. The isolation is provided by one of the following methods: two valves in a series; a single valve with a screwed cap or blind flange; a single locked closed valve; or a blind flange. These valves are under administrative control.

6.3.2.2.18 Accumulator Motor-Operated Valve Control

As part of the plant shutdown procedures, the operator is required to close these valves. This prevents a loss of accumulator water inventory to the RCS and is done after the RCS has been depressurized below 1000 psig. The redundant pressure and level alarms on each accumulator function to alert the operator to close these valves, if any are inadvertently left open. Power is locked out after the valves are closed.

During plant startup, Technical Specifications require these valves be open with power removed in mode 3 when the RCS pressure exceeds 1000 psig. Monitor lights in conjunction with an audible alarm alert the operator should any of these valves be left inadvertently closed. The audible alarm is enabled once the RCS pressure increases beyond the SI unblock setpoint. Power is locked out after these valves are opened.

The accumulator isolation valves are not required to move for the accumulators to perform their safety function during power operation or in a post-accident situation. For a discussion of limiting conditions for operation and surveillance requirements of these valves, refer to the Technical Specifications.

The accumulator isolation valves receive an SI signal to ensure that they are open in the event of an accident occurring during inservice inspection testing.

For further discussion of the instrumentation associated with these valves, refer to subsections 6.3.5, 7.3.1, and 7.6.4.

6.3.2.3 Applicable Codes and Standards

Applicable codes and standards for the ECCS are discussed in section 3.2.

6.3.2.4 Material Specifications and Compatibility

Materials employed for engineered safety feature components are discussed in subsection 6.1.1. Materials for ECCS components are selected to meet the applicable material requirements of the codes in table 3.2.2-1 and the following additional requirements:

A. All parts of components in contact with borated water are fabricated of or clad with austenitic stainless steel or equivalent corrosion resistant material.

B. All parts of components in contact (internal) with containment emergency sump solution during recirculation are fabricated of austenitic stainless steel or equivalent corrosion resistant material.

C. Valve seating surfaces are hard faced with Stellite No. 6 or equivalent to prevent galling and to reduce wear.

D. Valve stem materials are selected for their corrosion resistance, high-tensile properties and their resistance to surface scoring by the packing.

Table 6.3.2-4 summarizes the materials employed for ECCS components.

6.3.2.5 System Reliability

Reliability of the ECCS is considered in all aspects of the system from initial design to periodic testing of the components during plant operation. The ECCS is a two-train, fully redundant, safety-related system. The system has been designed and proven by analysis to withstand any credible single active failure during injection or active or passive failure during recirculation and to satisfy the performance requirements. Two trains of pumps, heat exchangers, and flowpaths are provided for redundance, since only one train is required to satisfy the performance requirements. The initiating signals for the ECCS are derived from independent sources as measured from process; e.g., pressurizer low pressure or environmental (containment high pressure) variables. Redundant as well as functionally independent variables are measured to initiate ECCS operation. Each train is physically separated and protected where necessary so that a single event cannot initiate a common failure. Power sources for the ECCS are divided into two independent trains supplied from the emergency buses from offsite power. Sufficient diesel generating capacity is maintained onsite to provide required power to the emergency buses if offsite power is not available. The diesel generators and their auxiliary systems are completely independent and each supplies power to one of the two ECCS trains.

The preoperational testing program ensures that the systems as designed and constructed meet the functional requirements as calculated in design. The ECCS is designed with the ability for online testing of most components so the availability and operational status can be readily determined. In addition to the above, the integrity of the ECCS is ensured through examination of critical components during the routine inservice inspection.

The reliability program extends to the procurement of ECCS components such that only designs which have been proven by past use in similar applications are acceptable for use. The procurement quality assurance program is discussed in chapter 17.

The ECCS is a two-train, fully redundant, engineered safety feature. During the long-term cooling period following a LOCA, ECCS flowpaths may be separated into two subsystems or trains, either of which can provide minimum core cooling functions. Due to this concept, either of the two subsystems can be isolated and removed from service if maintenance is required on any ECCS component.

Each compartment is provided with radiation shielding such that access may be allowed to compartments for maintenance during the recirculation phase. To obtain access to a given compartment, limited pump(s) in that compartment would be stopped and the lines flushed with water from the RWST. Provisions for washing down the floors and walls are provided to reduce contamination in the event that a leak occurs in a compartment during the recirculation phase. Ventilation is provided to facilitate access for maintenance.

During the long-term period, the RCS is depressurized to containment ambient pressure following the LOCA. During this period, the heat generated in the reactor core is in the form of residual decay heat; consequently, the RHR pumps provide the required flow; i.e., from the containment sump through the residual heat exchangers and into the reactor core, to perform reactor core residual decay heat removal.

The piping and valves associated with the pumps are arranged so that the system can be drained and flushed prior to maintenance. To meet this requirement, manual valves are provided with extended reach rods so that they can be operated from a position external to the pump compartments.

Proper initial fill and venting of the ECCS ensures that water hammer does not occur in ECCS lines. In addition, the head of water provided by the RWST further ensures the lines remain full and water hammer concerns do not develop. High point vents in the ECCS lines are provided to ensure means for proper venting of lines and pumps. Fill and venting procedures for the ECCS ensure removal of air from the system to prevent the possibility of a water hammer if injection flow is initiated. The RWST location/configuration ensures that the Technical Specification limit for the RWST low water level is above the ECCS high point required to maintain water solid ECCS lines.

Further, the existence of high point vents and the positive head of water provides means by which the operator can confirm water solid ECCS lines.

6.3.2.5.1 Active Failure Criteria

An active failure is the failure of a powered component such as a piece of mechanical equipment, a component of the electrical supply system, or instrumentation and control equipment to act on command to perform its design function. Examples include the failure of a motor-operated valve to move to its correct position, the failure of an electrical breaker or relay to respond, the failure of a pump, fan, or diesel generator to start, etc.

The failure mode and effects analysis (FMEA), provided in table 6.3.2-5, demonstrates the ability of the ECCS to withstand any single active failure. The analysis illustrates that the ECCS can sustain an active failure in either the short or long term and still meet the required level of performance for core cooling.

Since the short-term operation of the active components of the ECCS following a steam line rupture or a steam generator tube rupture is similar to that following a LOCA, the same analysis is applicable and the ECCS can sustain the failure of any single active component and still meet the level of performance for the addition of shutdown reactivity.

Portions of the ECCS are also relied upon to provide boration and makeup during a safety grade cold shutdown. The capability of the ECCS to sustain an active failure and still perform in conjunction with other systems of the cold shutdown design is presented in subsection 5.4.7.

6.3.2.5.2 Passive Failure Criteria

A passive failure is the structural failure of a static component which limits the component's effectiveness in carrying out its design function. Examples include cracks in pipes, sprung flanges, valve packing leaks, or pump seal failures.

A single passive failure analysis is presented in table 6.3.2-6. It demonstrates that the ECCS can sustain a single passive failure during the long-term phase and still retain an intact flowpath to the core to supply sufficient flow to keep the core covered and to effect the removal of decay heat. The procedure followed to establish the alternate flowpath also isolates the component which failed.

The following philosophy provides for necessary redundancy in component and system arrangement to meet the intent of the general design criterion on single failure as it specifically applies to failure of passive components in the ECCS. Thus, for the long term, the system design is based on accepting either a passive or an active failure, assuming no failures in the short term.

A. Redundancy of Flowpaths and Components for Long-Term Emergency Core Cooling

   In design of the ECCS, the following criteria are utilized:

   1. During the long-term cooling period following an accident, the emergency core cooling flowpaths are separable into two subsystems, either of which can provide minimum core cooling functions and return spilled water from the floor of the containment back to the RCS.

   2. Either of the two subsystems can be isolated and removed from service in the event of a leak outside the containment.

   3. Adequate redundancy of check valves is provided to tolerate failure of a check valve during the long term as a passive component.

   4. Should one of these two subsystems be isolated in this long-term period, the other subsystem remains operable.

   5. Provisions are also made in the design to detect leakage from components outside the containment, collect this leakage, and provide for maintenance of the affected equipment.

   For the long-term emergency core cooling function, adequate core cooling capacity exists with one flowpath removed from service.

B. Subsequent Leakage from Components in Safeguards Systems

   With respect to piping and mechanical equipment outside the containment, considering the provisions for visual inspection and leak detection, leaks can be detected before they propagate to major proportions. A review of the equipment in the system indicates that the largest sudden leak potential would be the sudden failure of a pump shaft seal. Evaluation of the leakrate assuming only the presence of a seal retention ring around the pump shaft showed flows less than 50 gal/min would result. Piping leaks, valve packing leaks, or flange gasket leaks have been of a nature to build up slowly with time and are considered less severe than the pump seal failure.

Larger leaks in the ECCS are prevented by the following:

1. The piping is classified in accordance with American National Standards Institute (ANSI) Safety Class 2 and receives the American Society of Mechanical Engineers (ASME) Class 2 quality assurance program associated with this safety class.
2. The piping, equipment, and supports are designed to ANSI Safety Class 2, Seismic Category 1 requirements, permitting no loss of function for the safe shutdown earthquake.
3. The system piping is located within a controlled area on the plant site.
4. The piping system receives periodic pressure tests and is accessible for periodic visual inspection.
5. The piping is austenitic stainless steel which, due to its ductility, can withstand severe distortion without failure.

   The design of the auxiliary building and related equipment is based upon handling of leaks up to a maximum of 50 gal/min. Subsection 9.3.3 describes the design features provided to detect and isolate such leaks in the ECCS flowpath within 30 min.

6.3.2.5.3 Lag Times

Lag times for initiation and operation of the ECCS are limited by pump startup time and consequential loading sequence of these motors onto the safeguard buses. Most valves are normally in the position conducive to safety; therefore, valve operation time is not considered for these valves. If there is no loss of offsite power, all pump motors and valve motors are loaded immediately onto the safeguards buses according to the sequencer. The charging pumps and all valves are applied to the buses in 0.5 s, the SI pumps in 5.5 s, and the RHR pumps in 10.5 s. Safeguards pumps are capable of obtaining operating speed and rated flow within 4 s of receipt of the start signal. In the case of loss of offsite power, the diesel generator is designed for a 9.5-s delay to start and to obtain operating speed and voltage prior to the safeguards pumps and valves being sequenced onto the safeguards buses, which is less than the time assumed in the accident analysis. These lag times refer to the time after initiation of the SI signal.

6.3.2.5.4 Potential Boron Precipitation

Boron precipitation in the reactor vessel can be prevented by a backflush of ECCS water through the core to terminate boiloff and the resulting increase in boron concentration of the water remaining in the reactor vessel. This is accomplished by the switchover from cold leg to hot leg recirculation at about 7.5 h following an accident. In addition to preventing boron precipitation by backflushing the core, hot leg recirculation provides subcooled water to terminate boiloff.

Three flowpaths, each with sufficient capacity to prevent precipitation, are available for hot leg recirculation of containment emergency sump water. Each SI pump can discharge to two hot legs with suction taken from the RHR pump discharge, either directly or indirectly via the charging pump cross connect. Each SI pump flow path provides an independent train of hot leg recirculation flow. In addition, the RHR pump of each train can also be aligned to deliver flow directly to two hot legs via a common hot leg recirculation header, through train B valve HV-8840 to provide the third flow path. Normal operator response is to align both RHR pumps to the hot legs through HV-8840 and both SI pumps to the hot legs. Sufficient flow to prevent precipitation only requires one SI pump aligned to the hot legs.

Loss of one pump or one flowpath or one complete train (including train B) will not prevent hot leg recirculation since redundant methods are available for use.

6.3.2.5.5 Safety Grade Cold Shutdown Function

During a safety-grade cold shutdown, the ECCS is relied upon to provide one of the two redundant flowpaths for boration and makeup. The BIT high-head injection header (Unit 1) and the CVCS charging pump high head cold leg injection header (Unit 2) provide this function. The redundant flowpath is the normal charging header, which is part of the chemical and volume control system (CVCS). Two independent subsystems, each consisting of a charging pump and the associated valves and piping, are provided and are powered by redundant emergency buses in a manner that ensures that at least one subsystem is always operable. A solenoid valve provided in each subsystem and located in the CVCS ensures that the remote throttling capability necessary for RCS inventory control and shutdown is available. Provisions are also included in the ECCS design to ensure that the accumulators can be either isolated or vented so that RCS depressurization can be accomplished. Details of the cold shutdown design are discussed in subsection 5.4.7. A failure mode and effects analysis for safety-grade cold shutdown operations is provided in table 6.3.2-9.

6.3.2.6 Protection Provisions

The provisions taken to protect the system from damage that might result from dynamic effects are discussed in section 3.6. The provisions taken to protect the system from missiles are discussed in section 3.5. The provisions to protect the system from seismic damage are discussed in sections 3.7.N, 3.9.N, and 3.10.N. Thermal stresses on the RCS are discussed in section 5.2.

6.3.2.7 Provisions for Performance Testing

Test lines are provided for performance testing of the ECCS as well as individual components. These test lines and instrumentation are shown in drawings 1X4DB119, 2X4DB119, 1X4DB120 and 1X4DB121. All pumps have miniflow lines for use in testing operability. Additional information on testing can be found in paragraph 6.3.4.2.

6.3.2.8 Manual Actions

The ECCS is automatically actuated by those accidents identified in subsection 6.3.1. Following actuation, the ECCS continues to operate in the injection mode until its operation is terminated by the operator or until its operation is switched to the recirculation mode. During the injection mode no manual actions are required for proper operation of the ECCS. For the loss-of-secondary-coolant accident and the tube rupture accident, the operator should stabilize plant conditions and terminate ECCS operation after satisfying the criteria for ECCS termination. For the LOCA, the operator may not be able to terminate ECCS operation and may have to initiate manual actions to align the ECCS for the recirculation mode. The following discussion addresses the limited manual actions that are required of the operator to realign the system for the cold leg recirculation mode of operation and, after approximately 7.5 h, for the hot leg recirculation mode of operation. These actions are delineated in table 6.3.2-7. Operator action (both short term and long term) required for the various modes of ECCS operation to mitigate the consequences of a LOCA or steam line break, as well as other accident conditions, is presented in the emergency operating procedures. These procedures discuss the alarms/indications available to the operator to lead him to take the appropriate actions.

The switchover from the injection mode to recirculation mode is initiated automatically and completed manually by operator action from the main control room. Protection logic is provided to automatically open the two containment emergency sump isolation valves when two out of four RWST level channels indicate a low-low level in conjunction with an SI signal. This automatic action aligns the two RHR pumps to take suction from the containment emergency sump. The RHR pumps continue to operate during this automatic switchover from the injection mode to the recirculation mode.

The two charging pumps and the two SI pumps continue to take suction from the RWST until manual operator action is taken to align these pumps in series with the RHR pumps. Between the low-low and empty levels, this manual operator action is performed in order to align the two charging pumps and two SI pumps in series with the two RHR pumps. As part of the manual switchover procedure, the suctions of the SI and charging pumps are cross-connected so that one RHR pump can deliver flow to the RCS and the SI and charging pumps in the event of the failure of the second RHR pump.

The RWST level protection logic consists of four level channels with each level channel assigned to a separate process control protection set. Four RWST level transmitters provide level signals to corresponding normally deenergized level channel bistables. Each level channel bistable is energized on receipt of an RWST level signal less than the low-low level setpoint. A two-out-of-four coincident logic is utilized in both protection cabinets A and B to ensure a trip signal in the event that two of the four level channel bistables are energized. This trip signal, in conjunction with the SI signal, provides the actuation signal to automatically open the corresponding containment emergency sump isolation valves.

The RWST low-low level signal is also alarmed to inform the operator to initiate the manual action required to realign the RHR, charging, and SI pumps for the recirculation mode.

Following the completion of the automatic and manual switchover action (completed after receiving the empty level alarm), the two RHR pumps are aligned to take suction from the containment emergency sump. The switchover process would begin approximately 28 min after the initiation of ECCS operation at the earliest. The RWST is sized to allow the operator approximately 41 min after the initiation of ECCS injection before completing the ECCS and CSS switchover operation.

The switchover from the cold leg recirculation mode to the hot leg recirculation mode requires further manual actions. The charging pumps are not realigned and they continue to deliver to the RCS cold legs.

See section 7.5 for process information available to the operator in the control room following an accident.

Time delay following a low-low RWST signal, in which the operator's failure to act has no adverse effects, is greater than 8 min.

The consequences of the operator failing to act altogether are loss of the SI, charging, and containment spray pumps.

6.3.2.9 References

1. Westinghouse Letter GP-15580 to McCoy, C. K., dated April 3, 1992.
2. Deleted.

6.3.3 PERFORMANCE EVALUATION

The accidents identified in subsection 6.3.1 result in emergency core cooling system (ECCS) actuation and are mitigated within acceptance criteria by ECCS operation. For the purpose of evaluation in chapter 15, the accidents that result in ECCS actuation are categorized as follows:

A. Increase in Heat Removal by the Secondary System
   1. Inadvertent opening of a steam generator power- operated atmospheric steam relief or safety valve.
   2. Steam system piping failure.

B. Decrease in Heat Removal by the Secondary System
   1. Feedwater system piping failure.

C. Decrease in Reactor Coolant System (RCS) Inventory
   1. Steam generator tube rupture.
   2. Loss-of-coolant accident (LOCA) from a spectrum of postulated RCS piping failures.
   3. Loss of coolant due to a rod cluster control assembly ejection accident. This type of accident is enveloped by the RCS piping failures.

Each of these accidents results in generation of a safety injection (SI) signal and ECCS operation. The SI signal can be generated by any of the following:

- Pressurizer low pressure.
- Steam line low pressure.
- Containment high pressure.
- Manual actuation.

In addition to initiating ECCS operation, the SI signal initiates other safeguards automatic actions, including reactor trip, auxiliary feedwater system initiation, feedwater isolation, and containment isolation.

Upon receipt of an SI signal, the actions in paragraph 6.3.2.1.A are automatically initiated and the ECCS is aligned to operate in the injection mode. The charging pumps are aligned to deliver borated water from the refueling water storage tank to the RCS cold legs. The SI pumps, residual heat removal (RHR) pumps, and the accumulators are aligned to deliver to the RCS cold legs should RCS pressure drop below their respective pump shutoff heads or tank static pressure, respectively. The ECCS pumps and the accumulator flowrates vary depending on the type of accident and its characteristic pressure transient.

6.3.3.1 Increase in Heat Removal by the Secondary System

A number of events have been postulated which could result in an increase in heat removal from the RCS by the secondary system. Detailed analyses of these events are presented in section 15.1. For those events which result in ECCS actuation, the following summarizes ECCS performance:

A. Inadvertent Opening of a Steam Generator Relief or Safety Valve

   The most severe core conditions resulting from an accidental depressurization of the main steam system are associated with an inadvertent opening of a single steam dump, relief, or safety valve. Refer to subsection 15.1.4 for a detailed description of this accident, including acceptance criteria and analytical results.

   For this accident, the ECCS is actuated upon generation of an SI signal and the charging pumps function to inject the borated water solution from the RWST into the RCS cold legs. Although the borated water solution does not provide sufficient negative reactivity to maintain the reactor below criticality, the core is ultimately shut down by the solution and the departure from nucleate boiling (DNB) design basis is met. The charging pump flow also functions to increase RCS inventory and to repressurize the RCS. For this accident, the RCS does not depressurize sufficiently to permit the SI pumps, RHR pumps, or accumulators to deliver to the RCS. Subsequent to stabilizing plant conditions and satisfying ECCS termination criteria, the operator terminates ECCS operation and initiates plant shutdown operations.

B. Steam System Pipe Failure

   The most severe core conditions resulting from a steam system piping failure are associated with a double-ended rupture of a main steam line which occurs at zero power. Effects of smaller piping failures at higher power levels are bounded by the double-ended rupture at zero power. Refer to subsection 15.1.5 for a detailed description of this accident, including acceptance criteria and analytical results.

   For this accident, the ECCS functions as described in paragraph 6.3.3.1.A for the inadvertent opening of a steam generator relief or safety valve. However, this piping failure constitutes a more severe cooldown transient. The negative reactivity provided by operation of the charging pumps is not sufficient to prevent the reactor from returning to criticality during the transient. However, the core is ultimately shut down by the borated water solution, and the DNB design basis is met.

6.3.3.2 Decrease in Heat Removal by the Secondary System

A number of events have been postulated which could result in a decrease in heat removal from the RCS by the secondary system. Detailed analyses of these events are presented in section 15.2. For those events which result in ECCS actuation, the following summarizes ECCS performance:

A. Feedwater System Pipe Failure

The most severe core conditions resulting from a feedwater system piping failure are associated with a double-ended rupture of a feed line at full power. Depending on break size and power level, a feedwater system pipe failure could cause either an RCS cooldown transient or RCS heatup transient. Only the RCS heatup transient is evaluated as a feedwater system pipe failure, since the spectrum of cooldown transients is bounded by the steam system pipe failure analyses. The heatup transient effects of smaller piping failures at reduced power levels are bounded by the double-ended feed line rupture at full power. Refer to subsection 15.2.8 for a detailed description of this accident, including acceptance criteria and analytical results.

For this accident, the ECCS is actuated upon generation of an SI signal and the charging pumps inject the borated water solution from the RWST into the RCS cold legs. The charging pump flow functions to increase RCS inventory to ensure that sufficient inventory exists to keep the core covered with water. Since the accident is characterized by a heatup transient, the borated water solution from the RWST is not required and is not taken credit for in the analysis to control core reactivity. The RCS does not depressurize to permit the SI pumps, RHR pumps, or accumulators to deliver to the RCS. Subsequent to stabilizing plant conditions and satisfying ECCS termination criteria, the operator terminates ECCS operation and initiates plant shutdown operations.

6.3.3.3 Decrease in RCS Inventory

A number of events have been postulated which could result in a decrease in RCS inventory. Detailed analyses of these events are presented in section 15.6. For those events which result in ECCS actuation, the following summarize ECCS performance:

A. Steam Generator Tube Rupture

Although a steam generator tube rupture is an accident which results in a decrease in RCS inventory, severe core conditions are not associated with a steam generator tube rupture. The accident analyzed is a complete severance of a single steam generator tube that occurs at power with the reactor coolant contaminated with fission products, corresponding to continuous operation with a limited amount of defective fuel rods. Effects of smaller breaks are bounded by the complete severance. Refer to subsection 15.6.3 for a detailed description of this accident, including acceptance criteria and analytical results.

For this accident, the ECCS is actuated upon generation of an SI signal and the charging pumps inject the borated water solution from the RWST into the RCS cold legs. The charging pump flow functions to replace RCS inventory that is being lost through the ruptured steam generator tube, provide a heat sink which helps absorb decay heat, and repressurize the RCS. Subsequent to stabilizing plant conditions and satisfying ECCS termination criteria, the operator terminates ECCS operation and initiates plant shutdown operations.

B. Loss-of-Coolant Accident

A LOCA is defined as a rupture of the RCS piping or branch piping which results in a decrease in RCS inventory that exceeds the flow capability of the normal makeup system. Ruptures which result in break flow within the capability of the normal makeup system will not result in decreasing RCS pressure and ECCS actuation. The maximum break size for which the normal makeup system can maintain RCS pressure is obtained by comparing the calculated flow from the RCS through the postulated break against the charging system makeup flow capacity when aligned for maximum charging at normal RCS pressure. Makeup flow from two charging pumps is adequate to sustain pressurizer pressure at approximately 2210 psig for a break through a 0.375-in. diameter hole. This break results in a loss of approximately 17.5 lbm/s. For breaks less than a 0.375-in. diameter hole, the normal makeup system can maintain RCS pressure and permit the operator to execute an orderly shutdown.

For the purpose of evaluation, the spectrum of postulated piping breaks in the RCS is divided into major pipe breaks (large break) and minor pipe breaks (small breaks). The large break is defined as a rupture with a total cross-sectional area equal to or greater than 1 ft^2. The small break is defined as a rupture with a total cross-sectional area less than 1 ft^2 but larger than the maximum break size for which the normal makeup system can maintain RCS pressure as described above. Refer to subsection 15.6.5 for a detailed description of this accident, including acceptance criteria and analytical results.

For this accident, the ECCS is actuated upon receipt of an SI signal. Once actuated, the ECCS mitigates the spectrum of LOCA accidents, but its performance varies depending on the LOCA transient. The charging pumps function to immediately inject borated water from the refueling water storage tank. The SI pumps and RHR pumps function to start delivering borated water from the refueling water storage tank when the RCS depressurizes to approximately 1500 psia and 200 psia, respectively. The accumulators begin to inject when the RCS depressurizes to approximately 600 psia. During the LOCA transient, flow to the RCS is dependent on the RCS pressure transient. The ECCS water injected into the RCS provides for heat transfer from the core, prevents excessive core clad temperatures, and eventually accomplishes core reflood (large break) or core recovery (small break). The LOCA analyses do not take credit for the boron content of the injected water.

Following completion of core reflood (large break) or core recovery (small break), the ECCS continues to supply water to the RCS for long-term cooling. After the water level in the refueling water storage tank reaches the low-low level setpoint, switchover to cold leg recirculation is initiated automatically and completed by manual operator action as discussed in paragraph 6.3.2.8. This permits continued cooling of the core by recirculation of the spilled water in the containment emergency sumps. At approximately 7.5 h after initiation of the LOCA, the ECCS is manually realigned in the hot leg recirculation mode to control boric acid concentration in the reactor vessel.

Figure 6.3.2-1 provides process flow diagrams which illustrate ECCS performance for the various modes of system operation.

6.3.3.4 <u>Use of Dual Function Components</u>

The ECCS contains components which have no other operating function and components which are shared with other systems. Components in each category are as follows:

A. Components of the ECCS which perform no other function are:

1. One accumulator for each loop which discharges borated water into its respective cold leg of the reactor coolant loop piping.
2. Two SI pumps, which supply borated water for core cooling to the RCS.
3. Deleted.
4. One BIT (Unit 1 only).
5. Deleted.
6. Associated piping, valves, and instrumentation.

B. Components which also have a normal operating function are as follows:

1. Two RHR pumps and two residual heat exchangers which are normally used for decay heat removal during the latter stages of normal plant shutdown and when the reactor is held at cold shutdown for maintenance or refueling conditions. During all other plant operating modes, they are aligned to perform the low-head injection function.
2. Two charging pumps which are normally aligned for charging service with suction from the volume control tank. As a part of the chemical and volume control system, the normal operation of these pumps is discussed in subsection 9.3.4.
3. One refueling water storage tank which is used to fill the refueling canal for refueling operations and to provide makeup to the spent fuel pool. However, during all other plant operating periods it is aligned to the suction of the SI pumps. It is also aligned to the suction of the RHR pumps during plant thermal power operating periods. The charging pumps are automatically aligned to the suction of the refueling water storage tank upon receipt of an SI signal or a volume control tank low level signal.

An evaluation of all components required for operation of the ECCS demonstrates that either:

A. The component is not shared with other systems.

B. If the component is shared with other systems, it is either aligned or not aligned during normal plant operation to perform its accident mitigation function.

   If not aligned to perform its accident mitigation function, two valves in parallel are provided to align the system for injection, and two valves in series are provided to isolate portions of the system not utilized for injection. These valves are automatically actuated by the SI signal.

Table 6.3.3-1 provides a shared function evaluation that indicates the alignment of components during normal operation and the realignment required to perform the accident function.

In all cases of component operation, SI has the priority usage such that an SI signal will override all other signals and start or align systems for injection.

6.3.3.5 Limits on System Parameters

The analyses show that the design basis performance characteristic of the ECCS is adequate to meet the requirements for core cooling following an accident with the minimum engineered safety features equipment operating. In order to ensure this capability in the event of the simultaneous failure to operate any single active component, technical specifications are established for reactor operation.

Normal operating status of ECCS components is given in table 6.3.3-2.

The ECCS components are available whenever the coolant energy is high and the reactor is critical. During low-temperature physics tests there is a negligible amount of stored energy in the coolant and low decay heat; therefore, an accident comparable in severity to accidents occurring at operating conditions is not possible and ECCS components are not required. The possibility of a LOCA during startup and shutdown has been considered. It has been demonstrated by analysis that a LOCA at startup or shutdown is bounded by the LOCA analyses described in chapter 15, even though various ECCS components are intentionally disabled in the shutdown mode. Portions of the ECCS may be temporarily realigned for check valve leakage testing prior to startup in Mode 3 by closing either HV-8809A or HV-8809B. Conservative analyses have been performed for ECCS configurations more restrictive than those established during check valve testing. The conservative analyses assumed that the SI actuation on low pressurizer pressure was blocked and that flow was available from one RHR pump, one safety injection pump, and one charging pump (no accumulator injection). The results demonstrate that the minimum ECCS flow requirements during Mode 3 are met and that the Chapter 15 LOCA analyses remain limiting.

The principal system parameters and the number of components which may be out of operation in test, quantities and concentrations of coolant available, and allowable time in a degraded status are provided in the Technical Specifications. If efforts to restore the operable status of the ECCS are not accomplished within Technical Specification requirements, the plant is required to be placed in a lower operational mode; i.e., hot standby to hot shutdown, hot shutdown to cold shutdown, etc.

6.3.4 TESTS AND INSPECTIONS

6.3.4.1 Emergency Core Cooling System Performance Tests

Conformance with the recommendations of Regulatory Guide 1.79 is discussed in section 1.9.

6.3.4.1.1 Preoperational Test Program at Ambient Conditions

Preoperational testing of the emergency core cooling system (ECCS) can be conducted during the testing of the reactor coolant system (RCS) following flushing and hydrostatic testing, with the system cold and the reactor vessel head removed. Provision should be made for excess water to drain into the refueling canal. The ECCS must be aligned for normal power operation. The operation of the emergency diesels can be tested in conjunction with the ECCS. This test should provide information including the following facets:

- Satisfactory safety injection (SI) signal generation and transmission.
- Proper operation of the emergency diesel generators, including sequential load pickup.
- Valve operating times.

- Pump starting times.

- Pump delivery rates at runout conditions (one point on the operating curve).

6.3.4.1.2 Components

6.3.4.1.2.1 Pumps. Separate flow tests of the pumps in the ECCS are conducted during preoperational testing (with the reactor vessel head off) to check capability for sustained operation. The charging, SI, and residual heat removal (RHR) pumps discharge into the reactor vessel through the injection lines, with the overflow from the reactor vessel passing into the refueling canal. Each pump is tested separately with water drawn from the refueling water storage tank. Data are taken to determine pump head and flow at this time. Pumps are then run on miniflow circuits and data taken to determine a second point on the head-flow characteristic curve.

6.3.4.1.2.2 Accumulators. Each accumulator is filled with water from the refueling water storage tank and pressurized with the motor-operated valve on the discharge line closed. Then the valve is opened and the accumulator allowed to discharge into the reactor vessel as part of the operational startup testing with the reactor cold and the vessel head off.

6.3.4.2 Reliability Tests and Inspections

Routine periodic testing of the ECCS components and all necessary support systems at power is planned. Valves which operate after a loss-of-coolant accident are operated through a complete cycle; pumps are operated individually on either their miniflow lines, or on recirculation back to the RWST except the charging pumps which are tested by their normal charging function. If such testing indicates a need for corrective maintenance, the redundancy of equipment in these systems permits such maintenance to be performed without shutting down under certain conditions. These conditions include considerations such as the period within which the component should be restored to service and the capability of the remaining equipment to provide the minimum required level of performance during such a period.

The series check valves between the accumulator and the RCS are tested to verify that each of the series check valves can independently sustain differential pressure across its disc and also verify that the valve is in its closed position. The required periodic tests are performed after each refueling just prior to plant startup, after the RCS has been pressurized.

Where series pairs of check valves form the high-pressure to low-pressure isolation barrier between the RCS and ECCS piping outside the reactor containment, periodic testing of these check valves is performed to provide assurance that certain postulated failure modes will not result in a loss of coolant from the low-pressure system outside containment with a simultaneous loss of ECCS pumping capacity.

The ECCS test line subsystem provides the capability for determination of the integrity of the pressure boundary formed by series check valves. The tests performed verify that each of the series check valves can independently sustain differential pressure across its disc and also verify that the valve is in its closed position. The required periodic tests are performed after each refueling just prior to plant startup, after the RCS has been pressurized.

For some series check valve tests, the ECCS may be temporarily realigned for a brief period of time. Due to redundancy of ECCS equipment, the minimum ECCS flow delivery requirements continue to be met.

Lines in which the series check valves are to be tested are the SI pump cold and hot leg injection lines and the RHR pump cold and hot leg injection lines.

To implement the periodic component testing requirements, technical specifications have been established. During periodic system testing, a visual inspection of pump seals, valve packings, flanged connections, and relief valves is made to detect leakage. Inservice inspection provides further confirmation that no significant deterioration is occurring in the ECCS pressure boundary.

Design measures have been taken to ensure that the following testing can be performed:

A. Active components may be tested periodically for operability (e.g., pumps on miniflow, certain valves, etc.).

B. An integrated system actuation test can be performed when the plant is cooled down and the RHR system is in operation. The ECCS is arranged so that no flow is introduced into the RCS for this test. Detailed discussion of SI signal testing provisions is provided in section 7.2.

C. An initial flow test of the full operational sequence can be performed.

The design features which ensure this test capability are specifically:

A. Power sources are provided to permit individual actuation of each active component of the ECCS.

B. The SI pumps can be tested periodically during plant operation using the miniflow recirculation lines provided.

C. The RHR pumps are used every time the RHR system is put into operation. They can also be tested periodically when the plant is at power using either the miniflow recirculation lines, or recirculation line back to the RWST.

D. The centrifugal charging pumps are either normally in use for charging service or can be tested periodically on miniflow.

E. Remotely operated valves can be exercised during routine plant maintenance.

F. Level and pressure instrumentation is provided for each accumulator tank for continuous monitoring of these parameters during plant operation.

G. Flow from each accumulator tank can be directed through a test line to verify isolation valve position. The test line can be used, when the RCS is pressurized, to ascertain backleakage through the accumulator check valves.

H. A flow indicator is provided in the charging pump, SI pump, and RHR pump headers. Pressure instrumentation is also provided in these lines.

I. An integrated system test can be performed when the plant is cooled down and the RHR system is in operation. This test does not introduce flow into the RCS but does demonstrate the operation of the valves, pump circuit breakers, and automatic circuitry, including diesel starting and the automatic loading of ECCS components on the diesels (by simultaneously simulating a loss of offsite power to the vital electrical buses).

The Technical Specifications specify requirements for test frequency, acceptability of testing, and measured parameters. The ECCS components and systems are designed to meet the intent of the American Society of Mechanical Engineers Code, Section XI, for inservice inspection.

6.3.5 INSTRUMENTATION REQUIREMENTS

Instrumentation and associated analog and logic channels employed for initiation of emergency core cooling system (ECCS) operation is discussed in section 7.3. This section describes the instrumentation employed for monitoring ECCS components during normal plant operation and also ECCS post-accident operation. All alarms are annunciated in the control room.

6.3.5.1 Deleted

6.3.5.1.1 Deleted

6.3.5.1.2 Residual Heat Exchanger Temperature

The fluid temperature at both the inlet and the outlet of each residual heat exchanger is recorded on the integrated plant computer. There is also a locally mounted temperature indicator at the outlet of each residual heat exchanger.

6.3.5.1.3 Deleted

6.3.5.2 Pressure Indication

6.3.5.2.1 Deleted

6.3.5.2.2 Charging Pump Suction and Discharge Pressure

There is local pressure indication at the suction and discharge of each charging pump.

6.3.5.2.3 Safety Injection Pump Suction Pressure

There is a locally mounted pressure indicator at the suction of each safety injection pump.

6.3.5.2.4 Safety Injection Pump Discharge Pressure

Safety injection pump discharge pressure for each pump is indicated in the control room.

6.3.5.2.5 Accumulator Pressure

Duplicate pressure channels are installed on each accumulator. Pressure indication in the control room and high- and low-pressure alarms are provided by each channel.

6.3.5.2.6 Test Line Pressure

A local pressure indicator, used to check for proper seating of the accumulator check valves between the injection lines and the reactor coolant system, is installed on the leakage test line.

6.3.5.2.7 Residual Heat Removal Pump Suction Pressure

Local pressure indication is provided at the inlet to each residual heat removal pump.

6.3.5.2.8 Residual Heat Removal Pump Discharge Pressure

Residual heat removal discharge pressure for each pump is indicated in the control room. A high-pressure alarm is actuated by each channel.

6.3.5.3 Flow Indication

6.3.5.3.1 Deleted

6.3.5.3.2 Charging Pump Injection Flow

Charging pump injection header flow to the reactor cold legs is indicated in the control room.

6.3.5.3.3 Safety Injection Pump Header Flow

Safety injection pump flow for each pump is indicated in the control room.

6.3.5.3.4 Safety Injection Pump Minimum Flow

A local flow indicator is installed in the safety injection pump minimum flow line.

6.3.5.3.5 Test Line Flow

A local flow indicator is provided in the accumulator test line.

6.3.5.3.6 Residual Heat Removal Pump Flow

The flow from each residual heat removal pump is indicated in the control room. These instruments also control the residual heat removal bypass valves, maintaining constant return flow to the reactor coolant system during normal cooldown.

6.3.5.3.7 Residual Heat Removal Pump Minimum Flow

A flowmeter installed in the discharge of each residual heat removal pump provides control for the valve located in the pump miniflow line.

6.3.5.4 <u>Level Indication</u>

6.3.5.4.1 Refueling Water Storage Tank Level

Four level indicator channels, which indicate in the control room, are provided for the refueling water storage tank. Each channel is provided with a high, low, low-low, and empty level alarm. The high level alarm is provided to protect against possible overflow of the refueling water storage tank. The low level alarm is provided to ensure that a sufficient volume of water is always available in the refueling water storage tank in conformance with the Technical Specifications. The refueling water storage tank low level signal isolates the sludge mixing system, which also is used to maintain temperature from the tank at a 50°F minimum. The low-low level alarm alerts the operator to begin performing manual actions to prepare for switchover to the recirculation mode. At the low-low level the RHR containment emergency sump isolation valves are automatically opened. Between the low-low and empty levels, manual action is taken to align the two charging pumps and the two SI pumps to take suction from the discharge of the two RHR pumps. The empty level alarm alerts the operator to complete manual actions to realign the RHR pumps and containment spray pumps from the injection mode to the recirculation mode. (Upon receipt of the empty alarm, the RWST contents are nearly exhausted; the remaining volume is only sufficient to complete manual switchover of the RHR pumps and containment spray pumps.) Each channel also provides level indication in the main control room.

Refer to subsection 6.3.2 and figure 6.3.2-5 for additional information on RWST sizing and alarm setpoints for ECCS and containment spray pump suction switchover from injection mode to recirculation mode.

6.3.5.4.2 Accumulator Level

Duplicate level channels are provided for each accumulator. Both channels provide indication in the control room and actuate high- and low-level alarms.

6.3.5.4.3 Deleted

6.3.5.5 Operating Status Indication

6.3.5.5.1 Pumps

The operating status of ECCS pumps is indicated on the control board by red (running) and green (stopped) lights that are integral with the pump switch assembly for each pump. Pump operating status is also indicated by monitor lights which are grouped in a common portion of the control board. The operating status of each ECCS pump is indicated by its monitor light which is dark (stopped) or bright (running) depending on pump operating status.

6.3.5.5.2 Valves

The position of ECCS valves is indicated on the control board by red (open) and green (closed) lights that are integral with the valve switch assembly for each valve. Valve position is also indicated by monitor lights which are grouped in a common portion of the control board. The position of each valve is indicated by its monitor light. For the centrifugal charging pump alternate miniflow valves (HV-8508A and HV-8508B), the monitor panel lights indicate that the valves are in the enabled mode; therefore, valve position is indicated only at the handswitches. The position indication lights for motor-operated valves are controlled by motor operator limit switches. For air-operated valves, these lights are controlled by stem-mounted limit switches.

The accumulator motor-operated valves have additional position indication. For each valve, an alarm annunciator point is activated by both a motor operator limit switch and by a stem-mounted limit switch whenever an accumulator valve is not fully open for any reason with the system at pressure. (The pressure at which the safety injection block is unblocked is approximately 1900 psig.) A separate annunciator point is used for each accumulator valve. The alarm activated by the stem-mounted limit switch will be recycled at approximately 1-h intervals to remind the operator of the improper valve lineup, until corrective action is taken.

TABLE 6.3.2-1 (SHEET 1 OF 3)

EMERGENCY CORE COOLING SYSTEM
COMPONENT PARAMETERS

Accumulators	
Number	4
Design pressure (psig)	700
Design temperature (°F)	300
Operating temperature (°F)	60-120
Normal operating pressure (psig)	650
Total volume (ft^3)	1350 each
Nominal water volume (ft^3)	900 each
Nominal volume N gas (ft^3)	400 each
Boron concentration, nominal (ppm)	1900-2600
Centrifugal charging pumps (See figure 6.3.2-3.)	
Number	2
Design pressure (psig)	2800
Design temperature (°F)	300
Design flow (gal/min)	150
Design head (ft)	5800
Maximum flow (gal/min)	555
Design head at maximum flow (ft)	1400
Design head at shutoff (ft)	6200
Motor rating (hp)	600
Required NPSH at maximum flow (ft)	(See figure 6.3.2-3.)
Available NPSH at maximum flow (ft) from RWST	78
Discharge orifice (1FO-10118 & 1FO-10122)	(See drawing 1X6AH02-300000 for sizing)
Discharge orifice (2FO-10122 & 2FO-10123)	(See drawing 2X6AH02-30000 for sizing)
SI pumps (See figure 6.3.2-4.)	
Number	2
Design pressure (psig)	1750
Design temperature (°F)	300
Design flow (gal/min)	425
Design head (ft)	2680
Maximum flow (gal/min)	660
Design head at maximum flow (ft)	1660
Design head at shutoff (ft)	3545
Motor rating (hp)	450
Required NPSH at maximum flow (ft)	(See figure 6.3.2-4.)

TABLE 6.3.2-1 (SHEET 2 OF 3)

Available NPSH at maximum flow (ft) from RWST	59
RHR pumps (See figure 6.3.2-2.)	
Number	2
Design pressure (psig)	600
Design temperature (°F)	400
Design flow (gal/min)	3000
Design head (ft)	375
Maximum flow (gal/min)	4500
Design head at maximum flow (ft)	325
Design head at shutoff (ft)	450
Motor rating (hp)	400
Required NPSH at maximum flow (ft)	(See figure 6.3.2-2.)
Available NPSH at maximum flow (ft)	
From RWST	91
From emergency sumps	Variable (see Appendix 6A)
Residual heat exchangers	
(See subsection 5.4.7 for design parameters.)	
Boron injection tank (Unit 1 only)	
Number	1
Total volume (gal)	900
Usable volume at operating conditions, solution (gal)	900
Boron concentration, nominal (ppm)	0-2600
Design pressure (psig)	2735
Operating pressure (psig)	2684
Design temperature	300
Operating temperature	Ambient
Heaters	Determinated

TABLE 6.3.2-1 (SHEET 3 OF 3)

Motor-operated valves stroke times are provided in table 6.3.2-3.

Refueling water storage tank

Number	1
Total volume, nominal (gal)	715,000
Boron concentration (ppm)	2400-2600
Operating pressure	Atmospheric
Operating temperature	Ambient, 50°F minimum
Heating system	
Number of heaters	1
Heater capacity (kw)	50
Number of pumps	1
Pump capacity (gal/min)	200
Number of eductors	9

TABLE 6.3.2-2

EMERGENCY CORE COOLING SYSTEM RELIEF VALVE DATA

Description	Fluid Discharged	Fluid Inlet Temperature Normal (°F)	Set Pressure (psig)	Backpressure Constant (psig)	Maximum Total Backpressure (psig)	Capacity
N_2 supply to accumulators	Nitrogen	120	700	0	0	1500 sf /min
SI pump discharge	Dilute H_3BO_3	120	1750	0 to 15	50	20 gal/min
RHR pump SI line	Dilute H_3BO_3	120	600	0 to 15	50	20 gal/min
SI pumps suction header	Dilute H_3BO_3	100	220	0 to 15	50	25 gal/min
Accumulator to containment	Nitrogen	120	700	0	0	1500 sf /min

TABLE 6.3.2-3 (SHEET 1 OF 3)

MOTOR-OPERATED ISOLATION VALVES IN THE EMERGENCY CORE COOLING SYSTEM

Location	Valve Identification	Interlocks	Automatic Features[a]	Position Indication[b]	Alarms
Accumulator isolation valves	HV-8808 A,B,C,D	SI signal, RCS pressure> unblock.	Opens on SI signal if closed and RCS pressure > unblock.	MCB	Yes-out of position
SI pump suction from RWST	HV-8806, HV-8923 A,B	None	None [c]	MCB	Yes-out of position
RHR suction from RWST	HV-8812 A,B	Cannot be opened unless corresponding sump valve closed and RHR discharge to SI or charging pumps closed.	None[c]	MCB	Yes-out of position
RHR discharge to SI/charging pump suction	HV-8804 A,B	Cannot be opened unless SI pump miniflow isolated, charging pump alternate miniflow isolated, RHR suction from RCS isolated, and corresponding sump valve open.	None[c]	MCB	Yes-out of position
SI hot leg injection	HV-8802 A,B[d]	None	None	MCB	Yes-out of position
RHR hot leg injection	HV-8840[d]	None	None	MCB	Yes-out of position
Containment emergency sump isolation valve	HV-8811 A,B[d]	Cannot be opened in normal operation unless RHR suction valves from RWST and RCS closed.	Opens on RWST low-low with SI signal.	MCB	Yes-out of position
CVCS suction from RWST	LV-112 D,E	SI signal	Opens on SI signal or VCT low-low level 15 s[c][e]	MCB	None
CVCS normal suction	LV-112 B,C	SI signal	Closes on SI signal or VCT low-low level if CVCS suction valves from RWST open 10 s[e]	MCB	Yes-out of position
SI pump to cold leg	HV-8835	None	None	MCB	Yes-out of position

TABLE 6.3.2-3 (SHEET 2 OF 3)

Location	Valve Identification	Interlocks	Automatic Features[a]	Position Indication[b]	Alarms
CVCS pump discharge	HV-8105, HV-8106, HV-8116	SI signal	Closes on SI signal. 10 s[f] for HV-8116 17 s[i] for HV-8105, HV-8106	MCB	None
BIT suction (Unit 1 only)	HV-8803 A,B	None	None[g]	None	None
BIT discharge (Unit 1) and CVCS charging pump high head cold leg	HV-8801 A,B	SI signal	Opens on SI signal.	MCB[b]	Yes-out of position
Charging pump/SI pump crossover crossover	HV-8807 A,B, HV-8924	None	None[c]	MCB	Yes-out of position
RHR to RCS cold legs	HV-8809 A,B	None	None	MCB	Yes-out of position
SI pump miniflow	HV-8813, HV-8814, HV-8920	Cannot be opened unless RHR discharge to SI and charging pumps closed.	None[c]	MCB	Yes-out of position
RHR cross-connect	HV-8716 A,B[h]	None	None[c]	MCB	Yes-out of position
SI pump cross-connect	HV-8821 A,B	None	None	MCB	Yes-out of position
Charging pump normal miniflow	HV-8110, HV-8111 A,B	SI signal	Closes on SI signal. 15 s	MCB	Yes-out of position
Charging pump suction	HV-8471 A,B	None	None	MCB	Yes-out of position
Charging pump discharge	HV-8485 A,B, HV-8438	None	None	MCB	Yes-out of position

TABLE 6.3.2-3 (SHEET 3 OF 3)

Location	Valve Identification	Interlocks	Automatic Features[a]	Position Indication[b]	Alarms
Charging pump alternate miniflow	HV-8508 A,B	Cannot be opened by operator unless volume control tank discharge valves closed and RHR discharge to SI and charging pumps closed.	Enabled on SI signal and will open or close based on centrifugal charging pump discharge pressure.	MCB	Yes-incorrect mode
	HV-8509 A,B	Cannot be opened unless RHR discharge to SI and charging pumps closed.	None[c]	MCB	Yes-out of position
RHR pump miniflow	FV-610, 611	None	Open if pump discharge flow is less than 824 gpm at 350°F, 780 gpm at 100°F and close when the flow exceeds 1944 gpm at 350°F, 1841 gpm at 100°F (10 s).	MCB	None

a. Times are maximum motor-operated valve stroke times that are significant to safety analysis/evaluations. No time is indicated where stroke time was irrelevant to safety analyses/evaluations.
b. MCB - main control board.
c. Vogtle FSAR table 6.3.2-7 provides the switchover sequence from the post-accident cold leg injection mode to the cold leg recirculation mode of operation. The times provided in FSAR table 6.3.2-7, in conjunction with the RWST outflow, are used to verify that there is sufficient volume between the RWST low-low alarm and an RWST level of 2.515 ft (seen in figure 6.3.2-5) to complete the switchover sequence. Changes to valve stroke time should be evaluated for impact on available RWST volume.
d. Valve disk is provided with bonnet vent on containment side of disk.
e. Valves LCV-112D, E open automatically on an SI signal. Valves LCV-112B, C begin to close when LCV-112D, E reach full open. The safety analyses assume that the SI flow path is unavailable until both sets of valves reach their final positions.
f. The analysis assumes ECCS flow at 25 s. The operating time for the closure of the normal discharge valves and opening the injection valves should not be significantly different; therefore, the nominal value of 10 s was specified for these valves.
g. Valve is normally locked open, with power removed at component. Valve is operated manually for maintenance only.
h. Valve disk is provided with bonnet vent to RHR pump side.
i. The analysis assumes ECCS flow at 25 s. The limiting operation is the alignment of the charging pump suction to the RWST from the VCT. The normal discharge valves and the injection valves can have stroke times up to 25 s before affecting the time it takes to establish safety injection. These valves should have similar stroke times to reduced charging pump runout. Closure of the normal discharge valves is 17 s and the injection valves is 17 s, and the opening time of the injection valves is 17 s.

TABLE 6.3.2-4 (SHEET 1 OF 2)

MATERIALS EMPLOYED FOR
EMERGENCY CORE COOLING SYSTEM COMPONENTS

Component	Material
Accumulators	Carbon steel clad with austenitic stainless steel
Boron injection tank (Unit 1 only)	Austenitic stainless steel
Boron injection surge tank[(a)] (Unit 1 only)	Austenitic stainless steel
Pumps	
Centrifugal charging	Austenitic stainless steel
Safety injection	Austenitic stainless steel
Residual heat removal	Austenitic stainless steel
Residual heat exchangers	
Shell	Carbon steel
Shell end cap	Carbon steel
Tubes	Austenitic stainless steel
Channel	Austenitic stainless steel
Channel cover	Austenitic stainless steel
Tube sheet	Austenitic stainless steel
Valves	
Motor-operated valves containing radioactive fluids	
Pressure containing parts	Austenitic stainless steel or equivalent corrosion resistant material
Body-to-bonnet bolting and nuts	Low alloy steel
Seating surfaces	Stellite No. 6 or equivalent corrosion resistant material
Stems	Austenitic stainless steel or 17-4 pH stainless

TABLE 6.3.2-4 (SHEET 2 OF 2)

Component	Material
Motor-operated valves, containing nonradioactive, boron-free fluids	
Body, bonnet, and flange	Carbon steel
Stems	Corrosion resistance steel
Diaphragm valves	Austenitic stainless steel
Accumulator check valves	
Parts contacting borated water	Austenitic stainless steel
Clapper arm shaft	17-4 pH stainless
Relief valves	
Stainless steel bodies	Stainless steel
Carbon steel bodies	Carbon steel
All nozzles, discs, spindles, and guides	Austenitic stainless steel
Bonnets for stainless steel valves without balancing bellows	Stainless steel or plated carbon steel
All other bonnets	Carbon steel
Piping	
All piping in contact with borated water	Austenitic stainless steel

a. The Unit 1 boron injection tank recirculation system is physically isolated from the ECCS flowpath.

TABLE 6.3.2-5 (SHEET 1 OF 9)

EMERGENCY CORE COOLING SYSTEM - SAFEGUARDS OPERATIONS - FAILURE MODES AND EFFECTS ANALYSIS

Component[a]	Failure Mode	Function	Effect on System Operation	Failure Detection Method[b]	Remarks
1. Motor-operated gate valve LV-112B (LV-112C analogous)	Fails to close on demand.	Provides isolation of fluid discharge from the volume control tank (VCT) to the suction of charging pumps.	Failure reduces redundancy of providing tank discharge isolation. Negligible effect on system operation. Alternate isolation valve LV-112C (LV-112B) provides backup tank discharge isolation.	Valve open/close position indication and valve close position monitor light and alarm for group monitoring of components at main control board (MCB).	Valve is electrically interlocked with isolation valve LV-112D (LV-112E) and the instrumentation that monitors fluid level of the VCT. Valve closes upon receipt of an SI signal or upon receipt of a VCT low water level signal providing that isolation valve LV-112D (LV-112E) is at full open position.
2. Motor-operated gate valve LV-112D (LV-112E analogous)	Fails to open on demand.	Provides isolation of fluid discharge from the RWST to the suction of charging pumps and an electrical interlock to the closing of isolation valve LV-112B (LV-112C).	Failure reduces redundancy of providing fluid flow from RWST to suction of charging pumps. Negligible effect on system operation. Alternate isolation valve LV-112E (LV-112D) opens to provide backup flowpath.	Valve open/close position indication and valve open position monitor light at MCB.	Valve is electrically interlocked with the instrumentation that monitors fluid level of the VCT. Valve opens upon receipt of an SI signal or upon receipt of a VCT low water level signal.
	Fails to close on demand.		Failure reduces redundancy of providing isolation of fluid discharged from residual heat exchanger 1 to RWST. No immediate effect on system operation during recirculation. Alternate isolation check valve 1208-U4-189 in common line from RWST provides backup tank isolation.		

TABLE 6.3.2-5 (SHEET 2 of 9)

Component	Failure Mode	Function	Effect on System Operation	Failure Detection Method[b]	Remarks
3. Centrifugal charging pump train A (pump train B analogous)	Fails to deliver working fluid.	Provides fluid flow of emergency coolant through the BIT for Unit 1 and the CVCS charging pump high head cold leg injection for Unit 2 to the RCS at the prevailing incident RCS pressure.	Failure reduces redundancy of providing emergency coolant to the RCS at high RCS pressures. Fluid flow from charging train A (train B) will be lost. Minimum flow requirements for high-head SI will be met by charging train B (train A).	Charging pump discharge header pressure and flow indication at MCB. Open/close pump switchgear circuit breaker indication on MCB. Circuit breaker close position monitor light for group monitoring of component at MCB. Common breaker trip alarm at MCB.	One pump may be used for normal charging of RCS during plant operation. Both pumps start upon receipt of an SI signal.
4. Motor-operated globe valve HV-8110	Fails to close on demand.	Provides isolation of fluid flow from the charging pump discharge header to the seal water heat exchanger via minimum flow bypass line.	Failure reduces redundancy of providing isolation of charging pump miniflow line. Negligible effect on system operation. Alternate isolation valves HV-8111A and HV-8111B in individual charging pump minimum flow bypass lines provide backup miniflow line isolation.	Same as item 1.	Valve closes upon receipt of an SI signal.
5. Motor-operated globe valve HV-8111A (HV-8111B analogous)	Fails to close on demand.	Provides isolation of fluid flow from charging train A (train B) to the seal water heat exchanger flow via minimum bypass line.	Failure reduces redundancy of providing isolation of charging pump miniflow line. Negligible effect on system operation. Alternate isolation valve 8110 provides backup miniflow line isolation.	Same as item 1.	Valve closes upon receipt of an SI signal.
6. Motor-operated gate valve HV-8105 (HV-8106 analogous)	Fails to close on demand.	Provides isolation of fluid flow from the charging pump discharge header to the chemical and volume control system (CVCS) normal charging line to the RCS.	Failure reduces redundancy of providing isolation of charging pump discharge to normal charging line. Negligible effect on system operation. Alternate isolation valve HV-8106 (HV-8105) provides backup normal charging line isolation.	Same as item 1 except no valve close monitor alarm for group monitoring.	Same as item 4.

TABLE 6.3.2-5 SHEET 3 of 9)

Component	Failure Mode	Function	Effect on System Operation	Failure Detection Method[b]	Remarks
7. Motor-operated gate valve HV-8801A (HV-8801B analogous)	Fails to open on demand.	Provides isolation of fluid discharge from the BIT for Unit 1 and the CVCS charging pumps for Unit 2 to high head injection header connected to the cold legs.	Failure reduces redundancy of providing fluid flow from BIT for Unit 1 and CVCS charging pumps for Unit 2 to high head injection header feeding the cold legs. Negligible effect on system operation. Alternate isolation valve HV-8801B (HV-8801A) opens to provide backup flowpath to header.	Valve open/close position indication and valve open position monitor light and alarm for group monitoring of components at MCB.	Valve opens upon receipt of an SI signal.
8. Motor-operated gate valve FV-610 (FV-611 analogous)	Fails open.	Provides regulation of fluid flow through miniflow bypass line to suction of train A (train B) to protect against overheating of the pump and loss of discharge flow from the pump.	Failure reduces working fluid delivered to RCS from RHR train A (train B). Minimum flow requirements will be met by RHR train B (train A) and SI and charging pumps.	Same as item 1.	Valves are regulated by signals from flow transmitter located in each pump discharge header. The control valves open when a RHR pump discharge flow is less than approximately 824 gpm at 350°F, 780 gpm at100°F and close when the flow exceeds approximately 1944 gpm at 350°F, 1841 gpm at 100°F.
	Fails closed.		Failure results in an insufficient fluid flow through RHR train A (train B) pump for a small LOCA or steam break resulting in possible pump damage. Minimum flow requirements will be met by RHR train B (train A) and SI and charging pumps delivering coolant fluid to RCS.		
9. RHR pump train A (train B pump analogous)	Fails to deliver working fluid.	Provides fluid flow of emergency coolant to the RCS when the incident RCS loop pressure drops below shutoff head of pump and provides long term recirculation capability for core cooling following the injection phase of LOCA.	Failure reduces redundancy of providing emergency coolant to the RCS at low RCS pressure. Fluid flow from RHR pump train A (train B) will be lost. Minimum flow requirement will be met by RHR pump train B (train A).	Same as that stated for item 3 except RHR pump discharge pressure and flow indication at MCB.	The RHR pumps are used to deliver reactor coolant through the residual heat exchanger to meet the plant cooldown requirements and are used during cooldown and startup operation. The RHR pumps start upon receipt of an SI signal.

TABLE 6.3.2-5 (SHEET 4 of 9)

Component	Failure Mode	Function	Effect on System Operation	Failure Detection Method[b]	Remarks
10. Motor-operated gate valve HV-8811A (HV-8811B analogous)	Fails to open on demand.	Provides isolation of fluid discharge from containment emergency sump to suction line of RHR train A (train B).	Failure reduces redundancy of providing fluid flow from the containment emergency sump to the RCS. RHR train A (train B) not available for recirculation. Minimum flow requirements will be met by RHR train B (train A) through opening of isolation valve HV-8811B (HV-8811A). Negligible effect on system operation.	Same as item 7.	Valves open automatically on receipt of a 2/4 RWST lolo level signal in coincidence with SI signal being present (i.e., latched in.) Valve is electrically interlocked from being remotely opened from MCB.
11. Motor-operated gate valve HV-8812A (HV-8812B analogous)	Fails to close on demand.	Provides isolation of fluid discharge from the RWST to suction line of RHR train A (train B).	Failure reduces redundancy of providing RWST isolation from suction line of RHR train A (train B). Negligible effect on system operation. A series check valve 1205-U4-001(1205-U4-002) provides backup isolation against fluid flow from the suction of RHR train A (train B) to the RWST.	Same as item 1.	
12. Motor-operated gate valve HV-8716A (HV-8716B analogous)	Fails to close on demand.	Controls the RHR system resistance to prevent RHR pump runout by blocking or opening flowpaths Provides separation between two independent flowpaths outside containment during cold leg recirculation. Directs LHSI flow to hot legs during hot leg recirculation.	Failure reduces redundancy to prevent excessive RHR pump runout during cold leg recirculation. No effect on system operation. Isolation valve HV-8716B (HV-8716A) provides backup isolation to limit RHR pump runout flow.	Same as item 1.	During the first 11 h of long-term core cooling phase incident recovery RHR, SI, and charging pumps are aligned for injection into cold legs of RCS coolant loops. After 11 h, RHR and SI pumps are aligned by operator for recirculation flow into the hot legs.
	Fails to open on demand.		Failure reduces redundancy of providing fluid flow from RHR pumps for injection into hot legs of RCS loops. Minimum flow requirements will be met by opening of isolation valve HV-8716B (HV-8716A) and flow from RHR train B (train A).		Hot leg RCS coolant loop recirculation from at least SI pump required to prevent boron precipitation during longterm core cooling.

TABLE 6.3.2-5 (SHEET 5 of 9)

Component	Failure Mode	Function	Effect on System Operation	Failure Detection Method[b]	Remarks
13. Motor-operated gate valve HV-8809A (HV-8809B analogous)	Fails to close on demand.	Provides isolation of fluid flow from RHR train A (train B) to cold leg injection header of RCS coolant loops.	Failure reduces flow of recirculation coolant to hot legs of RCS coolant loops from RHR train A (train B) Minimum flow requirements to hot leg of RCS coolant loops will be met by delivery of coolant from RHR train B (train A) and SI pumps to the hot legs.	Same as item 1.	
14. Motor-operated gate valve HV-8840	Fails to open on demand.	Provides isolation of fluid flow from RHR pumps to hot leg injection header of RCS coolant loops.	Failure prevents fluid fluid flow from RHR pumps directly to hot leg injection header of RCS coolant loops. Minimum flow requirements to hot legs of RCS coolant loop will be met by delivery of coolant from either of the two SI pumps, thus maintaining redundant hot leg recirculation capability.	Same as item 7.	Same as item 12.
	Fails to close on demand.		Failure reduces redundancy of providing isolation of recirculation of fluid into hot legs of RCS coolant loops by RHR pumps. Negligible effect on recirculation into cold legs of RCS coolant loops. Alternate fluid flow isolation provided by closing of isolation valves HV-8716A and HV-8716B.		
15. Motor-operated gate valve HV-8804A	Fails to open on demand.	Provides isolation of fluid flow from RHR train A via RHR heat exchanger A to suction line of charging pumps.	Failure reduces redundancy of providing flow to the suction of the charging pumps from the RHR pumps. No effect on system operation. Charging pumps will be provided suction head by RHR train B via opening valve HV-8804B and the high-head SI suction crosstie via opening valve HV-8807A or HV-8807B.	Same as item 7.	

TABLE 6.3.2-5 (SHEET 6 of 9)

Component	Failure Mode	Function	Effect on System Operation	Failure Detection Method[(b)]	Remarks
16. Motor-operated gate valve HV-8804B	Fails to open on demand.	Provides isolation of fluid flow from RHR train B via RHR heat exchanger B to suction line of SI pumps.	Failure reduces redundancy of providing flow to the suction of the SI pumps from the RHR pumps. No effect on system operation. SI pumps will be provided suction head by RHR train A via opening valve HV-8804A and the HHSI suction crosstie via opening valve HV-8807A or HV-8807B.	Same as item 7.	
17. Motor-operated gate valve HV-8807A (HV-8807B analogous)	Fails to open on demand.	Provides fluid flow between the suction of the charging pumps and the SI pumps.	Failure reduces redundancy of providing long term recirculation fluid between the suction of the charging pumps and the SI pumps. Negligible effect on system operation. Suction fluid flow provided by opening alternate isolation valve HV-8807B (HV-8807A).	Same as item 7.	
18. Motor-operated gate valve HV-8924	Fails to close on demand.	Provides isolation barrier to separate the suction of the charging pumps and SI pumps in the event of a single passive failure which occurs in the recirculation mode.	No effect on system operation. Isolation barrier is provided by closing of alternate isolation valves HV-8807A and HV-8807B.	Same as item 1.	The normal operating position of the valve during recirculation is open.
19. Motor-operated gate valve HV-8835	Fails to close on demand.	Provides isolation of fluid flow from SI pumps discharge line to cold legs of RCS coolant loops.	Failure reduces redundancy of providing flow isolation of SI pump flow to cold coolant loops. No effect on safety for system operation. Alternate isolation valves HV-8821A and HV-8821B in discharge crosstie line between SI pumps provide backup isolation against flow of coolant to cold legs.	Same as item 1.	

TABLE 6.3.2-5 (SHEET 7 of 9)

Component	Failure Mode	Function	Effect on System Operation	Failure Detection Method[b]	Remarks
20. Motor-operated gate valve HV-8802A (HV-8802B analogous)	Fails to open on demand.	Provides isolation of fluid flow from SI train A (train B) discharge line to hot legs of RCS coolant loops.	Failure reduces redundancy of providing fluid flow from SI pumps to hot legs of RCS coolant loops. Minimum flow requirements will be met by SI train B (train A) and RHR pump flow to hot legs of RCS coolant loops.	Same as item 7.	Same as item 12. Valve is positioned open by operator for recirculation into hot legs 1 and 4 (hot legs 2 and 3) of RCS coolant loops.
21. Motor-operated gate valve HV-8821A(HV-8821B analogous)	Fails to close on demand.	Directs SI flow to cold legs during cold leg recirculation. Provides separation between two independent flowpath outside containment during hot leg recirculation isolation to separate SI flowpaths.	Failure reduces redundancy to provide independent SI flowpaths during hot leg recirculation. No effect on system operation. Valve HV-8821B (HV-8821A) provides backup	Same as item 1.	Same as item 12.
22. SI train A (train B analogous)	Fails to deliver working fluid.	Provides fluid flow of emergency coolant to the RCS when the RCS loop pressure drops below shutoff head of pump and provides long-term recirculation capability for core cooling following the injection phase of LOCA.	Failure reduces redundancy of providing emergency coolant to the RCS at high RCS pressure. Fluid flow from SI pump train A (train B) will be lost. Minimum flow requirements for high-head SI will be met by SI pump train B (train A) and charging pumps.	Same as stated for item 3 except SI pump discharge pressure and flow indication at MCB.	The SI pumps start upon receipt of an SI signal.
23. Motor-operated globe valve HV-8813	Fails to close on demand.	Provides isolation of fluid flow from the SI pump discharge header to the RWST.	Failure reduces redundancy of providing isolation of SI pumps miniflow line isolation from RWST. No effect on safety for system operation. Alternate isolation valves HV-8814 and HV-8920 in each SI pump miniflow line provide backup isolation.	Same as item 1.	Valve is electrically interlocked with isolation valves HV-8804A and HV-8804B and may not be opened unless these valves are closed.

TABLE 6.3.2-5 (SHEET 8 of 9)

Component	Failure Mode	Function	Effect on System Operation	Failure Detection Method[(b)]	Remarks
24. Motor-operated globe valve HV-8814 (HV-8920 analogous)	Fails to close on demand.	Provides isolation of fluid flow from SI pump train A (train B) to the RWST.	Failure reduces redundancy of providing isolation of SI pump train A (train B) miniflow isolation from RWST. No effect on safety for system operation. Alternate isolation valve HV-8813 in miniflow header provides backup isolation.	Same as item 1.	Same as item 23.
25. Motor-operated gate valve HV-8806	Fails to close on demand.	Provides isolation of fluid discharge from the RWST to suction line of SI pumps.	Failure reduces redundancy of providing isolation of SI pump suction to RWST. No effect on safety for system operation. Alternate check isolation valve1204-U4-090 provides backup isolation.	Same as item 1.	
26. Motor-operated gate valve HV-8923A (HV-8923B analogous)	Fails to close on demand.	Provides isolation barrier to form two independent SI pump flowpaths in the event of a single passive failure.	No effect on system operation. Isolation barrier is provided by closing of alternate isolation valve HV-8923B (HV-8923A).	Same as item 1.	The normal operating position of the valve during recirculation is open.
27. Motor-operated globe valve HV-8508A (HV-8508B analogous)	Fails to open on demand.	Provides alternate miniflow path for charging pump train A (train B) following isolation of normal miniflow line.	Failure prevents use of alternate miniflow line following receipt of SI signal. Charging train A (train B) degradation may occur if RCS pressure then increases to pump shutoff head. High-head SI injection flow will be provided by charging pump train B (train A) and SI pumps.	Valve open/close position indication at valve handswitch. Valve enabled condition at monitor light box and alarm for group monitoring of components at MCB.	Valve enabled by SI signal and opens or closes based on centrifugal charging pump discharge pressure.
	Fails to close on demand.		Failure reduces redundancy of providing isolation of charging pump alternate miniflow line. Alternate isolation valve HV-8509B (HV-8509A) provides backup miniflow line isolation.		Valve is closed by the operator during the switch-over from injection to recirculation.

TABLE 6.3.2-5 (SHEET 9 of 9)

Component	Failure Mode	Function	Effect on System Operation	Failure Detection Method[b]	Remarks
28. Motor-operated globe valve HV-8509A (HV-8509B analogous)	Fails to close on demand.		Failure reduces redundancy of providing isolation of charging pump train B (train A) alternate miniflow line. Alternate isolation valve HV-8508B (HV-8508A) provides backup miniflow line isolation.	Same as item 1.	Same as item 27.

a. Components 1 through 6, 27, and 28 are components of the CVCS that perform an ECCS safeguards function. Components 8, 9, and 12 are components of the RHR system that perform an ECCS safeguards function.

b. As part of plant operation, periodic tests, surveillance inspections, and instrumentation calibrations are made to monitor equipment and performance. Failures may be detected during such monitoring of equipment in addition to detection methods noted.

TABLE 6.3.2-6

EMERGENCY CORE COOLING SYSTEM RECIRCULATION PIPING PASSIVE FAILURE ANALYSIS
LONG TERM PHASE

Flowpath	Indication of Loss of Flowpath	Alternate Flowpath
Low-head recirculation		
From containment sump to low-head injection header via the RHR pumps and the residual heat exchangers.	Accumulation of water in a RHR pump compartment or auxiliary building sump.	Via the independent, identical low-head flowpath utilizing the second residual heat exchanger and RHR pump.
High-head recirculation		
From containment sump to the high-head injection header via RHR pump, heat exchanger, and the high-head SI pumps.	Accumulation of water in a RHR pump compartment or the auxiliary building sump or SI or charging pump compartment.	From containment sump to the high-head SI headers via alternate RHR pump, RHR heat exchanger, and SI or charging pump.

TABLE 8.3.2-7

125-V-dc BATTERY B LOAD REQUIREMENTS
(SBO)

Load Description	Unit[b]	0-1 min	1-240 min	Random Load
		Current Required per Time Interval after ac Power Loss (A)		
Total load includes inverters, MOV[a], dc distribution panels,[a,c] dc switchgear, MCC indication and relaying.	1	444	257	82
	2	429	255	50

a. The field flash current has not been added to the first period or random load and the MOV current has not been added to the random load since the peak load occurring during the period has been considered. The peak load is due to the breakers closing, which does not occur coincidentally with the field flash or MOV currents.

b. Differences between switchgear and control load design configurations cause amperages to vary between Units 1 and 2.

c. The dc distribution panels include the following loads: Class 1E ac switchgear circuit breaker operation, safety features status indication relays and lights, diesel generator field flashing, diesel generator control, reactor trip switchgear, solenoid valves, and Class 1E control cabinet circuit indicators.

TABLE 6.3.2-7 (SHEET 2 OF 4)

Switchover Steps[(a)]

The steps 1 through 6 manual actions function to align the suction of the RHR pumps to the containment emergency sump and to align the suction of the charging and SI pumps to the discharge of the RHR pumps, thereby assuring an available suction source for all ECCS pumps. The steps 7 and 8 manual actions provide redundant isolation of the RWST from the recirculation fluid. In the cold leg recirculation alignment, both RHR pumps, both SI pumps, and both charging pumps are delivering to the RCS cold legs.

Step 1: When each containment emergency sump isolation valve has reached the full open position, take action to close the corresponding RWST to RHR pump suction isolation valve (HV-8812 A and B). The maximum time allowed for operator actions prior to and including completion of this step is 6.5 minutes from receipt of the RWST low-low level alarm.

Step 2: Close the three SI pump miniflow valves (HV-8813, HV-8814, and HV-8920).

Step 3: Close the two isolation valves in each charging pump's alternate miniflow line (HV-8508 A and B, HV-8509 A and B).

Step 4: Close the two valves in the crossover line downstream of the RHR heat exchangers (HV-8716 A and B).

Step 5: Open the two parallel valves in the common suction lines between the charging pump suction and the SI pump suction (HV-8807 A and B).

Step 6: Open each valve from each RHR pump discharge line to the charging pump suction and to the SI pump suction (HV-8804 A and B, respectively).

Step 7: Close the two parallel valves in the line from the RWST to the charging pump suction (LV-112D and E).

Step 8: Restore power to and close the valve in the common line from the RWST to both SI pumps (HV-8806).

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a. The operator actions for switchover from injection to cold leg recirculation and CSS switchover are not to be interrupted until all of the steps in the switchover are completed; however, corrective actions for any components failures during the switchover procedure will be performed following completion of the switchover procedure.

TABLE 6.3.2-7 (SHEET 3 OF 4)

Following ECCS realignment from injection to recirculation and upon receipt of an RWST empty level alarm, the spray pumps' suctions are remote manually transferred to the containment emergency sumps. The steps 9 through 12 manual actions provide for this alignment and isolation of the RWST from the recirculation fluid. Upon completion of step 12, the CSS is aligned for recirculation mode of operation, with both CSS pumps taking suction from the containment emergency sumps and delivering flow to the containment spray ring headers.

Step 9: Open the containment emergency sump isolation valves in train A of the CSS (HV-9002A and HV-9003A).

Step 10: When the containment emergency sump isolation valves have reached the full open position, take action to close the corresponding RWST to CSS pump suction isolation valve (HV-9017A).

Step 11: Open the containment emergency sump isolation valves in train B of the CSS (HV-9002B and HV-9003B).

Step 12: When the containment emergency sump isolation valves have reached the full open position, take action to close the corresponding RWST to CSS pump suction isolation valve (HV-9017B).

TABLE 6.3.2-7 (SHEET 4 OF 4)

Switchover from Cold Leg Recirculation to Hot Leg Recirculation

At approximately 7.5 h after the accident, hot leg recirculation shall be initiated. The manual operator switchover steps stated below are normally used to perform the switchover operation from the cold leg recirculation mode to the hot leg recirculation mode. Upon completion of the switchover steps, both RHR pumps are delivering from the containment emergency sumps directly to the RCS hot legs and are also delivering to the suction of the SI and charging pumps. Both SI pumps are delivering to the RCS hot legs and both charging pumps are delivering to the RCS cold legs. The CSS is not affected by the switchover to the hot leg recirculation procedure.

Switchover Steps

Step 1: Close the RHR pump discharge cold leg header isolation valves (HV-8809 A and B).

Step 2: Open the RHR pump discharge crossover isolation valves (HV-8716 A and B).

Step 3: Open the RHR pump discharge hot leg header isolation valve (HV-8840).

Step 4: Stop SI train A pump.

Step 5: Close the corresponding SI pump discharge crossover header isolation valve (HV-8821 A).

Step 6: Open the corresponding SI pump discharge hot leg header isolation valve (HV-8802 A).

Step 7: Restart SI train A pump.

Step 8: Stop SI train B pump.

Step 9: Close the corresponding SI pump discharge crossover isolation valve (HV-8821 B).

Step 10: Open the corresponding SI pump discharge hot leg header isolation valve (HV-8802 B).

Step 11: Restart SI train B pump.

Step 12: Close the SI pump discharge cold leg header isolation valve (HV-8835).

TABLE 6.3.2-8

EMERGENCY CORE COOLING SYSTEM AIR-OPERATED VALVES[a]

Valve Location Number	Correct Position Following Safeguards Actuation	Failure Position	Automatic Positioning Signal	Position Indication Red/Green	Position Indication Monitor Lights
HV-8843	C	FC	CI-A	Yes	Yes
HV-8882	C	FC	--	Yes	--
HV-8964	C	FC	CI-A	Yes	Yes
HV-8871	C	FC	CI-A	Yes	Yes
HV-8888	C	FC	CI-A	Yes	Yes
HV-8879 A,B,C,D	C	FC	--	Yes	--
HV-8877 A,B,C,D	C	FC	--	Yes	--
HV-8878 A,B,C,D	C	FC	--	Yes	--
HV-8880	C	FC	CI-A	Yes	Yes
HV-8889 A,B,C,D	C	FC	--	Yes	--
HV-8823	C	FC	CI-A	Yes	Yes
HV-8824	C	FC	CI-A	Yes	Yes
HV-8825	C	FC	CI-A	Yes	Yes
HV-8881	C	FC	CI-A	Yes	Yes
HV-8890 A,B	C	FC	CI-A	Yes	Yes
FV-618	C	FC	--	No	--
FV-619	C	FC	--	No	--
HV-606	O	FO	--	No[b]	Yes
HV-607	O	FO	--	No[b]	Yes

a. Abbreviations:

FC - fails closed.
FO - fails open.
C - closed.
O - open.
SI - safety injection.
CI-A --containment isolation phase A.

b. Position indication by percent valve opening.

TABLE 6.3.2-9 (SHEET 1 OF 5)

FAILURE MODES AND EFFECTS ANALYSIS FOR SAFETY GRADE COLD SHUTDOWN OPERATONS

Component[(a)]	Failure Mode	Function	Effect on System Operation	Failure Detection Methods[(c]	Remarks
1. Motor-operated gate valve HV-8812A (HV-8812B analogous).	Fails to close on demand.	Provides isolation of fluid from the RWST to suction of RHR pump 1 during cooldown operation.	No effect on safety for system operation. Plant cooldown requirements are met by reactor coolant flow from hot leg loop 4 flowing through train B of RHRS; however, time required to reduce RCS temperature is extended.	Valve open/closed position indication at CB and valve (closed) monitor light and alarm at CB.	Valve is normally open to align RHRS for ECCS operation during plant power operation and load follow. Valve must be closed during plant cooldown to satisfy electrical interlock to permit valves HV-8701A and B (HV-8702A, B) to be opened.
2. Centrifugal charging pump 1 (pump 2 analogous).	Fails to deliver working fluid.	Provides fluid flow of borated water from the BAT or RWST to the RCS.	Failure reduces redundancy of providing borated water to the RCS at high RCS pressures. Fluid flow from charging pump1 is lost. Minimum flow requirements for boration and makeup are met by charging pump 2.	Charging pump discharge header pressure and flow indication at CB. Open/close pump switchgear circuit breaker indication on CB. Circuit breaker close position monitor light for group monitoring of component at CB. Common breaker trip alarm at CB.	The charging pumps provide boration and makeup flow to the RCS during safety grade cold shutdown operations.
3. Motor-operated gate valve LCV-112B (LCV-112C analogous).	Fails to close on demand	Provides isolation of fluid discharge from the VCT to the suction of charging pumps.	Failure reduces redundancy of providing VCT discharge isolation. Negligible effect on safety for system operation. Alternate isolation valve provides backup tank discharge isolation.	Same as item 1.	The charging pumps suction is isolated from the VCT and aligned to the BAT (for boration) or RWST (for boration and makeup) during safety grade cold shutdown operations.
4. Motor-operated gate valve LCV-112D (LCV-112E analogous).	Fails to open on demand.	Provides isolation of fluid discharge from the RWST to the suction of charging pumps.	Failure reduces redundancy of providing fluid flow from RWST to suction of charging pumps. Negligible effect on safety for system operation. Alternate isolation valve opens to provide backup flowpath to suction of charging pumps. This path is also the alternate to HV-8104 for boration during safety grade cold shutdown operations (see item 18).	Valves open/close position indication at CB and valve (open) monitor light and alarm at CB.	The charging pumps suction is aligned to the RSWT for boration and makeup to the RCS during safety grade cold shutdown operations.
5. Motor-operated gate valve HV-8803A (HV-8803B analogous) (Unit 1 only).	N/A	Provides isolation of fluid flow from charging pump discharge header to the inlet of the BIT.	N/A	N/A	Electric power supply has been disconnected. Hand switches have been removed.

TABLE 6.3.2-9 (SHEET 2 OF 5)

Component[a]	Failure Mode	Function	Effect on System Operation	Failure Detection Methods[c]	Remarks
6. Solenoid-operated globe valve HCV-190A (HCV-190B analogous).	Fails to open on demand.	Provides control of fluid flow from charging pump to RCS during plant boration and makeup.	Failure reduces redundancy of controlling boration and makeup flow to the RCS. Negligible effect on safety for system operation. Alternate control valve HCV-190B flow from charging pump.	Valve position indication at CB; and charging pump discharge header flow indication at CB.	
7. Motor-operated globe valve HV-8116.	Fails to open on demand.	Provides isolation of fluid flow from charging pump discharge header to RCS through valve HCV-190A.	Failure reduces redundancy of providing boration flow to the RCS. Negligible effect on safety for system operation. Boration flow provided by charging pump through valve HCV-190B.	Same as item 4.	Same as item 5.
8. Solenoid-operated globe valve HV-8095A (HV-8095B analogous).	a. Fails to open on demand.	Provides isolation of fluid flow from the RV head to the PRT.	a. Failure reduces redundancy of providing flow from the RV head to the PRT. Negligible effect on safety for system operation. RV head letdown flow provided by parallel head letdown path through alternate isolation valve.	Valve open/close position, indication at CB; and RV head letdown high temperature indication and alarm at CB.	The RV head letdown path to the PRT provides fluid flow out of the RCS to accommodate boration flow into the RCS.
	b. Fails to close on demand.		b. Failure reduces redundancy of isolating flow from the RV head to the PRT. Negligible effect on safety for system operation. RV head letdown flow isolation provided by alternate series isolation valve.		
9. Solenoid-operated globe valve HV-8096-A (HV-8096B analogous).	a. Fails to open on demand.	Same as item 8.	a. Same as item 8.a.	Same as item 8.	Same as item 8.
	b. Fails to close on demand.		b. Same as item 8.b.		
10. Solenoid-operated globe valve HCV-442A (HCV-442B analogous).	Fails to open on demand.	Same as item 8.	Same as item 8.a.	Valve position indication at CB; RV letdown temperature indication at CB.	Same as item 8.

TABLE 6.3.2-9 (SHEET 3 OF 5)

Component[a]	Failure Mode	Function	Effect on System Operation	Failure Detection Methods[c]	Remarks
11. Solenoid- operated power-operated relief valve PCV-455A (PCV-456 analogous).	a. Fails to open on demand.	Provides isolation of fluid flow from pressurizer to PRT.	a. Failure reduces redundancy of providing flow from pressurizer to PRT. Negligible effect on safety for system operation. Pressurizer vent flow provided by a parallel pressurizer vent path through alternate isolation valves.	Valve open/close position indication at CB; Pressurizer power-operated relief valve outlet temperature indication at CB.	Pressurizer vent path to the PRT provides fluid flow out of the RCS to permit RCS depressurization to RHRS initiation conditions
	b. Fails to close on demand.		b. Failure reduces redundancy of isolating flow from the pressurizer to the PRT. Negligible effect on safety for system operation. Pressurizer vent flow isolation provided by alternate series isolation valve.		
12. Motor-operated gate valve HV-8000A (HV-8000B analogous).	Fails to close on demand.	Same as item 11.	Same as item 11.b except pressurizer vent flow isolation provided by alternate series isolation valve.	Same as item 11.	Same as item 11.
13. Motor-operated gate valve HV-8808A (HV-8808B, HV-8808C, and HV-8808D analogous).	Fails to close on demand.	Provides isolation of fluid flow from accumulator 1 to the RCS.	Failure prevents isolation of accumulator 1 from the RCS. Negligible effect on safety for system operation. Accumulator 1 is depressurized by opening vent isolation valves.	Valve open/closed position indication at CB, valve (closed) monitor light and alarm at CB; and accumulator pressure indication and low alarm at CB.	Accumulators are isolated or vented during plant cooldown to not affect RCS depressurization.
14. Solenoid-operated globe valve HV-8875A (HV-8875B, HV-8875C, and HV-8875D analogous).	Fails to open on demand.	Provides venting of nitrogen gas from accumulator 1 to containment.	Failure reduces redundancy for venting accumulator 1 to containment. No effect on safety for system operation. Accumulator 1 can be vented by opening vent valves HV-8875E and HCV-943A, or isolated from the RCS by closing isolation valve HV-8808A.	Valve open/closed position indication at CB and accumulator pressure indication and low alarm at CB.	Same as item 13.

TABLE 6.3.2-9 (SHEET 4 OF 5)

Component[a]	Failure Mode	Function	Effect on System Operation	Failure Detection Methods[c]	Remarks
15. Solenoid-operated globe valve HV-8875E (HV-8875F, HV-8875G, and HV-8875H analogous).	Fails to open on demand.	Same as item 14.	Failure reduces redundancy for venting accumulator 1 to containment. No effect on safety for system operation. Accumulator 1 can be vented by opening vent valves HV-8875A and HCV-943A, or isolated from the RCS by closing isolation valve HV-8808A.	Same as item 14.	Same as item 13.
16. Solenoid-operated globe valve HCV-943A (HCV-943B analogous).	Fails to open on demand.	Provides venting of nitrogen gas from accumulators to containment.	Failure reduces redundancy for venting accumulators to containment. No effect on safety for system operation. Accumulators can be vented by opening vent valve HCV-943B or isolated from RCS by closing isolation valves HV-8808A, B, C, and D.	Valve position indication at CB and accumulator pressure indication and low alarm at CB.	Same as item 13.
17. Boric acid transfer pump 1 (pump 2 analogous).	Fails to deliver working fluid.	Provides fluid flow of concentrated boric acid from BAT to charging pump suction.	Failure reduces redundancy of providing concentrated boric acid to charging pump suction. Fluid flow from boric acid transfer pump 1 is lost. Minimum flow requirements for boration is met by boric acid transfer pump 2.	Pump motor start relay position indication (open) at CB and local pump discharge pressure indication.	The boric acid transfer pumps provide boration flow to the charging pumps suction during safety grade cold shutdown operations.
18. Motor-operated globe valve HV-8104.	Fails to open on demand.	Provides isolation of fluid flow from either boric acid transfer pump to charging pump suction.	Failure reduces redundancy of providing concentrated boric acid to charging pump suction. Negligible effect on safety for system operation Concentrated boric acid provided to charging pump suction through valves LV-112D or LV-112E from the RWST.	Valve open/close position indication at CB; and boration flow indication at CB.	The charging pumps' suction is aligned to the BAT pumps for A-train boration of the RCS during safety grade cold shutdown operations. Alternate A and B train paths are aligned through valves LV-112D or LV-112E from the RWST.

TABLE 6.3.2-9 (SHEET 5 OF 5)

a. Components 1, 5, and 13 through 16 are components of the ECCS that perform a safety-grade cold shutdown function. Components 2 through 4, 6, 7, 17 and 18 are components of the CVCS that perform a safety-grade cold shutdown function. Components 8 through 12 are components of the RCS that perform a safety-grade cold shutdown function.

b. List of acronyms and abbreviations.

Auto	- Automatic.
BAT	- Boric acid tank.
BIT	- Boron injection tank (Unit 1 only).
CB	- Main control board.
CVCS	- Chemical and volume control system.
ECCS	- Emergency core cooling system.
HELB	- High-energy line break.
MELB	- Moderate-energy line break.
PRT	- Pressurizer relief tank.
RC	- Reactor coolant.
RCS	- Reactor coolant system.
RHR	- Residual heat removal.
RHRS	- Residual heat removal system.
RWST	- Refueling water storage tank.
RV	- Reactor vessel.
SI	- Safety injection.
VCT	- Volume control tank.

c. As part of plant operation, periodic tests, surveillance inspections, and instrument calibrations are made to monitor equipment and performance. Failures may be detected during such monitoring of equipment in addition to detection methods noted.

TABLE 6.3.3-1

EMERGENCY CORE COOLING SYSTEM SHARED FUNCTIONS EVALUATION

Component	Normal Operating Arrangement	Accident Arrangement
Refueling water storage tank	Lined up to suction of SI and RHR pumps.	Lined up to suction of centrifugal charging, SI, and RHR pumps.
Charging pumps	Lined up for charging service suction from volume control tank; discharge via normal charging line.	Suction from refueling water storage tank; discharge lined up to cold legs of reactor coolant piping through high head header. Valves for realignment meet single failure criteria.
RHR pumps	Lined up to cold legs of reactor coolant piping.	Lined up to cold legs of reactor coolant piping.
Residual heat exchangers	Lined up to cold legs of reactor coolant piping.	Lined up to cold legs of reactor coolant piping.

TABLE 6.3.3-2

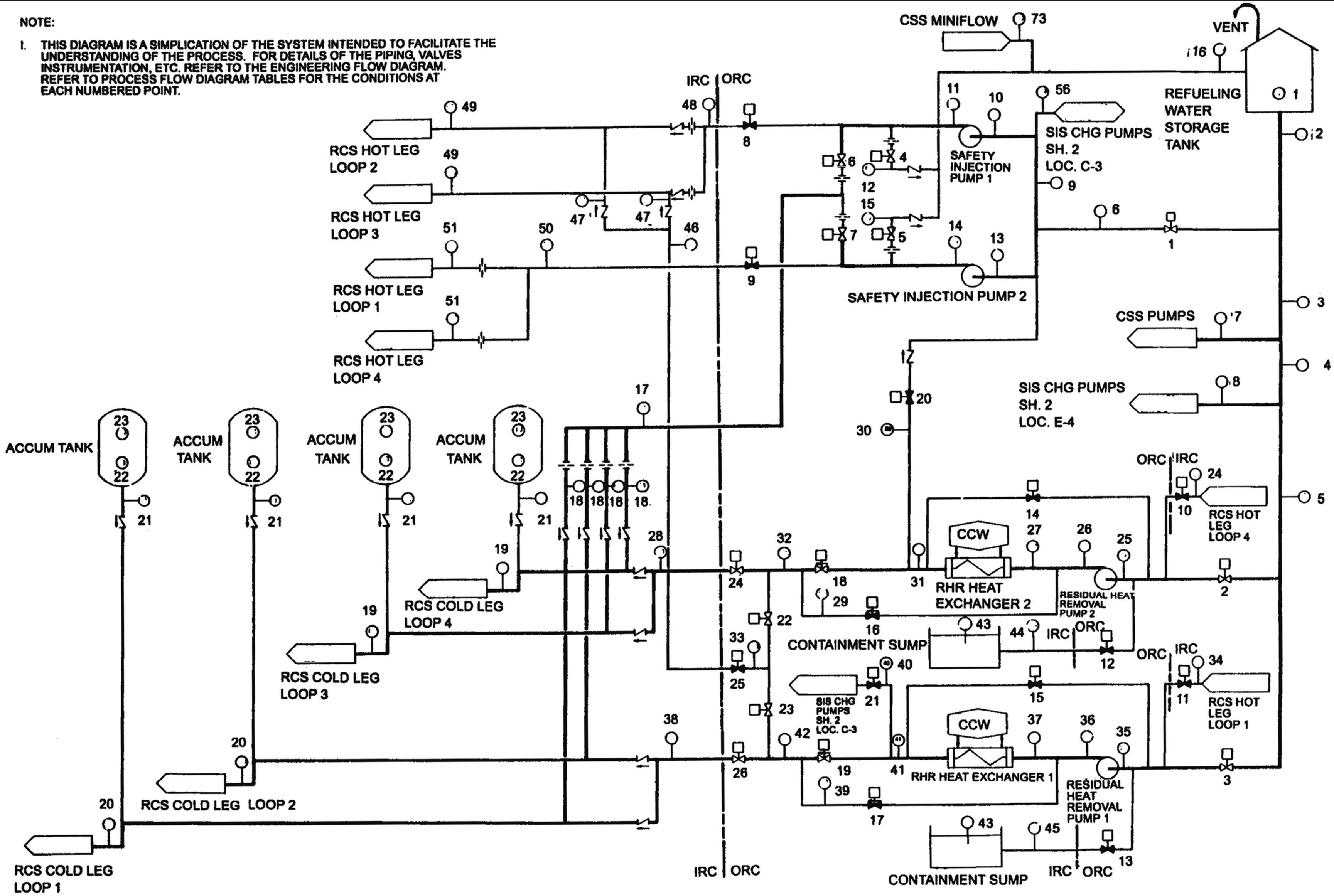
NORMAL OPERATING STATUS OF EMERGENCY CORE COOLING SYSTEM COMPONENTS FOR CORE COOLING

Number of SI pumps operable	2
Number of charging pumps operable	2
Number of RHR pumps operable	2
Number of residual heat exchangers operable	2
Refueling water storage tank volume, nominal (gal)	715,000
Boron concentration in refueling water storage tank (ppm)	2400-2600
Boron concentration in accumulators (ppm)	1900-2600
Boron concentration in BIT (ppm) (Unit 1 only)	0-2600[a]
Number of accumulators operable	4
Minimum accumulator pressure (psig)	617
Nominal accumulator water volume (ft^3)	900
System valves, interlocks, and piping required for the above components which are operable	All

a. No credit taken in accident analyses.

NOTE:

1. THIS DIAGRAM IS A SIMPLICATION OF THE SYSTEM INTENDED TO FACILITATE THE UNDERSTANDING OF THE PROCESS. FOR DETAILS OF THE PIPING, VALVES INSTRUMENTATION, ETC. REFER TO THE ENGINEERING FLOW DIAGRAM. REFER TO PROCESS FLOW DIAGRAM TABLES FOR THE CONDITIONS AT EACH NUMBERED POINT.



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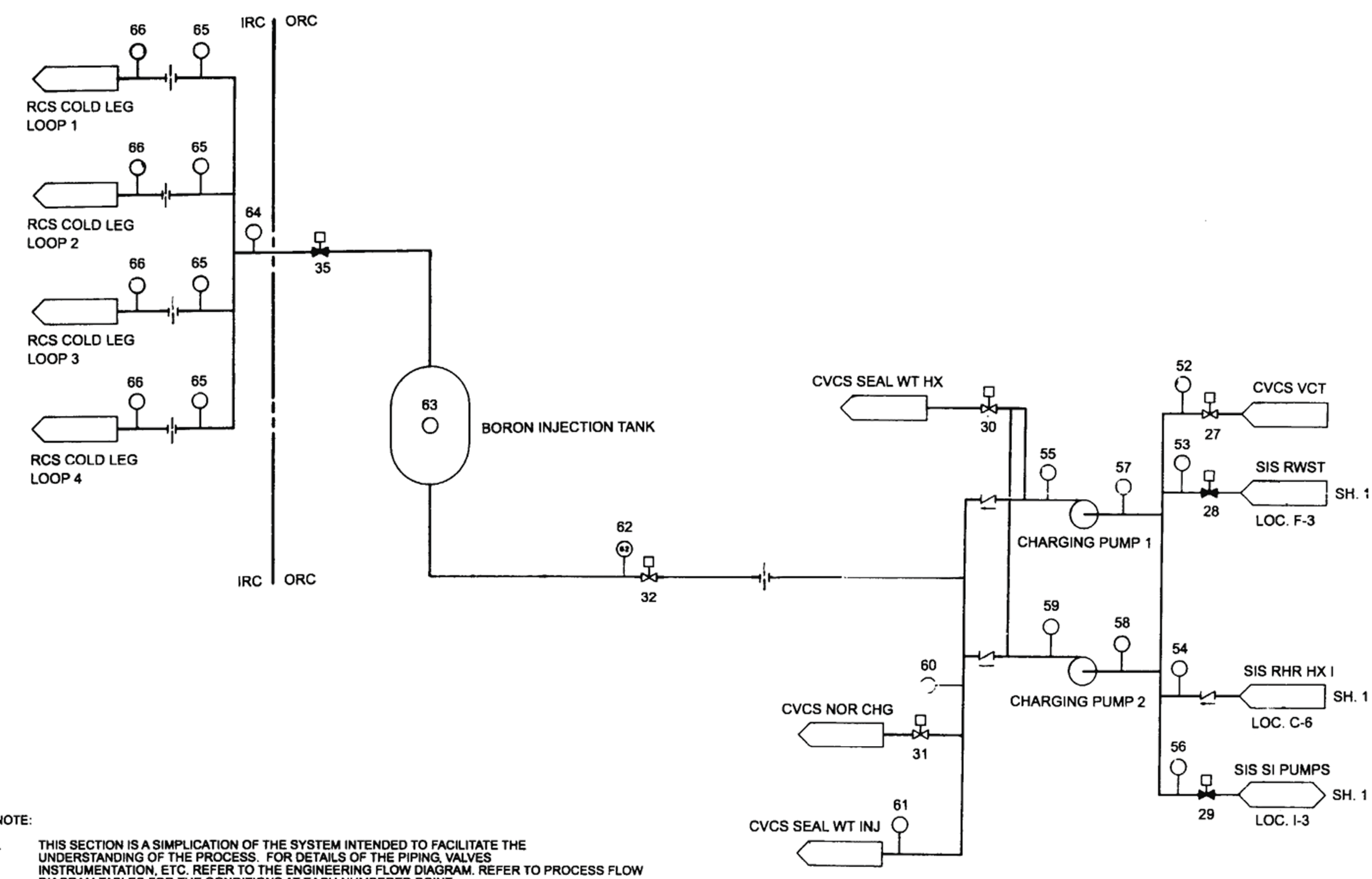
EMERGENCY CORE COOLING SYSTEM
PROCESS FLOW DIAGRAM

FIGURE 6.3.2–1 (SHEET 1 OF 22)



NOTE:

I. THIS SECTION IS A SIMPLICATION OF THE SYSTEM INTENDED TO FACILITATE THE UNDERSTANDING OF THE PROCESS. FOR DETAILS OF THE PIPING, VALVES INSTRUMENTATION, ETC. REFER TO THE ENGINEERING FLOW DIAGRAM. REFER TO PROCESS FLOW DIAGRAM TABLES FOR THE CONDITIONS AT EACH NUMBERED POINT.

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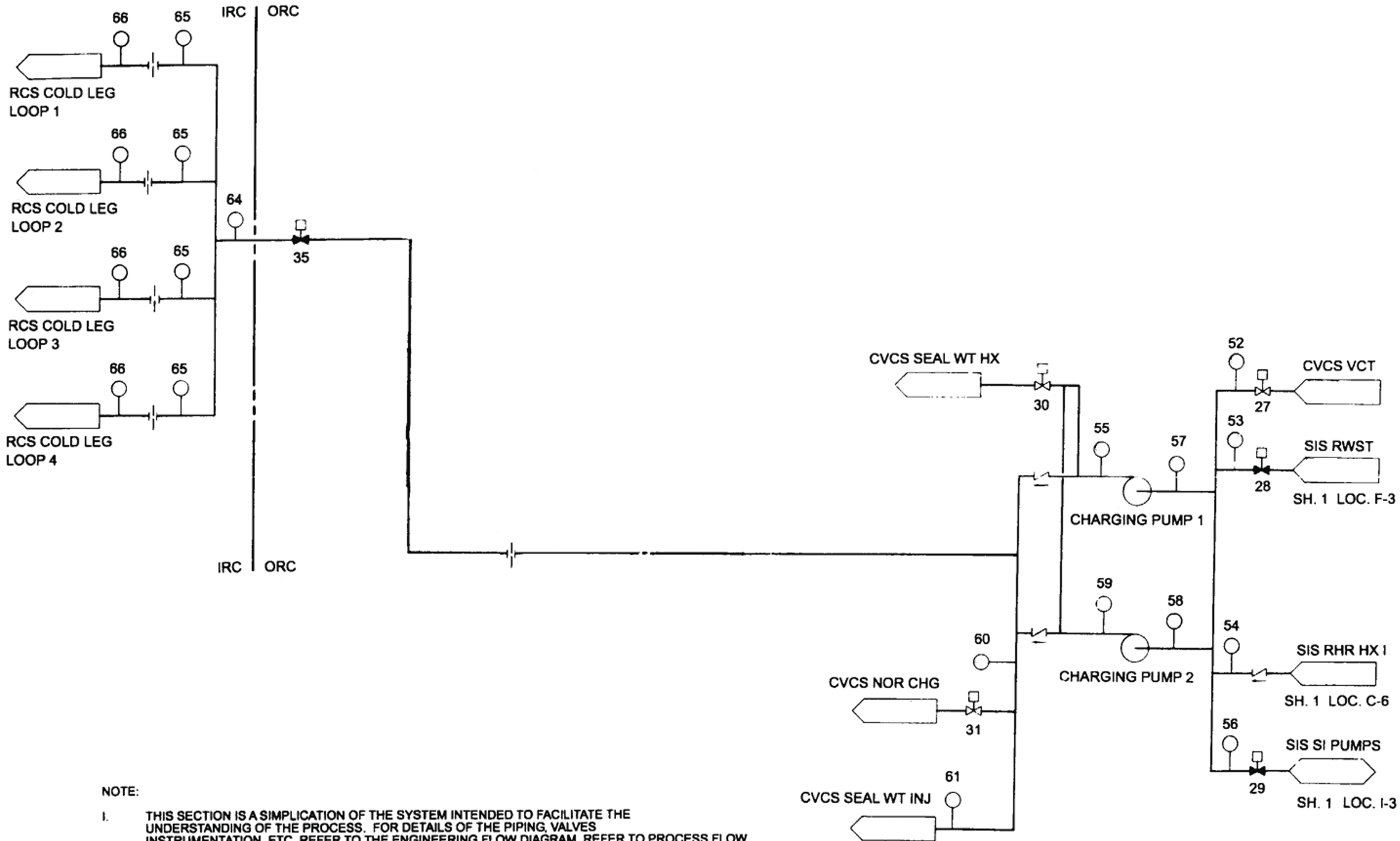
EMERGENCY CORE COOLING SYSTEM
PROCESS FLOW DIAGRAM (UNIT 1)

FIGURE 6.3.2–1 (SHEET 2 OF 22)



NOTE:

I. THIS SECTION IS A SIMPLICATION OF THE SYSTEM INTENDED TO FACILITATE THE UNDERSTANDING OF THE PROCESS. FOR DETAILS OF THE PIPING, VALVES INSTRUMENTATION, ETC. REFER TO THE ENGINEERING FLOW DIAGRAM. REFER TO PROCESS FLOW DIAGRAM TABLES FOR THE CONDITIONS AT EACH NUMBERED POINT.

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EMERGENCY CORE COOLING SYSTEM
PROCESS FLOW DIAGRAM (UNIT 2)

FIGURE 6.3.2–1 (SHEET 3 OF 22)

MODES OF OPERATION

MODE A - INJECTION

This mode presents the process conditions for the case of maximum safeguards, i.e., all pumps operating, following accumulator delivery. Two RHR pumps, two SI pumps, and two charging pumps operate, taking suction from the RWST and delivering to the reactor through the cold leg connections. Note that the flow from each pump is less than its maximum runout since the pump discharge piping is shared by the two pumps of each subsystem. Note also that the SI pump branch connections to the residual heat removal lines are close to their discharge into the accumulator lines, thereby minimizing any increase in the RHR branch line head loss due to the combined flows of the RHR and SI pumps.

MODE B - COLD LEG RECIRCULATION

This mode presents the process conditions for the case of cold leg recirculation assuming RHR pump train B, SI pumps A and B, and charging pumps A and B operating. It is assumed that the spray pumps have emptied the RWST at this time.

In this mode the safeguards pumps operate in series, with only the RHR pump capable of taking suction from the containment sump. The recirculated coolant is then delivered by the RHR pump to both of the SI pumps which deliver to the reactor through their cold leg connections and to both of the charging pumps which deliver to the reactor through their cold leg connections. The RHR pump also delivers flow directly to the reactor through two cold legs since the RHR discharge cross-connect valves are closed when making the transfer from injection to recirculation.

MODE C - HOT LEG RECIRCULATION

This mode presents the process conditions for the case of hot leg recirculation assuming train A RHR pump, charging pumps A and B, and SI pumps A and B operating.

In this mode, the safeguards pumps again operate in series with only the RHR pump taking suction from the containment emergency sump. The recirculated coolant is then delivered by the RHR pump to both of the charging pumps which continue to deliver to the reactor through their cold leg connections and to both of the SI pumps which also deliver to the reactor through their hot leg connections. The RHR pump also delivers directly to the reactor through two hot leg connections.

VALVE ALIGNMENT CHART

Valve	Injection (Mode A)	Cold Leg Recirculation (Mode B)	Hot Leg Recirculation (Mode C)
HV-8806	Open	Closed	Closed
HV-8812B	Open	Closed	Closed
HV-8812A	Open	Closed	Closed
HV-8814	Open	Closed	Closed
HV-8920	Open	Closed	Closed
HV-8821A	Open	Open	Closed
HV-8821B	Open	Open	Closed
HV-8802A	Closed	Closed	Open
HV-8802B	Closed	Closed	Open
HV-8702A	Closed	Closed	Closed
HV-8701A	Closed	Closed	Closed
HV-8811B	Closed	Open	Open
HV-8811A	Closed	Open	Open
FV-0611	Closed	Closed	Closed
FV-0610	Closed	Closed	Closed
FV-0619	Closed	Closed	Closed
FV-0618	Closed	Closed	Closed
HV-0607	Open	Open	Open
HV-0606	Open	Open	Open
HV-8804B	Closed	Open	Open
HV-8804A	Closed	Open	Open
HV-8716B	Open	Closed	Closed (a)
HV-8716A	Open	Closed	Open
HV-8809B	Open	Open	Closed
HV-8840	Closed	Closed	Open
HV-8809A	Open	Open	Closed
LV-112C	Closed	Closed	Closed
LV-112D/E	Open	Closed	Closed
HV-8924	Open	Open	Open
HV-8110	Closed	Closed	Closed
HV-8106	Closed	Closed	Closed
HV-8803A/B(Unit 1 only)	Open	Open	Open
HV-8801A/B	Open	Open	Open

a. Valve HV-8716B is normally open during the hot leg recirculation mode. However, for the "mode C" scenario, the B-train RHR is assumed to be faulted. Therefore, valve HV-8716B would be closed to separate the two trains of RHR.

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EMERGENCY CORE COOLING SYSTEM
PROCESS FLOW DIAGRAM

FIGURE 6.3.2–1 (SHEET 5 OF 22)

MODE A - INJECTION PHASE
(RUNOUT CONDITIONS FOLLOWING ACCUMULATOR DELIVERY)

Location	Fluid	Pressure (psig)	Temperature (°F)	Flow (gal/min)[a]	Volume (gal)
1	Refueling water	Atmospheric tank	100	-	715,000
2	Refueling water	-	100	15,600	
3	Refueling water	13 psia	100	14,660	-
4	Refueling water	-	100	7920	-
5	Refueling water	-	100	7000	-
6	Refueling water	11 psia	100	940	-
7	Refueling water	10 psia	100	6740[b]	
8	Refueling water	10 psia	100	920	-
9	Refueling water	10 psia	100	470	-
10	Refueling water	10 psia	100	470	-
11	Refueling water	1325	100	470	-
12	Refueling water	25	100	38	-
13	Refueling water	10 psia	100	470	-
14	Refueling water	1325	100	470	-

Location	Fluid	Pressure (psig)	Temperature (°F)	Flow (gal/min)	Volume (gal)
15	Refueling water	25	100	38	-
16	Refueling water	-	100	76	-
17	Refueling water	1250	100	864	-
18	Refueling water	105	100	216	-
19	Refueling water	-	100	1966	-
20	Refueling water	-	100	1966	-
21	Nitrogen	0	100	0	-
22	Nitrogen	0	100	0	850
23	Nitrogen	0	100	0	500
24	Reactor coolant	-	120	0	-
25	Refueling water	~ 0	100	3500	-
26	Refueling water	175	100	3500	
27	Refueling water	175	100	3500	-
28	Refueling water	150	100	3500	-
29	Refueling water	160	100	0	-
30	Refueling water	160	100	0	-
31	Refueling water	160	100	3500	-

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Location	Fluid	Pressure (psig)	Temperature (°F)	Flow (gal/min)	Volume (gal)
32	Refueling water	160	100	3500	-
33	Refueling water	160	100	0	-
34	Reactor coolant	-	120	0	-
35	Refueling water	~ 0	100	3500	-
36	Refueling water	175	100	3500	-
37	Refueling water	175	100	3500	-
38	Refueling water	150	100	3500	-
39	Refueling water	160	100	0	-
40	Refueling water	160	120	0	-
41	Refueling water	160	100	3500	-
42	Refueling water	160	100	3500	-
43	Recirc-ulating coolant	Containment pressure	220	0	-
44	Recirc-ulating coolant	Containment pressure	120	0	-
45	Recirc-ulating coolant	Containment pressure	120	0	-
46	Refueling water	Low pressure	100	0	-

Location	Fluid	Pressure (psig)	Temperature (°F)	Flow (gal/min)	Volume (gal)
47	Refueling water	Low pressure	100	0	-
48	Refueling water	Low pressure	100	0	-
49	Refueling water	Low pressure	100	0	-
50	Refueling water	Low pressure	100	0	-
51	Refueling water	Low pressure	100	0	-
52	Refueling water	Low pressure	100	0	-
53	Refueling water	10 psia	100	920	-
54	Refueling water	-	100	0	-
55	Refueling water	1620	100	460	-
56	Refueling water	-	100	0	-
57	Refueling water	10 psia	100	460	-
58	Refueling water	10 psia	100	460	-
59	Refueling water	1620	100	460	-
60	Refueling water	1610	100	104	-
61	Refueling water	1610	100	104	-
62	Refueling water	1500	100	816	-

Location	Fluid	Pressure (psig)	Temperature (°F)	Flow (gal/min)	Volume (gal)
63(Unit 1 only)	Refueling water	-	100	816	900
64	Refueling water	1400	100	816	-
65	Refueling water	1170	100	204	-
66	Refueling water	40	100	204	-

a. At reference conditions 100°F and 0 psig.

b. Estimated spray pump flow.

MODE B - COLD LEG RECIRCULATION
(RHR PUMP 2 Operating)

Location	Fluid	Pressure (psig)	Temperature (°F)	Flow (gal/min)[a]	Volume (gal)
1	Refueling water	Atmospheric tank	100	-	-
2	Refueling water	-	100	0	-
3	Refueling water	-	100	0	-
4	Refueling water	-	100	0	-
5	Refueling water	-	100	0	-
6	Recirc-ulating coolant	-	182	0	-
7	Refueling water	-	100	0	-
8	Refueling water	-	100	0	-
9	Recirc-ulating coolant	~ 35	182	1350	-
10	Recirc-ulating coolant	~ 35	185	430	-
11	Recirc-ulating coolant	1325	182	430	-
12	Refueling water	-	100	0	-

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Location	Fluid	Pressure (psig)	Temperature (°F)	Flow (gal/min)	Volume (gal)
13	Recirc-ulating coolant	~ 35	182	430	-
14	Recirc-ulating coolant	1325	182	430	-
15	Refueling water	-	100	0	-
16	Refueling water	-	100	0	-
17	Recirc-ulating coolant	1250	182	860	-
18	Recirc-ulating coolant	105	182	215	-
19	Recirc-ulating coolant	-	182	1975	-
20	Recirc-ulating coolant	-	182	215	-
21	Nitrogen	0	Ambient	0	-
22	Nitrogen	0	Ambient	0	850[b]
23	Nitrogen	0	Ambient	0	500
24	Recirc-ulating coolant	-	212	0	-
25	Recirc-ulating coolant	10	212	4300	-
26	Recirc-ulating coolant	170	212	4300	-

Location	Fluid	Pressure (psig)	Temperature (°F)	Flow (gal/min)	Volume (gal)
27	Recirc-ulating coolant	-	212	4300	-
28	Recircu-ulating coolant	130	182	2520	-
29	Recirc-ulating coolant	140	182	0	-
30	Recircu-ulating coolant	150	182	1780	-
31	Recirc-ulating coolant	160	182	4300	-
32	Recirc-ulating coolant	140	182	2520	-
33	Recirc-ulating coolant	0	182	0	-
34	Recirc-ulating coolant	-	212	0	-
35	Refueling water	-	100	0	-
36	Refueling water	-	100	0	-
37	Refueling water	-	100	0	-
38	Refueling water	-	100	0	-
39	Refueling water	-	100	0	-

Location	Fluid	Pressure (psig)	Temperature (°F)	Flow (gal/min)	Volume (gal)
40	Refueling water	-	100	0	-
41	Refueling water	-	100	0	-
42	Refueling water	-	100	0	-
43	Recirc-ulating coolant	Containment pressure	212	0	~540,000
44	Recirc-ulating coolant	Containment pressure	212	4300	-
45	Recirc-ulating coolant	Containment pressure	212	0	-
46	Refueling water	Low pressure	100	0	-
47	Refueling water	Low pressure	100	0	-
48	Refueling water	Low pressure	100	0	-
49	Refueling water	Low pressure	100	0	-
50	Refueling water	Low pressure	100	0	-
51	Refueling water	Low pressure	100	0	-
52	Recirc-ulating coolant	-	182	0	-
53	Recirc-ulating coolant	-	182	0	-

Location	Fluid	Pressure (psig)	Temperature (°F)	Flow (gal/min)	Volume (gal)
54	Recirc-ulating coolant	-	182	0	-
55	Recirc-ulating coolant	1620	182	460	-
56	Recirc-ulating coolant	30	182	920	-
57	Recirc-ulating coolant	30	182	460	-
58	Recirc-ulating coolant	30	182	460	-
59	Recir-ulating coolant	1620	182	460	-
60	Recirc-ulating coolant	1610	182	104	-
61	Recirc-ulating coolant	1610	182	104	-
62	Recirc-ulating coolant	1500	182	816	-
63	Recirc-ulating coolant(Unit 1 only)	-	182	816	-
64	Recirc-ulating coolant	1400	182	816	-
65	Recirc-ulating coolant	1170	182	204	-

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Location	Fluid	Pressure (psig)	Temperature (°F)	Flow (gal/min)	Volume (gal)
66	Recirc-ulating coolant	40	182	204	-

---

a. At reference conditions 212°F and 0 psig.

b. Minimum water volume at operating conditions.

MODE C - HOT LEG RECIRCULATION
(RHR PUMP NO. 1 OPERATING)

Location	Fluid	Pressure (psig)	Temperature (°F)	Flow (gal/min)[a]	Volume (gal)
1	Refueling water	Atmospheric tank	100	-	-
2	Refueling water	-	100	0	-
3	Refueling water	-	100	0	-
4	Refueling water	-	100	0	-
5	Refueling water	-	100	0	-
6	Recirc-ulating coolant	-	182	0	-
7	Refueling water	-	100	0	-
8	Refueling water	-	100	0	-
9	Recirc-ulating coolant	25	182	660	-
10	Recirc-ulating coolant	25	182	660	-
11	Recirc-ulating water	805	182	660	-
12	Refueling water	-	100	0	-

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Location	Fluid	Pressure (psig)	Temperature (°F)	Flow (gal/min)	Volume (gal)
13	Recirc-ulating coolant	25	182	660	-
14	Recirc-ulating coolant	805	182	660	-
15	Refueling water	-	100	0	-
16	Refueling water	-	100	0	-
17	Recirc-ulating coolant	0	182	0	-
18	Recirc-ulating coolant	-	182	0	-
19	Recirc-ulating coolant	-	182	0	-
20	Recirc-ulating coolant	-	182	0	-
21	Nitrogen	-	Ambient	0	-
22	Nitrogen	0	Ambient	0	850[b]
23	Nitrogen	0	Ambient	0	500
24	Recirc-ulating coolant	-	212	0	-
25	Recirc-ulating coolant	-	< 212	0	-
26	Recirc-ulating coolant	-	< 212	0	-

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Location	Fluid	Pressure (psig)	Temperature (°F)	Flow (gal/min)	Volume (gal)
27	Recirc-ulating coolant	-	< 212	0	-
28	Recirc-ulating coolant	-	< 182	0	-
29	Recirc-ulating coolant	-	< 182	0	-
30	Recirc-ulating coolant	-	< 182	0	-
31	Recirc-ulating coolant	-	< 182	0	-
32	Recirc-ulating coolant	-	< 182	0	-
33	Recirc-ulating coolant	50	182	2060	-
34	Recirc-ulating coolant	-	212	0	-
35	Recirc-ulating coolant	12	212	4300	-
36	Recirc-ulating coolant	140	212	4300	-
37	Recirc-ulating coolant	-	212	4300	-
38	Recirc-ulating coolant	-	< 182	0	-

Location	Fluid	Pressure (psig)	Temperature (°F)	Flow (gal/min)	Volume (gal)
39	Recirc-ulating coolant	120	182	0	-
40	Recirc-ulating coolant	130	182	2240	-
41	Recirc-ulating coolant	135	182	4300	-
42	Recirc-ulating coolant	120	182	2060	-
43	Recirc-ulating coolant	Containment pressure	212	-	~540,000
44	Recirc-ulating coolant	Containment pressure	212	0	-
45	Recirc-ulating coolant	Containment pressure	212	4300	-
46	Recirc-ulating coolant	10	182	2060	-
47	Recirc-ulating coolant	10	182	1030	-
48	Recirc-ulating coolant	700	182	660	-
49	Recirc-ulating coolant	-	182	1360	-
50	Recirc-ulating coolant	700	182	660	-

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Location	Fluid	Pressure (psig)	Temperature (°F)	Flow (gal/min)	Volume (gal)
51	Recirc-ulating coolant	-	182	330	-
52	Recirc-ulating coolant	-	182	0	-
53	Recirc-ulating coolant	-	182	0	-
54	Recirc-ulating coolant	-	182	2240	-
55	Recirc-ulating coolant	1620	182	460	-
56	Recirc-ulating coolant	35	182	1320	-
57	Recirc-ulating coolant	35	182	460	-
58	Recirc-ulating coolant	35	182	460	-
59	Recirc-ulating coolant	1620	182	460	-
60	Recirc-ulating coolant	1620	182	104	-
61	Recirc-ulating coolant	1620	182	104	-
62	Recirc-ulating coolant	1500	182	816	-

Location	Fluid	Pressure (psig)	Temperature (°F)	Flow (gal/min)	Volume (gal)
63(Unit 1 only)	Recirc-ulating coolant	-	182	816	-
64	Recirc-ulating coolant	1400	182	816	-
65	Recirc-ulating coolant	1170	182	204	-
66	Recirc-ulating coolant	40	182	204	-

a. At reference conditions 212°F and 0 psig.

b. Minimum water volume at operating conditions.

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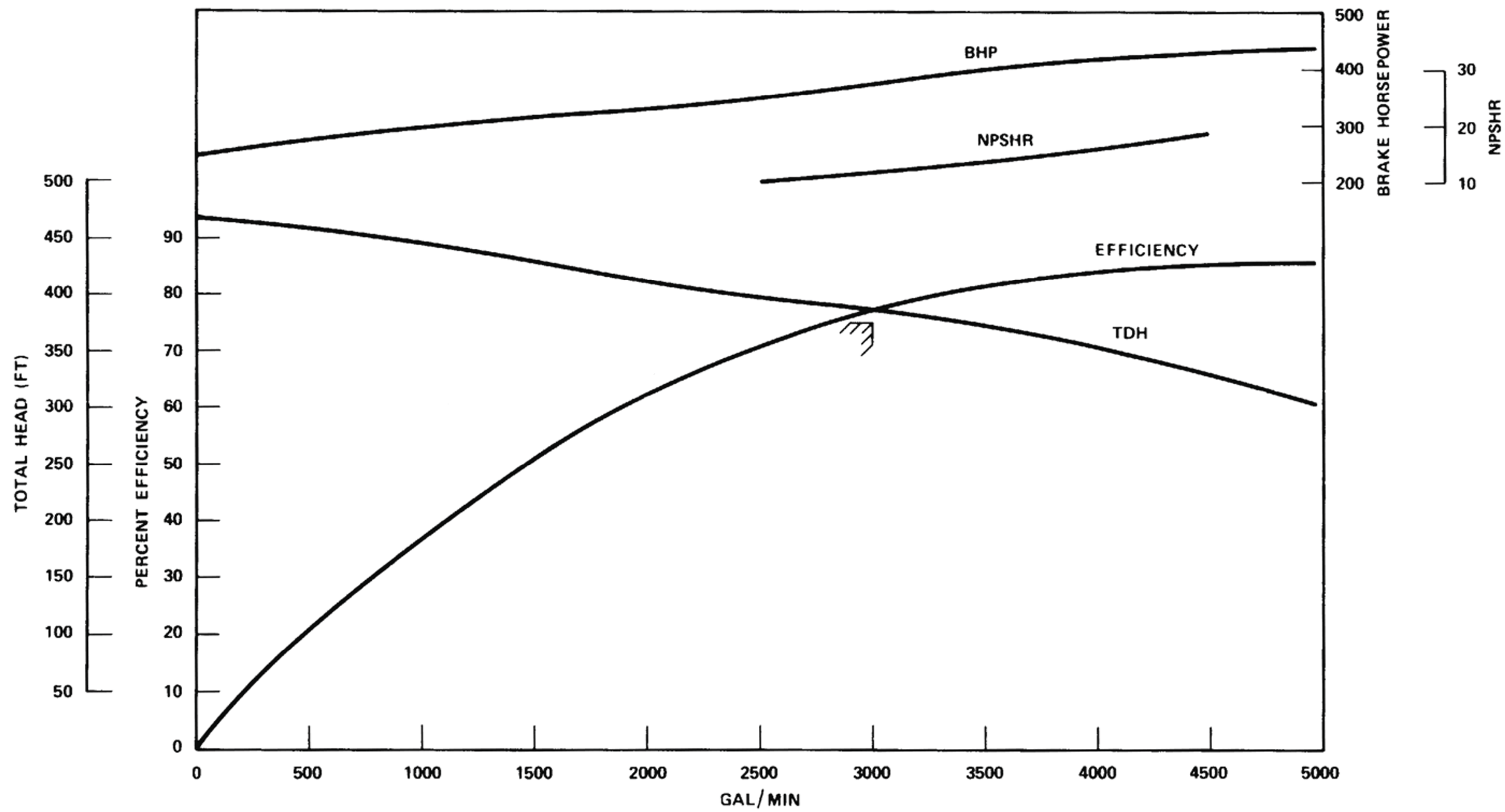

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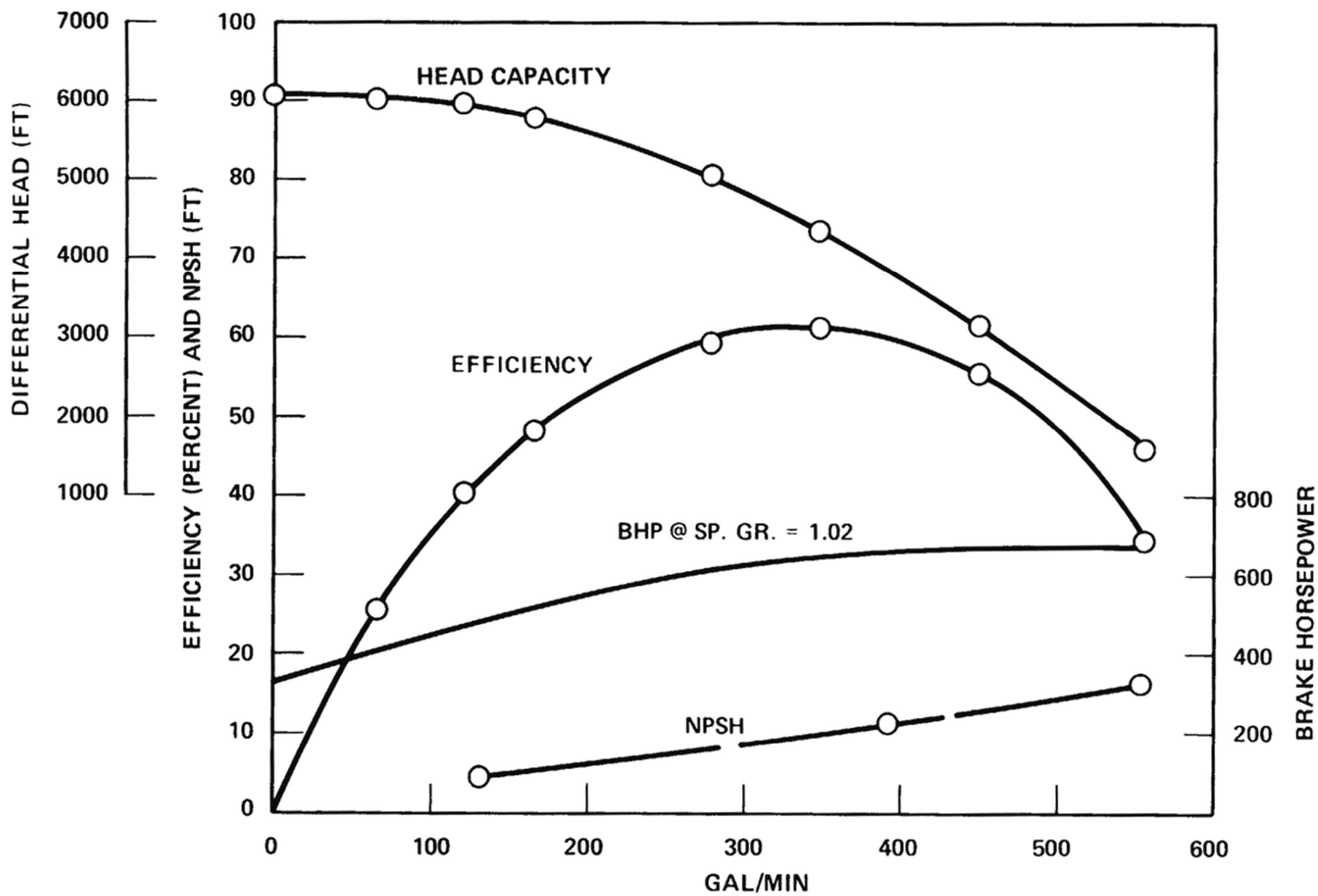
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

PERFORMANCE CURVES
RESIDUAL HEAT REMOVAL PUMPS

FIGURE 6.3.2–2



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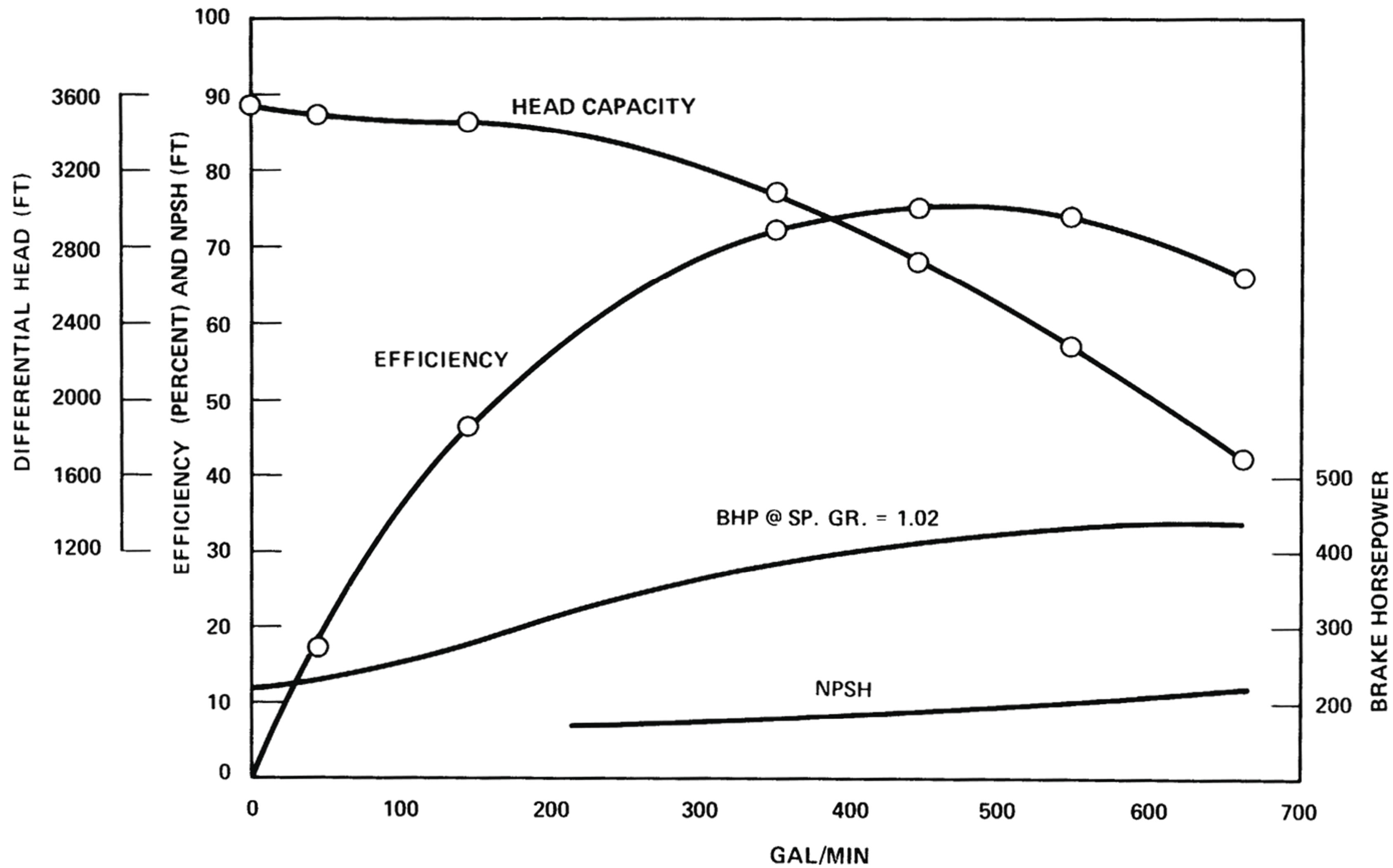
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

PERFORMANCE CURVES
CENTRIFUGAL CHARGING PUMPS

FIGURE 6.3.2–3



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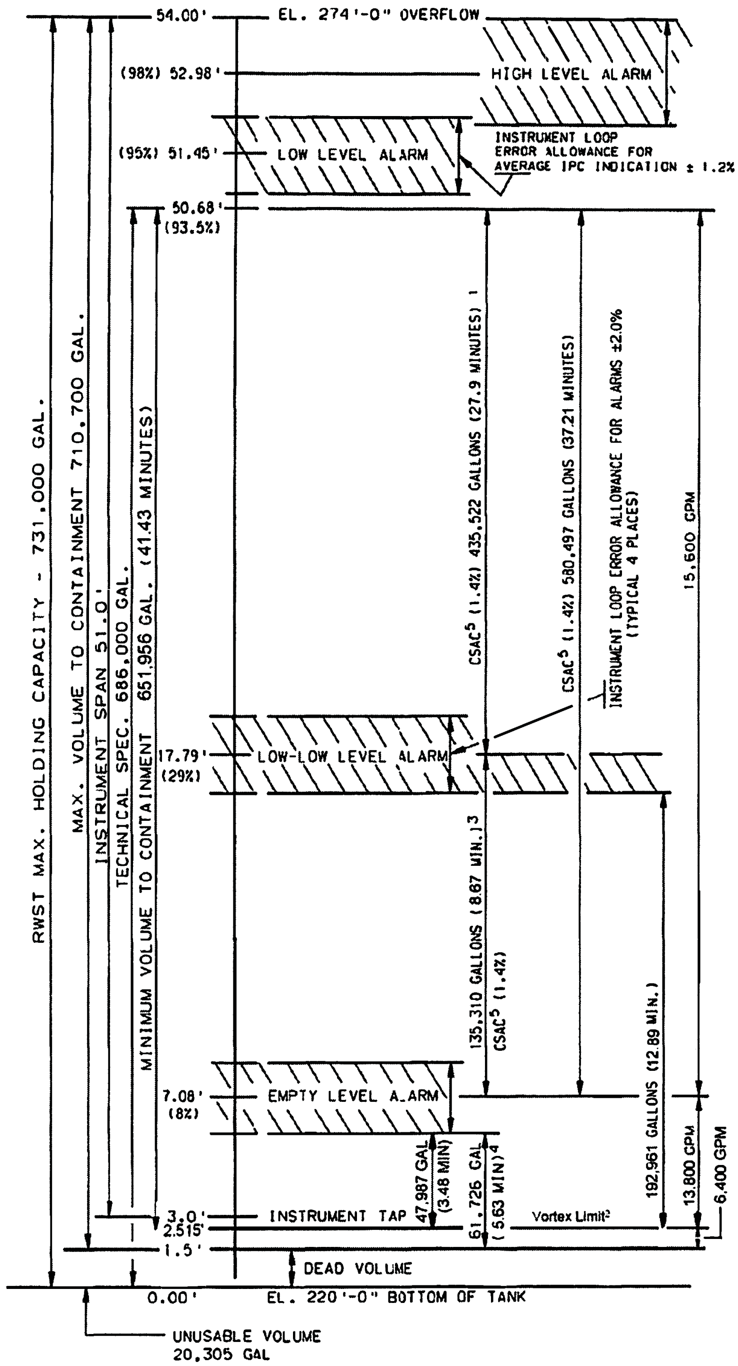
PERFORMANCE CURVES
SAFETY INJECTION PUMPS

FIGURE 6.3.2–4



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UNIT 1 AND UNIT 2

RWST SIZING

FIGURE 6.3.2–5

6.4 HABITABILITY SYSTEMS

The control room habitability systems include missile protection; radiation shielding; radiation monitoring; and smoke detection capability; air filtration, adsorption, and pressurization; and air-conditioning, lighting, personnel support, and fire protection equipment. (Refer also to section 3.1 for a discussion on conformance with 10 CFR 50, Appendix A, General Design Criterion 19.)

The heating, ventilation, and air-conditioning (HVAC) equipment discussed in this section is also discussed in subsection 9.4.1 which is directed toward normal use of the equipment. This section only addresses emergency service requirements and the response and operation of control room HVAC equipment under emergency conditions. Other equipment and systems are described only as necessary to define their connection with control room habitability. Reference is made to other sections as appropriate.

6.4.1 DESIGN BASES

The safety design bases for the control room habitability systems are as follows.

The habitability systems provide coverage for the control room envelope defined in paragraph 6.4.2.1.

The control room emergency ventilation and air-conditioning system is capable of maintaining the control room atmosphere in a condition suitable for prolonged occupancy throughout the duration of any one of the postulated accidents discussed in chapter 15.

The control room emergency ventilation and air-conditioning system is capable of maintaining an environment suitable for sustained occupancy for a five-person minimum, with higher occupancy levels for shorter periods of time.

Food, water, medical supplies, and sanitary facilities are provided for a minimum sustained control room occupancy of five persons for 5 days. The control room will have approximately five hundred 130-mg potassium iodide tablets.

The radiation exposure of control room personnel through the duration of any one of the postulated limiting faults discussed in chapter 15 does not exceed the limits set by 10 CFR 50, Appendix A, General Design Criterion 19.

The habitability systems provide the capability to detect and protect control room personnel from smoke, and airborne radioactivity.

Respiratory, eye, and skin protection is provided for emergency use within the control room envelope.

The control room emergency HVAC system is capable of automatic and manual transfer from its normal operating mode to the emergency modes. Smoke and radiation detectors, and control equipment are provided at plant locations as necessary to ensure the appropriate operation of the system.

A single active failure of any component of the control room emergency HVAC system, assuming a loss of offsite power, does not impair the ability of the system to function. Each train of the control room HVAC system is connected to a separate and independent Class 1E power supply.

The control room emergency HVAC system is designed to remain functional during and after a safe shutdown earthquake. All airducts and their supports above the control room suspended ceiling, as well as the ceiling itself, are Seismic Category 1.

The control room normal HVAC system is described in subsection 9.4.1.

Protection of the habitability systems in the control room from wind and tornado effects is discussed in section 3.3. Flood design is discussed in section 3.4. Missile protection is discussed in section 3.5. Protection against dynamic effects associated with the postulated rupture of piping is discussed in section 3.6. Environmental design is discussed in section 3.11. The fire protection system is discussed in subsection 9.5.1. The fire hazard analysis is discussed in appendix 9A. The control room ventilation isolation is described in subsection 7.3.6. The design of the control room habitability system meets the intent of Regulatory Guides 1.52, 1.78, and 1.95 as discussed in section 1.9.

6.4.2 SYSTEM DESIGN

6.4.2.1 Definition of the Control Room Envelope

The areas, equipment, and materials to which the control room operator requires access during an emergency are shown in drawing AX1D11A04. Those spaces requiring continuous or frequent operator occupancy are also shown in drawing AX1D11A04. A description of shielding required to maintain habitability of the control room during the course of postulated accidents is provided in section 12.3.

6.4.2.2 Ventilation System Design

6.4.2.2.1 General Description

Subsection 9.4.1 contains an overall description of the control room heating, ventilation, and air-conditioning (HVAC) system. The system is shown schematically in drawings AX4DB206-1, AX4DB206-2 and AX4DB206-3. Drawing AX6DD310 shows the plant layout, including the location of potential radiological and onsite toxic chemical release points with respect to the control room air intakes. Elevation and plan drawings with descriptions providing building dimensions and locations are in section 1.2. Potential sources of toxic gas and radiological releases are discussed in subsection 2.2.3.

The volume of the habitability zone served by the HVAC system in the emergency mode or the isolation mode is approximately 161,500 ft^3.

Environmental design criteria for the air purification system are based on the most limiting conditions resulting from any of the postulated design basis accidents (DBAs) and on their duration, in accordance with Regulatory Guide 1.52, as discussed in section 1.9.

Two redundant and physically separated air handling unit trains with a moisture eliminator, an electric preheater, high-efficiency particulate air (HEPA) filters, and charcoal adsorbers are provided for each unit to process intake airflow and recirculated airflow in the combined control room. Each of the two redundant units belongs to a different safety train. Performance characteristics and parameters for major components are listed in table 6.4.2-1. The seismic and quality classifications of components, instrumentation, and ducting are given in table 3.2.2-1.

6.4.2.2.2 Component Description

Each essential air handling unit contains a fan, a moisture eliminator, an electric heating coil, an upstream HEPA filter, an activated charcoal filter, a downstream HEPA filter, and a cooling coil. Pneumatic and/or motor-operated dampers are provided for system isolation purposes.

The control room emergency HVAC system is shared by both Units 1 and 2. The two units' control rooms are partially separated by a partition. Areas in the vicinity of the shift technical advisor work station, and the balance of plant (BOP) and nuclear steam supply system (NSSS) control panels provide access between the Unit 1 and Unit 2 areas of the control room as shown in drawing AX1D11A04. The air ducts serving the control room are a common system connected to the Units 1 and 2 safety-related air handling units. Four safety-related air handling units are available to serve the control room envelope.

A. Filter Unit Housings

The filter unit housings are Seismic Category 1 and are made of carbon steel. Each housing is provided with a service access door, explosion-proof light, filter test connections, connections for pressure gauges, and floor drains. The housings are of all-welded construction. Filter unit housings are designed in accordance with Regulatory Guide 1.52, as discussed in section 1.9.

B. Moisture Separator

The moisture separator is a two-stage unit using louvers followed by relatively coarse glass fiber or galvanized steel pads. The moisture separator will remove 99 percent of 5 to 10 μm diameter droplets without any visible carryover. The moisture separator is designed and qualified in accordance with Regulatory Guide 1.52, as discussed in section 1.9.

C. Electric Heaters

The electric heater is sized to reduce the relative humidity of the airstream to 70 percent from as high as 100 percent. Heating elements are a finned tubular type, with 80-percent nickel/20-percent chromium resistance wire embedded in insulation inside a monel sheath. Fins are of monel and are permanently attached to the tubes. The elements are supported in a type 304 stainless steel casing. The electric heaters are designed in accordance with American National Standards Institute N509, as discussed in paragraph 1.9.52.2.

D. HEPA Filters

HEPA filter elements are of pleated fiberglass with aluminum separator design, measure 24 x 24 x 11.5 in., and are capable of handling a nominal flowrate of 1000 ft^3/min each. The filter medium is cased in stainless steel, has face guards on both sides, and is water and fire resistant. HEPA filter elements are manufactured and tested prior to installation in accordance with MIL-F-51068D. The filter element minimum acceptance criterion is removal of 99.97 percent of 0.3-mm thermal-generated, monodispersed dioctyl phthalate particles.

E. Carbon Adsorbers

The carbon adsorbers for the emergency air handling units are of the bulk type, are 4 in. deep, and have an all-welded design. The carbon adsorbers are a rechargeable type. Minimum air residence time in the carbon is 0.5 s at a nominal face velocity of 40 ft/min. An 8 x 16 mesh of impregnated, activated charcoal is used in each filter.

F. Cooling Coil

The cooling coils are of nonferrous construction with copper fins mechanically bonded to seamless 90-percent copper/10-percent nickel tubing. Coils are arranged for counterflow operation using chilled water. The tube bundle is enclosed in a stainless steel frame. Coils are arranged for horizontal airflow and are provided with inlet and outlet piping, vent, and drain connections. The chilled water system is discussed in subsection 9.2.9. The cooling coil is Seismic Category 1 and American Society of Mechanical Engineers Section III, Class 3.

G. Emergency Filtration Train Fans

The emergency filtration train fans are Seismic Category 1 and are capable of delivering 25,000-ft^3/min flowrate with all filters at their design pressure drop. Fans are chosen with a steeply rising pressure-flow characteristic to maintain a reasonable constant airflow over the full filter train life. Fan and motor materials are suitable for operation under the environmental conditions associated with the postulated DBA, in conformance with Regulatory Guide 1.52, as discussed in section 1.9. The emergency ventilation recirculation rate for each train is balanced for a flow of 19,000 ft^3/min.

H. Control Room Return Fan

The emergency control room return fans are disabled and abandoned in place as their function is not required.

I. Ductwork and Dampers

The system ductwork and dampers are Seismic Category 1 and are designed in accordance with Regulatory Guide 1.52. Ductwork is redundant where required to provide functional support to active components in meeting the single active failure criteria. Leaktight ductwork and bubbletight isolation dampers are provided, where required, to isolate the system from unfiltered outside air.

In general conformance with Position C4 of Regulatory Guide 1.52 as discussed in section 1.9, accessibility and adequate working space for maintenance and testing operations are provided in the design and layout of the air purification system equipment.

J. Control Room Access Doors

To minimize inleakage, the control room access doors are equipped with self-closing devices that shut the doors automatically following the passage of personnel. Two sets of doors with a vestibule between, acting as an airlock, are provided at each of the entrances to the combined control room and associated spaces.

A separate doorway is provided to access the record storage area which, while not part of the control room proper, is within the control room HVAC envelope. The door is equipped with a self-closing device to shut the door automatically following the passage of personnel and can only be accessed by passing through an air lock (two-door vestibule) or another door in series.

K. Isolation Dampers

System isolation dampers are capable of automatically closing in 6 s after receipt of an actuation signal, as verified by manufacturer testing. The isolation dampers are factory tested as bubbletight dampers for zero leakage.

L. Radiation Detectors

Redundant radiation detectors are installed in the control room ventilation outside air intake plenum. Each unit is responsive to gaseous activity at concentrations as low as 10-6 $\mu Ci/cm^3$ of Xe-133. Airborne particulate and iodine activities are also detected. The detectors are described in section 11.5.

M. Smoke Detectors

Redundant smoke detectors are installed in each control room ventilation outside air intake (a total of four detectors). These detectors indicate the presence of smoke entering the control room envelope from outside. Each smoke detector actuates an alarm in the control room on the HVAC control panel. Redundant smoke detectors are also installed inside the control room envelope. These smoke detectors detect smoke inside the control room envelope and actuate an alarm in the control room on the fire protection panel.

N. Breathing Apparatus

Self-contained portable breathing equipment with air bottles is stored within the habitability area of the control room. The quantity available is sufficient to allow manning of five people for 6 h each for each individual (30 h).

The remainder of the system; i.e., supply/recirculation fans, exhaust fans, ductwork, and dampers, are components that function during normal operation and are described in subsection 9.4.1.

O. Backdraft Dampers

Backdraft dampers in the outside air and return ductwork are provided to prevent excessive backflow in faulted conditions. See Failure Modes and Effects Analysis, table 6.4.4-1, for further description.

6.4.2.3 Leaktightness (HISTORICAL)

The exfiltration and infiltration analyses are performed using the methods and assumptions given in American Society of Heating, Refrigerating, and Air-Conditioning Engineers Handbook of Fundamentals and Regulatory Guide 1.78 and "Conventional Buildings for Reactor Containment," published by Atomics International, Catalog No. NAA-SR-10100, dated June 15, 1965. The leakage rates were calculated using the following equations:

A. Penetrations and Doors

$Q = AP + BP^{1/2}$

where:

Q = *leakage rate per unit leak path (ft^3/min).*

P = *differential pressure (in. WG).*

A and B = coefficients from test data.

B. Dampers

Leaktightness is determined from actual test data on dampers.

The leak paths considered are ductwork, piping, and electrical penetrations; dampers and doors; and construction joints and materials.

Table 6.4.2-2 provides a listing of leakage data and total leakage rates for potential leak paths. For analysis of exfiltration from the pressurized control room envelope, a positive 1/8-in. WG pressure differential is considered for all leak paths resulting in a total outleakage of 1500 ft^3/min (at emergency conditions). For analysis of infiltration to the unpressurized control room envelope, a negative 1/8-in. WG pressure differential is considered for all leak paths resulting in a total inleakage of 750 ft^3/min. The control room envelope is pressurized during normal operation. The normal outside air supply is designed to pressurize the control room to 1/8 in. WG and is sized to deliver up to 3000-ft^3/min flowrate into the control room during the normal mode of operation. Based on the rate of outleakage, this flowrate is adequate to maintain a 1/8-in. positive pressure in the control room envelope during normal operation.

6.4.2.4 Interaction with Other Zones and Pressurized Equipment

The outside air intake duct is located such that:

A. It is protected from the effects of a main steam line break.

B. It minimizes the introduction of airborne radioactive material from unit release points.

C. It minimizes the introduction of diesel generator exhaust and other noxious gases.

The probability of radioactive material, noxious gases, or steam being transferred directly into the control room from adjacent areas and buildings other than through the outside air duct is minimized by the following design arrangements and considerations.

A. The control room is maintained at 1/8-in. WG pressure above atmospheric to prevent infiltration of air during normal conditions. The volume of the control room and other space protected by the habitability system is approximately 161,500 ft^3. The outside air supply of 3000 ft^3/min for the normal mode ensures pressurization of the area in excess of 1/8 in. WG so that all flow of air through the potential leakage paths, doors, ductwork, filtration units, and cable penetrations is outward and not inward. The outside air intake is through the plenum system at el 281 ft 0 in. The inlet to the plenum is through openings at the upper part of the building above the roof. The plenum system is designed as a Seismic Category 1 structure, which is an integral part of the building structure.

   The two air intakes are located at the southeast and southwest corners of the control building. There is no direct horizontal path from any sources of radioactivity, noxious gases, or steam to the air intake.

B. The normal releases from the auxiliary, fuel handling, and containment buildings are exhausted through an elevated stack atop the containments. This precludes any direct transfer of contaminants to the control room intake.

C. The control room consists of two air spaces separated partially by a suspended ceiling. The upper air space contains cable penetrations (sealed) from the upper cable spreading room above, Seismic Category 1 duct hangers, Seismic Category 1 tray hangers, Seismic Category 1 ceiling hangers, recessed light fixture enclosures (with power connections), and the Seismic Category 1 HVAC air ducts. There is no leakage path from any of these attachments nor penetrations in the 8-in. floor slab to the cable spreading room above the control room. The suspended ceiling is not sealed from the lower air space containing the control room equipment.

D. The floor of the control room contains sealed cable penetrations from the cable spreading area below the control room. There is, therefore, no leakage path from the lower cable spreading room through the control room floor into the control room.

E. There are three doorways into the combined control room:

1. At the northwest corner of the control room.
2. In the south wall of the control room.
3. At the east wall of the control room.

The doorways to the control room are each arranged with two sets of doors acting as an airlock. The doors are provided with seals to reduce leakage and to maintain pressurization.

A separate doorway is provided to access the record storage area which, while not part of the control room proper, is within the control room HVAC envelope. The door is equipped with a self-closing device to shut the door automatically following the passage of personnel and can only be accessed by passing through an air lock (two-door vestibule) or another door in series.

F. The ductwork for the essential HVAC system for the control room under accident conditions is separated from connections to other areas or to the normal operating HVAC air handling units by two Seismic Category 1, bubbletight dampers independently actuated and powered by the two engineered safety features trains. Each isolation damper automatically closes when an emergency air handling unit is started in the corresponding safety train. The emergency air handling units start automatically on either of the following signals: safety injection, or high radiation levels in the outside air intake. Under emergency conditions, filters are used for the makeup air supply to the essential HVAC system, in conformance with Regulatory Guide 1.52, as discussed in section 1.9.

G. When the control room is isolated but not pressurized, the air leakage into the control room is no greater than 750 ft^3/min from all pathways, based on a 1/8-in. WG differential. This amounts to approximately 0.3-h^{-1} air change. The infiltration is distributed as shown in table 6.4.2-2. (HISTORICAL)

H. Halon 1301 bottles provide fire protection capability for the shutdown panels, records storage, and plant and technical support center computer areas.

6.4.2.5 Shielding Design

The design basis loss-of-coolant accident (LOCA) dictates the shielding requirements for the control room. Control room shielding design bases are discussed in section 12.3. Descriptions of the design basis LOCA source terms, control room shielding parameters, and evaluation of DBA doses to control room personnel are presented in section 15.6.

The control room and its location in the plant, identifying distances and shield thicknesses with respect to radiation sources discussed in section 15.6, are shown on drawing AX6DD404.

6.4.2.6 Reference

1. "Testing of Nuclear Air-Cleaning Systems," ANSI/ASME N510-1980.

6.4.3 SYSTEM OPERATIONAL PROCEDURES

The control room normal and emergency airflow schematic is shown in drawings AX4DB206-1, AX4DB206-2, AX4DB206-3, AX4DB255-1, AX4DB255-3, and AX4DB256-1.

6.4.3.1 Normal Mode

Control room heating, ventilation, and air-conditioning (HVAC) system operation in the normal mode is described in subsection 9.4.1.

6.4.3.2 Emergency Mode

A safety injection signal or the detection of high radiation levels in the control room outside air intake shall cause the initiation of the control room isolation (CRI) signal. The CRI signal causes the activation of the emergency air filtration systems for the control room and the onsite technical support center. The control room system logic permits only a single train to start through lead/lag logic. In addition, the CRI closes the isolation dampers between the normal and emergency systems. Lead/lag control logic permits only one train of fans per unit to operate during the emergency mode. The logic provides automatic start of a standby (lag) fan if the lead fan fails, such that no more than two fans total (for two units) are running. The control room normal air handling units will automatically trip as the isolation dampers close. If one train from each unit's control room HVAC is simultaneously activated, the control room operator may stop one train manually by first resetting the CRI signal for the selected train and then stopping the selected train's HVAC system. During this mode of operation, conference room, kitchen, and toilet exhaust ducts are also isolated through automatic closure of the isolation dampers on the receipt of the CRI signal. Subsection 7.3.6 provides a discussion of the actuation of the CRI signal and the operation of the emergency HVAC system.

6.4.3.3 Smoke Removal Mode

This operation mode is provided to remove smoke from the control room envelope by exhausting smoke-contaminated air to the atmosphere while introducing 100-percent outside air as dilutant makeup.

When there is smoke inside the control room, interior smoke detectors are actuated and sound an alarm in the control room. The operator analyzes the situation, and then manually opens or closes the appropriate dampers to start the smoke removal mode of operation.

In this mode of operation, 100-percent outside air from the intake plenum at el 281 ft 0 in. is supplied by a normal air handling unit which purges the control room. The control room return dampers are isolated, the purge exhaust damper is opened, and the return/exhaust fan exhausts the air by discharging it to the outside at el 302 ft 0 in.

When there is smoke outside the control room, the smoke detectors in the outside air intake plenum actuate the annunciator alarms in the control room. The operator then analyzes the situation on the HVAC panel and, if necessary, actuates the isolation mode by manually generating a CRI signal and closing the outside air intake dampers. In the isolation mode of operation the emergency air filtration system runs in recirculation without outside air. The air from the control room is continually recirculated, cooled, and filtered by the emergency filtration units.

6.4.4 DESIGN EVALUATIONS

6.4.4.1 Radiological Protection

The effects of potential radiological accidents are analyzed in chapter 15. The radiological protection afforded to the operators in the event of an accident is described in subsections 6.4.2, 12.3.2, 12.3.3, and 12.3.4 and in section 11.5.

6.4.4.2 Toxic Gas Protection

Control room protection from the effects of toxic gases is in accordance with Regulatory Guide 1.78 as discussed in subsection 2.2.3. The analysis of potential sources for toxic gases is presented in subsection 2.2.3. The analysis of onsite and offsite sources for toxic gases is presented in paragraphs 2.2.3.1.4.1 through 2.2.3.1.4.3. These sources are analyzed deterministically and it is shown that either the 8-h toxicity limit is not exceeded in the control room, or that there is at least 2-min between detection and reaching the short-term toxicity limit, such that the operators have time to put on breathing apparatus. These results are shown in table 2.2.3-20.

6.4.4.3 Implementation of Design Bases

Control room habitability system components discussed in paragraph 6.4.2.2.2 are arranged in redundant safety-related ventilation trains as shown in drawings AX4DB206-1, AX4DB206-2, AX4DB206-3, AX4DB256-1, 1X4DB257-1, AX4DB266-2, 2X4DB266-1, AX4DB376, AX4DB269, and AX4DB270. The location of components and ductwork within the control room envelope ensures an adequate supply of filtered air to all areas requiring access as shown in drawing AX1D11A04.

By using chilled water cooling coils, the control room essential air-conditioning system maintains the temperature between 70°F and 85°F and the relative humidity below 50 percent. The control room pressure is maintained at least 1/8 in. WG above atmospheric pressure during normal operation. The control room emergency air-conditioning system maintains the same temperature and humidity conditions when operating in the emergency and isolation modes.

The control room air-conditioning system is capable of removing sensible and latent heat loads including consideration of equipment heat loads and minimum personnel occupancy requirements. The transfer to emergency or isolation operation mode does not create a hazard for CO_2 buildup. In case of emergency operation, there is a supply of outside air of 1500 ft^3/min and the long term equilibrium for CO_2 will remain below one part per thousand for a five-person occupancy. In case of isolation mode operation, where the control room is sealed, the critical level of 3 percent would be reached in 5 days for an occupancy of five persons. The technical support center will provide an additional habitable location to relieve crowding in the control room as discussed in paragraphs 9.4.1.8 and 9.5.10.2.

Food, water, medical supplies, and sanitary facilities are provided for a minimum occupancy of five persons for 5 days. Storage locations provided ensure that the above supplies will not be contaminated as a result of postulated accidents. The supply of food and water is sufficient for a prolonged occupancy because outside supplies can be provided within the 5-day interval.

The control room air purification system and shielding designs are based on the most limiting design basis assumptions contained in Regulatory Guide 1.4. Automatic transfer of the control room from the normal heating, ventilation, and air-conditioning (HVAC) system to the emergency system is accomplished upon receipt of a control room isolation signal which is generated on receipt of either the high-radiation signal from the outside air intake duct radiation detector or the safety injection actuation signal. Transfer to the emergency system also may be manually initiated from the control room. Refer to subsection 7.3.6 for a discussion of the actuation logic.

The airborne fission product source term in the reactor containment following the postulated loss-of-coolant accident (LOCA) is assumed to leak from the containment at a rate of 0.2 percent per day for the first 24 h after the accident and 0.1 percent per day thereafter. The concentration of radioactivity, which is postulated to surround the control room after the postulated accident, is evaluated as a function of the fission product decay constants, the containment spray system effectiveness, the containment leak rate, and the meteorological conditions assumed to occur. The assessment of the amount of radioactivity within the control room takes into consideration the flowrate through the control room outside air intake, the effectiveness of the control room air purification system, the radiological decay of fission products, and the exfiltration rate from the control room.

Air within the control room is recirculated continuously through the emergency air-conditioning units, which contain upstream high-efficiency particulate air (HEPA) filters, charcoal adsorbers, downstream HEPA filters, cooling coil, and fan, to control the room temperature and airborne radioactivity. The outside air required for pressurization is mixed with the return air before it enters the filtration unit. During the emergency mode of operation, the control room HVAC is designed to pressurize the control room to 1/8-in. WG pressure to prevent unfiltered inleakage.

Doses to control room personnel resulting from a postulated LOCA are presented in section 15.6. A detailed discussion of the calculational models is given in appendix 15A. Air leaks have been taken into account in the calculations for ingress and egress losses in conformance with Regulatory Guide 1.78.

Control room shielding design, based on the most limiting design basis LOCA fission product release, is discussed in section 12.3 and is evaluated in chapter 15.

As discussed and evaluated in subsection 9.5.1, the use of noncombustible construction and heat- and flame-resistant materials throughout the plant minimizes the likelihood of fire and consequential fouling of the control room atmosphere.

A supply of protective clothing, respirators, and self-contained breathing apparatus adequate for at least five persons is stored at specified locations within the control room envelope. Five persons is the design basis operating shift crew size for operation as described in section 13.1.

To protect against high airborne radioactivity inside the control room, the control room HVAC system is automatically transferred from the normal mode to the emergency mode of operation upon receipt of a control room outside air intake high radiation signal. Transfer of the system to emergency or isolation modes may also be initiated manually from the control room.

The filtration and cooling functions of the control room HVAC system may be performed fully even if the capability of the system is reduced by a single active component failure within the system or its supporting systems. Should the lead air filtration unit fail, the lag (redundant) train will provide the required cooling and air filtration. Should an excessive pressure drop develop across one filter train, the operator manually starts the redundant train to provide the required cooling and filtration. Normally open isolation dampers are arranged in series, so that the failure of one damper to shut upon transfer to the emergency mode will not prevent isolation. There are two emergency diesel generators for each unit. If one of the emergency diesel generators fails to start and assume its load, the control room emergency ventilation system equipment powered by the other diesel generator will provide the required cooling and air filtration.

A failure modes and effects analysis is provided in table 6.4.4-1.

Refer to subsection 7.3.6 for control room emergency filtration system actuation logic.

6.4.5 TESTING AND INSPECTION

A detailed program of preoperational and postoperational testing requirements to ensure continued system capability is implemented prior to station operation. Emphasis is placed on tests and inspections essential to a determination that performance criteria and operational capability are achieved and maintained.

Acceptance testing is performed to verify the unfiltered inleakage for a pressurized control room (emergency mode) is less than or equal to 120 cfm and the unfiltered makeup rate is less than or equal to 3000 cfm with the normal control room HVAC in service. Measurement of the control room envelope (CRE) pressure with respect to areas adjacent to the CRE, at designated locations, is performed in assessing the CRE boundary on a periodic basis. Obtaining and trending pressure data provides additional assurance that significant degradation of the CRE boundary will not go undetected between CRE inleakage determinations.

The control room isolation capability and the ability to process outside air through one of the two high-efficiency filter trains are tested periodically. The filtration trains are tested periodically by standard methods in general conformance with Regulatory Guide 1.52, as discussed in section 1.9.

Performance of fans is initially verified in accordance with Air Moving and Conditioning Association Standard 210[(1)] at the maximum anticipated system pressure drop. Ductwork is tested for leakage during installation. Testing and inspection of the control room normal outside air intake duct radiation monitors is discussed in section 11.5.

6.4.5.1 Preoperational Testing

High-efficiency filter air (HEPA) filter elements are tested individually prior to installation to verify an efficiency of 99.97 percent with a thermally generated, monodispersed, 0.3-μm dioctyl phthalate penetration aerosol. HEPA filter banks are tested in place prior to operation and periodically thereafter in conformance with American National Standards Institute (ANSI) N510 and conform with Position C.5.b of Regulatory Guide 1.52, as discussed in section 1.9.

The original and replacement batches of impregnated, activated carbon are batch tested in accordance with Regulatory Guide 1.52, as discussed in section 1.9, prior to loading into the adsorber section. The carbon adsorber section is filled with carbon in a manner which ensures a uniform packing density and minimizes dusting. The adsorber section is leak tested for gaseous halogenated hydrocarbon refrigerant prior to operation and periodically thereafter to verify a minimum of 99.95 percent retention, in conformance with ANSI N510, as discussed in paragraph 1.9.52.2. In addition, a periodic laboratory test of a representative sample of the impregnated, activated carbon is performed to verify iodine removal efficiencies in accordance with Position C.6 and Table 2 of Regulatory Guide 1.52, as discussed in section 1.9, for the assigned decontamination efficiency and bed depth.

Design and testing of filtration systems is consistent with the recommendations of Regulatory Guide 1.52, as discussed in section 1.9.

The emergency mode of the control room emergency ventilation system will undergo an acceptance test to verify that the system maintains a 1/8-in. WG positive pressure, with respect to adjacent areas, in the emergency zone.

Testing performed on the control room emergency ventilation systems is discussed in chapter 14.

6.4.5.2 Inservice Testing

Inservice testing of the control room essential heating, ventilation, and air-conditioning system is conducted in accordance with the surveillance requirements specified in the Technical Specifications.

Portable equipment such as air samplers, personnel dosimeters, and other radiation analysis equipment applicable to control room habitability is tested and inspected periodically, as noted in section 12.5.

Inplace leak testing of the HEPA filters is conducted initially prior to operation and at least every 18 months thereafter to confirm that the allowable penetration as defined in Regulatory Guide 1.52 is not exceeded. The inplace testing will be performed to the requirements of ANSI N510, as discussed in paragraph 1.9.52.2.

Carbon adsorbers are leak tested with a gaseous halogenated hydrocarbon refrigerant to ensure that bypass leakage is equal to or less than the allowable leakage required by Regulatory Guide 1.52, as discussed in section 1.9. Leak testing is performed in accordance with ANSI 510, as discussed in paragraph 1.9.52.2, prior to operation and periodically when HEPA testing is conducted.

6.4.5.3 Reference

1. "Laboratory Methods of Testing Fans for Rating Purposes," Air Moving and Conditioning Association Standard 210, 1974.

6.4.6 INSTRUMENTATION REQUIREMENT

The indications in the control room to monitor the heating, ventilation, and air-conditioning (HVAC) systems are listed in table 6.4.6-1.

Instrumentation required for actuation of the control room essential HVAC system is discussed in paragraph 6.4.2.2.2 and in subsection 7.3.6. The control room ventilation logic diagram is shown in drawings AX5DN020-4, AX5DN020-5, AX5DN020-6, AX5DN020-8, AX5DN020-10, AX5DN031-1, AX5DN031-2, AX5DN031-4, AX5DN032-1, AX5DN032-3, AX5DN034-2, and AX5DN037-1.

Details of the radiation monitors used to provide the control room indication actuation signal for the control room essential ventilation system are given in section 11.5.

The instrumentation is designed as Seismic Category 1. A description of initiating circuits, logic interlocks, periodic testing requirements, and redundancy of instrumentation relating to control room habitability is provided in subsection 7.3.6.

TABLE 6.4.2-1 (SHEET 1 OF 2)

PERFORMANCE CHARACTERISTICS OF MAJOR SYSTEM COMPONENTS

Control Building Control Room Filter Units

Quantity	4
System components	
Supply fan	
Type	Centrifugal
Capacity (ft^3/min) (maximum)	25,000
Static pressure (in. WG)	14
Motor (hp)	125
Charcoal absorber	
Efficiency (%)	99 at 70% relative humidity (for elemental and organic iodines)
Face velocity (ft^3/min)	40
Residence time (s/4-in. bed depth)	0.5
Nominal size (Tyler mesh)	8 x 16
HEPA filters	
Filter element	Pleated fiberglass
Size (in.)	24 x 24 x 12
Efficiency (%)	99.97 on 0.3 μm and larger
Capacity for size indicated (ft^3/min)	1000
Moisture eliminator	
Separator element	Fiberglass or galvanized steel
Efficiency (%)	99% for 5 to 10 μm droplets
Electric heater	
Heater element	80% Ni/20% Cr
Heating capacity (kW)	118
Cooling coil	
Cooling capacity (Btu/h)	1.09×10^6
Entering water temperature (°F)	44
Leaving water temperature (°F)	56
Chilled waterflow (gal/min)	175

TABLE 6.4.2-1 (SHEET 2 OF 2)

<u>Control Building Control Room Return Air Fan</u>

Type	Vane axial
Capacity (ft^3/min)	24,800
Static pressure (in. WG)	2.5
Motor (hp)	20

(NOTE: The return air fans are disabled and abandoned in place as their function is not required.

(HISTORICAL)
TABLE 6.4.2-2

LEAKAGE DATA AND LEAKAGE RATES

Leak Path	*Inleakage Rate at 1/8 in. WG (ft^3/min)*	*Outleakage Rate at 1/8 in. WG (ft^3/min)*
Concrete walls and floors	*2*	*5*
Ducts, piping, and electrical penetrations	*559*	*500*
Dampers	*0*	*10*
Doors	*125*	*125*
Ductwork	*20*	*15*
Supply fans and filtration units	*24*	*675*
Return fan	*4*	*150*
Supply fan enclosure	*16*	*20*
TOTAL	*750*	*1500*

TABLE 6.4.4-1 (SHEET 1 OF 14)

CONTROL ROOM EMERGENCY HVAC SYSTEM FAILURE MODES AND EFFECTS ANALYSIS

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
1.	1HV12146 air-operated on-off damper, normally open/fail closed (NO/FC) (supply side)	Remain open to allow flow of air, and closed on CRI so that EFU will provide HVAC	A	Inadvertent closed	Position indicating lights	None. Damper can be manually opened to provide HVAC in normal mode.	
			B, C	Fail to close	Position indicating lights	None. Redundant damper (item 2) available.	
			D	Inadvertent closed	Position indicating lights	None. Dampers can be manually opened to remove smoke.	
2.	1HV12147 air-operated on-off damper, NO/FC (supply side)	Remain open to allow flow of air, and closed on CRI so that EFU will provide HVAC	A	Inadvertent closed	Position indicating lights	None. Damper can be manually opened to provide HVAC in normal mode.	
			B, C	Fail to close	Position indicating lights	None. Redundant damper (item 1) available.	
			D	Inadvertent closed	Position indicating lights	None. Damper can be manually opened to remove smoke.	
3.	1HV12148 air-operated on-off damper, NO/FC (return side)	Remain open to allow flow of air, and closed on CRI so that EFU will provide HVAC	A	Inadvertent closed	Position indicating lights	None. Damper can be manually opened to provide HVAC in normal mode.	
			B, C	Fail to close	Position indicating lights	None. Redundant damper (item 4) available.	
			D	Inadvertent closed	Position indicating lights	None. Damper can be manually opened to remove smoke.	

TABLE 6.4.4-1 (SHEET 2 OF 14)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
4.	1HV12149 air-operated on-off damper, NO/FC (return side)	Remain open to allow flow of air, and closed on CRI so that EFU will provide HVAC	A	Inadvertent closed	Position indicating lights	None. Damper can be manually opened to provide HVAC in normal mode.	
			B, C	Fail to close	Position indicating lights	None. Redundant damper (item 3) available	
			D	Inadvertent closed	Position indicating lights	None. Damper can be manually opened to remove smoke.	
5.	No. 16 breaker on 1ABA 480-V MCC, 1E Bus, for item 7, normally closed (NC)	Provide continuity and protection to damper motor (item 7)	A	Inadvertent open	Position indicating lights; motor control center (MCC) alarm	None. Loss of intake air from Unit 1. Intake air from Unit 2 available.	
			B	Inadvertent open	Position indicating lights; MCC alarm	None. No loss of EFU.	
			C	Inadvertent open	Position indicating lights; MCC alarm	None. Open damper will close.	
6.	No. 16 motor starter for item 7, NC	Provide continuity to damper (item 7)	A	Inadvertent open	Position indicating lights	None. Loss of intake air from Unit 1. Intake air from Unit 2 available.	
			B	Inadvertent open	Position indicating lights	None. No loss of EFU.	
			C	Fail to open	Position indicating lights	None. Dampers (item10) available.	
7.	1HV12114 motor-operated on-off damper, NO	Remain open to allow flow of air on NU and CRI modes	A	Inadvertent closed	Position indicating lights	None. Loss of intake air from Unit 1. Intake air from Unit 2 available.	
			B	Inadvertent closed	Position indicating lights	None. No loss of EFU. Loss of intake air from Unit 1. Intake air from Unit 2 available to maintain positive pressure.	
			C	Fail to close	Position indicating lights	None. Damper (item 10) is already closed.	

TABLE 6.4.4-1 (SHEET 3 OF 14)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
8.	No. 16 breakers on 1BBA 480-V MCC, 1E Bus, for item 10, NC	Provide continuity and protection to damper motor (item 10)	A	Inadvertent open	Position indicating lights; MCC alarm	None. Loss of intake air from Unit 1. Intake air from Unit 2 available.	
			B	Inadvertent open	Position indicating lights; MCC alarm	None. No loss of EFU.	
			C	Inadvertent open	Position indicating lights; MCC alarm	None. Open damper will close.	
9.	No. 16 motor starter for item 10, NC	Provide continuity to 1HV12115 (item 10)	A	Inadvertent open	Position indicating lights	None. Loss of intake air from Unit 1. Intake air from Unit 2 available.	
			B	Inadvertent open	Position indicating lights	None. No loss of EFU.	
			C	Fail to open	Position indicating lights	None. Dampers (item 7) available.	
10.	1HV12115 motor-operated on-off damper, NO	Remain open to allow flow of air on NU and CRI modes	A	Inadvertent closed	Position indicating lights	None. Loss of intake air from Unit 1. Intake air from Unit 2 available.	
			B	Inadvertent closed	Position indicating lights	None. No loss of EFU. Loss of intake air from Unit 1. Intake air from Unit 2 available to maintain positive pressure.	
			C	Fail to close	Position indicating lights	None. Dampers (item 7) is already closed.	
11.	HV12152 air-operated on-off damper, NO/FC	Remain open to allow flow of air during normal mode, and closed on CRI so that EFU will provide HVAC	A	Inadvertent closed	Flow alarm, low; position indicating lights	None. Damper can be manually opened to provide HVAC in normal mode.	Common to Units 1 and 2
			B, C	Fail to close	Position indicating lights	None. Redundant damper (item 12) available.	

TABLE 6.4.4-1 (SHEET 4 OF 14)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
			D	Inadvertent closed	Position indicating lights	None. Smoke mode intake available.	
12.	HV12153 air-operated on-off damper, NO/FC	Remain open to allow flow of air, and closed on CRI so that EFU will provide HVAC	A	Inadvertent closed	Flow alarm, low; position indicating lights	None. Damper can be manually opened to provide HVAC in normal mode.	Common to Units 1 and 2
			B, C	Fail to close	Position indicating lights	None. Redundant damper (item 11) available.	
			D	Inadvertent closed	Position indicating lights	None. Smoke mode intake available.	
13.	DELETED						
14.	DELETED.						
15.	DELETED.						
16.	DELETED.						
17.	DELETED.						
18.	DELETED.						
19.	Breakers, 480-V switchgear, 1E Bus, for item 20, No. 4 breaker on 1AB05	Provide continuity and protection to fan motor (item 20)	A	Inadvertent closed	Motor indicating lights	None. EFU not required. NUs provide HVAC.	
			B, C	Fail to close	Motor indicating lights; flow alarm, low	Loss of train A. Train B available.	

TABLE 6.4.4-1 (SHEET 5 OF 14)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
20.	Control building control room filter unit fan motor, normally deenergized (ND) 1-1531-N7-001-M01	Provide motive power to circulate air	A	N/A	N/A	None. EFU not required. NUs provide HVAC.	
			B, C	Fail to operate fan motor	Flow alarm, low; motor indicating lights	Loss of train A. Train B available.	
21.	Breakers, 480-V switchgear, 1E Bus, for item 22, No. 4 breaker on 1BB07	Provide continuity and protection to fan motor item 22	A	Inadvertent closed	Motor indicating lights	None. EFU not required. NUs provide HVAC.	
			B, C	Fail to close	Motor indicating lights; flow alarm, low	None. Loss of train B. Train A available.	
22.	Control building control room filter unit fan motor, ND 1-1531-N7-002-M01	Provide motor power to circulate air	A	N/A	N/A	None. EFU not required. NUs provide HVAC.	
			B, C	Fail to operate fan motor	Flow alarm, low; motor indicating lights	None. Loss of train B. Train A available.	
23.	Breakers, 480-V switchgear, 1E Bus, for item 24 No. 06 breaker on 1AB05	Provide continuity and protection to heater (item 24)	A	Inadvertent closed	Heater indicating lights	None. EFU not required. NUs provide HVAC.	
			B, C	Fail to close	Heater indicating lights; flow alarm, low	None. Loss of train A. Train B available.	
24.	Control building control room electrical heater, ND 1-1531-N7-001-H01	Provide heat, and reduce relative humidity and extract moisture	A	N/A	N/A	None. EFU not required. NUs provide HVAC.	
			B, C	Fail to operate	Moisture alarm; temperature indicating lights	None. Loss of train A. Train B available.	

TABLE 6.4.4-1 (SHEET 6 OF 14)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
25.	Breaker 480-V switchgear, 1E Bus, for item 26, NO No. 6 breaker on 1BB07	Provide continuity and protection to heater (item 26)	A	Inadvertent closed	Heater indicating lights	None. EFU not required. NUs provide HVAC.	
			B, C	Fail to close	Heater indicating lights; flow alarm, low	None. Loss of train B. Train B available.	
26.	Control building control room electrical heater, ND 1-1531-N7-002-H01	Provide heat, and reduce relative humidity and extract moisture	A	N/A	N/A	None. EFU not required. NUs provide HVAC.	
			B, C	Fail to operate	Moisture alarm; temperature indicating lights	None. Loss of train B. Train A available.	
27.	Breakers, 480-V MCC, 1E Bus, for item 29, NC No. 23 breaker on 1ABA	Provide continuity and protection to damper (item 29)	A, D	Inadvertent open	Position indicating lights; MCC alarm	None. Normally closed damper will remain closed.	
			B, C	Inadvertent open	Flow alarm, low; position indicating lights; MCC alarm	None. Loss of train A. Train B available.	
28.	Motor starter for item 29, NC No. 23 motor starter on 1ABA	Provide continuity to damper (item 29)	A, D	Inadvertent closed	Position indicating lights	None. EFU not required. NUs provide HVAC.	
			B, C	Fail to close	Flow alarm, low; position indicating lights	None. Loss of train A. Train B available.	

TABLE 6.4.4-1 (SHEET 7 OF 14)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
29.	Motor-operated on-off damper, NC 1HV12128 on 1ABA	Remain close on normal mode, and opens on CRI	A, D	Inadvertent open	Position indicating lights	None. EFU not required. NUs provide HVAC. In smoke mode, close the damper manually.	
			B, C	Fail to open	Flow alarm, low; position indicating lights	None; Loss of train A. Train B available.	
30.	Breaker, 480-V MCC, 1E Bus, for item 32, NC No. 23 breaker on 1BBA	Provide continuity and protection to damper (item 32)	A, D	Inadvertent open	Position indicating lights; MCC alarm	None. Normally closed damper will remain closed.	
			B, C	Inadvertent open	Flow alarm, low; position indicating lights; MCC alarm	None. Loss of train B. Train A available.	
31.	Motor starter for item 32, NC No. 23 motor starter on 1BBA	Provide continuity to damper (item 32)	A, D	Inadvertent closed	Position indicating lights	None. EFU not required. NUs provide HVAC.	
			B, C	Fail to close	Flow alarm, low; position indicating lights	None. Loss of train B. Train A available.	
32.	Motor-operated on/off damper, NC 1HV12129 on 1BBA	Remain closed on normal mode, and open on CRI	A, D	Inadvertent open	Position indicating lights	None. EFU not required. NUs provide HVAC. In smoke mode, close the damper manually.	
			B, C	Fail to open	Flow alarm, low; position indicating lights	None. Loss of train B. Train A available.	
33.	Breakers, 480-V MCC, 1E Bus, for item 35, NC No. 6 breaker on 1ABA[c]	Provide continuity and protection to fan motor (item 35)	A, D	Inadvertent open	MCC alarm; motor indicating lights	None. EFU not required. NUs provide HVAC.	
			B, C	Inadvertent open	Flow alarm, low; position indicating lights; MCC alarm	None. Loss of train A. Train B available.	

TABLE 6.4.4-1 (SHEET 8 OF 14)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
34.	Motor starter for item 35, NO No. 6 motor starter on 1ABA[c]	Provide continuity and protection to fan motor (item 35)	A, D	Inadvertent closed	Motor indicating lights	None. EFU not required. NUs provide HVAC.	
			B, C	Fail to close	Flow alarm, low; motor indicating lights	None. Loss of train A. Train B available.	
35.	Control building control room return air fan motor, ND 1-1531-B7-005-M01[c]	Provide motive power to circulate air	A, D	N/A	N/A	None. EFU not required.	
			B, C	Fail to operate fan motor	Flow alarm, low; motor indicating lights	None. Loss of train A. Train B available.	
36.	Breaker, 480-V MCC, 1E Bus, for item 38, NC No. 6 breaker on 1BBA[c]	Provide continuity and protection to fan motor (item 38)	A, D	Inadvertent open	MCC alarm; motor indicating lights	None. EFU not required. NUs provide HVAC.	
			B, C	Inadvertent open	Flow alarm, low; position indicating lights; MCC alarm	None. Loss of train B. Train A available.	
37.	Motor starter for item 38, NO No. 6 motor starter on 1BBA[c]	Provide continuity and protection to fan motor (item 38)	A, D	Inadvertent closed	Motor indicating lights	None. EFU not required. NUs provide HVAC.	
			B, C	Fail to close	Flow alarm, low; motor indicating lights	None. Loss of train B. Train A available.	
38.	Control building control room return air fan motor, ND 1-1531-B7-006-M01[c]	Provide motor power to circulate air	A, D	N/A	N/A	None. EFU not required.	
			B, C	Fail to operate	Flow alarm, low; motor indicating lights	None. Loss of train B. Train A available.	
39.	Breaker, 480-V MCC, 1E Bus, for item 41, NC No. 21 breaker on 1ABA	Provide continuity and protection to damper (item 41)	A, D	Inadvertent open	Position indicating lights; MCC alarm	None. Normally closed damper will remain closed.	

TABLE 6.4.4-1 (SHEET 9 OF 14)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
			B, C	Inadvertent open	Flow alarm, low; position indicating lights; MCC alarm	None. Loss of train A. Train B available.	
40.	Motor starter for item 41, NO No. 21 motor starter on 1ABA	Provide continuity to damper (item 41)	A, D	Inadvertent close	Position indicating lights	None. EFU not required. NUs provide HVAC.	
			B, C	Fail to close	Flow alarm, low; position indicating lights	None. Loss of train A. Train B available.	
41.	Motor-operated on-off damper, NC 1HV12130 damper on 1ABA	Remain closed on normal mode, and open on CRI	A, D	Inadvertent open	Position indicating lights	None. EFU not required. NUs provide HVAC. In smoke mode, damper can be closed manually.	
			B, C	Fail to open	Flow alarm, low; position indicating lights	None. Loss of train A. Train B available.	
42.	Breaker, 480-V MCC, 1E Bus, for item 44, NC No. 21 breaker on 1BBA	Provide continuity and protection to damper (item 44)	A, D	Inadvertent open	Position indicating lights; MCC alarm	None. Normally closed damper will remain closed.	
			B, C	Inadvertent open	Flow alarm, low; position indicating lights; MCC alarm	None. Loss of train B. Train A available.	
43.	Motor starter for item 44, NO No. 21 motor starter on 1BBA	Provide continuity to damper item 44	A, D	Inadvertent close	Position indicating lights	None. EFU not required. NUs provide HVAC.	
			B, C	Fail to close	Flow alarm, low; position indicating lights	None. Loss of train B. Train A available.	
44.	Motor-operated on-off damper, NC 1HV12131 on 1BB1	Remain closed on normal mode and opens on CRI	A, D	Inadvertent open	Position indicating lights	None. EFU not required. NUs provide HVAC. In smoke mode, damper can be closed manually.	
			B, C	Fail to open	Flow alarm, low; position indicating lights	None. Loss of train B. Train A available.	

TABLE 6.4.4-1 (SHEET 10 OF 14)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
45.	Breakers, 480-V MCC, 1E Bus, for item 47, NC No. 14 breaker on 1ABA	Provide continuity and protection to fan motor item 47	A, B, C, D	Inadvertent open	MCC alarm; motor indicating lights; flow alarm, low	None. Loss of train A. Train B available.	
46.	Motor starter for item 47, NC No. 14 motor starter on 1ABA	Provide continuity to fan motor, item 47	A, B, C, D	Inadvertent open	Flow alarm, low; motor indicating lights	None. Loss of train A. Train B available.	
47.	Control building control room engineered safety features (ESF) chiller room exhaust fan motor, normally energized (NE) 1-1531-B7-002-M01	Provide motive power, to exhaust air	A, B, C, D	Fail to operate	Flow alarm, low; motor indicating lights	None. Loss of train A. Train B available.	
48.	Breaker 480-V MCC, 1E Bus, for item 50, NC No. 14 breaker on 1BBA	Provide continuity protection to fan motor item 50	A, B, C, D	Inadvertent open	MCC alarm; motor indicating lights; flow alarm, low	None. Loss of train B. Train A available.	
49.	Motor starter for item 50, NC No. 14 motor starter on 1BBA	Provide continuity to fan motor (item 50)	A, B, C, D	Inadvertent open	Flow alarm, low; motor indicating lights	None. Loss of train B. Train A available.	
50.	Control building control room ESF chiller room exhaust fan motor NE 1-1531-B7-004-M01	Provide motor power to exhaust air	A, B, C, D	Fail to operate	Flow alarm, low; motor indicating lights	None. Loss of train B. Train A available.	
51.	Fan, fan shaft, bearing, filter, damper, etc., for air filtration unit 1-1531-N7-001-000	Provide circulation filtration and control of air flow	B, C	Mechanical failure	Flow alarm, low; pressure differential alarm, high; temperature alarm, high	None. Loss of train A. Train B available.	
52.	Fan, fan shaft, bearing, filter, damper, etc., for air filtration unit 1-1531-N7-002-000	Provide circulation filtration and control of air flow	B, C	Mechanical failure	Flow alarm, low; pressure differential alarm, high; temperature alarm, high	None. Loss of train B. Train A available.	

TABLE 6.4.4-1 (SHEET 11 OF 14)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
53.	Cooling coil for air filtration unit 1-1531-N7-001-000	Provide cooling and heat removal in the area	B, C	Leakage in cooling coil	Water flow alarm, low; temperature alarm, low	None. Loss of train A. Train B available.	
54.	Cooling coil for air filtration unit 1-1531-N7-002-000	Provide cooling and heat removal in the area	B, C	Leakage in cooling coil	Water flow alarm, low; temperature alarm, high	None. Loss of Train B. Train A available.	
55.	HV12162 air-operated on-off damper NO/FC	Remain open to allow flow of air in normal and smoke modes, and close on CRI so that EFU will provide HVAC	A	Inadvertent closed	Position indicating lights	None. Damper can be manually opened.	Common to Units 1 and 2
			B, C	Fail to close	Position indicating lights	None. Item 56 available.	
			D	Inadvertent closed	Position indicating lights	None. Damper can be manually opened	
56.	HV12163 air-operated on-off dampers NO/FC	Remain open to allow flow of air in normal and smoke modes, and close on CRI so that EFU will provide HVAC	A	Inadvertent closed	Position indicating lights	None. Damper can be manually opened.	Common to Units 1 and 2
			B, C	Fail to close	Position indicating lights	None. Item 55 available.	
			D	Inadvertent closed	Position indicating lights	None. Damper can be manually opened.	
57.	1-1531-B7-002-000 fan, fan shaft bearing, motor, etc.	Provide motive power to circulate air	B, C, D	Mechanical failure	Flow alarm, low; temperature alarm, high	None. Loss of train A. Train B available.	

TABLE 6.4.4-1 (SHEET 12 OF 14)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
58.	1-1531-B7-004-000 fan, fan shaft, bearing, motor, etc.	Provide motive power to circulate air	B, C, D	Mechanical failure	Flow alarm, low; temperature alarm, high	None. Loss of train B. Train A available.	
59.	DELETED.						
60.	DELETED.						
61.	Smoke monitor 1AE12167	Monitor smoke in intake air and alarms at high smoke concentration and isolates intake air	C	Fail to give smoke alarm at high smoke concentration	Smoke alarm high on smoke monitor 1AE12166	None. Automatically isolate Unit 1 side intake by closing dampers 1HV12114 and 1HV12115. Use Unit 2 air intake.	If smoke concentration is also high on Unit 2 air intake, go on recirculation mode with no outside air intake
				False alarm	No alarm on smoke monitor 1AE12166	None. Smoke concentration is not high.	
62.	Smoke monitor 1AE12166	Monitor smoke in intake air and alarms at high smoke concentration and isolates intake air	C	Fail to give smoke alarm at high smoke concentration	Smoke alarm high on smoke monitor 1AE12167	None. Automatically isolate Unit 1 side intake by closing dampers 1HV12114 and 1HV12115. Use Unit 2 air intake.	If smoke concentration is also high in Unit 2 air intake go on recirculation mode with no outside air intake
				False alarm	No alarm on smoke monitor 1AE12167	None. Smoke concentration is not high.	
63.	Radiation monitor 1RE12117	Monitor radiation in intake air and alarms at high radiation level	C	Fail to give radiation alarm at high radiation	Radiation alarm high on radiation monitor 1RE12116	None. Use EFU to filter iodine. Item 64 available also.	
				False alarm	No alarm on radiation monitor 1RE12116	None. Radiation level is not high.	

TABLE 6.4.4-1 (SHEET 13 OF 14)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
64.	Radiation monitor 1RE12116	Monitor radiation in intake air, and alarms at high radiation level	C	Fail to give radiation alarm at high radiation	Radiation alarm high on radiation monitor 1RE12117	None. EFU to filter iodine. Item 63 available also.	
				False alarm	No alarm on radiation monitor 1RE12117	None. Radiation level is not high.	
65.	1-1531-D7-103 backdraft damper (return duct)	Open with air flow in return direction and close on opposite flow	A&D	N/A	N/A	N/A	
			B&C	One blade fails to open	None	None. Flow variation is within allowable tolerances. Control room +VE pressure will be maintained.	
66.	1-1531-D7-104 backdraft damper (outside air)	Open with air flow in outside air supply direction and close on opposite flow	A&C&D	N/A	N/A	N/A	
			B	One blade fails to open	None	None. Flow variation is within allowable tolerances. Control room +VE pressure will be maintained.	
67.	1-1531-D7-105 backdraft damper (return duct)	Same as Item 65					
68.	1-1531-D7-106 backdraft damper (outside air)	Same as Item 66					

TABLE 6.4.4-1 (SHEET 14 OF 14)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
69.	Flow switch FSL-12045	Monitor supply air flow of filter unit 1-1531-N7-002 to prevent starting of 1-1531-N7-001; or upon sensing low flow, to provide permissive start of filter unit 1-1531-N7-001	A&D	N/A	N/A	N/A	
			B&C	Fail to detect air flow; no power	Lights for both units 1-1531-N7-001 1-1531-N7-002 will run until N7-002[(b)]	None. Flow switch FSL-12045 will detect no flow in 1-1531-N7-002 supply duct and thus start 1-1531-N7-001.	
70.	Flow switch FSL-12046	Monitor supply air flow of filter unit 1-1531-N7-001 to stop lead filtration unit 1-1531-N7-002 upon sensing flow	A&D	N/A	N/A	N/A	
			B&C	Fail to detect air flow; no power	None	None. Flow indicator FI-12192 will indicate 1-1531-N7-002 is running.	
				False flow indication	None	None, Lead/lag logic will start 1-1531-N7-001	

a. Plant operating modes are as follows:

A - Normal mode: HVAC normal units (NU) operating; outside and recirculation supply air; positive room pressure relative to the atmosphere.
B - Emergency mode: HVAC emergency filtration units (EFU) operating; outside and recirculation supply air; positive room pressure relative to the atmosphere. *Trips after FSL-12046 sensing flow on N7-001 unit.
C - Isolation mode: EFU operating; recirculation only; zero pressure differential; outside smoke.
D - Smoke purge mode: HVAC NU operating; outside air only; negative room pressure relative to the atmosphere (smoke inside control room).

b. Trips after FSL-12046 sensing flow on N7-001 unit.

c. The return air fans are disabled and abandoned in place.

TABLE 6.4.6-1

CONTROL ROOM HVAC INDICATIONS AND ALARMS

Control room differential pressure (high or low alarm)

Control room area radiation (indication and high alarm)

Control room smoke (high alarm)

Smoke in control room intake (high alarm)

Radiation level in control room intake (indication and high alarm)

Fan operating status

Isolation damper position

Differential pressure across first HEPA filter (indication and high alarm)

Differential pressure across total filter unit (indication and high alarm)

Moisture content downstream of the moisture eliminator (indication and high alarm)

Temperature in charcoal filter (high alarm, high high alarm)

Temperature of filter unit upstream and downstream of the charcoal filter (indication)

Airflow rate at filter unit outlet (indication and high or low alarm)

6.5 FISSION PRODUCT REMOVAL AND CONTROL SYSTEMS

Several plant features serve to reduce or limit the release of fission products following a postulated loss-of-coolant accident (LOCA) or fuel handling accident. This section provides a discussion of the function of the emergency filter systems (subsection 6.5.1) and the containment spray system (subsection 6.5.2) to mitigate the consequences of an accident. The design of each of these engineered safety features (ESF) is discussed in other referenced sections. Chapter 15 addresses the radiological consequences of postulated accidents and demonstrates the adequacy of the fission product removal and control systems.

Other sections provide the design bases and safety evaluations which demonstrate that the design and construction of these systems is commensurate with acceptable practices for ESF. This includes, but is not limited to, ensuring redundancy, isolation from nonsafety-related portions, seismic classification, conformance with Regulatory Guide 1.52 (section 1.9), suitability of material for the intended service, Class 1E power supply from onsite or offsite sources, qualification testing, and capability for inspection and testing.

6.5.1 ENGINEERED SAFETY FEATURES FILTER SYSTEMS

The ESF filter systems include the control room heating, ventilation, and air-conditioning (HVAC) system discussed in section 6.4 and subsection 9.4.1, the fuel handling building post-accident exhaust system discussed in subsection 9.4.2, and the piping penetration filter exhaust system discussed in subsection 9.4.3. The performance of the systems under postulated accident conditions is discussed in sections 15.6 and 15.7. The post-LOCA purge exhaust system is nonsafety related; it is discussed in subsection 6.2.5.

6.5.1.1 Design Bases

The ESF filter systems are designed to accomplish the following:

A. The control room HVAC system ensures that the radiation exposures to operating personnel in the control room resulting from a design basis accident, as discussed in chapter 15, are within the guideline values of 10 CFR 50, Appendix A, General Design Criterion (GDC) 19.

B. The piping penetration filter exhaust system is designed to maintain the filtration unit rooms at - 1/4 in. WG with respect to atmosphere. This condition ensures that the piping penetration areas which contain post-LOCA recirculation components are maintained at a negative pressure with respect to adjacent areas to prevent uncontrolled exfiltration of potentially contaminated air and to minimize release of airborne radioactivity to the outside atmosphere resulting from containment and penetration area leakage under accident conditions. The piping penetration filter exhaust system ensures that the offsite radiation exposures resulting from the postulated post-LOCA leakage in recirculation piping, as discussed in subsection 15.6.5, are within the guideline values of 10 CFR 100. It also ensures that the emergency core cooling system and containment spray pump rooms can be purged to allow access for repair and maintenance of the equipment.

   The drain isolation valves for ESF equipment rooms and negative pressure boundary areas are procured as project class 313 but are installed as project class 414. These valves are required to be locked closed to ensure validity of the offsite dose exposure analysis as tabulated in table 15.6.5-6.

C. The fuel handling building post-accident exhaust system is designed to maintain a slightly negative pressure within the fuel handling building following a fuel handling accident to minimize release of airborne radioactivity to the outside atmosphere. The post-accident exhaust system filter will reduce doses, but is not required to ensure that the offsite radiation exposures and exposures to operating personnel in the control room resulting from a postulated fuel handling accident in the fuel handling building, are within the guideline values of 10 CFR 100 and 10 CFR 50, Appendix A, GDC 19, respectively. As discussed in subsection 15.7.4, no credit is taken for filter operation.

D. The failure of any active component in a filtration system, assuming loss of offsite power, cannot impair the ability of the system to perform its safety function.

E. The ESF filter systems are designed to remain intact and functional in the event of a safe shutdown earthquake.

F. The ESF filter systems are designed to be consistent with the recommendations of Regulatory Guide 1.52, as discussed in section 1.9.

The design bases for sizing the filters, fans, and associated ductwork are discussed in subsections 9.4.1, 9.4.2, 9.4.3, and 9.4.5.

6.5.1.2 System Design

6.5.1.2.1 General System Description

The control room emergency ventilation and air-conditioning system is described in section 6.4 and subsection 9.4.1. The piping penetration filter exhaust system is described in subsection 9.4.3. The fuel handling building post-accident cleanup system is described in subsection 9.4.2. Flow diagrams for each system are shown in the appropriate subsections.

6.5.1.2.2 Component Description

Each ESF filter train consists of a moisture separator, a heating coil, an upstream high-efficiency particulate air (HEPA) filter, a charcoal adsorber with fire detection temperature sensors, and a downstream HEPA filter. The filtration trains are connected to fans with direct drive motors, associated ductwork, and controls. Specific component design parameters are provided in table 6.5.1-1.

The filter housing design provides adequate space for filter maintenance and inspection. The housing is fitted with the necessary ports for testing. Pipe, cable, and conduit penetrations are sealed to minimize leakage. Access doors are marine-type, bulkhead doors with gas-tight seals.

The charcoal adsorber portion of each filter train is provided with a fire detection system and a water spray system to allow flooding of the charcoal bed to prevent bed ignition from radioactivity-induced heat. Fire protection systems for the carbon adsorbers are discussed in subsection 9.5.1.

The electric heaters provided in the control room emergency ventilation and air conditioning system air filtration units are designed to reduce the relative humidity of the entering air stream mixture to 70 percent from as high as 100 percent.

Relative humidity is maintained by use of a moisture controller which, as relative humidity approaches 70 percent, modulates the electric heater to gradually raise the air temperature, thus lowering the relative humidity.

The electric heaters in the piping penetration filter exhaust system and the fuel handling building post-accident exhaust system reduce relative humidity, thereby improving adsorber efficiency. However, the heaters are not required to maintain the relative humidity of the entering air stream mixture to less than 70 percent. Although a moisture controller is provided to modulate the electric heaters as relative humidity approaches 70 percent, no credit is taken for humidity control in these systems.

6.5.1.2.3 System Operation

In the event of a LOCA, the piping penetration filter exhaust system functions to limit and reduce the potential release of fission products due to ECCS recirculation line and component leakage. Specific details of system operation following a LOCA are provided in subsections 9.4.3 and 9.4.5.

In the event of a fuel handling accident in the fuel handling building, the emergency exhaust system functions to reduce the fission product release from that building. Specific details of system operation following a fuel handling accident are provided in subsection 9.4.2.

In the event of high radiation levels in the control room outside air intake, the control room emergency HVAC systems provide the control room with a filtered supply of air. Specific details of system operation following a LOCA are discussed in section 6.4 and subsection 9.4.1.

6.5.1.3 Design Evaluation

A. The performance capability of the control room emergency filters and the design of individual components which ensure the capability to perform the safety function are discussed in section 6.4. Control room doses resulting from postulated radiological accidents are given in section 15.6. These doses are within the guideline values of 10 CFR 50, Appendix A, GDC 19.

B. Component descriptions and safety evaluation for the piping penetration exhaust filters are provided in subsection 9.4.3. Dose analyses of post-LOCA leakage in recirculation piping is discussed in subsection 15.6.5. Offsite radiation exposures and control room doses resulting from this leakage are within the guideline values of 10 CFR 100 and 10 CFR 50, Appendix A, GDC 19, respectively.

C. Component descriptions and safety evaluation for the fuel handling building post-accident exhaust system are provided in subsection 9.4.2. Dose analyses of postulated fuel handling accidents are discussed in subsection 15.7.4. Offsite radiation exposures and control room doses resulting from these accidents are within the guideline values of 10 CFR 100 and 10 CFR 50, Appendix A, GDC 19, respectively.

D. The control room HVAC system, the piping penetration filter exhaust system, and the fuel handling building post-accident exhaust system each consist of two independent and redundant filtration trains with respect to active components. Should any active component in one train fail, filtration can be performed by the other train, which is powered from a separate Class 1E electrical bus. Failure modes and effects analyses are provided in section 6.4 and subsections 9.4.2 and 9.4.3.

E. The ESF filter systems are designed to Seismic Category 1 requirements. The components and supporting structures of any system, piece of equipment, or structure that is not Seismic Category 1, and whose collapse could result in loss of safety function of the ESF filter systems through either impact or flooding, have been evaluated to determine that they will not collapse when subjected to seismic loading.

F. The ESF filter systems are designed and constructed to be consistent with the recommendations of Regulatory Guide 1.52 as discussed in section 1.9.

G. The ESF filters have been conservatively analyzed to determine the bed temperature under worst-case accident conditions. The analysis demonstrated that the temperature of the charcoal beds will remain below the 300°F limit recommended by ANSI N509-1980. Thus, no cooling mechanism is supplied for the filters.

6.5.1.4 Tests and Inspections

6.5.1.4.1 Preoperational Testing

The HEPA filters are manufactured and tested prior to installation in accordance with MIL-F-51068. The HEPA filter banks are tested in place prior to operation to verify a minimum of 99.95-percent retention (99.0 percent for FHB filters) with a dioctyl phthalate aerosol (DOP) in accordance with American National Standards Institute (ANSI) N510 and conforms with Position C.5.b of Regulatory Guide 1.52, as discussed in section 1.9.

The original and replacement batches of impregnated, activated carbon are batch tested in accordance with Regulatory Guide 1.52, as discussed in section 1.9, prior to loading into the adsorber section. Tests include particle size distribution, hardness, density, moisture content, impregnant content, ash content, impregnant leachout, and elemental iodine and methyl iodine removal efficiencies at postulated accident conditions. The charcoal adsorber is leak tested prior to operation to verify a minimum of 99.95-percent retention. In addition, a laboratory test of a representative sample of the impregnated, activated charcoal is performed to verify iodine removal efficiencies in accordance with Position C.6 and table 2 of Regulatory Guide 1.52, as discussed in section 1.9.

Air filtration units are acceptance tested in accordance with ANSI N510, as discussed in section 1.9.

Design and testing of ESF filtration systems are consistent with the recommendations of Regulatory Guide 1.52, as discussed in section 1.9.

Fans are factory tested in accordance with standards of the Air Moving and Conditioning Association Standard 210.(2)

Moisture separators are tested in accordance with ANSI N509, paragraph 5.4, as discussed in subsection 1.9.52, and capable of removing at least 99 percent of the entrained moisture in an airstream.

The drain design and the accessibility of components and provisions for maintenance are in accordance with ANSI N509, as discussed in section 1.9.

6.5.1.4.2 Inservice Testing

Inservice testing of the ESF filtration systems is conducted in accordance with the surveillance requirements given in the Technical Specifications and Technical Requirements Manual, as applicable.

6.5.1.5 Instrumentation Requirements

Controls and instrumentation for the control room HVAC, piping penetration filter exhaust, and fuel handling building post-accident exhaust systems are discussed in section 7.3 and subsections 9.4.1, 9.4.2, and 9.4.3. Instrumentation is summarized in table 6.5.1-2. Each system is designed to function automatically upon receipt of an ESF actuation system signal. Fans can also be controlled from the control room. The status of the ESF filter systems equipment is displayed in the control room during both normal and accident operations. Instrumentation is consistent with the recommendations of Regulatory Guide 1.52, as discussed in section 1.9.

6.5.1.6 Materials

The materials of construction used in or on the filter systems are given in table 6.5.1-3. Each of the materials is compatible with the normal and accident environments postulated in the control room, the fuel handling building, and the penetration areas.

6.5.1.7 Standard Review Plan Evaluation

The design of the ESF atmospheric cleanup systems conforms to the majority of the items delineated in table 6.5.1-1. The requirements of table 6.5.1-1 and nonconformative items are listed below with the VEGP design rationale:

A. A prefilter ahead of the pre-HEPA is required for the removal of submicron particles.

   The demister provided for the ESF filtration systems has the same filtration efficiency as a prefilter in removing submicron particles in the airstream. Therefore, the demister serves the same function as a prefilter in preserving the life of the HEPA filter. Regulatory Guide 1.52, paragraph C.2.(2) permits demisters to fulfill the prefilter function.

B. Local and control room temperature readout and alarm signals are required for the air entering the electric heater.

   The basic purpose of providing an electric heater in the airstream is to lower the relative humidity of the air before it reaches the charcoal filters, which are less efficient at high relative humidity. Moisture entering the HEPA filters is monitored with a high alarm provided in the control room. In addition, temperature indication upstream and downstream of the charcoal filters is also provided in the control room.

For clarification, air that passes through the ESF filtration systems is room air conditioned to the design temperatures which range from 40°F to 104°F.

C. Local pressure drop indication and high alarm signal are required for the second HEPA (post-HEPA).

A local high alarm of the pressure drop across the second HEPA filter is not provided, since the filter equipment rooms are potentially high radiation areas under post-accident conditions. Dust loading would result in a high pressure drop across the first HEPA filter, which is alarmed, before it would cause high pressure drop across the second HEPA filter.

Charcoal used in the charcoal adsorbers meets the specifications of ANSI N509; therefore, only a small quantity of charcoal fines would be expected to accumulate on the second HEPA filter. Since the ESF filtration systems do not operate during normal operation, periodic maintenance and surveillance in accordance with the Technical Specifications and Technical Requirements Manual will ensure filter pressure drops are in normal operating ranges.

D. Local and control room hand switch and status indication is required for the deluge valves.

The ESF filtration units charcoal filters are protected by manual deluge systems with automatic detection. Unit 1/Common filtration units have the deluge system water supply positively isolated by removal of a pipe spool piece. Unit 2 filtration units are provided with a manual fire hose connection.

E. No local indication (or continuous recording in the control room) is provided for unit inlet or outlet flow.

System flow is indicated and high-flow or low-flow is alarmed in the control room, which is a continuously manned location. Local indication is not provided since filter equipment rooms are potentially high radiation areas under post-accident conditions.

F. No local high alarm signal is provided of the pressure drop across the prefilter (demister in the VEGP design).

Demister pressure drop is indicated locally. Standard Review Plan table 6.5.1-1 does not require an alarm, which is listed as optional.

G. Local status indication is provided for the electric heater.

H. No local indication, high alarm, and low alarm signals are provided, and no high alarm, low alarm, and trip alarm signals are provided in the control room for a temperature sensor located between the heater and the first HEPA filter.

Temperature downstream of the first HEPA filter is monitored in lieu of the upstream temperature. The downstream temperature, which is indicated in the control room, is representative of the upstream temperature. The temperature sensor was located on the downstream side of the HEPA filter to minimize the influence of thermal radiation from the heaters. Local indication and alarm is not provided since equipment rooms are potentially high radiation areas under post-accident conditions.

In addition to the above indication, temperature of the charcoal bed is also monitored. A two-stage high-temperature alarm is provided in the control room. Although no low temperature alarm is provided in the control room, a high humidity alarm is available which provides direct indication of high humidity rather than the indirect indication a low temperature alarm would provide.

The heater unit also has two temperature sensing elements that will automatically shut down the heater. The heater is automatically shut down when the temperature in the airstream exceeds approximately 210°F. As the temperature is reduced, the cutout will automatically reset. If the temperature in the airstream should exceed approximately 260°F, the heater is automatically shut down. As the temperature is reduced, the cutout will automatically reset. Although no high alarm or trip alarm signals are provided in the control room for a temperature sensor between the heater and the first HEPA filter, the above described automatic cutout features of the heater unit, the temperature indication in the control room for the temperature downstream of the first HEPA filter, and the high alarm and high-high alarm in the control room for the charcoal bed temperature assure that the ESF atmosphere cleanup systems perform their design safety functions.

I. No local high alarm signal is provided, and no recorded indication is provided in the control room of the pressure drop across the first HEPA filter.

A local high alarm of the pressure drop across the first HEPA filter is not provided, since the filter equipment rooms are potentially high radiation areas under post-accident conditions.

Although no recorded indication is provided in the control room of the pressure drop across the first HEPA filter, indication and a high pressure drop alarm across the first HEPA filter is provided in the control room.

A high pressure drop across the entire filtration unit is also alarmed in the control room. This provides the necessary information to access the effectiveness of the first HEPA filter.

J. No local two-stage high alarm signal is provided for a temperature sensor located between the adsorber and the second HEPA filter.

A local two-stage high alarm of the temperature between the charcoal adsorber and the second HEPA filter is not provided, since the filter equipment rooms are potentially high radiation areas under post-accident conditions.

A two-stage high alarm signal is provided in the control room for charcoal bed temperature as described in "H" above.

6.5.1.8 References

1. "Filter, Particulate, High Efficiency, Fire Resistant," MIL-F-51068D.
2. "Laboratory Methods of Testing Fans for Rating Purposes," Air Moving and Conditioning Association Standard 210, 1974.

6.5.2 CONTAINMENT SPRAY SYSTEMS (FISSION PRODUCT REMOVAL)

The containment spray system (CSS) is an engineered safety features (ESF) system that is operated, following a postulated loss-of-coolant accident (LOCA), to reduce the pressure, temperature, and iodine activity of the containment atmosphere. To accomplish these aims, the system sprays subcooled solution into the containment through nozzles suspended from the containment dome.

Radioiodines are of primary concern in the radiological consequence evaluation of a LOCA. A primary function of the spray system is the absorption of elemental iodine.

To enhance the spray's iodine absorption capacity, the spray recirculation solution is adjusted to an alkaline pH which promotes the hydrolysis of iodine to nonvolatile forms.

The mechanical components of the CSS are described in subsection 6.2.2. The actuation times for the CSS are event dependent and are described in the individual accident analyses.

6.5.2.1 <u>Design Bases (For Fission Product Removal)</u>

The CSS provides a spray injection solution with a pH of approximately 4.5 and a final recirculation sump solution with a pH in the range of 7.0 to 10.5.

Fifty percent of the core equilibrium iodine inventory is assumed to be released to the containment atmosphere and available for leakage to the environment. The iodine released from the core is assumed to consist of 91% elemental, 4% organic, and 5% particulates.[1]

The CSS reduces the elemental iodine inventory in the containment atmosphere until a decontamination factor (DF) of 21.4 is achieved. The CSS also removes particulates from the containment atmosphere. The extent to which credit is taken for particulate removal is discussed in paragraph 6.5.2.3.

Additional design bases associated with the heat removal capability of the CSS are presented in subsection 6.2.2.

6.5.2.2 <u>System Design (For Fission Product Removal)</u>

The containment spray pumps and headers described in subsection 6.2.2 are utilized for fission product removal.

Crystalline trisodium phosphate (TSP) is utilized to raise the pH of the ECCS solution in the containment sump since the initial pH of the boric acid ECCS solution will be approximately 4.5. The TSP will be stored in baskets located in the post-LOCA flooded region of the containment building. As the initial spray solution and subsequently the recirculation solution comes in contact with the TSP, the TSP will dissolve, raising the pH of the sump solution to an equilibrium value in the range of 7.0 to 10.5.

This ensures that elemental iodine will be retained in the sump and will not re-evolve from the spray droplets during the recirculation phase.

The mechanical components and operation of the spray additive system are described in detail in subsection 6.2.2. There are two independent trains of spray nozzles located in the containment dome region. Each train consists of three ring headers. There is a total of 342 spray nozzles. The spray nozzle locations and orientations are shown in drawings 1X4DL4A01, 1X4DL4D01, and 1X4DL4D09.

The spray nozzles used are SPRACO model 1713A. The nozzles are the ramp bottom, swirl chamber type with a discharge orifice diameter of 3/8 in. The nozzles cannot clog since there are no internal parts, such as swirl vanes, and the maximum particle size entrained in the spray flow is limited to < 3.8 in. in diameter (see section 6.1.2) by the emergency sump screen perforations. Spray drop size distribution is presented in figure 6.5.2-1 and is discussed in detail in reference 2. The spray system operating modes, water sources, and initiation signals are described in paragraph 6.2.2.2. The system component design parameters are presented in table 6.2.2-4.

Approximately 78 percent of the net free containment volume is sprayed. This volume consists of the containment volume above the operating deck and the regions below the operating deck impinged directly by the spray. The unsprayed containment regions are described in table 6.5.2-1. The mixing rate between the sprayed and unsprayed containment volumes is assumed to be the minimum safeguards containment cooler air flowrate.

6.5.2.3 Design Evaluation

Containment spray system performance is evaluated using a spray model developed by Westinghouse. The model considers the effects of spray drop size distribution, droplet coalescence, gas and liquid phase mass transfer resistance, drop trajectories, and condensation of steam on the drops.

The elemental iodine removal capability of the containment spray is described in terms of the individual spray droplets. The behavior of the aggregate spray is related to the behavior of the individual drops, by means of a drop size distribution function.

An advantage to using this microscopic approach is the ability to derive the model from first principles. Thus, the model is free of any scaling factors which would be required to extrapolate laboratory test data to a full-size reactor containment.

A conservative spray removal coefficient as shown in table 6.5.2-2 is used based on data provided in references 5 and 6. The elemental iodine removal analysis assumes that the containment spray system is operating at minimum capacity (one of two spray pumps) and that the emergency core cooling system (ECCS) is operating at maximum capacity. Although the CSS will operate for a minimum of 2 h, no spray removal of elemental iodine is assumed after a DF of 21.4 is achieved for the containment atmosphere.

The particulate washout coefficient is calculated by the method outlined in reference 5. Removal of particulate iodine is assumed for the duration of the spray period.

The deposition removal coefficient for elemental iodine is determined based on guidance of reference 5. Deposition is assumed to occur only on galvanized surfaces and surfaces coated with zinc based paint or epoxy paint. Deposition removal of iodine is assumed to continue at the initial rate until a DF of 50 is achieved for the containment atmosphere and then at a reduced rate until a DF of 200 is achieved.

The spray system performance was evaluated at the peak containment pressure postulated to occur following a LOCA. Presented in figure 6.5.2-2 is the spray reduction factor as a function of post-LOCA containment saturation temperature. In the determination of operating deck coverage, the reduction factor was applied to both the spray throw distance and the spray envelope diameter.

The spray nozzle capacity curve is presented in figure 6.5.2-3. In those cases where operation of containment spray has been initiated and a LOCA is indicated, the containment will be sprayed continuously for a minimum of 2 hours. The transfer from spray injection to spray recirculation will be made manually.

Table 6.5.2-2 lists the input parameters and results of the spray iodine removal analysis.

6.5.2.4 Tests and Inspection

Refer to subsection 6.2.2 for a description of provisions for testing the CSS.

6.5.2.5 Instrumentation Requirements

Refer to subsection 6.2.2 for a description of the CSS instrumentation.

6.5.2.6 Materials

Refer to subsection 6.2.2 for a discussion of the CSS materials chemistry.

6.5.2.7 Standard Review Plan Evaluation

The VEGP is equipped with a semiautomatic switchover from injection to recirculation modes.

The ECCS switchover from injection to recirculation is semiautomatic. The sump suction valves open automatically on low refueling water storage tank level. The valve changes to switch suctions of the safety injection and charging pumps to the residual heat removal discharge and the isolation of the suctions from the refueling water storage tank are manual. Thus the switchover is semiautomatic. The CSS switchover from injection to recirculation is entirely manual. The CSS is designed to continuously deliver spray to containment and is capable of continuing for a time equal to or greater than the duration of the initial 2-h period following the accident.

6.5.2.8 References

1. U.S. Nuclear Regulatory Commission, "Containment Spray as a Fission Product Cleanup System," Standard Review Plan 6.5.2.
2. Sanford, M. O., "SPRACO Model-1713A Nozzle Spray Drop-Size Distribution," WCAP-8258-R1 (Nonproprietary).
3. Somers, E. V., and Sanford, M. O., "Iodine Removal by Spray in the Joseph M. Farley Station Containment," WCAP-8376 (Nonproprietary).
4. Deleted.
5. U.S. Nuclear Regulatory Commission, "Technological Bases for Models of Spray Washout of Airborne Contaminants in Containment Vessels," NUREG/CR-0009.
6. U.S. Atomic Energy Commission, "A Review of Mathematical Models for Predicting Spray Removal of Fission Products in Reactor Containment Vessels," WASH-1329, June 15, 1974.

6.5.3 FISSION PRODUCT CONTROL SYSTEMS

6.5.3.1 Primary Containment

The containment consists of a prestressed, post-tensioned, reinforced concrete structure with cylindrical walls, hemispherical dome, and base slab lined with welded 1/4-in. carbon steel liner plate, which forms a continuous, leaktight membrane. Details of the containment structural design are discussed in section 3.8. Layout drawings of the containment structure and the related items are given in the general arrangement drawings of section 1.2.

The containment walls, liner plate, penetrations, and isolation valves function to limit the release of radioactive materials subsequent to postulated accidents, such that the resulting offsite doses are less than the guideline values of 10 CFR 100. Containment parameters affecting fission product release accident analyses are given in table 6.5.3-1.

Long-term containment pressure and temperature response to the design basis accident are shown in section 6.2. Relative to this time period, the spray system is operated to reduce iodine concentrations and containment atmospheric temperature and pressure commencing with system initiation, as discussed in section 6.2, and ending when containment pressure has returned to normal.

The containment minipurge system may be operated for personnel access to the containment when the reactor is at power, as discussed in subsection 9.4.6. For this reason, the radiological assessment of a loss-of-coolant accident assumes that the minipurge valves are open at the initiation of the event. However, the minipurge valves receive automatic signals to shut from diverse parameters. The valves are designed to close within 5 s. (See the description in subsection 6.2.4.)

The fission product removal capability of the containment spray system is discussed in subsection 6.5.2.

Redundant, safety-related hydrogen recombiners are provided in the containment as the primary means of controlling post-accident hydrogen concentrations. A hydrogen purge system is provided for backup hydrogen control. Although use of the hydrogen purge system is not expected for post-accident hydrogen control, offsite dose analyses assuming the operation of the hydrogen purge system have been performed to determine its incremental contribution on the radiological doses. This analysis is provided in chapter 15.

Containment combustible gas control systems are discussed in detail in subsection 6.2.5.

6.5.3.2 Secondary Containment

This paragraph is not applicable to the VEGP.

TABLE 6.5.1-1 (SHEET 1 OF 3)

ESF FILTER SYSTEM DESIGN PARAMETERS
(FOR UNIT 1 OR 2)

Control Room Emergency Filter System	
Quantity	2 (one on standby)
Capacity (ft^3/min)	25,000
HEPA Filters	
Number of stages	2 (one upstream and one downstream of charcoal filter)
Cell size	24 in. x 24 in. x 12 in.
Pressure drop	
Clean (in. WG)	1.0
Loaded (in. WG)	2.0
Efficiency	99.97% for 0.3-μm particles
Charcoal Filter	
Bed depth (in.)	4
Face velocity (ft/min)	40
Average residence time (s)	0.25 per 2-in. bed depth
Filter media	Impregnated coconut shell
Decontamination efficiency	99% at 70% relative humidity (for elemental and organic iodines)
Filter capacity	2.5 mg of total iodine per gram of activated carbon
Moisture Eliminator	
Eliminator media	Spun glass fiber or galvanized steel
Maximum pressure drop (in. WG)	1.0
Efficiency	99% of 5 to 10 μm diameter droplets
Heating Coil	
Heating capacity (kW)	118
Heating element	Finned tubular
Heating coil	80% Ni/20% Cr
Fan	
Quantity	1
Type	Centrifugal
Static press (in. WG)	14
Motor (hp)	125
Cooling Coils	
Cooling capacity (Btu/h)	1.09×10^6
Air entering temperature (°F)	82 dry bulb, 65 wet bulb
Air exiting temperature (°F)	50.5 dry bulb, 50 wet bulb

TABLE 6.5.1-1 (SHEET 2 OF 3)

Water entering temperature (°F)	44
Water exiting temperature (°F)	56
Piping Penetration Filter System	
Quantity	2 (one on standby)
Capacity (ft^3/min)	15,500
HEPA Filters	
Number of stages	2 (one upstream and one downstream of charcoal filter)
Cell size	24 in. x 24 in. x 12 in.
Pressure drop	
Clean (in. WG)	1.0
Loaded (in. WG)	2.0
Efficiency	99.97% for 0.3-μm particles
Charcoal Filter	
Bed depth (in.)	4
Face velocity (ft/min)	40
Average residence time (s)	0.25 per 2-in. bed depth
Filter media	Impregnated coconut shell
Decontamination efficiency	90% elemental iodine, 30% organic iodine, at 95% relative humidity
Filter capacity	2.5 mg of total iodine per gram of activated carbon
Eliminator media	Spun glass fiber or galvanized steel
Maximum pressure drop (in. WG)	1.0
Efficiency	99% of 5 to 10 μm diameter droplets
Heating Coil	
Heating capacity (kW)	80
Heating element	Finned tubular
Heating material	80% Ni/20% Cr
Fan	
Quantity	1
Type	Vane axial
Static pressure (in. WG)	16
Motor (hp)	75
Fuel Handling Building Post-Accident Filter System (shared by both units)	
Quantity	2 (one on standby)
Capacity (ft^3/min)	5000

TABLE 6.5.1-1 (SHEET 3 OF 3)

HEPA Filters	
Number of stages	2 (one upstream and one downstream of charcoal filter)
Cell size	24 in. x 24 in. x 12 in.
Resistance	
Clean (in. WG)	1.0
Loaded (in. WG)	2.0
Efficiency	99.97% for 0.3-μm particles
Charcoal Filters	
Bed depth (in.)	4.0
Face velocity (ft/min)	40
Average residence time (s)	0.25 per 2-in. bed depth
Filter media	Impregnated coconut shell
Decontamination efficiency	90% elemental iodine, 30% organic iodine, at 95% relative humidity
Filter capacity	2.5 mg of total iodine per gram of activated carbon
Eliminator media	Spun glass fiber or galvanized steel
Maximum pressure drop (in. WG)	1.0
Efficiency	99% of 5 to 10 μm diameter droplets
Heating Coil	
Heating capacity (kW)	20
Heating element	Finned tubular
Heating coil material	80% Ni, 20% Cr
Fan	
Quantity	1
Type	Vane axial
Static pressure (in. WG)	14
Motor (hp)	40

TABLE 6.5.1-2 (SHEET 1 OF 2)

ESF FILTER SYSTEM INSTRUMENTATION
(TYPICAL FOR EACH FILTER TRAIN)

Sensing Location	Local	Control Room
Unit outlet flowrate	---	Indication; alarm[a]
Moisture separator pressure drop	Indication	---
Space between heater and first HEPA filter moisture content	---	Indication; alarm[a]
First HEPA filter pressure drop	Indication	Indication; alarm[a]
Space between first HEPA and charcoal filter temperature	---	Indication
Charcoal filter temperature	---	Alarm;[a] high-high alarm
Space between charcoal filter and second HEPA temperature	---	Indication
Second HEPA filter pressure drop	Indication	---
Fan	---	Hand switch status indication
Damper	---	Hand switch status indication
Deluge valves	---	Status indication
Electric Heater	Indication	---

TABLE 6.5.1-2 (SHEET 2 OF 2)

Sensing Location	Local	Control Room
Total system pressure drop	Indication	Indication alarm[a]

a. There is one trouble alarm for each filter train. The alarm is actuated by high or low filter outlet flow, high pressure drop across first HEPA filter, high charcoal filter temperature, high pressure drop across total filter system, or high moisture content in space between heater and first HEPA filter.

TABLE 6.5.1-3 (SHEET 1 OF 3)

ESF FILTER SYSTEM MATERIALS

(Control Room Emergency Air-Conditioning Units)

Component	Material/ Chemical Composition	Estimated Quantity per Housing (lb)
Filter housing	ASTM A-36	-
Moisture eliminators		
Eliminator medium	Spun fiberglass or galvanized steel	6
Holding frame	304 SS	445
Total assembly	304 SS	1004
HEPA filters		
Filter medium	Glass fiber with 5% binder	48 total
Separator	Aluminum foil	83 total
Holding frames	304 SS; ASTM A-240	829 total
Charcoal filters		
Filter media	Impregnated, activated coconut shell charcoal	8905
Holding frames	304 SS; ASTM A-240	9364
Electric heater		
Element	304 SS; ASTM A-240	252
Casing	304 SS; ASTM A-240	283
Cooling coils		4625 dry; 5208 wet
Coils	Copper; ASTM B-152; UNS-C11000	2950
Fins and header	Copper-nickel ASME SB-111; UNS-C70600	92; 1086
Casing	304 SS; ASTM A-240	497
Exhaust fans		
Housing	Carbon steel; ASTM A-36	610 [a]
Blades	Ex-Ten 50; ASTM A-607	60

TABLE 6.5.1-3 (SHEET 2 OF 3)

(Piping Penetration Room Filtration Units)

Composition	Material/ Chemical Component	Estimated Quantity per Housing (lb)
Filter housing	ASTM A-36	-
Moisture eliminators		
Eliminator medium	Spun fiberglass or galvanized steel	
Holding frame	304 SS	254
Total assembly	ASTM A-240	1127
HEPA filters		
Filter medium	Glass fiber with 5% binder	128 total
Separator	Aluminum foil	221 total
Holding frames	304 SS; ASTM A-240	2211 total
Charcoal filters		
Filter media	Impregnated, activated coconut shell charcoal	5446
Holding frames	304 SS; ASTM A-240	5408
Electric heater		
Element	304 SS; ASTM A-240	210
Casing	304 SS; ASTM A-240	200
Exhaust fans		
Housing	ASTM A-283 grade D	294[b]
Blades	Aluminum, ASTM B-108	21 total[c]

TABLE 6.5.1-3 (SHEET 3 OF 3)

(Fuel Handling Building Post-Accident Cleanup Units)

Composition	Material/ Chemical Component	Estimated Quantity per Housing (lb)
Filter housing	ASTM A-36	-
Moisture eliminators		
Eliminator medium	Spun fiberglass or galvanized steel	3
Holding frame	304 SS	114
Total assembly	304 SS	592
HEPA filters		
Filter medium	Glass fiber with 5% binder	48 total
Separators	Aluminum foil	83 total
Holding frames	304 SS; ASTM A-240	829 total
Charcoal filters		
Filter media	Impregnated, activated coconut shell charcoal	1918
Holding frames	304 SS; ASTM A-240	3019
Electric heater		
Element	304 SS; ASTM A-240	63
Casing	304 SS; ASTM A-240	187
Exhaust fans		
Housing	ASTM A-283 grade D	148[b]
Blades	Aluminum; ASTM B-108	5 total[c]

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a. Housing weights consist of shell material only and do not include stiffening or roll shapes.

b. Housing weights consist of outer casing and flanges.

c. Blade weight includes only blades and no studs.

TABLE 6.5.2-1

CONTAINMENT UNSPRAYED REGIONS

Unsprayed Containment Net Free Volume above Operating Level	Volume (ft^3)
Sheltered volume by steam generator compartment concrete	6900
Pressurizer compartment net free volume	200
Sheltered volume by stairs, No. 1 and No. 2	8300
Sheltered volume by containment cooling units	300
Sheltered volume by auxiliary containment cooling units	8800
Sheltered volume by containment building preaccess filtration unit	33600
Volume underneath polar crane girders	10800
Total unsprayed net free volume above operating deck	68900
Unsprayed Containment Volume below Operating Level	
Total net free volume below operating level	603200
Refueling canal	42500
Total unsprayed volume below operating level	560700
Total unsprayed containment net free volume above and below operating level	629600
Total net free containment volume	2932000
Percentage of unsprayed containment volume	21.5
Percentage of sprayed containment volume	78.5

TABLE 6.5.2-2 (SHEET 1 OF 2)

INPUT PARAMETERS AND RESULTS OF
SPRAY IODINE REMOVAL ANALYSIS

Total containment free volume (ft^3)	2.93×10^6
Unsprayed containment free volume (%)	21.5
Area coverage at the operating deck (%)	87
Mixing rate between sprayed and unsprayed volumes (ft^3/min)	87,000
Containment model	Two region
Minimum vertical distance to operating deck from lowest spray header (ft)	134
Net spray flowrate per train, injection phase (gal/min)	2500
Number of spray pumps operating	1
Minimum spray solution pH	
Injection phase	4.5
Recirculation phase	7.0
Partition factor between liquid and gas phases	40
Average spray drop diameter (μm)	1240
Elemental iodine spray removal coefficient (h^{-1})	10 (DF $\leq$ 21.4) 0 (DF > 21.4)
Particulate iodine spray removal coefficient (h^{-1})	4.19 (DF $\leq$ 50) 0.419 (DF > 50)
Duration of spray phase (h)	2

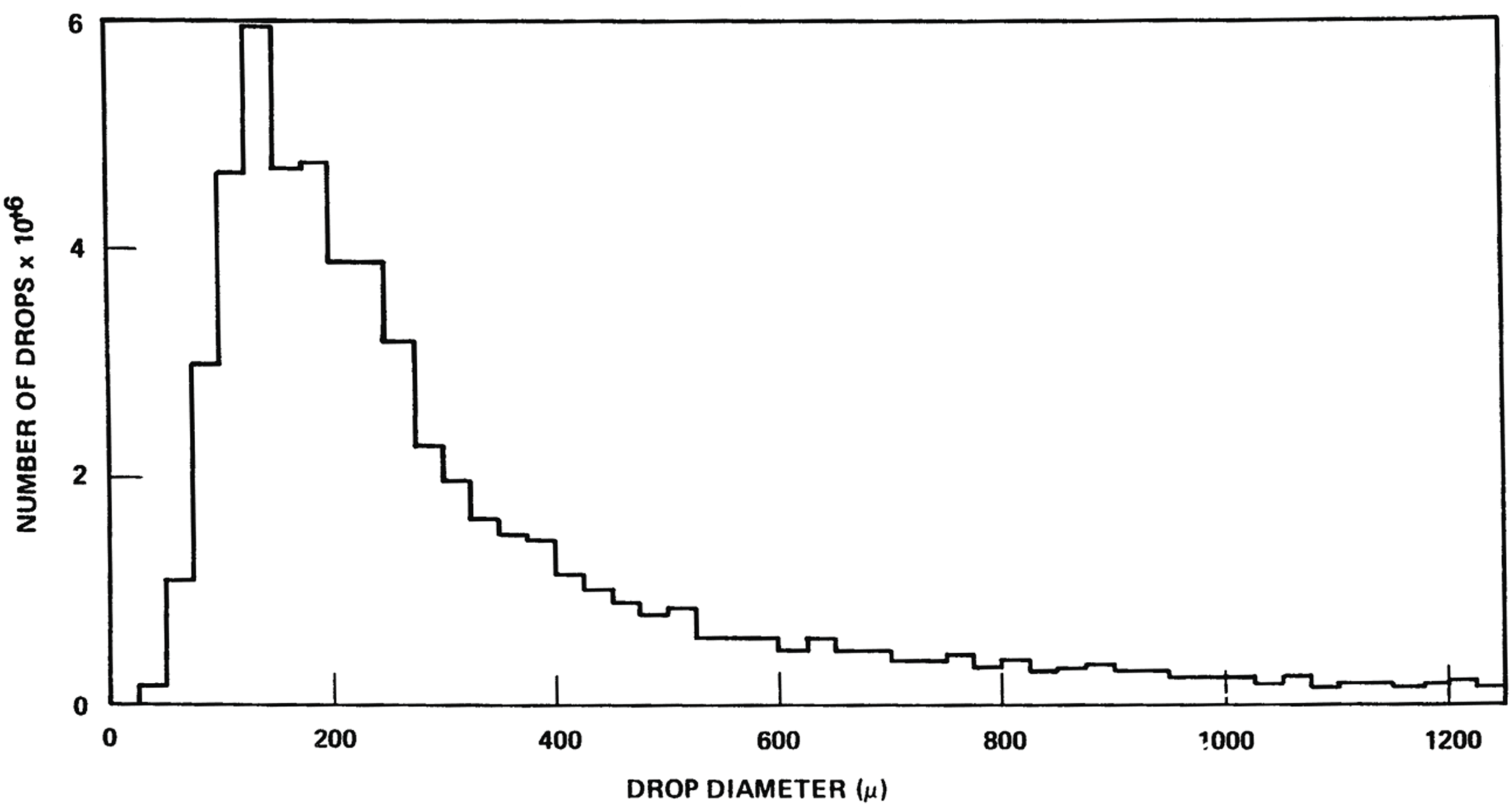
TABLE 6.5.2-2 (SHEET 2 OF 2)

Elemental iodine wall deposition coefficient (h^{-1})	4.76 (DF $\leq$ 200) 0 (DF > 200)
Area in containment subject to iodine deposition, i.e., coated with epoxy paint, zinc based paint or galvanized (ft^2)	7.94 x 10^5
Average iodine deposition mass transfer coefficient (m/h)	4.9

TABLE 6.5.3-1

PRIMARY CONTAINMENT OPERATION
FOLLOWING A DESIGN BASIS ACCIDENT

Type of structure	Reinforced concrete cylindrical containment with hemispherical dome. Interior wall lined with 1/4-in. liner plate.
Containment free volume	2.75 x 10^6 ft^3
Containment leak rate	0.2 v/o per day, 0-24 h 0.1 v/o per day, 1-30 days



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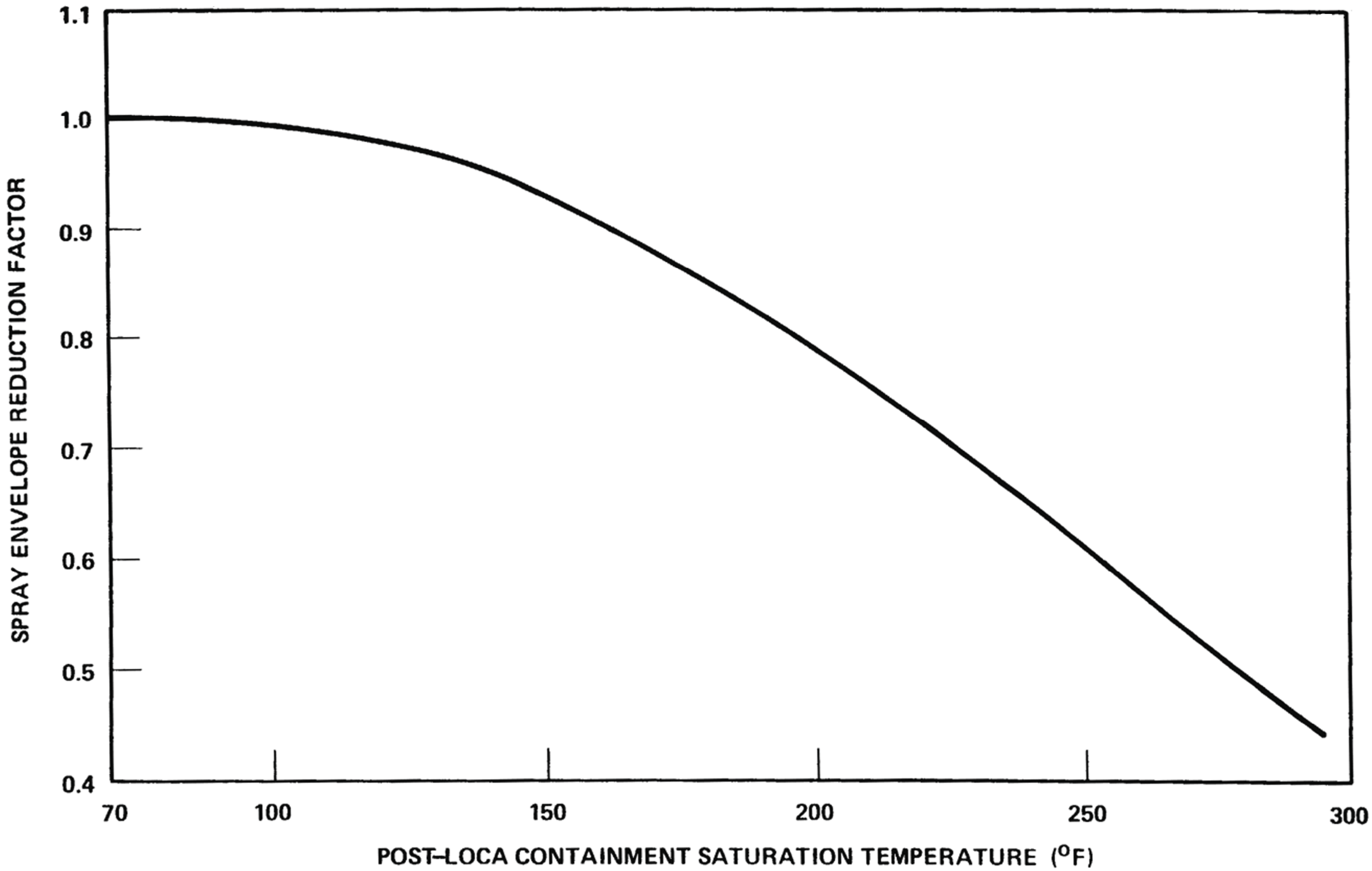
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

SPATIAL DROP–SIZE DISTRIBUTION

FIGURE 6.5.2–1



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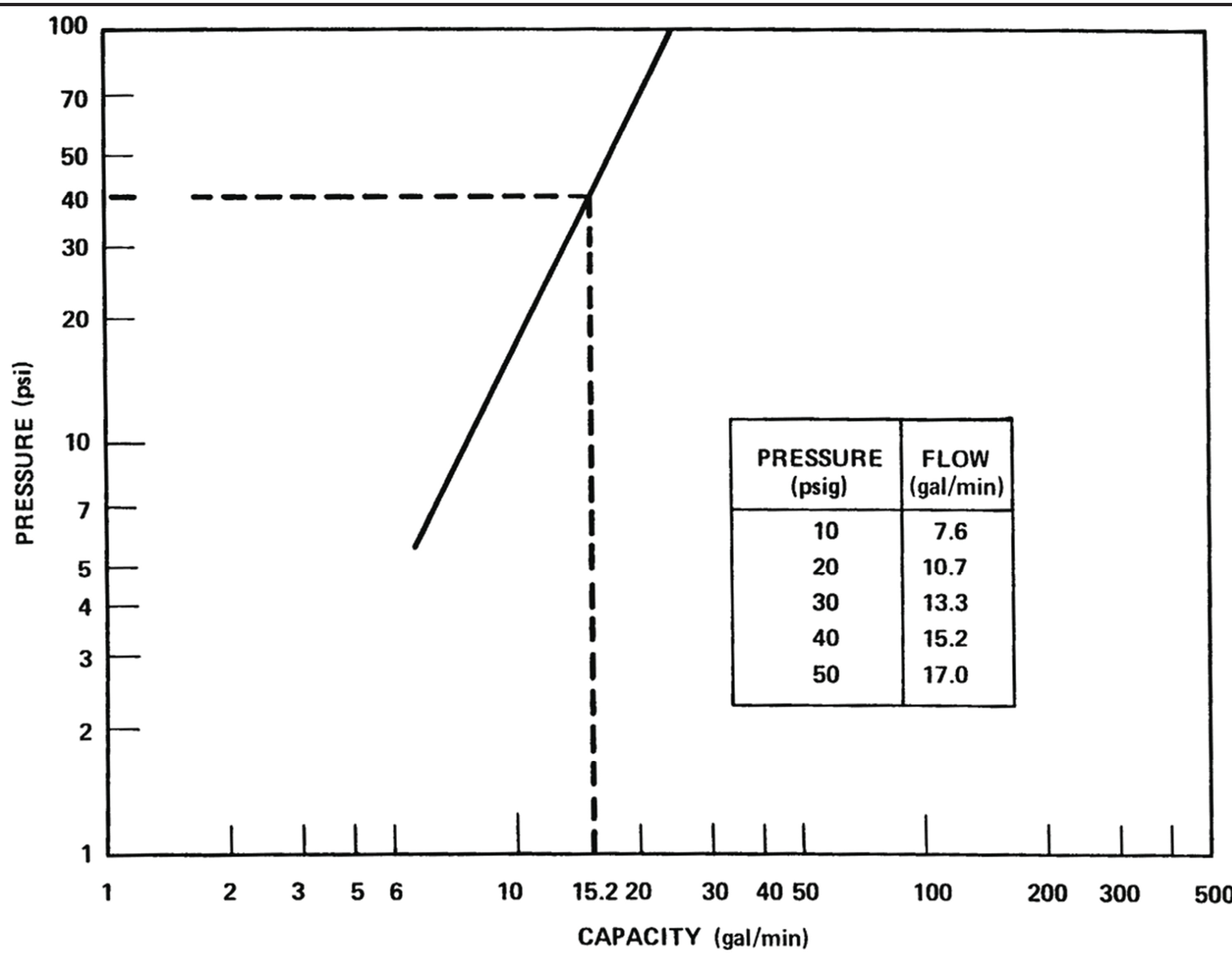
SPRAY ENVELOPE REDUCTION FACTOR

FIGURE 6.5.2–2



PRESSURE (psig)	FLOW (gal/min)
10	7.6
20	10.7
30	13.3
40	15.2
50	17.0

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CAPACITY CURVE SPRACO 1713A NOZZLE

FIGURE 6.5.2–3

6.6 INSERVICE INSPECTION OF CLASS 2 AND 3 COMPONENTS[a]

6.6.1 COMPONENTS SUBJECT TO EXAMINATION

Inservice inspection and testing of Class 2 and 3 pressure-retaining components such as vessels, piping, pumps, valves, bolting, and supports shall be performed in accordance with Section XI of the American Society of Mechanical Engineers (ASME) Code including subsections IWC and IWD and any applicable addenda of the code in accordance with 10 CFR 50.55a(g) (specific edition and any applicable addenda of the code will be delineated in each program). The testing of pumps and valves is discussed in subsection 3.9.6. Class 1 component examinations are addressed in subsection 5.2.4. Certain exceptions to the above requirements may be taken whenever specific written relief is granted by the Nuclear Regulatory Commission (NRC) in accordance with 10 CFR 50.55a(g)(6)(i).

The preservice inspection program requirements for each unit were completed prior to the commercial operation date for each of the respective units. The preservice inspection program for Unit 1 complied with the ASME Code, Section XI, 1980 Edition including addenda through Winter 1980, except that reactor pressure vessel examinations were performed using the 1980 Edition including addenda through Winter 1981. The preservice inspection program for Unit 2 complied with the ASME Code, Section XI, 1983 Edition including addenda through Summer 1983, except that reactor pressure vessel examinations were performed using the 1980 Edition including addenda through Winter 1981. Certain preservice inspection requirements of the ASME Code, Section XI were determined to be impractical and relief requests were granted by the NRC pursuant to 10 CFR 50.55a(g) (i). The relief requests were supported by information pursuant to 10 CFR 50.55a(a) (3). In addition, the preservice inspection program included a volumetric examination of a minimum of 8 percent of the Class 2 piping welds in the engineered safety systems.

The inservice inspection program and inservice test program were submitted to the NRC prior to commercial operation. These programs comply with applicable inservice inspection provisions of 10 CFR 50.55a(g) and the NRC guidelines attached as an appendix to section 121.0 of review questions entitled, "Guidance for Preparing Preservice and Inservice Inspection Programs and Relief Requests Pursuant to 10 CFR 50.55a(g)." Where compliance with code requirements is not practical, relief requests have been submitted to the NRC for review and approval. The inservice programs will detail the areas subject to examination and method, extent, and frequency of examinations. Additionally, component supports and snubber testing requirements are included in the inspection programs.

6.6.2 ACCESSIBILITY

The physical arrangement of components was designed to allow personnel and equipment access to the extent practical to perform the inservice inspection examinations. Removable insulation was provided on those piping systems requiring volumetric and surface inspection. Removable hangers and pipe whip restraints are provided as necessary and practical to facilitate inservice inspection. Working platforms were provided in areas requiring inspection and servicing of pumps and valves. Temporary or permanent platforms, scaffolding, and ladders were provided to facilitate access to piping welds.

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[a] The Inservice Inspection Program is credited as a license renewal aging management program (see subsection 19.2.13).

An inservice inspection design review was undertaken to identify exceptions to the access requirements of the code with subsequent design modifications and/or inspection technique development to ensure code compliance to the extent practical. Additional exceptions may be identified and reported to the Nuclear Regulatory Commission after plant operation, as specified in 10 CFR 50.55a(g)(5)(iv).

Space is provided to handle and store insulation, structural members, shielding, and other material related to the inspection. Suitable hoists and other handling equipment, lighting, and sources of power for inspection equipment were installed at appropriate locations.

6.6.3 EXAMINATION TECHNIQUES AND PROCEDURES

The visual, surface, and volumetric examination techniques and procedures are in accordance with the requirements of American Society of Mechanical Engineers Code, Section XI, subarticle IWA-2200. Where compliance with code requirements is not practical, relief requests and proposed alternatives have been submitted to the NRC for review and approval. SNC will apply the code cases listed in the latest revision of Regulatory Guide 1.147 endorsed by the NRC in 10 CFR 50.55a on a case-by-case basis as the need arises during inservice inspection. Code cases, which are determined as necessary to accomplish inservice inspection activities, will be used.

The liquid penetrant or magnetic particle methods are used for surface examinations. Radiography or ultrasonic methods, whether manual or remote, are used for volumetric examinations.

The reportable indications and data compilation format provide for comparison of data from subsequent examinations.

6.6.4 INSPECTION INTERVALS

Inspection intervals are as defined in subarticle IWA-2400 of American Society of Mechanical Engineers (ASME) Code, Section XI. The periods within each inspection interval may be extended by as much as 1 year to permit weld inspections to be concurrent with plant outages. It is intended that inservice examinations be performed during normal plant outages such as refueling shutdowns or maintenance shutdowns occurring during the inspection interval.

6.6.5 EXAMINATION CATEGORIES AND REQUIREMENTS

Examination categories are in accordance with subsection IWC and table IWC-2500 of American Society of Mechanical Engineers (ASME) Code, Section XI, and the methods used comply with table IWC-2500 for Class 2 components. The examination categories of Class 3 components and the methods used comply with subsection IWD. The preservice examination of Class 2 and 3 components was in accordance with the requirements of IWC-2200 and IWD-2100, respectively.

6.6.6 EVALUATION OF EXAMINATION RESULTS

Examination results are evaluated per IWA-3000, IWC-3000, and IWD-3000 of American Society of Mechanical Engineers (ASME) Code, Section XI. Repair procedures are in accordance with IWC-4000 and IWD-4000. If the guidelines of IWC-4000 and IWD-4000 are inappropriate for the components, then the guidelines of IWA-4000 apply.

6.6.7 SYSTEM PRESSURE TESTS

System pressure tests comply with IWA-5000, IWC-5000 and IWD-5000 of American Society of Mechanical Engineers (ASME) Code, Section XI, for Class 2 and 3 components.

6.6.8 AUGMENTED INSERVICE INSPECTION TO PROTECT AGAINST POSTULATED PIPING FAILURES

An augmented inservice inspection program is provided for high-energy fluid systems piping between containment isolation valves or where no isolation valve is used inside containment, between the first rigid pipe connection to the containment penetration or the first pipe whip restraint inside containment and the outside isolation valve.

This program includes 100 percent volumetric examination of welds in the affected piping during each inspection interval and will be conducted in accordance with American Society of Mechanical Engineers (ASME) Code, Section XI, and covers the high-energy fluid systems described in subsections 3.6.1 and 3.6.2.

APPENDIX 6A

RESOLUTION OF NRC GENERIC LETTER 2004-02

6A.1 INTRODUCTION AND RISK-INFORMED APPROACH SUMMARY

NRC Generic Letter (GL) 2004-02 (Reference 1) required licensees to perform an evaluation of the emergency core cooling system (ECCS) and containment spray system (CSS) recirculation functions, and the flow paths necessary to support those functions, based on the potential susceptibility of sump strainers to debris blockage during design basis accidents requiring recirculation operation of ECCS or CSS. This generic letter resulted from Generic Safety Issue (GSI) 191, "Assessment of Debris Accumulation on Pressurized-Water Reactor Sump Performance." As a result of the evaluation required by GL 2004-02, and to ensure system function, sump strainer design modifications were implemented.

The plant licensing basis considers long-term core cooling (LTCC) following a loss of coolant accident (LOCA) as identified in 10 CFR 50.46(b)(5). Long-term cooling is supported by the ECCS, which includes the charging, safety injection (SI), and residual heat removal (RHR) systems. These systems and the CSS are subject to the effects of accident-generated debris because they rely on the containment emergency sump in the recirculation mode. Debris generated from non-LOCA initiating events (secondary side breaks inside containment that result in a consequential LOCA) are also considered. The risk-informed evaluation analyzes the following events:

1. Large, medium, and small LOCAs due to:
   - i. Pipe breaks
   - ii. Failure of non-piping components
   - iii. Water hammer
2. Secondary side breaks inside containment that result in a consequential LOCA upon failure to terminate safety injection or a stuck open PORV requiring sump recirculation
3. Seismically-induced LOCAs

To respond to GL 2004-02, a risk-informed evaluation was performed (Reference 13) and was reviewed by the NRC (Reference 14). The evaluation provides confidence that the sump design supports LTCC following a LOCA. The evaluation meets the acceptance guidelines for a very small risk impact as defined in Regulatory Guide (RG) 1.174 (Reference 2).

The licensing basis with regard to effects of debris is determination of a high probability that the ECCS and CSS can perform their design basis functions based on VEGP-specific testing using an NRC-approved methodology. The risk from breaks that could generate debris and that do not meet one (or more) of the GSI-191 acceptance criteria is very small and is, therefore, acceptable in accordance with the RG 1.174 guidelines (Reference 2).

The use of a risk-informed method, rather than the deterministic methods prescribed in the regulation, required an exemption to 10 CFR 50.46(a)(1), which has been granted pursuant to 10 CFR 50.12.

The risk-informed approach identifies scenarios that fail any one of the following GSI-191 acceptance criteria, as determined by break-specific analysis:

1. Strainer debris limits (based on VEGP-specific head loss testing),
2. Strainer structural differential pressure limit,

3. Partially-submerged strainer head loss limit,
4. Pump void fraction limit,
5. Flashing limit
6. Pump net positive suction head (NPSH) margin
7. Core blockage limits.

The NARWHAL model is an integral part of the risk-informed analysis. The software is used to perform break-specific analysis by integrating the results from different calculations and the acceptance criteria listed above. The conditional failure probabilities (CFPs) are also determined in the NARWHAL model. The resulting CFPs are used with the VEGP PRA model to calculate the change in core damage frequency (ΔCDF) and change in large early release frequency (ΔLERF) related to the effects of debris. The ΔCDF and ΔLERF values are calculated based on the difference between the calculated CFP values and a hypothetical condition with no debris related failures (CFPs of 0). The ΔCDF and ΔLERF values are used for comparison to the guidelines in RG 1.174 (Reference 2). The results of the evaluation show that the risk from the proposed change is "very small" (i.e., in Region III of RG 1.174). The methodology includes conservatisms in the plant-specific testing and in the assumption that all unbounded breaks result in loss of core cooling.

Key aspects of the risk-informed evaluation include:

1. The methodology used to quantify the amount of debris generated at each break location, including the assumed zone of influence (ZOI) size based on the target destruction pressure and break size, and the assumed ZOI shape (spherical or hemispherical) based on whether the break is a double-ended guillotine break or partial break.
2. The methodology used to evaluate debris transport to the residual heat removal and containment spray strainers.
3. The methodology used to quantify chemical precipitates, including the refinements to WCAP-16530-P-A (Reference 6), application of the solubility correlation, and application of the WCAP-17788-P autoclave testing (Reference 7).
4. The strainer debris limits shown in TS Bases Table B 3.6.7-1, which are based on tested and analyzed debris quantities.
5. The methodology and acceptance criteria used to assess ex-vessel component blockage and wear.
6. The methodology used to assess in-vessel downstream effects and the associated limits.
7. The methodology used to quantify conditional failure probabilities, and ΔCDF and ΔLERF.

Key aspects of the risk-informed evaluation may be performed outside of the NARWHAL model for certain scenarios (e.g., for operability evaluation where only selected breaks are affected and a conservative estimate of impact is of interest). However, integrated analysis will require the use of the NARWHAL software, which is a key element for the risk-informed analysis.

6A.2 DEBRIS GENERATION

Post-accident debris includes insulation, fire barrier, and coatings debris generated within the ZOI of the pipe break, as well as latent debris, unqualified coatings, and miscellaneous debris in containment. To support the debris generation evaluation, containment walkdowns were performed using the guidance of NEI 02-01 (Reference 3).

The pipe break characterization followed the methodology of NEI 04-07 (Reference 4) and associated NRC safety evaluation (SE) (Reference 5), with the exception that it characterized a full range of breaks rather than just the worst-case breaks as suggested by NEI 04-07. Double-ended guillotine breaks (DEGBs) and partial breaks on every in-service inspection (ISI) weld within the Class 1 pressure boundary were considered. All break sizes and locations were characterized by placing each analyzed break into three high-level categories: small-break LOCAs (SBLOCAs) – breaks smaller than 2 inches, medium-break LOCAs (MBLOCAs) - breaks greater than or equal to 2 inches and less than 6 inches, and large-break LOCAs (LBLOCAs) – breaks greater than or equal to 6 inches with the largest break being a DEGB of the 31 inch crossover leg.

In the debris generation calculation, a three-dimensional CAD model of the Unit 1 containment building was used to model the ZOI for each postulated break. Note that the Unit 1 model was used to represent both units because the containment buildings are almost identical. ZOIs representing possible breaks on the reactor coolant system (RCS) piping were modeled at each ISI weld.

DEGBs are modeled using a spherical ZOI with a radius proportional to the pipe inner diameter. Partial breaks are any breaks smaller than a DEGB and are modeled using a hemispherical ZOI with a radius proportional to the equivalent break size. Break sizes ranging from ½ inch up to a DEGB were modeled at each weld. In addition, because the orientation of partial breaks can have a significant effect on the results, partial breaks were modeled every 45 degrees around the circumference of the pipe at each weld. Credit was taken for shielding by concrete walls. While DEGBs on main loop piping are typically bounding with regard to the volume of debris generated, smaller breaks are more likely to occur.

Although the probability of occurrence is low, a secondary side break inside containment could require ECCS recirculation. Therefore, secondary side breaks from the steam generator feedwater lines and main steam lines were characterized. Because secondary side breaks occur at lower pressure and temperature than the primary side breaks, the ZOI size corresponding to the insulation destruction pressure would be smaller, compared with the primary side breaks. The appropriate ZOI sizes were calculated based on the ANSI jet methodology described in Appendix I of NEI 04-07 Volume 2 (Reference 5). Breaks were postulated along the main steam and feedwater pipes. All secondary side breaks were assumed to be DEGBs. Only Nukon insulation was considered for the secondary side breaks because there is no fire barrier within the vicinity of the main steam and feedwater lines, and the coating quantities would be bounded by the primary side breaks.

Since different material types have different destruction pressures, a ZOI was determined for each type of material. The quantity of generated debris for each break case was calculated using these material specific ZOI sizes.

Unqualified coatings considered in the analysis include coatings within containment that do not have a specified preparation, application, or inspection compliant with plant specifications; previously qualified coatings that have noticeably deteriorated; coatings inaccessible for inspection; and coatings applied by vendors on vendor-supplied items that cannot be qualified. There are several types of unqualified coatings applied over numerous substrates within containment, including epoxy, inorganic zinc, and alkyd coatings. Unqualified coatings were conservatively assumed to fail at the start of sump recirculation for all postulated breaks.

The total amount of latent debris calculated based on walkdown data was 60 lbm; however, 200 lbm is assumed in the strainer evaluation. This conservatively bounds the 60 lbm of actual latent debris with ample operating margin. Per the guidance in NEI 04-07 Volume 2, latent debris is assumed to consist of 15 percent fiber and 85 percent particulate by mass (Reference 5).

A total of 2 ft^2 of foreign materials, such as labels, tags, stickers, placards and other miscellaneous materials, were identified via walkdown. However, 50 ft^2 of miscellaneous debris is assumed in the strainer evaluation to account for foreign materials. Per the guidance in NEI 04-07 (Reference 4) and the SE (Reference 5), the total surface area of miscellaneous debris was assumed to block an equivalent surface area of the sump strainers after allowance for 25% overlap.

6A.3 DEBRIS TRANSPORT TO THE SUMP STRAINERS

The debris transport analysis determines the fraction of each type and size of debris that could be transported to the sump strainers. The evaluation considers debris transport during the blowdown, washdown, pool fill, and recirculation phases based on plant-specific layout and flow conditions. For the recirculation phase, computational fluid dynamic (CFD) modeling was used to determine the sump pool flow conditions and transport of debris inside the pool for different break locations and pump lineups (e.g., number of ECCS and CSS trains in service). Debris accumulation on the two ECCS strainers and two CSS strainers is assumed to be proportional to the flow split across the four strainers.

Potential upstream blockage points in containment were reviewed. Specifically, the refueling canal drains and doorways through the secondary shield wall were qualitatively evaluated and it was concluded that blockage would not occur at these locations.

6A.4 CHEMICAL EFFECTS

The post-LOCA sump strainer chemical effects analysis methodology includes:

- Calculation of plant-specific chemical precipitate (sodium aluminum silicate and calcium phosphate) loading using the WCAP-16530-NP-A (Reference 6) base methodology with modification to the aluminum release rate by crediting phosphate passivation of aluminum.
- Consideration of aluminum solubility to determine when to account for sodium aluminum silicate precipitate loading.

All Class 1 weld locations on the primary RCS piping upstream of the first isolation valve were evaluated for chemical product generation. The amount of chemical precipitate generated was calculated for each of the breaks using the break-specific debris generation quantity. Other plant-specific inputs, such as pH, temperature, pool volume, aluminum quantity, and spray time, were used to calculate the amount of chemical precipitate. The amount of precipitate was scaled by the ratio of test strainer area to plant strainer area and compared to the chemical precipitate amounts in the strainer testing to determine the analyzed head loss across the strainer as a function of time.

Calcium release was determined using the WCAP-16530-NP-A (Reference 6) release rates. Calcium phosphate is assumed to precipitate as soon as the calcium is released into solution. Aluminum release from non-metallic sources was determined using the WCAP-16530-NP-A (Reference 6) release rates. For metallic aluminum sources, an aluminum release rate that was developed based on testing performed at the University of New Mexico in a trisodium phosphate buffered environment was used. It was assumed that aluminum in the post-LOCA pool precipitates once the dissolved aluminum concentration reaches a solubility limit, as calculated using a solubility equation that was developed based on testing at Argonne National Laboratory

(ANL). For each pipe break that does not reach the calculated aluminum solubility limit before 24 hours, it was conservatively assumed that all aluminum in solution precipitates at 24 hours.

The phosphate passivation and aluminum solubility modifications to the base WCAP-16530-NP-A (Reference 6) methodology were validated using autoclave test results documented in WCAP-17788-P, Volume 5 (Reference 7). Additionally, the following assumptions are considered essential parts of the phosphate passivation and aluminum solubility modifications to the base WCAP-16530-NP-A (Reference 7) methodology:

- A double-ended pump suction LOCA with minimum safeguards temperature profile is used to determine chemical release, which promotes greater aluminum release.
- The pH was analytically combined to use a maximum sump pool pH of 7.8 for aluminum release with a less than design-basis minimum pH of 7.0 for solubility. The way the pH values were combined is not physically possible and bounds potential pH profile variations.
- Unsubmerged aluminum is treated as fully submerged or fully wetted in the containment spray solution.
- No credit is taken for aluminum that remains soluble after precipitation is predicted to occur.

6A.5 SUMP STRAINER EVALUATIONS

There are several failure criteria considered in the sump strainer evaluation: tested debris limits, strainer partial submergence, vortexing, void fraction, flashing, pump NPSH, and strainer structural margin. A postulated break that exceeds one or more of these criteria for the RHR or CSS strainers/pumps is treated as a failure of the corresponding ECCS or CSS train(s). Each of the failure criteria was evaluated during the LOCA transient to determine if an ECCS or CSS failure would occur.

The containment sump pool water volume following a LOCA was determined by considering all water sources (i.e., the refueling water storage tank, reactor coolant system, and accumulators) and subtracting the various holdup volumes. The holdup volumes include dead volumes inside the containment, filling of empty pipe, water in transit, and steam holdup. The sump pool volume was used to determine the pool water level using a correlation between pool water depth and volume.

Strainer Head Loss Test Limits

Head loss tests were performed to measure the head losses of the conventional debris (fiber and particulate) and chemical precipitate debris generated and transported to the sump strainers following a LOCA. The test program used a test strainer, debris quantities, and flow rates that were prototypical to Vogtle. Different test cases were performed with the thin bed and full debris load protocols, following the 2008 NRC staff review guidance (Reference 8).

A sump strainer is conservatively assumed to fail for any break where the transported quantity of fiber, particulate, and/or chemical precipitate debris exceeds the tested debris quantities (scaled from the test strainer area to the plant strainer area with adjustments for partial submergence and/or blockage by miscellaneous debris).

The results of the head loss tests provided a matrix of head loss data for various combinations of conventional and chemical debris loads. This matrix was used to determine the head loss for the debris load associated with each break scenario. A rule-based approach was used to calculate head loss based on the results of head loss testing. If the fiber debris load at the strainer is less than the tested quantity from the thin bed test, the maximum thin bed conventional debris head loss was returned. If the quantity was greater than what was tested in the thin bed test, the conventional head loss of the full-load test was returned. A similar rule-based approach was applied for chemical debris head loss. If chemical products are generated, the maximum head loss from testing was applied.

Partially Submerged Strainer Criteria

If the strainers are partially submerged, the risk-informed calculation assumed that the strainer would fail if the head loss across the debris bed and strainer is equal to or greater than half of the submerged strainer height per RG 1.82 (Reference 9). Note that the pump NPSH and strainer structural limits are also applicable for a partially submerged strainer. The calculation tracks time-dependent accumulation of debris on the strainer. When the strainer is partially submerged, the evaluation only credits the surface area of the submerged portion of the strainers for flow and debris accumulation. Based on the calculated sump pool water level, the sump strainers are fully submerged for most breaks.

Strainer Vortexing Criteria

In lieu of vortexing calculations, testing was conducted to identify under which conditions vortexing and air ingestion is expected to occur in the plant for both clean strainer and debris laden conditions. The vortex test used a prototype strainer assembly with a conservatively high approach velocity and low strainer submergence. Comparison of test results with plant conditions showed no vortex formation for the plant strainers up to the tested debris limits.

Void Fraction Criteria

A pump failure due to degasification was assumed if the calculated steady-state gas void fraction at the pump is greater than 2 percent by volume. The quantity of air released from a given volume of water across the strainer was determined by calculating the difference between the concentration of air dissolved in the sump water and the concentration of air dissolved in water downstream of the strainer. A small amount of accident pressure was credited in the gas void calculation. Note that the pump NPSH required was adjusted to account for the void fraction in accordance with the guidance in RG 1.82 (Reference 9).

Flashing Criteria

The acceptance criterion is zero flashing as the fluid experiences a pressure drop across the debris bed and strainer. Strainer flashing was calculated by comparing the internal strainer pressure at the top of the strainer to the sump water saturation pressure. If the internal strainer pressure is less than the saturation pressure, the water flashes and the strainer is assumed to fail. By crediting a small amount of accident pressure (i.e., above saturation pressure), no strainer failure due to flashing was recorded.

Pump NPSH Criteria

The RHR and CS pump NPSH margin was calculated based on the NPSH available minus the NPSH required for the respective pumps. NPSH available was defined without considering strainer head loss. This was calculated as a time-dependent parameter based on containment pressure, sump temperature, water level, losses in the pump suction piping (which are a function of the friction factor), and vapor pressure. The NPSH required was also calculated as a time-dependent parameter based on flow rate and gas void fraction.

Containment accident pressure is not credited in the analysis for pump NPSH. For containment pressure, the saturation pressure at the sump temperature was assumed for sump temperatures greater than 211°F. Note that the temperature of 211°F corresponds to the saturation temperature at the Technical Specification (TS) minimum containment pressure of -0.3 psig (or

14.396 psia). For sump temperatures below 211°F, the minimum containment pressure of -0.3 psig was used to calculate the pump NPSH available.

Because NPSH available is calculated without considering strainer head loss, the acceptance criterion is that the total strainer head loss (i.e., clean screen head loss plus conventional debris head loss plus chemical debris head loss) must be less than the pump NPSH margin. This was evaluated on a time-dependent basis.

Because the SI pumps and centrifugal charging pumps (CCPs) take suction from the RHR pumps during recirculation, only the NPSH margins of the RHR and CS pumps are calculated.

Strainer Structural Criteria

The strainers are located outside the secondary shield wall between the secondary shield wall and the containment wall and, as such, are not exposed to pipe whip, jet impingement, or postulated missiles generated from the LOCA event.

The analyzed strainer structural limit for each strainer is 24.0 ft. The head loss across each of the RHR and CS strainers was compared to this value to ensure that the structural margin is not exceeded.

6A.6 DOWNSTREAM EFFECTS – COMPONENTS AND SYSTEMS

An analysis was performed to evaluate the impact of debris on the wear or blockage of the ECCS and CSS piping and components downstream of the strainer (excluding reactor vessel) following a LOCA. This ex-vessel downstream effects evaluation used the methodology presented in WCAP-16406-P-A (Reference 10). The analyzed effects of debris ingested through the containment sump strainers during the recirculation mode include erosive wear, abrasion, and potential blockage of downstream flow paths.

The smallest clearance for the VEGP heat exchangers, orifices, and spray nozzles in the recirculation flow paths is larger than the sump strainer hole size. Therefore, no blockage of the containment spray flow paths is expected.

ECCS and CSS instrumentation tubing was evaluated for potential debris accumulation in the sensing lines. The transverse velocity past this tubing was determined to be sufficient to prevent debris settlement in the instrument lines; therefore, debris effects will not cause an instrument failure.

The heat exchangers, orifices, and spray nozzles were evaluated for the effects of erosive wear for a bounding debris concentration over the 30-day mission time. The erosive wear on these components was determined to be insufficient to affect the system performance.

The effects of debris ingestion were evaluated for three aspects of pump operability including hydraulic performance, mechanical shaft seal assembly performance, and the mechanical performance (vibration) of the pump. These performances were determined to not be affected by the recirculating sump debris.

Evaluations of the system valves showed that the minimum recirculation flow rates are adequate to preclude debris sedimentation in all cases. All of the valves that are subject to being blocked pass the plugging criteria at their current positions, since the strainer mesh size is smaller than the minimum valve clearance. All of the valves that are subject to erosion pass the acceptable criteria for the 30-day mission time.

6A.7 DOWNSTREAM EFFECTS – FUEL AND VESSEL

During the post-LOCA sump recirculation phase, debris that passes through the ECCS sump strainers could accumulate at the reactor core inlet or inside the reactor vessel, potentially challenging LTCC. In-vessel downstream effects were analyzed using WCAP-17788-P (Reference 11) and plant-specific penetration test data.

Testing was conducted to collect time-dependent fiber penetration data for a prototypical strainer under various conditions (e.g., approach velocity and water chemistry) and strainer configurations (e.g., number of strainer disks). The test results were used to derive a model that was used to quantify fiber penetration for the RHR and CSS strainers at plant conditions. This model defines the time dependent downstream debris source term used to calculate the fiber accumulation in the reactor vessel.

Methods and acceptance criteria contained in WCAP-17788-P, Revision 1 (Reference 11) were used to evaluate the accumulation of fiber inside the reactor vessel. An evaluation was performed to demonstrate applicability of the WCAP-17788-P methods and results to VEGP in accordance with the NRC staff review guidance for in-vessel effects (Reference 12). The applicability evaluation compares the values of key parameters assumed in the WCAP-17788 analysis to VEGP-specific values. The quantity of fiber accumulation inside the reactor vessel was calculated using break specific debris quantities and the appropriate accumulation based on the break location (i.e., hot leg break vs. cold leg break scenarios). The accumulated debris was compared to the debris limits defined in WCAP-17788-P (Reference 11). In-vessel debris limit failures were determined to be bounded by strainer debris limit failures (see Section 6A.8).

6A.8 ANALYZED DEBRIS LIMITS

Containment accident generated and transported debris is defined as the quantity of debris calculated to arrive at the containment sump strainers. As described in the previous sections, the evaluation of the effects of debris includes strainer head loss, downstream ex-vessel effects, and downstream in-vessel effects. Of these three aspects of the evaluation, strainer head loss has the bounding debris limits.

Based on the tested and analyzed debris quantities, strainer debris limits were defined as shown in TS Bases Table B 3.6.7-1. These debris limits cannot be exceeded for breaks smaller than or equal to 10 inches for two RHR train operation or breaks smaller than or equal to 6 inches for single RHR train operation. Larger breaks may exceed these debris limits without exceeding the RG 1.174 Region III acceptance guidelines (Reference 2).

If debris quantities greater than the analyzed debris limits are identified, the containment sump LCO (TS 3.6.7) would not be met and Condition A would be entered. Immediate action would be initiated to mitigate the condition and restore the sump to operable status in accordance with the TS and as described in the TS Bases.

6A.9 REFERENCES

1. NRC Generic Letter (GL) 2004-02, “Potential Impact of Debris Blockage on Emergency Recirculation during Design Basis Accidents for Pressurized-Water Reactors,” September 13, 2004.

2. Regulatory Guide 1.174, “An Approach for Using Probabilistic Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis,” Revision 3, January 2018.

3. NEI 02-01, “Condition Assessment Guidelines: Debris Sources Inside PWR Containments,” April 2002.

4. NEI 04-07 Volume 1, “Pressurized Water Reactor Sump Performance Evaluation Methodology,” Revision 0, December 2004.

5. NEI 04-07 Volume 2, “Safety Evaluation by the Office of Nuclear Reactor Regulation Related to NRC Generic Letter 2004-02,” Revision 0, December 2004.

6. WCAP-16530-NP-A, “Evaluation of Post-Accident Chemical Effects in Containment Sump Fluids to Support GSI-191,” March 2008.

7. WCAP-17788-P Volume 5, “Comprehensive Analysis and Test Program for GSI-191 Closure (PA-SEE-1090) – Autoclave Chemical Effects Testing for GSI-191 Long-Term Cooling,” Revision 1, December 2019.

8. ML080230038, “NRC Staff Review Guidance Regarding Generic Letter 2004-02 Closure in the Area of Strainer Head Loss and Vortexing,” March 2008.

9. Regulatory Guide 1.82, “Water Sources for Long Term Recirculation Cooling Following a Loss of Coolant Accident,” Revision 3, November 2003.

10. WCAP-16406-P-A, “Evaluation of Downstream Sump Debris Effects in Support of GSI-191,” Revision 1, March 2008.

11. WCAP-17788-P Volume 1, “Comprehensive Analysis and Test Program for GSI-191 Closure (PA-SEE-1090),” Revision 1, December 2019.

12. ML19228A011, “U.S. Nuclear Regulatory Commission Staff Review Guidance for In-Vessel Downstream Effects Supporting Review of Generic Letter 2004-02 Responses,” September 4, 2019.

13. SNC Letter NL-18-0915 (ML18193B163 and ML18193B165), "Vogtle Electric Generating Plant - Units 1 and 2, Supplemental Response to NRC Generic Letter 2004-02," July 10, 2018.

14. ML19120A469, "Final Staff Evaluation for Vogtle Electric Generating Plant, Units 1 and 2, Systematic Risk-Informed Assessment of Debris Technical Report (EPID L-2017-TOP-0038)," September 30, 2019.

7.0 INSTRUMENTATION AND CONTROLS

7.1 INTRODUCTION

This chapter presents the various plant instrumentation and control systems by relating the functional performance requirements, design bases, system descriptions, design evaluations, and tests and inspections for each. The information provided in this chapter emphasizes the instruments and associated equipment that constitute the protection system as defined in Institute of Electrical and Electronics Engineers (IEEE) Standard 279-1971, Criteria for Protection Systems for Nuclear Power Generating Stations.

The standard Westinghouse solid state protection system design, which incorporates signal multiplexing for the control board and the plant computer, is applicable to VEGP.

The primary purpose of the instrumentation and control systems is to provide automatic protection and exercise proper control against unsafe and improper reactor operation during steady-state and transient power operations (American Nuclear Society (ANS) Conditions I, II, and III) and to provide initiating signals to mitigate the consequences of faulted conditions (ANS Condition IV). ANS conditions are discussed in chapter 15. Consequently, the information presented in this chapter emphasizes the instrumentation and control systems that are central to ensuring that the reactor can be operated to produce power in a manner that ensures no undue risk to the health and safety of the public.

It is shown that the applicable criteria and codes, such as general design criteria (GDC) and IEEE Standards, concerned with the safe generation of nuclear power are met by these systems. (See table 7.1.1-1 for a listing of applicable criteria as applied to instrumentation and control systems.)

A. Definitions

Terminology used in this chapter is based on the definitions given in IEEE Standard 279-1971, which is listed in subsection 7.1.2. In addition, the following definitions apply:

1. Degree of redundancy - The difference between the number of channels monitoring a variable and the minimum number of channels which, when tripped, would cause an automatic system trip.
2. Minimum degree of redundancy - The degree of redundancy below which operation is prohibited or otherwise restricted by the Technical Specifications.
3. Cold shutdown condition - When the reactor is subcritical by at least 1 percent $\Delta k/k$ and T_{avg} is $\leq 200°F$.
4. Hot shutdown condition - When the reactor is subcritical by an amount greater than or equal to the margin specified in the applicable Technical Specification and T_{avg} is greater than or equal to the temperature specified in the applicable Technical Specification.
5. Phase A containment isolation (CIA) - Closure of all purging ducts and nonessential process lines which penetrate containment initiated by the safety injection signal. (See subsection 6.2.4.)
6. Phase B containment isolation (CIB) - Not applicable.

7. Containment ventilation isolation - Closure of containment ventilation penetrations due to high radiation conditions existing inside the containment.

B. System Response Times

1. Reactor trip system response time - The time delays are defined as the time required for the reactor trip (i.e., the time the rods are free and begin to fall) to be initiated following a step change in the variable being monitored from 5 percent below to 5 percent above the trip setpoint.

2. Engineered safety features actuation system (ESFAS) response time - The interval required for the engineered safety features (ESF) sequence to be initiated subsequent to the point in time that the appropriate variable(s) exceed setpoints. The response time includes sensor/process (analog) and logic (digital) delay.

3. Reproducibility - This definition is taken from Scientific Apparatus Manufacturers Association (SAMA) Standard PMC-20.1-1973, Process Measurement and Control Terminology: "the closeness of agreement among repeated measurements of the output for the same value of input, under normal operating conditions over a period of time, approaching from both directions." It includes drift due to environmental effects, hysteresis, long-term drift, and repeatability. Long-term drift (aging of components, etc.) is not an important factor in accuracy requirements since, in general, the drift is not significant with respect to the time elapsed between testing. Therefore, long-term drift may be eliminated from this definition. In most cases reproducibility is a part of the definition of accuracy.

4. Accuracy - This definition is derived from SAMA Standard PMC-20.1-1973, Process Measurement and Control Terminology. An accuracy statement for a device falls under note 2 of the SAMA definition of accuracy, which means reference accuracy or the accuracy of that device at reference operating conditions: "reference accuracy includes conformity, hysteresis, and repeatability." To adequately define the accuracy of a system, the term "reproducibility" is useful as it covers normal operating conditions. The following terms, "trip accuracy" and "indicated accuracy," etc., include conformity and reproducibility under normal operating conditions. Where the final result does not have to conform to an actual process variable but is related to another value established by testing, conformity may be eliminated, and the term "reproducibility" may be substituted for accuracy.

5. Normal operating conditions - For this document, these conditions cover all normal process temperature and pressure changes. Also included are ambient temperature changes around the transmitter and racks.

6. Readout devices - The final device of a complete channel is considered a readout device. This includes indicators, recorders, isolators (nonadjustable), and controllers.

7. Channel accuracy - This definition includes accuracy of primary element, transmitter, and rack modules. It does not include readout devices or rack environmental effects but does include process and environmental effects on field-mounted hardware. Rack environmental effects are

included in the next two definitions to avoid duplication resulting from dual inputs.

8. Indicated and/or recorded accuracy - This definition includes channel accuracy, accuracy of readout devices, and rack environmental effects.

9. Trip accuracy - This definition includes comparator accuracy, channel accuracy for each input, and rack environmental effects. This is the tolerance expressed in process terms (or percent of span) within which the complete channel must perform its intended trip function. This includes all instrument errors but no process effects such as streaming. The term "actuation accuracy" may be used where the word "trip" might cause confusion, e.g., when starting pumps and other equipment.

10. Control accuracy - This definition includes channel accuracy, accuracy of readout devices (isolator and controller), and rack environmental effects. Where an isolator separates control and protection signals, the isolator accuracy is added to the channel accuracy to determine control accuracy, but credit is taken for tuning beyond this point; i.e., the accuracy of these modules (excluding controllers) is included in the original channel accuracy. The control accuracy is defined as the accuracy of the control signal in percent of the span of that signal. This includes gain changes where the control span is different from the span of the measured variable. Where controllers are involved, the control span is the input span of the controller. No error is included for the time the system is in a nonsteady-state condition.

7.1.1 IDENTIFICATION OF SAFETY-RELATED SYSTEMS

Safety-related instrumentation and control systems and their supporting systems are those systems required to ensure:

A. The integrity of the reactor coolant pressure boundary.

B. The capability to shut down the reactor and maintain it in a safe shutdown condition.

C. The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to the guideline exposures of 10 CFR 100.

The definitions provided below are used to classify the instrumentation systems into the categories listed in chapter 7.0 of Regulatory Guide 1.70.

7.1.1.1 <u>Reactor Protection System</u>

The reactor protection system consists of the reactor trip system, the ESFAS, and the instrumentation and control power supply system.

7.1.1.1.1 Reactor Trip System

The reactor trip system is described in section 7.2. Design bases for the reactor trip system are given in paragraph 7.1.2.1. Figure 7.1.1-1 is a schematic diagram of this system.

7.1.1.1.2 Engineered Safety Features Actuation System

The ESFAS is a functionally defined system described in section 7.3. The equipment which provides the actuation functions is identified and discussed in section 7.3. Design bases for the ESFAS are given in paragraph 7.1.2.1.

The ESFAS are those instrumentation systems that are needed to actuate the equipment and systems required to mitigate the consequences of postulated design basis accidents. As discussed in section 7.3 the ESF requiring actuation are:

A. Emergency core cooling (section 6.3).

B. Main steam line and feedwater isolation (subsection 6.2.4).

C. Containment isolation (subsection 6.2.4).

D. Containment heat removal (subsection 6.2.2).

E. Containment combustible gas control (subsection 6.2.5).

F. Containment ventilation isolation (subsection 6.2.4).

G. Fuel building exhaust isolation (subsection 9.4.2).

H. Control room ventilation isolation (subsection 9.4.1).

I. Auxiliary feedwater supply (subsection 10.4.9).

7.1.1.1.3 Instrumentation and Control Power Supply System

Design bases for the instrumentation and control power supply system are given in paragraph 7.1.2.1. Further description of this system is provided in subsection 7.6.1 and in chapter 8.

7.1.1.2 Other Instrumentation Systems Required for Safety

7.1.1.2.1 Information Systems Important to Safety

Information systems important to safety provide information for the operator to manually perform reactor trip, ESF actuation, post-accident monitoring, or safe shutdown functions.

Identification of the equipment and information systems important to safety is provided in section 7.5. Descriptions of other indicating systems that provide information for monitoring equipment and processes are also provided in section 7.5.

Section 7.5 also summarizes information systems required to maintain the plant in a hot shutdown condition or to proceed to cold shutdown.

7.1.1.2.2 Interlock Systems Important to Safety and Mode Switchover Instrumentation

These safety-related instrumentation systems are the systems and components that have a preventive role in reducing the effects of accidents. Single failures in these systems do not inhibit reactor trip, ESF actuation, or functions required for safe shutdown. Other interlock systems important to safety consist of the following:

A. Residual heat removal isolation valve interlocks.

B. Refueling interlocks.

C. Accumulator motor-operated valve interlocks.

D. Emergency core cooling system switchover from injection mode to recirculation mode.

E. Interlocks for RCS pressure control during low temperature operation.

F. Isolation of nonsafety-related systems for safety-related systems.

Item B above is described in subsection 9.1.4. Item D is discussed in section 6.3. The remaining items are described in subsection 7.6.5.

7.1.1.3 Systems Required for Safe Shutdown

Systems required for safe shutdown are defined as those essential for pressure and reactivity control, coolant inventory makeup, and removal of residual heat once the reactor has been brought to a subcritical condition.

Identification of the equipment and systems required for safe shutdown is provided in section 7.4. Additional information regarding provisions for cold shutdown from outside the control room is also provided in section 7.4.

7.1.1.4 Control Systems Not Required for Safety

Control systems not required for safety are the automatic and manual systems with the primary purpose of normal load control, startup, and shutdown of the main power generating system. As shown in section 7.7, malfunctions in these systems do not result in unsafe conditions.

7.1.1.5 Comparison with Other Plants

The systems discussed in chapter 7 are compared with the systems of other plants of similar design in section 1.3.

7.1.2 IDENTIFICATION OF SAFETY CRITERIA

Paragraph 7.1.2.1 gives design bases for the systems identified in subsection 7.1.1. Design bases for nonsafety-related systems are provided in the sections that describe the systems. Considerations for instrument errors are included in the accident analyses presented in chapter 15. Functional requirements developed on the basis of the results of the accident analyses that have utilized conservative assumptions and parameters are used in designing these systems, and a preoperational testing program verifies the adequacy of the design. Accuracies are given in sections 7.2, 7.3, and 7.5.

The criteria listed in table 7.1.1-1 are considered in the design of the systems given in subsection 7.I.I. In general, the scope of these documents is given in the document itself. This determines the systems or parts of systems to which the document is applicable. A discussion of compliance with each document for systems in its scope is provided in the referenced sections given in table 7.1.1-1 for each criterion. Because some documents were issued after design and testing had been completed, the equipment documentation may not meet the format requirements of some standards. Justification for any exceptions taken to each document for systems in its scope is provided in the referenced sections.

7.1.2.1 Design Bases

7.1.2.1.1 Reactor Trip System

The reactor trip system acts to limit the consequences of Condition II events (faults of moderate frequency such as loss of feedwater flow) by, at most, a shutdown of the reactor and turbine. The plant is capable of returning to operation after corrective action. The reactor trip system limits plant operation to ensure that the reactor safety limits are not exceeded during Condition II events and that these events can be accommodated without developing into more severe conditions. Reactor trip setpoints are given in the Technical Specifications.

The design requirements for the reactor trip system are derived by analyses of plant operating and fault conditions where automatic rapid control rod insertion is necessary in order to prevent or limit core or reactor coolant boundary damage. The design bases addressed in IEEE Standard 279-1971 are discussed in subsection 7.2.1. The design limits specified by Westinghouse for the reactor trip system are:

A. Minimum departure from nucleate boiling ratio (DNBR) shall not be less than the design basis limit as a result of any anticipated transient or malfunction (Condition II events).

B. Power density shall not exceed the rated linear power density for Condition II events. Refer to chapter 4 for fuel design limits.

C. The stress limit of the reactor coolant system for the various conditions shall be as specified in chapter 5.

D. Release of radioactive material shall be limited so as not to interrupt or restrict public use of areas beyond the exclusion radius as a result of any Condition III event.

E. For any Condition IV event, release of radioactive material shall not result in an undue risk to public health and safety.

7.1.2.1.2 Engineered Safety Features Actuation System

The engineered safety features actuation system (ESFAS) acts to limit the consequences of Condition III events (infrequent faults such as primary coolant spillage from a small rupture which exceeds normal charging system makeup and requires actuation of the safety injection system). The ESFAS acts to mitigate Condition IV events (limiting faults which include the potential for significant release of radioactive material).

The design bases for the ESFAS are derived from the design bases given in chapter 6 for the engineered safety features (ESF). Design bases requirements of IEEE Standard 279-1971 are addressed in paragraph 7.3.1.2. General design requirements are given below.

A. Automatic Actuation Requirements

The primary requirement of the ESFAS is to receive input signals (information) from the various ongoing processes within the reactor plant and containment and to automatically provide, as output, timely and effective signals to actuate the various components and subsystems comprising the ESF system.

B. Manual Actuation Requirements

The ESFAS must have provisions in the control room for manually initiating the functions of the ESF system.

7.1.2.1.3 Instrumentation and Control Power Supply System

The instrumentation and control power supply system provides continuous, reliable, regulated single phase ac power to all instrumentation and control equipment required for plant safety. Details of this system are provided in sections 7.6 and 8.3. The design bases are given below:

A. The inverter shall have the capacity and regulation required for the ac output for proper operation of the equipment supplied.

B. Redundant loads shall be assigned to different distribution panels which are supplied from different inverters.

C. Auxiliary devices that are required to operate dependent equipment shall be supplied from the same distribution panel to prevent the loss of electric power in one protection set from causing the loss of equipment in another protection set. No single failure shall cause a loss of power supply to more than one distribution panel.

D. Each of the distribution panels shall have access only to its respective inverter supply and a standby power supply.

E. The system shall comply with IEEE Standard 308-1974, section 5.4.

7.1.2.1.4 Emergency Power

Design bases and system description for the emergency power supply is provided in chapter 8.

7.1.2.1.5 Interlocks

Interlocks are discussed in sections 7.2, 7.3, 7.6, and 7.7. The protection (P) interlocks are given in tables 7.2.1-2 and 7.3.1-3. The safety analyses demonstrate that, even under conservative critical conditions for either postulated or hypothetical accidents, the protective systems ensure that the nuclear steam supply system (NSSS) is put into and maintained in a safe state following an ANS Condition II, III, or IV accident commensurate with applicable technical specifications and pertinent ANS criteria. The protective systems are designed to meet IEEE Standard 279-1971 and are entirely redundant and separate, including all permissives and blocks.

All blocks of a protective function are automatically cleared whenever the protective function is required to function in accordance with GDC 20, 21, and 22 and sections 4.11, 4.12, and 4.I3 of IEEE Standard 279-1971. Control interlocks (C) are identified in table 7.7-1. Because control interlocks are not safety related, they are not specifically designed to meet the requirements of IEEE protection system standards.

7.1.2.1.6 Bypasses

Bypasses are designed to meet the requirements of IEEE Standard 279-1971, sections 4.11, 4.12, 4.13, and 4.14. A discussion of bypasses provided is given in sections 7.2, 7.3, and 7.5.

A method has been developed to enable testing of the reactor trip system (RTS) and the engineered safety features actuation system (ESFAS) channels in the bypass condition as opposed to the tripped condition. At VEGP, bypass testing is provided for the 7300 process protection system, the nuclear instrumentation system, and various inputs to the solid state protection system.

The bypass test instrumentation (BTI) at VEGP will conform to applicable regulatory criteria including IEEE 279-1971 and Regulatory Guide 1.47 as well as prior regulatory guidance concerning tests in bypass. With implementation of the BTI, routine testing of analog RTS and ESFAS channels will be performed in a bypassed condition instead of a tripped condition. The Technical Specifications allow for the ability to test in the bypassed condition and govern the time that a channel can be in the bypassed condition for either test or maintenance. Reference 4 provides additional information concerning tests in bypass.

7.1.2.1.7 Equipment Protection

The criteria for equipment protection are given in chapter 3. Equipment related to safe operation of the plant is designed, constructed, and installed to protect it from damage. This is accomplished by working to accepted standards and criteria aimed at providing reliable instrumentation which is available under varying conditions. As an example, certain equipment is seismically qualified in accordance with IEEE Standard 344-1975. During construction, independence and separation are achieved, as required by IEEE Standard 279-1971, IEEE Standard 384-1981, and Regulatory Guide 1.75, either by barriers, physical separation, or demonstration test. This serves to protect against complete destruction of a system by fires, missiles, or other natural hazards.

7.1.2.1.8 Diversity

Functional diversity as discussed in reference 1 is designed into the system. The extent of diverse system variables is evaluated for a wide variety of postulated accidents. Generally, two or more diverse protection functions automatically terminate an accident before unacceptable consequences occur.

For example, there are automatic reactor trips based upon neutron flux measurements, reactor coolant loop temperature measurements, pressurizer pressure and level measurements, and reactor coolant pump underfrequency and undervoltage measurements. The system may also be activated manually and by initiation of a safety injection signal.

Regarding the ESFAS for a loss-of-coolant accident, a safety injection signal can be obtained manually or by automatic initiation from two diverse parameter measurements:

A. Low pressurizer pressure.

B. High containment pressure (high-1).

For a steam line break accident, safety injection signal actuation is provided by:

A. Low steam line pressure (lead-lag compensated).

B. Low pressurizer pressure.

For a steam line break inside containment, high containment pressure (high-1) provides an additional parameter for generation of the signal.

All of the above sets of signals are redundant and physically separated and meet the requirements of IEEE Standard 279-1971.

7.1.2.1.9 Bistable Trip Setpoints

Three values applicable to reactor trip and ESF actuation have been specified; they are safety limit, limiting value, and nominal value.

The safety limit is the value assumed in the accident analysis and is the least conservative value.

The limiting value is the technical specification value and is obtained by subtracting a safety margin from the safety limit. The safety margin accounts for instrument error, process uncertainties such as flow stratification and transport factor effects, etc.

The nominal value is the value set into the equipment and is obtained by subtracting allowances for instrument drift from the limiting value. The nominal value allows for the normal expected instrument setpoint drifts such that the technical specification limits are not exceeded under normal operation.

The setpoints that require trip action are given in the Technical Specifications. A further discussion on setpoints is found in paragraph 7.2.2.2.1.

The trip setpoint is determined by factors other than the most accurate portion of the instrument's range. The safety limit is determined only by the accident analysis.

As described above, allowance is then made for process uncertainties, instrument error, instrument drift, and calibration uncertainty to obtain the nominal value which is actually set into the equipment. The only requirement on the instrument's accuracy value is that over the instrument span, the error must always be less than or equal to the error value allowed in the accident analysis. The instrument does not need to be the most accurate at the setpoint value as long as it meets the minimum accuracy requirement. The accident analysis accounts for the expected errors at the actual setpoint.

Range selection for the instrumentation covers the expected range of the process variable being monitored consistent with its application. The design of the reactor protection and ESF systems is such that the bistable trip setpoints do not require process transmitters to operate within 5 percent of the high and low end of their calibrated span or range. Functional requirements established for every channel in the reactor protection and ESF systems stipulate the maximum allowable errors on accuracy, linearity, and reproducibility. The protection channels have the capability for and are tested to ascertain that the characteristics throughout the entire span in all aspects are acceptable and meet functional requirement specifications. As a result, no protection channel operates normally within 5 percent of the limits of its specified span.

In this regard, it should be noted that the specific functional requirements for response time, setpoint, and operating span are finalized contingent on the results and evaluation of safety studies to be carried out using data pertinent to the plant. Emphasis is placed on establishing adequate performance requirements under both normal and faulted conditions. This includes consideration of process transmitter margins such that, even under a highly improbable situation of full-power operation at the limits of the operating map (as defined by the high- and low-pressure reactor trip, ΔT overpower and overtemperature trip lines (DNB protection), and the steam generator safety valve pressure setpoint), adequate instrument response is available to ensure plant safety.

7.1.2.1.10 Engineered Safety Features Motor Specifications

The voltage for the residual heat removal (RHR) pump motor and ESF auxiliary system pump motors rated 4 kV (and above) and 460 V is 75 percent of rated voltage at the motor terminals to start and accelerate the driven equipment. (For the boric acid transfer pump, 80 percent of rated voltage is required.) The motors are capable of accelerating the driven equipment from rest to operating speed within 4 s.

The minimum margin of motor torque over the pump full-load torque (as defined by the pump speed/torque curve) is sufficient to accelerate all the driven equipment as necessary and with 75 percent of rated voltage at the motor terminals from standstill to operating speed. (For the boric acid transfer pump and boron injection recirculation pump motors, 80 percent of rated voltage is required.)

Verification of the ESF pump motors capability to operate within design temperature ratings, including the National Electrical Manufacturers Association (NEMA) Test Specification MG1-20.43 ("number of starts"), is based on the design tests of the prototype motor that are performed at the manufacturer's test facilities, rather than by means of initial or periodic tests in the field.

Six stator resistance type temperature detectors embedded in two slots of each phase between top and bottom coil sides are provided on 4-kV motors, except for the RHR pump motors. Abnormalities in the motor windings may be monitored with this instrumentation. For conditions where the motor stalls or fails to start, the influence of these conditions is best monitored from the current versus time characteristics, and equipment protection for this is provided by the circuit breaker trip function.

The design of 4-kV ESF pump motors does not preclude the surveillance of the hot spots on the rotor side of the motor. Should there be justification for making use of it, the procedure for surveillance would include removal of the motor from the system and return to the manufacturer's test facilities for evaluation, by means of reverification of prototype test results. Westinghouse does not believe there are maintenance benefits over the method of evaluation of the effects of motor overloads by means of the six stator resistance type temperature detectors and the conventional method of equipment protection by means of a circuit breaker trip function coordinated with the motor thermal overload characteristic.

7.1.2.2 Independence of Redundant Safety-Related Systems

The safety-related systems described in subsection 7.1.1 are designed to meet the independence and separation requirements of General Design Criterion 22 and section 4.6 of IEEE Standard 279-1971. Conformance with the specific provisions of Regulatory Guide 1.75 is discussed in chapter 8 and paragraph 7.1.2.2.1.

The electrical power supply, instrumentation, and controls for redundant circuits of a nuclear plant have physical separation to preserve redundancy and to ensure that no single credible event will prevent operation of the associated function resulting from electrical conductor damage. Critical circuits and functions include power, control, and analog instrumentation associated with the operation of the reactor trip system or ESFAS. Credible events include, but are not limited to, the effects of short circuits, pipe rupture, missiles, fire, etc., and are considered in the basic plant design. Control board details are given in chapter 18. In the control board, separation of redundant circuits is maintained as described in paragraph 7.1.2.2.2.

7.1.2.2.1 General

The physical separation criteria for redundant safety-related system sensors, sensing lines, wireways, cables, and components on racks meet recommendations contained in Regulatory Guide 1.75 with the following comments for NSSS equipment:

A. The design of the protection system relies on the provisions of IEEE Standard 384-1981 relative to overcurrent devices to prevent malfunctions in one circuit from causing unacceptable influences on the functioning of the protection system. The protection system uses redundant instrumentation channels and actuation trains and incorporates physical and electrical separation to prevent faults in one channel from degrading any other protection channel.

B. Separation recommendations for redundant instrumentation racks are not the same as those given in Regulatory Position C.16 of Regulatory Guide 1.75 for the control boards because of different functional requirements. Main control boards contain redundant circuits which are required to be physically separated from each other. However, since there are no redundant circuits which share a single compartment of an NSSS protection instrumentation rack and since these redundant protection instrumentation racks are physically separated from each other, the physical separation requirements specified for the main control board do not apply.

   However, redundant isolated control signal cables leaving the protection racks are brought into close proximity elsewhere in the plant, such as the control board. It could be postulated that electrical faults or interference at these locations might be propagated into all redundant racks and might degrade protection circuits because of the close proximity of protection and control wiring within each rack. Regulatory Guide 1.75 (Regulatory Position C.4) and IEEE Standard 384-1974 (section 4.5(3)) provide the option to demonstrate by tests that the absence of physical separation could not significantly reduce the availability of Class 1E circuits.

   Westinghouse test programs have demonstrated that Class 1E protection systems (nuclear instrumentation system, solid-state protection system, and 7300 process control system) are not degraded by non-Class 1E circuits sharing the same enclosure. Conformance to the requirements of IEEE Standard 279-1971 and Regulatory Guide 1.75 has been established and accepted by the Nuclear Regulatory Commission (NRC) based on the following, which is applicable to these systems at the VEGP.

   Tests conducted on the as-built designs of the nuclear instrumentation system and solid-state protection system were reported and accepted by the NRC in support of the Diablo Canyon application (Docket Nos. 50-275 and 50-323). Westinghouse considers these programs as applicable to all plants, including VEGP. Westinghouse tests on the 7300 process control system were covered in a report entitled, "7300 Series Process Control System Noise Tests," subsequently reissued as reference 2. In a letter dated April 20, 1977,[3] the NRC accepted the report in which the applicability of the VEGP is established.

C. The physical separation criteria for instrument cabinets within Westinghouse NSSS scope and the Westinghouse-supplied 7300 series for balance of plant scope meet the recommendations contained in section 6.7 of IEEE Standard 384-1981.

7.1.2.2.2 Specific Systems

Independence is maintained throughout the system, extending from the sensor to the devices actuating the protective function. Physical separation is used to achieve separation of redundant transmitters. Separation of wiring is achieved using separate wireways, cable trays, conduit runs, and containment penetrations for each redundant protection channel set. Redundant analog equipment is separated by locating modules in different protection rack sets. Each redundant channel set is energized from a separate ac power feed.

There are four separate process analog sets. Separation of redundant analog channels begins at the process sensors and is maintained in the field wiring, containment penetrations, and analog protection cabinets to the redundant trains in the logic racks.

In the nuclear instrumentation system, process systems, and the solid-state protection system input cabinets where redundant channel instrumentation are physically adjacent, there are no wireways or cable penetrations which would permit; for example, a fire resulting from electrical failure in one channel to propagate into redundant channels in the logic racks. Redundant analog channels are separated by locating modules in different cabinets. Since all equipment within any cabinet is associated with a single protection set, there is no requirement for separation of wiring and components within the cabinet.

Two reactor trip breakers are actuated by two separate logic matrices to interrupt power to the control rod drive mechanisms. The breaker main contacts are connected in series with the power supply so that opening either breaker interrupts power to all control rod drive mechanisms, permitting the rods to free-fall into the core.

A. Reactor Trip System

   1. Separate routing is maintained for the four basic reactor trip system channel sets analog sensing signals, bistable output signals, and power supplies for such systems. The separation of these four channel sets is maintained from sensors to instrument cabinets to logic system input cabinets.

   2. Separate routing of the redundant reactor trip signals from the redundant logic system cabinets is maintained. In addition, they are separated (by spatial separation, by provision of barriers, or by separate cable trays or wireways) from the four analog channel sets.

B. Engineered Safety Features Actuation System

   1. Separate routing is maintained for the four basic sets of ESFAS analog sensing signals, bistable output signals, and power supplies for such systems. The separation of these four channel sets is maintained from sensors to instrument cabinets to logic system input cabinets.

   2. Separate routing of the ESF actuation signals from the redundant logic system cabinets are maintained. In addition, they are separated by spatial separation, by provisions of barriers, or by separate cable trays or wireways from the four analog channel sets.

3. Separate routing of control and power circuits associated with the operation of ESF equipment is required to retain redundancies provided in the system design and power supplies.

C. Instrumentation and Control Power Supply System

The separation criteria presented also apply to the power supplies for the load centers and buses distributing power to redundant components and to the control of these power supplies.

Reactor trip system and ESFAS analog circuits may be routed in the same wireways, provided circuits have the same power supply and channel set identified (I, II, III, or IV).

In order to maintain separation between wiring on the main control board associated with different trains, mutually redundant safety train wiring is not terminated on a single device. Backup manual actuation switches link the separate trains by mechanical means to provide greater reliability of operator action for the manual reactor trip function and manual ESF actuations. The linked switches are themselves redundant so that operation of either set of linked switches will actuate safety trains A and B simultaneously. This is shown in figure 7.2.1-2. The design of the manual reactor trip function and manual ESF actuations conform with Regulatory Guide 1.62. (See also subsection 7.3.1.)

7.1.2.2.3 Fire Protection

For electrical equipment within the NSSS scope of supply, including the balance of plant Westinghouse-supplied 7300 series cabinets, Westinghouse specifies noncombustible or fire retardant material and conducts vendor-supplied specification reviews of this equipment, which includes assurance that materials are not used which may ignite or explode from an electrical spark, flame, or from heating or will independently support combustion. These reviews also include assurance of conservative current carrying capacities of all instrument cabinet wiring, which precludes electrical fires resulting from excessive overcurrent (I^2R) losses. For example, wiring used for instrument cabinet construction has Teflon or Tefzel insulation and is adequately sized based on current carrying capacities set forth by the National Electric Code. In addition, fire retardant paint is used on protection rack or cabinet construction to retard fire or heat propagation from rack to rack. Braided sheathed material used in the cables is noncombustible. For in-field wiring, cables in power trays are sized using derating factors listed in Insulated Cable Engineers Association (ICEA) Publication P-46-426 or Publication P-54-440. Paragraph 8.3.1.4.2 provides details regarding cable derating and cable tray fill.

For early warning protection against propagation of electrical fires, smoke or other detectors are provided for fire detection and alarm in remote wireways or other unattended areas where large concentrations of cables are installed.

The criteria and bases for the independence of electrical cable including routing, marking, and cable derating are covered in section 8.3. Fire detection and protection in the areas where wiring is installed is covered in subsection 9.5.1.

7.1.2.3 <u>Physical Identification of Safety-Related Equipment</u>

There are four separate protection sets identifiable with process equipment associated with the reactor trip and engineered safeguards actuation systems. A protection set may be comprised of more than a single process equipment cabinet. The color coding of each process equipment rack nameplate coincides with the color code established for the protection set of which it is a part. Redundant channels are separated by locating them in different equipment cabinets. Separation of redundant channels begins at the process sensors and is maintained in the field wiring, containment penetrations, and equipment cabinets to the redundant trains in the logic racks. The solid-state protection system input cabinets are divided into four isolated compartments, each serving one of the four redundant input channels. Horizontal 1/8-in.-thick solid steel barriers coated with fire retardant paint separate the compartments. Four 1/8-in.-thick solid steel wireways coated with fire retardant paint enter the input cabinets vertically in their own quadrant. The wireway for a particular compartment is open only into that compartment so that flame could not propagate to affect other channels. At the logic racks the protection set color coding for redundant channels is clearly maintained until the channel loses its identity in the redundant logic trains. The color-coded nameplates described in subsection 8.3.1 provide identification of equipment associated with protective functions and their channel set association.

All noncabinet-mounted protective equipment and components are provided with an identification tag or nameplate. Small electrical components such as relays have nameplates on the enclosure which houses them. All cables are numbered with identification tags. Cable trays and conduits are identified using permanent markings which identify the associated separation group. The purpose of such markings is to facilitate cable routing identification for future modification or additions. Positive permanent identification of cables and/or conductors is made at all terminal points. There are also identification nameplates on the input panels of the solid-state logic protection system. See section 8.3 for further details of physical identification of balance of plant safety-related equipment.

7.1.2.4 Conformance to Criteria

A listing of applicable criteria and the sections where conformance is discussed is given in table 7.1.1-1. An additional discussion of Westinghouse conformance to Regulatory Guide 1.22 and IEEE Standards 338-1975 and 379-1972 is given in the following paragraph.

7.1.2.5 Conformance to Regulatory Guide 1.22

Periodic testing of the reactor trip and ESFAS, as described in section 1.9 and subsections 7.2.2 and 7.3.1, conforms with Regulatory Guide 1.22, Periodic Testing of Protection System Actuation Functions.

Where the ability of a system to respond to a bona fide accident signal is intentionally bypassed for the purpose of performing a test during reactor operation, each bypass condition is automatically indicated to the reactor operator in the main control room by a separate annunciator for the train in test. Test circuitry does not allow two trains of the SSPS to be tested at the same time so that extension of the bypass condition to the redundant system is prevented. Administrative and procedural controls are used to prevent simultaneous testing of more than one protection set of the analog circuitry.

The actuation logic for the reactor trip and ESFAS is tested as described in sections 7.2 and 7.3. As recommended by Regulatory Guide 1.22, where actuated equipment is not tested during reactor operation it has been determined that:

A. There is no practicable system design that would permit operation of the equipment without adversely affecting the safety or operability of the plant.

B. The probability that the protection system will fail to initiate the operation of the equipment is, and can be maintained, acceptably low without testing the equipment during reactor operation.

C. The equipment can routinely be tested when the reactor is shut down.

The list of reactor trip ESFAS equipment that cannot be tested at full power so as not to damage equipment or upset plant operation is:

A. Manual actuation switches for reactor trip system and ESFAS.

B. Turbine trip system.

C. Main steam line isolation valves (close).

D. Main feedwater and feedwater bypass isolation valves (close).

E. Feedwater regulating valves (close).

F. Main feedwater pump trips.

G. Reactor coolant pump breakers.

H. Reactor coolant pump seal water return valves (close).

I. Pressurizer power operated relief valves (PORVs) (open).

J. Instrument air containment isolation valves (close).

The justifications for not testing the above items at full power are discussed below:

A. Manual Actuation Switches for Reactor Trip System and ESFAS

These switches would cause initiation of their protection system function at power causing plant upset and/or reactor trip. It should be noted that the reactor trip function that is derived from the automatic safety injection signal is tested at power.

The analog signals, from which the automatic safety injection signal is derived, are tested at power in the same manner as the other analog signals and as described in paragraph 7.2.2.2.3. The processing of these signals in the solid-state protection system wherein their channel orientation converts to a logic train orientation is tested at power by the built-in semiautomatic test provisions of the solid-state protection system. The reactor trip breakers are tested at power as discussed in paragraph 7.2.2.2.3.

B. Turbine Trip System

Testing of the main turbine trip function under power operation is discussed in subsections 10.2.2 and 10.2.5.

C. Closing the Main Steam Line Isolation Valves

Main steam line isolation valves are routinely tested during refueling outages. Testing of the main steam line isolation valves to closure at power is not practical. As the plant power is increased, the coolant average temperature is programmed to increase. If the valves are closed under these elevated temperature conditions, the steam pressure transient would unnecessarily operate the steam generator relief valves and possibly the steam generator safety valves. The steam pressure transient produced would cause shrinkage in the steam generator level, which would cause the reactor to trip on low-low steam generator water level. Testing during operation will decrease the operating life of the valve.

Based on the above-identified problems incurred with periodic testing of the main steam line isolation valves at power and since:

1. No practical system design permits operation of the valves without adversely affecting the safety or operability of the plant.
2. The probability that the protection system will fail to initiate the actuated equipment is acceptably low due to testing up to final actuation.
3. These valves are routinely tested during refueling outages.

The proposed resolution meets the guidelines of Regulatory Position D.4 of Regulatory Guide 1.22.

The main steam isolation valve actuator, except for Unit 2 Train A actuators, can be exercized periodically at power to approximately 90 percent of full open. For the applicable valves, separate control switches and position lights are provided to test each redundant actuator hydraulic circuit on each valve.

The main steam isolation bypass valves can be closed at power, since the effect of the resulting change in steam flow is insufficient to upset the operation of the reactor average coolant temperature regulation system.

D. Closing the Main Feedwater and Feedwater Bypass Isolation Valves

The main feedwater and feedwater bypass isolation valves are routinely tested during refueling outages. Periodic testing of these isolation valves by closing them completely at power would induce steam generator water level transients and oscillations which would trip the reactor. These transient conditions would be caused by perturbing the feedwater flow and pressure conditions necessary for proper operation of the variable speed feedwater pump control system and the steam generator water level control system. Any operation which induces perturbations in the main feedwater flow, whether deliberate or otherwise, generally leads to a reactor trip and should be avoided.

Based on these identified problems incurred with periodic testing of these isolation valves at power and since:

1. No practical system design permits operation of these valves without adversely affecting the safety or operability of the plant.
2. The probability that the protection system will fail to initiate the activated equipment is acceptably low due to testing up to final actuation.
3. These valves are routinely tested during refueling outages.

The proposed resolution meets the guidelines of Regulatory Position D.4 of Regulatory Guide 1.22.

The main feedwater isolation valve actuator can be exercized periodically at power to approximately 90 percent of full open. Separate control switches and position lights are provided to test each redundant actuator hydraulic circuit on each valve. The feedwater bypass isolation valve cannot be similarly tested.

E. Closing the Feedwater Regulating Valves

These valves are routinely tested during refueling outages. To close them at power would adversely affect the operability of the plant. The verification of operability of feedwater regulating valves at power is ensured by confirmation of proper operation of the steam generator water level control system. The actuation function of the solenoids, which provide the closing function, is periodically tested at power as discussed in paragraph 7.3.2.2.5. The operability of the slave relay which actuates the solenoid, which is the actuating device, is verified during this test. Although the closing of these regulating valves is blocked when the slave relay is tested, all functions are tested to ensure that no electrical malfunctions have occurred which could defeat the protective function. It is noted that the solenoids work on the deenergize-to-actuate principle, so that the feedwater regulating valves close upon either the loss of electrical power to the solenoids or loss of air pressure.

Based on the above, the testing of the isolating function of feedwater regulating valves meets the guidelines of Regulatory Position D.4 of Regulatory Guide 1.22.

At low power operation the bypass feedwater regulating valves are opened and the main feedwater regulating valves are closed. Testing of the bypass feedwater regulating valves under this condition is not permitted since it could cause unacceptable flow perturbation. The bypass feedwater regulating valves can be tested closed at full power since they are normally closed under these conditions. This is done by first opening and then closing the bypass feedwater regulating valves.

F. Main Feedwater Pump Trips

Since no credit is taken for automatic tripping of the feedwater pumps, the main feedwater pump trips do not require periodic testing.

G. Reactor Coolant Pump Breakers

No credit is taken in the accident analyses for a reactor coolant pump breaker opening causing a direct reactor trip. Testing at power would result in a plant trip. Hence, these breakers are tested during scheduled refueling outages.

H. Reactor Coolant Pump Seal Water Return Valves (Close)

Seal water return line isolation valves are routinely tested during refueling outages. Closure of these valves during operation would cause the seal water system relief valve to lift, with the possibility of valve chatter. Valve chatter could damage this relief valve. Testing of these valves at power could cause equipment damage. Therefore, these valves are tested during scheduled refueling outages. As above, additional containment penetrations and containment isolation valves introduce additional unnecessary potential pathways for radioactive release following a postulated accident. Thus, the guidelines of Regulatory Position D.4 of Regulatory Guide 1.22 are met.

I. Pressurizer Power Operated Relief Valves (PORVs)

Testing of the pressurizer power relief valves to open at power is not practical. Opening of these valves at power would cause an unwarranted depressurization of the reactor coolant system. The valves should be routinely tested during plant shutdown with the block valve (corresponding to the pressurizer power relief valve being tested) in the open position, the relief valve solenoid is energized. The status of the relief valve is then verified to be in the open position via the limit switch indication. This solenoid should then be immediately deenergized and the position of the relief valve verified to be in the close position. This process should be repeated for each relief valve.

J. Instrument Air Containment Isolation Valve

The instrument air containment isolation valve is routinely tested during refueling outages. Testing of the instrument air containment isolation valve to close at power is not practical. Periodic testing of this valve by closing it completely would induce the change of the normal position of several pneumatic valves inside the containment (e.g., CVCS letdown line isolation valve, RCP seal no. 3 supply valves, steam generator blowdown isolation valves, containment drain sump isolation valve, and containment normal purge isolation valves).

The actuation function of the solenoids, which provide the closing function, is periodically tested at power as discussed in paragraph 7.3.1.2.2.5. The operability of the slave relay which actuates the solenoid, which is the actuating device, is verified during this test. Although the closing of this valve is blocked when the slave relay is tested, all functions are tested to ensure that no electrical malfunctions have occurred which could defeat the protective function. It is noted that the solenoids work on the deenergize-to- actuate principle, so that the valve closes upon either the loss of electrical power to the solenoids or loss of air pressure.

Based on the above, the testing of the isolating function of the valve meets the guidelines of Regulatory Position D.4 of Regulatory Guide 1.22.

7.1.2.6 Conformance to Regulatory Guide 1.53 and IEEE Standard 379-1972

The principles described in IEEE Standard 379-I972 are used in the design of both the Westinghouse protection system and the balance of plant ESFAS. These systems conform with the intent of this standard and the additional guidance of Regulatory Guide 1.53.

For the Westinghouse systems, the formal analyses are not documented exactly as outlined. Westinghouse has gone beyond the required analyses and has performed a fault tree analysis.(1)

The referenced report provides details of the analyses of the protection systems previously made to show conformance with the single-failure criterion set forth in section 4.2 of IEEE Standard 279-1971. The interpretation of the single-failure criterion provided by IEEE Standard 379-1972 does not indicate substantial differences with the Westinghouse interpretation of the criterion except in the methods used to confirm design reliability. Established design criteria in conjunction with sound engineering practices form the bases for the Westinghouse protection systems. The reactor trip and engineered safeguards actuation systems are each redundant safety systems. The required periodic testing of these systems discloses any failures or loss of redundancy which have occurred in the interval between tests, thus ensuring the availability of these systems.

7.1.2.7 Conformance to IEEE Standard 338-1975

The periodic testing of the reactor trip system and ESFAS conforms to the requirements of IEEE Standard 338-1975 with the following comments:

A. The surveillance requirements of the Technical Specifications for a protection system ensure that the system's functional operability is maintained comparable to the original design standards. Periodic tests at frequent intervals demonstrate this capability for the system, excluding sensors.

Overall protection systems response times are demonstrated by test. Sensors within the Westinghouse scope are demonstrated to be adequate for this design by vendor testing, by onsite tests in operating plants with appropriately similar design, or by suitable type testing. The nuclear instrumentation system detectors are excluded, since they exhibit response-time characteristics such that delays attributable to them are negligible in the overall channel response time required for safety.

Response time may be verified by actual response time tests in any series of sequential, overlapping, or total channel measurements, or by the summation of allocated sensor, signal processing, and actuation logic response times with actual response time tests on the remainder of the channel. Allocations for sensor response times may be obtained from: (1) historical records based on acceptable response time tests (hydraulic, noise, or power interrupt tests), (2) in place, onsite, or offsite (e.g., vendor) test measurements, or (3) vendor engineering specifications. Reference 5 provides the basis and methodology for using allocated sensor response times in the overall verification of the channel response time for specific sensors. Response time verification for other sensor types must be demonstrated by test.

Reference 6 provides the basis and methodology for using allocated signal processing and actuation logic response times in the overall verification of the protection system channel response time. The allocations for sensor, signal conditioning, and actuation logic response times must be verified prior to placing the component in operational service and reverified following maintenance that may adversely affect response time. In general, electrical repair work does not impact response time provided the parts used for repair are of the same type and value. Specific components may be replaced without verification testing. One example where response time could be affected is replacing the sensing assembly of a transmitter.

Each test shall include at least one logic train such that both logic trains are tested at least once per 36 months and one channel per function such that all channels are tested at least once every N times 18 months, where N is the total number of redundant channels in a specific protective function.

The measurement of response time provides assurance that the protective and ESF action function associated with each channel is completed within the time limit assumed in the accident analyses.

B. The reliability goals specified in section 4.2 of IEEE Standard 338-1975 are being developed, and adequacy of time intervals will be demonstrated at a later date.

C. The periodic time interval discussed in section 4.3 of IEEE Standard 338-1975 and specified in the Technical Specifications is conservatively selected to ensure that equipment associated with protection functions has not drifted beyond its minimum performance requirements. If any protection channel appears to be marginal or requires more frequent adjustments due to plant condition changes, the time interval is decreased to accommodate the situation until the marginal performance is resolved.

D. The test interval discussed in section 5.2 of IEEE Standard 338-1975 is developed primarily on past operating experience and modified if necessary to ensure that system and subsystem protection is reliably provided. Analytical methods for determining reliability are not used to determine test interval.

Based on the scope definition given in IEEE Standard 338-1975, no other systems described in chapter 7 are required to comply with this standard.

7.1.2.8 References

1. T. W. T. Burnett, "Reactor Protection System Diversity in Westinghouse Pressurized Water Reactors," WCAP-7306, April 1969.
2. Marasco, F. W., and Siroky, R. M., "Westinghouse 7300 Series Process Control System Noise Tests," WCAP-8892-A, June 1977.
3. Letter dated April 20, 1977, R. L. Tedesco (NRC) to C. Eicheldinger (Westinghouse).
4. Mermigos, J. F., "Bypass Test Instrumentation for the Vogtle Electric Generating Plant, Units 1 and 2," WCAP-13376, Revision 2, September 1992.
5. Howard, R. C., “Elimination of Pressure Sensor Response Time Testing Requirements,” WCAP-13632-P-A, Revision 2, January 1996.
6. Morgan, C. E., “Elimination of Periodic Protection Channel Response Time Tests,” WCAP-14036-P-A, Revision 1, October 1998.

TABLE 7.1.1-1 (SHEET 1 OF 7)

LISTING OF CRITERIA AS APPLIED TO
INSTRUMENTATION AND CONTROL SYSTEMS

	Criteria	Title	Conformance Discussed In
1.	General Design Criteria (GDC), Appendix A to 10 CFR 50		
	GDC 1	Quality Standards and Records	3.1, 7.2.2
	GDC 2	Design Bases for Protection Against Natural Phenomena	3.1, 7.2.1
	GDC 3	Fire Protection	3.1, 9.5.1, 7.1.2
	GDC 4	Environmental and Missile Design Bases	3.1, 7.2.1
	GDC 5	Sharing of Structures, Systems, and Components	3.1
	GDC 10	Reactor Design	3.1, 7.2.2
	GDC 12	Suppression of Reactor Power Oscillations	3.1
	GDC 13	Instrumentation and Control	3.1, 7.3.1, 7.3.2
	GDC 15	Reactor Coolant System Design	3.1, 7.2.2
	GDC 17	Electric Power Systems	3.1, 8.3, 8.2
	GDC 19	Control Room	3.1
	GDC 20	Protection System Functions	3.1, 7.1.2, 7.2.2, 7.3.1, 7.3.2
	GDC 21	Protection System Reliability and Testability	3.1, 7.1.2, 7.2.2, 7.3.1, 7.3.2

TABLE 7.1.1-1 (SHEET 2 OF 7)

Criteria	Title	Conformance Discussed In
GDC 22	Protection System Independence	3.1, 7.1.2, 7.2.2, 7.3.1, 7.3.2
GDC 23	Protection System Failure Modes	3.1, 7.2.2, 7.3.1, 7.3.2
GDC 24	Separation of Protection and Control Systems	3.1, 7.2.2, 7.3.1, 7.3.2
GDC 25	Protection System Requirements for Reactivity Control Malfunctions	3.1, 7.3.2
GDC 26	Reactivity Control System Redundancy and Capability	3.1
GDC 27	Combined Reactivity Control Systems Capability	3.1, 7.3.1, 7.3.2
GDC 28	Reactivity Limits	3.1, 7.3.1, 7.3.2
GDC 29	Protection Against Anticipated Operational Occurrences	3.1, 7.2.2
GDC 33	Reactor Coolant Makeup	3.1
GDC 34	Residual Heat Removal	3.1
GDC 35	Emergency Core Cooling	3.1, 7.3.1, 7.3.2
GDC 37	Testing of Emergency Core Cooling System	3.1, 7.3.2
GDC 38	Containment Heat Removal	3.1, 7.3.1, 7.3.2
GDC 40	Testing of Containment Heat Removal System	3.1, 7.3.2
GDC 41	Containment Atmosphere Cleanup	3.1, 7.3.2
GDC 43	Testing of Containment Atmosphere Cleanup Systems	3.1, 7.3.2
GDC 44	Cooling Water	3.1

TABLE 7.1.1-1 (SHEET 3 OF 7)

Criteria	Title	Conformance Discussed In
GDC 46	Testing of Cooling Water System	3.1, 7.3.2
GDC 50	Containment Design Basis	3.1
GDC 54	Piping Systems Penetrating Containment	3.1, 6.2.4
GDC 55	Reactor Coolant Pressure Boundary Penetrating Containment	3.1, 6.2.4
GDC 56	Primary Containment Isolation	3.1, 6.2.4, .3.1
GDC 57	Closed System Isolation Valves	3.1, 6.2.4

2. IEEE Standards

IEEE Std 279-1971 (ANSI N42.7-1972)	Criteria for Protection Systems for Nuclear Power Generating Stations	7.1, 7.2, 7.3, 7.6, 7.7
IEEE Std 308-1974	Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations	7.6, 7.1, 8.1, 8.3
IEEE Std 317-1976	Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations	7.1.2, 8.1, 8.3
IEEE Std 323-1974	Qualifying Class 1E Equipment for Nuclear Power Generating Stations	3.11, 1.9, 8.1, 8.3 (RG 1.89)]
[(HISTORICAL) IEEE Std 336-1971 (ANSI N45.2.4-1972)	*Installation, Inspection and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations*	*7.1.2, 8.0]*
IEEE Std 336-1985 (ASME NQA-1-1994)	Installation, Inspection, and Testing Requirements for Power, Instrumentation, and Control Equipment at Nuclear Facilities	7.1.2, 8.0
IEEE Std 338-1975	Trial-Use Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems	7.1.2, 8.0

TABLE 7.1.1-1 (SHEET 4 OF 7)

Criteria	Title	Conformance Discussed In
IEEE Std 344-1975 (ANSI N41.7)	Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations	3.10, 7.1.2, 8.1, 8.3
IEEE Std 379-1972 (ANSI N41.2)	Trial-Use Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems	7.1.2, 8.0
IEEE Std 383-1974	Standard for Type Test of Class 1E Electric Cables, Field Splices, and Connectors for Nuclear Power Generating Stations	1.9.131, 8.1.4, 8.3
IEEE Std 384-1981	Standard Criteria for Independence of Class 1E Equipment and Circuits	7.1.2, 7.1.2, 8.1, 8.3
IEEE Std 603-1991	Standard Criteria for Safety Systems for Nuclear Power Generating Stations	8.3.1.1.3.F
IEEE Std 7-4.3.2-1993	Standard Criteria for Programmable Digital Devices in Safety Systems of Nuclear Power Generating Stations	8.3.1.1.3.F
3. Regulatory Guides (RG)		
RG 1.6	Independence Between Redundant Standby (Onsite)Power Sources and Between Their Distribution Systems	1.9, 7.6, 8.0
RG 1.11	Instrument Lines Penetrating Primary Reactor Containment	1.9, 7.3.1
RG 1.12	Instrument for Earthquakes	1.9, 3.7.4
RG 1.22	Periodic Testing of Protection System Actuation Functions	1.9, 7.1.2, 7.3.2
RG 1.29	Seismic Design Classification	1.9
RG 1.30	Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment	1.9, 17.0
RG 1.32	Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants	1.9

TABLE 7.1.1-1 (SHEET 5 OF 7)

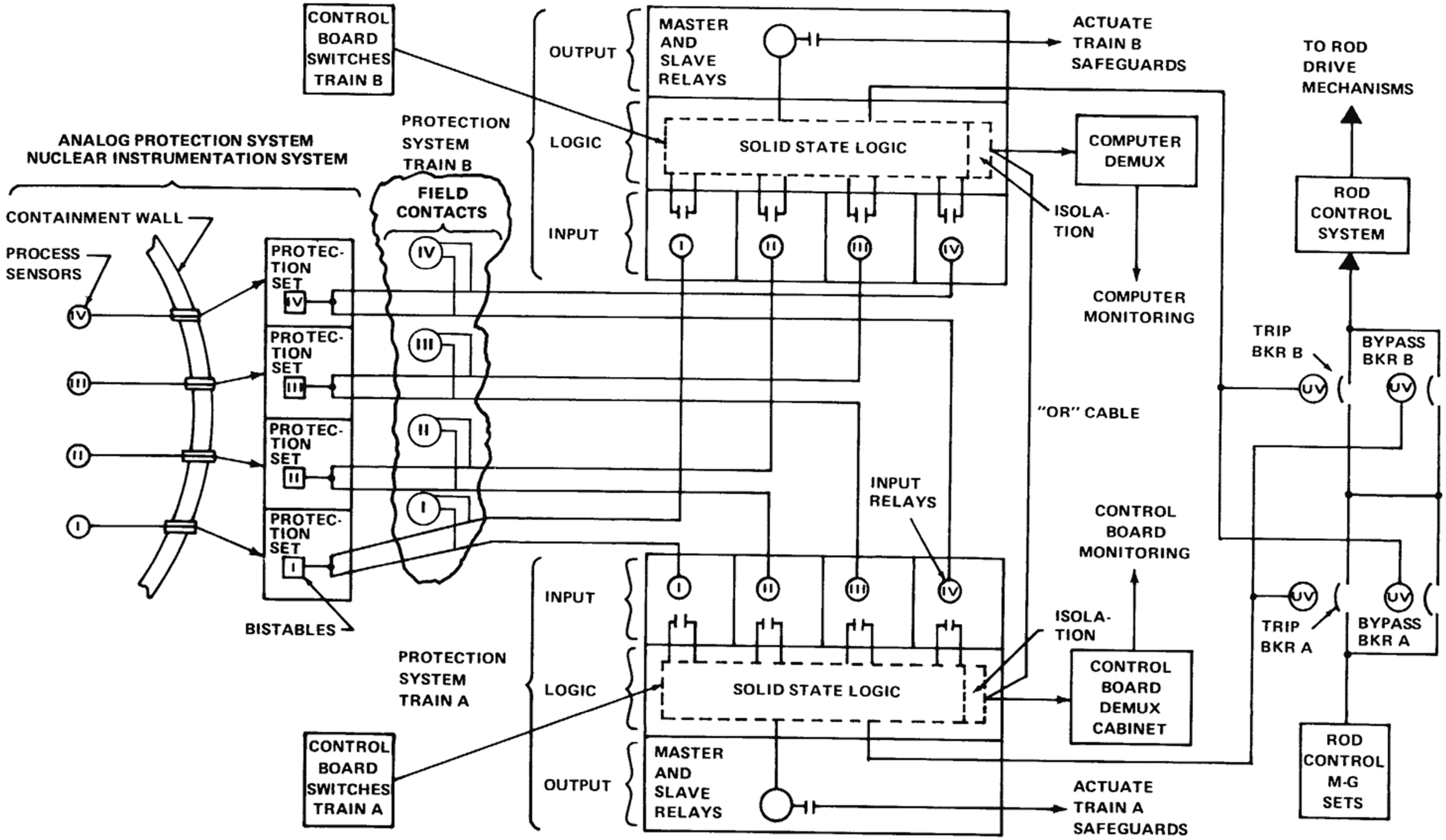
Criteria	Title	Conformance Discussed In
RG 1.45	Reactor Coolant Pressure Boundary Leakage Detection System	1.9, 5.2.5
RG 1.47	Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems	1.9, 7.5.5
RG 1.53	Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems	1.9, 7.1.2
RG 1.62	Manual Initiation of Protection Actions	1.9, 7.3.1
RG 1.63	Electric Penetration Assemblies in Containment Structures for Light Water-Cooled Nuclear Power Plants	1.9, 8.1, 8.3
RG 1.67	Installation of Overpressure Protection Devices	3.9.B.3
RG 1.68	Initial Test Programs for Water-Cooled Nuclear Power Plants	1.9, 14.0
RG 1.70	Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants LWR Edition	1.9
RG 1.75	Physical Independence of Electric Systems	1.9, 7.1.2
RG 1.80	Preoperational Testing of Instrumentation Air Systems	1.9, 9.3.1, 14.2.7
RG 1.89	Qualification of Class 1E Equipment for Nuclear Power Plants	1.9, 3.11
RG 1.95	Protection of Nuclear Power Plant Control Room Operators Against an Accidental Chlorine Release	1.9
RG 1.97	Instrumentation for Light Water-Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident	1.9
RG 1.100	Seismic Qualification of Electric Equipment for Nuclear Power Plants	1.9, 3.10
RG 1.105	Instrument Setpoints	7.1.2

TABLE 7.1.1-1 (SHEET 6 OF 7)

	Criteria	Title	Conformance Discussed In
	RG 1.118	Periodic Testing of Electric Power and Protection Systems	1.9
	RG 1.120	Fire Protection Guidelines for Nuclear Power Plants	1.9
4.	Branch Technical Positions (BTP) ICSB		
	BTP ICSB 3	Isolation of Low-Pressure Systems from the High-Pressure Reactor Coolant System	7.6.2
	BTP ICSB 4	Requirements on Motor-Operated Valves in the ECCS Accumulator Lines	7.6.4
	BTP ICSB 5	Scram Breaker Test Requirements – Technical Specifications	7.2.2, Technical Specifications
	BTP ICSB 9	Definition and Use of "Channel Calibration" - Technical Specifications	Technical Specifications
	BTP ICSB 10	Electrical and Mechanical Equipment Seismic Qualification Program	3.10
	BTP ICSB 12	Protection System Trip Point Changes for Operation with Reactor Coolant Pumps Out of Service	7.2.2, Technical Specifications
	BTP ICSB 13	Design Criteria for Auxiliary Feedwater Systems	7.3.2
	BTP ICSB 14	Spurious Withdrawals of Single Control Rods in Pressurized Water Reactors	7.7.2 15.2.1, 15.2.2, 15.3.6
	BTP ICSB 15	Reactor Coolant Pump Breaker Qualification	3.10, 7.1.2, 7.2.1
	BTP ICSB 18	Application of the Single Failure Criteria to Manually-Controlled Electrically-Operated Valves	Technical Specifications
	BTP ICSB 20	Design of Instrumentation and Controls Provided to Accomplish Changeover from Injection to Recirculation Mode	7.6.5, 6.3.2

TABLE 7.1.1-1 (SHEET 7 OF 7)

Criteria	Title	Conformance Discussed In
BTP ICSB 21	Guidance for Application of Regulatory Guide 1.47	7.5.5
BTP ICSB 22	Guidance for Application of Regulatory Guide 1.22	7.1.2
BTP ICSB 26	Requirements for Reactor Protection System Anticipatory Trips	7.2.1



REV 14 10/07

SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

PROTECTION SYSTEM BLOCK DIAGRAM

FIGURE 7.1.1–1

7.2 REACTOR TRIP SYSTEM

7.2.1 DESCRIPTION

7.2.1.1 System Description

The reactor trip system automatically keeps the reactor operating within a safe region by shutting down the reactor whenever the limits of the region are approached. The safe operating region is defined by several considerations, such as mechanical/hydraulic limitations on equipment and heat transfer phenomena. Therefore, the reactor trip system keeps surveillance on process variables that are directly related to equipment mechanical limitations, such as pressure and pressurizer water level (to prevent water discharge through safety valves and uncovering heaters), and also on variables that directly affect the heat transfer capability of the reactor (e.g., flow and reactor coolant temperatures). Still other parameters utilized in the reactor trip system are calculated from various process variables. In any event, whenever a direct process or calculated variable exceeds a setpoint, the reactor will be shut down in order to protect against either gross damage to fuel cladding or loss of system integrity which could lead to release of radioactive fission products into the containment.

The following systems make up the reactor trip system. (See references 1, 2, 3, 5, 6, 7, 8, and 9 for additional background information.)

- Process instrumentation and control system.
- Nuclear instrumentation system.
- Solid-state logic protection system.
- Reactor trip switchgear.
- Manual actuation circuit.

The reactor trip system consists of sensors, which monitor various plant parameters when connected with analog circuitry consisting of two to four redundant channels, and of digital circuitry, consisting of two redundant logic trains, which receives inputs from the analog protection channels to complete the logic necessary to automatically open the reactor trip breakers.

Either of the two trains, A or B, is capable of opening a separate and independent reactor trip breaker, RTA and RTB, respectively. The two trip breakers, in series, connect three-phase ac power from the rod drive motor generator sets to the rod drive power cabinets, as shown in drawing 1X6AA02-226. During plant power operation a dc undervoltage coil on each reactor trip breaker holds a trip plunger out against its spring, allowing the power to be available at the rod control power supply cabinets. For reactor trip, a loss of dc voltage to the undervoltage coil as well as energization of the shunt trip coils trips open the breaker. When either of the trip breakers opens, power is interrupted to the rod drive power supply, and the control and shutdown rods fall into the core. The rods cannot be withdrawn until the trip breakers are manually reset. The trip breakers cannot be reset until the abnormal condition which initiated the trip is corrected. Bypass breakers BYA and BYB are provided to permit testing of the trip breakers, as discussed in paragraph 7.2.2.2.3.

7.2.1.1.1 Functional Performance Requirements

The reactor trip system automatically initiates reactor trip:

A. Whenever necessary to prevent fuel damage for an anticipated operational transient (Condition II).

B. To limit core damage for infrequent faults (Condition III).

C. So that the energy generated in the core is compatible with the design provisions to protect the reactor coolant pressure boundary for limiting fault conditions (Condition IV).

The reactor trip system initiates a turbine trip signal whenever reactor trip is initiated. This prevents the reactivity insertion that would otherwise result from excessive reactor system cooldown to avoid unnecessary actuation of the engineered safety features actuation system.

The reactor trip system provides for manual initiation of reactor trip by operator action.

7.2.1.1.2 Reactor Trips

The various reactor trip circuits automatically open the reactor trip breakers whenever a condition monitored by the reactor trip system reaches a preset level. To ensure a reliable system, high-quality design, components, manufacturing, quality control, and testing are used. In addition to redundant channels and trains, the design approach provides a reactor trip system which monitors numerous system variables, thereby providing protection system functional diversity. The extent of this diversity has been evaluated for a wide variety of postulated accidents.

Table 7.2.1-1 provides a list of reactor trips which are described below. Table 7.2.1-2 provides a listing of the protection system interlocks and their P designations.

A. Nuclear Overpower Trips

The specific trip functions generated are described below.

1. Power Range High Neutron Flux Trip

   The power range high neutron flux trip circuit trips the reactor when two out of the four power range channels exceed the trip setpoint.

   There are two bistables in each channel, each with its own trip setting used for a high-and low-range trip setting. The high trip setting provides protection during normal power operation and is always active. The low trip setting, which provides protection during startup, can be manually bypassed when two out of the four power range channels read above approximately 10-percent power (P-10). Three out of the four channels below 10 percent automatically reinstate the trip function.

2. Intermediate Range High Neutron Flux Trip

   The intermediate range high neutron flux trip circuit trips the reactor when one out of the two intermediate range channels exceeds the trip setpoint. This trip, which provides protection during reactor startup, can be manually blocked if two out of four power range channels are above approximately 10-percent power (P-10). Three out of the four power range channels below this value automatically reinstate the intermediate range high neutron flux trip. The intermediate range channels (including detectors) are separate from the power range channels. The intermediate range channels can be individually bypassed at the nuclear instrumentation racks to permit channel testing during plant shutdown or prior to startup. This bypass action is monitored and annunciated on the control board.

3. Source Range High Neutron Flux Trip

The source range high neutron flux trip circuit trips the reactor when one out of the two source range channels exceeds the trip setpoint. This trip, which provides protection during reactor startup and plant shutdown, can be manually bypassed when one out of the two intermediate range channels reads above the P-6 setpoint value, and the trip is automatically reinstated when both intermediate range channels decrease below the P-6 setpoint value. This trip is automatically bypassed by two out of four logic from the power range protection interlock (P-10). This trip function can also be reinstated below P-10 by an administrative action requiring manual actuation of two control board-mounted switches. Each switch will reinstate the trip function in one of the two protection logic trains. The source range trip point is set between the P-6 setpoint (source range block power level) and the maximum source range power level. The channels can be individually bypassed at the nuclear instrumentation racks to permit channel testing during plant shutdown or prior to startup. This bypass action is monitored and annunciated on the control board.

4. Power Range High Positive Neutron Flux Rate Trip

This circuit trips the reactor when a sudden abnormal increase in nuclear power occurs in two out of four power range channels. This trip provides protection against rod ejection accidents of low worth from midpower and is always active. (See subsection 15.4.8.) This trip also provides protection when there is a rapid power increase (e.g., an uncontrolled rod cluster assembly withdrawal at power; see subsection 15.4.2).

Drawings 1X6AA02-227 and 1X6AA02-228 shows the logic for all of the nuclear overpower and rate trips.

B. Core Thermal Overpower Trips

The specific trip functions generated are described below.

1. Overtemperature ΔT Trip

This trip protects the core against low DNBR and trips the reactor on coincidence, as listed in table 7.2.1-1, with one set of temperature measurements per loop; where $\frac{\Delta t\ (1+\tau_1 s)}{(1+\tau_2 s)\ \ (1+\tau_3 s)} \leq \Delta T$ setpoint.

The ΔT setpoint for this trip is continuously calculated by analog circuitry for each loop by solving the following expression:

$$\Delta T_0 \left[K_1 - K_2 \frac{(1+\tau_4 s)}{1+\tau_5 s} \left[(T_{avg} \frac{(1)}{1+\tau_6 s} - T^o_{avg})\right] + K_3 \ (P - P_0) - f(\Delta\phi)\right]$$

where:

ΔT	=	measured ΔT.
ΔT_0	=	indicated ΔT at rated thermal power.
T_{avg}	=	average reactor coolant temperature (°F).
T°_{avg}	=	nominal T_{avg} at rated thermal power (°F).
P	=	pressurizer pressure (psig).
K_1	=	preset bias.
K_2	=	preset gain which compensates for effects of temperature on the DNB limits.
K_3	=	preset gain which compensate for effect of pressure on the DNB limits.
τ_1, τ_2	=	preset constants utilized in lead-lag compensator for ΔT.
P_0	=	nominal RCS operating pressure (psig).
τ_3	=	preset constant utilized in lag compensator for ΔT.
τ_4,τ_5	=	preset constants which compensate for instrument time delay(s).
τ_6	=	preset constant utilized for measured T_{avg} response compensation.
s	=	LaPlace transform operator.
f ($\Delta\phi$)	=	function of the neutron flux difference between upper and lower long ion chambers. (Refer to figure 7.2.1-1.)

A separate long ion chamber unit supplies the flux signal for each overtemperature ΔT channel.

Increases in $\Delta\phi$ beyond a predefined deadband results in a decrease in trip setpoint. (Refer to figure 7.2.1-1.)

For T_{avg}<T°_{avg}, the value of (T°_{avg}-T_{avg}) is clamped to limit the increase in the setpoint during cooldown transients.

The required one pressurizer pressure parameter per loop is obtained from separate sensors connected to three pressure taps at the top of the pressurizer. Four pressurizer pressure signals are obtained from the three taps by connecting one of the taps to two pressure transmitters. Refer to paragraph 7.2.2.3.3 for an analysis of this arrangement.

Drawing 1X6AA02-229 shows the logic for overtemperature ΔT trip function.

2. Overpower ΔT Trip

This trip protects against excessive power (fuel rod rating protection) and trips the reactor on coincidence as listed in table 7.2.1-1, with one set of temperature measurements per loop, where

$$\Delta T \frac{(1 + \tau_1 s)}{(1 + \tau_2 s)(1 + \tau_3 s)} \leq \Delta T \text{ setpoint.}$$

The ΔT setpoint for this trip is continuously calculated by analog circuitry for each loop using the following expression:

$$\Delta T_0 \left[K_4 - K_5 \frac{\tau_7 s}{1 + \tau_7 s} \frac{1}{1 + \tau_6 s} T_{avg} - K_5 \left[T_{avg} \left(\frac{1}{1 + \tau_6 s}\right) - T_{avg}^{\infty}\right] - f(\Delta\phi)\right]$$

where:

ΔT	=	measured ΔT.
ΔT_0	=	indicated ΔT rated thermal power.
$f(\Delta\phi)$	=	a function of the neutron flux difference between upper and lower long ion chamber section.
K_4	=	a preset bias.
K_5	=	a constant which compensates for instrument time delay.
K_6	=	a constant which compensates for the change in density flow and heat capacity of the water with temperature.
T_{avg}^{∞}	=	indicated T_{avg} at rated thermal power (°F).
T_{avg}	=	average reactor coolant temperature (°F).
τ_1, τ_2	=	preset constants utilized in lead-lag compensator for ΔT.

τ_3	=	preset constant utilized in lag compensator for ΔT.
τ_7	=	preset time constant (s).
s	=	LaPlace transform operator.
τ_6	=	preset constant utilized for measured T_{avg} response compensation.

The source of temperature and flux information is identical to that of the overtemperature ΔT trip, and the resultant ΔT setpoint is compared to the same ΔT. Drawing 1X6AA02-229 shows the logic for this trip function.

C. Reactor Coolant System Pressurizer Pressure and Water Level Trips

The specific trip functions generated are described below.

1. Pressurizer Low-Pressure Trip

   The purpose of this trip is to protect against low pressure which could lead to DNB. The parameter being sensed is reactor coolant pressure, as measured in the pressurizer. Above P-7 the reactor is tripped when the pressurizer pressure measurements (compensated for rate of change) fall below preset limits. This trip is blocked below P-7 to permit startup. The trip logic and interlocks are given in table 7.2.1-1.

   The trip logic is shown in drawing 1X6AA02-230.

2. Pressurizer High-Pressure Trip

   The purpose of this trip is to protect the reactor coolant system against system overpressure. The same sensors and transmitters used for the pressurizer low-pressure trip are used for the high-pressure trip, except that separate bistables are used for trip. These bistables trip when uncompensated pressurizer pressure signals exceed preset limits on coincidence, as listed in table 7.2.1-1. There are no interlocks or permissives associated with this trip function.

   The logic for this trip is shown in drawing 1X6AA02-230.

3. Pressurizer High Water Level Trip

   This trip is provided as a backup to the high pressurizer pressure trip and serves to prevent water relief through the pressurizer safety valves. This trip is blocked below P-7 to permit startup. The coincidence logic and interlocks of pressurizer high water level signals are given in table 7.2.1 1.

   The trip logic for this function is shown in drawing 1X6AA02-230.

D. Reactor Coolant System Low Flow Trips

These trips protect the core from DNB in the event of a loss of coolant flow situation. Drawings 1X6AA02-228 and 1X6AA02-229 shows the logic for these trips. The means of sensing the loss of coolant flow are described below.

1. Low Reactor Coolant Flow

   The parameter sensed is reactor coolant flow. Four elbow taps in each coolant loop are used as a flow device that indicates the status of reactor coolant flow. The basic function of this device is to provide information as to whether or not a reduction in flow has occurred. An output signal from two out of the three bistables in a loop would indicate a low flow in that loop.

   The coincidence logic and interlocks are given in table 7.2.1-1

2. Reactor Coolant Pump Undervoltage Trip

   This trip is provided to protect against low flow which can result from loss of voltage to more than one reactor coolant pump motor (e.g., from plant blackout or reactor coolant pump breakers opening).

   Two undervoltage relays sense the voltage on the motor side of each reactor coolant pump breaker. These relays provide an output signal when the pump motor power bus voltage drops below approximately 70 percent of rated voltage. Signals from these relays are time delayed to prevent spurious trips caused by short-term voltage perturbations. The coincidence logic and interlocks are given in table 7.2.1-1.

3. Reactor Coolant Pump Underfrequency Trip

   This trip protects against low flow resulting from pump underfrequency, for example, a major power grid frequency disturbance. The function of this trip is to trip the reactor for an underfrequency condition greater than approximately 2.4 Hz.

   Two underfrequency relays sense the underfrequency on the motorside of each reactor coolant pump breaker. Signals from these relays are time delayed to prevent spurious trips caused by short-term frequency perturbations. The coincidence logic and interlocks are given in table 7.2.1-1.

E. Steam Generator Trip

The specific trip function generated is low-low steam generator water level trip.

This trip protects the reactor from loss of heat sink. This trip is actuated on two out of four low-low water level signals occurring in any steam generator.

The logic is shown in drawing 1X6AA02-231.

F. Reactor Trip on a Turbine Trip (Anticipatory)

The reactor trip on a turbine trip is actuated by two- out-of-three logic from emergency trip fluid pressure signals or by all closed signals from the turbine steam stop valves. A turbine trip causes a direct reactor trip above P-9. Although not credited in any safe`ty analysis, the reactor trip on turbine trip provides additional protection and conservatism beyond that required for the health and safety of the public. This trip is included as part of good engineering practice and prudent design and satisfies the requirement of TMI Action Items II.K.3.10 and II.K.3.12.

The turbine provides anticipatory trips to the reactor protection system from contacts which change position when the turbine stop valves close or when the turbine emergency trip fluid pressure goes below its setpoint.

Components specified for use as sensors for input signals to the reactor protection system for "emergency trip oil pressure low" and "turbine stop valves close" conform to the requirements of Institute of Electrical and Electronics Engineers (IEEE) 279-1971 and are environmentally qualified. However, pipe whip, jet impingement, and seismic criteria are not included in qualification, regarding mounting and location for that portion of the trip system located within non-Seismic Category 1 structures. (These criteria are also applicable to the steam dump solenoid valves and turbine impulse chamber pressure transmitters.)

Loss of signal from equipment located within non-Seismic Category 1 structures will result in a trip input to the reactor protection system.

In addition, the following measures will be taken to ensure the integrity of the cabling to the solid-state protection system (SSPS):

1. Inputs from the turbine steam stop valves will originate from four separate limit switches (one per valve), each of which is dedicated to providing an input to one channel of the SSPS. Cables carrying these signals will be routed in individual conduits. The four circuits will be separated from one another and from non-Class 1E circuits and identified according to the criteria imposed on Class 1E circuits, from their source up to their terminations within the SSPS cabinets.

   Additionally, fuses have been added in each turbine stop valve limit switch circuit before the circuit enters the turbine building. In the event of multiple ground faults, the fuses will isolate the affected channels and provide a trip signal input to the SSPS.

2. Input from the emergency trip oil pressure originates from three separate pressure transmitters powered from the balance of plant safety-related process instrumentation cabinet. The cables for these transmitters are routed in individual conduits within the turbine building, according to the criteria imposed on Class 1E circuits.

The logic for this trip is shown in drawings 1X6AA02-228 and 1X6AA02-240.

G. Safety Injection Signal Actuation Trip

A reactor trip occurs when the safety injection system is actuated. The means of actuating the safety injection system are described in section 7.3. This trip protects the core against a loss of reactor coolant or a steam line rupture.

Drawings 1X6AA02-232 and 1X6AA02-519 show the logic for this trip.

H. Manual Trip

The manual trip consists of two switches with two-train outputs on each switch on the main control board, and two single-train switches, one on each of the shutdown panels. One of the two-train outputs is used to actuate the train A reactor trip breaker, and the other output actuates the train B reactor trip breaker. Operating a manual trip switch removes the voltage from the undervoltage trip coil and energizes the shunt trip coil of each breaker.

There are no interlocks which can block this trip. Drawing 1X6AA02-227 shows the manual trip logic. The design conforms to Regulatory Guide 1.62, as shown in figure 7.2.1-2.

I. Solid State Protection System General Warning Alarm Reactor Trip

General warning alarm reactor trip is discussed in paragraph 7.2.2.2.3.

7.2.1.1.3 Reactor Trip System Interlocks

A. Power Escalation Permissives

The overpower protection provided by the out of core nuclear instrumentation consists of three discrete, but overlapping, ranges. Continuation of startup operation or power increase requires a permissive signal from the higher range instrumentation channels before the lower range level trips can be manually blocked by the operator.

A one-out-of-two intermediate range permissive signal (P-6) is required prior to source range trip blocking. Source range trips are automatically reactivated when both intermediate range channels are below the permissive (P-6) setpoint. There are two manual reset switches for administratively reactivating the source range level trip, if required, when it is between the permissive P-6 and P-10 setpoints. Source range level trip block is always maintained when above the permissive P-10 setpoint.

The intermediate range level trip and power range (low setpoint) trip can only be blocked after satisfactory operation and permissive information are obtained from two out of four power range channels. Four individual blocking switches are provided so that the low range power range trip and intermediate range trip can be independently blocked (one switch for each train).

These trips are automatically reactivated when three out of the four power range channels are below the permissive (P-10) setpoint, thus ensuring automatic activation of more restrictive trip protection.

The development of permissives P-6 and P-10 is shown in drawing 1X6AA02-228. All of the permissives are digital. They are derived from analog signals in the nuclear power range and intermediate range channels.

B. Blocks of Reactor Trips at Low Power

Interlock P-7 blocks a reactor trip at low power (below approximately 10 percent of full power) on a low reactor coolant flow in more than one loop, reactor coolant pump undervoltage, reactor coolant pump underfrequency, pressurizer low pressure, or pressurizer high water level. See drawings 1X6AA02-229 and 1X6AA02-230 for permissive applications. The low power signal is derived from three out of four power range neutron flux signals below the setpoint in coincidence with two out of two turbine impulse chamber pressure signals below the setpoint (low plant load). Turbine impulse chamber pressure transmitters and circuits in the turbine building are designed to criteria similar to the reactor trip on turbine trip circuits as described in paragraph 7.2.1.1.2.F. See drawings 1X6AA02-228 and 1X6AA02-240 for the derivation of P-7.

The P-8 interlock blocks a reactor trip when the plant is below approximately 48 percent of full power, on a low reactor coolant flow in any one loop. The block action (absence of the P-8 interlock signal) occurs when three out of four neutron flux power range signals are below the setpoint. Thus, below the P-8 setpoint, the reactor will be allowed to operate with one inactive loop, and trip will not occur until two loops are indicated as low flow. See drawing 1X6AA02-228 for derivation of P-8 and drawing 1X6AA02-229 for applicable logic.

7.2.1.1.4 Coolant Temperature Sensor Arrangement

The hot and cold leg temperature signals required for input to the protection and control functions are obtained using thermowell-mounted RTDs installed in each reactor coolant loop. The hot leg temperature measurement in each loop is accomplished using three fast-response, dual-element, narrow-range RTDs mounted in thermowells. The three thermowells in each loop are located within hot leg scoops 120 degrees apart in the cross-sectional plane of the piping, with one located at the top of the pipe, to obtain a representative temperature sample. The scoops have a flow hole machined into the end to facilitate the flow of water through holes in the leading edge of the scoop, past the thermowell, and back into the flow stream.

The temperatures measured by the three thermowell-mounted RTDs are different due to hot leg temperature streaming and vary as a function of thermal power. Therefore, these signals are averaged using electronic weighting to generate a hot leg average temperature. Provisions are incorporated into the process electronics to allow for operation with only two RTDs in service. The two RTD measurements can be biased to compensate for the loss of the third RTD as described in reference 4.

The cold leg temperature measurement in each loop is accomplished by one fast-response, dual-element, narrow-range RTD mounted in a thermowell.

7.2.1.1.5 Pressurizer Water Level Reference Leg Arrangement

The design of the pressurizer water level instrumentation employs the usual tank level measuring arrangement, using differential pressure between an upper and a lower tap on a column of water. A reference leg connected to the upper tap is kept full of water by condensation of steam at the top of the leg.

7.2.1.1.6 Analog System

The analog system consists of two instrumentation systems, the process instrumentation system, and the nuclear instrumentation system.

Process instrumentation includes those devices (and their interconnection into systems) which measure temperature, pressure, fluid flow, fluid level in tanks or vessels, and, occasionally, physicochemical parameters such as fluid conductivity or chemical concentration. Process instrumentation specifically excludes nuclear and radiation measurements. The process instrumentation includes the process measuring devices, power supplies, indicator, recorders, alarm actuating devices, controllers, signal conditioning devices, etc., which are necessary for day-to-day operation of the nuclear steam supply system, as well as for monitoring the plant and providing initiation of protective functions.

The primary function of nuclear instrumentation is to protect the reactor by monitoring the neutron flux and generating appropriate trips and alarms for various phases of reactor operating and shutdown conditions. It also provides a secondary control function and indicates reactor status during startup and power operation. The nuclear instrumentation system uses information from three separate types of instrumentation channels to provide three discrete protection levels. Each range of instrumentation (source, intermediate, and power) provides the necessary overpower reactor trip protection required during operation in that range. The overlap of instrument ranges provides reliable continuous protection, beginning with source level through the intermediate and low power level. As the reactor power increases, the overpower protection level is increased by administrative control and in-plant procedures after satisfactory higher range instrumentation operation is obtained. Automatic reset to more restrictive trip protection is provided when reducing power.

Various types of neutron detectors, with appropriate solid-state electronic circuitry, are used to monitor the leakage neutron flux from a completely shutdown condition to 200 percent of full power. The neutron flux covers a wide range between these extremes. Therefore, monitoring with several ranges of instrumentation is necessary.

The lowest range (source range) covers 7 decades of leakage neutron flux. The lowest observed count rate depends on the strength of the neutron sources in the core and the core multiplication associated with the shutdown reactivity. This is generally greater than two counts per second. The intermediate range covers 8 decades to 200 percent full power. Detectors and instrumentation are chosen to provide overlap between the higher portion of the source range and the lower portion of the intermediate range. The power range covers approximately 2 decades of the total instrumentation range to 120 percent full power. This is a linear range that overlaps with the higher portion of the intermediate range.

The system described above provides control room indication and recording of signals proportional to reactor neutron flux during core loading, shutdown, startup, and power operation, as well as during subsequent refueling. Startup rate indication for the source and intermediate range channels is provided at the control board. Reactor trip, rod stop, control, and alarm signals are transmitted to the reactor control and protection system for automatic plant control. Equipment failures and test status information are annunciated in the control room.

See references 1 and 2 for additional background information on the process and nuclear instrumentation.

7.2.1.1.7 Solid-State Logic Protection System

The solid-state logic protection system takes binary inputs (voltage/no voltage) from the process and nuclear instrument channels (nuclear steam supply system/balance of plant) and from field instrument channels corresponding to conditions (normal/abnormal) of plant parameters. The system combines these signals in the required logic combination and generates a trip signal (no voltage) to the undervoltage trip attachment and shunt trip auxiliary relay coils of the reactor trip circuit breakers when the necessary combination of signals occur. The system also provides annunciator, status light, and computer input signals which indicate the condition of bistable input signals, partial trip, and full trip functions and the status of the various blocking, permissive, and actuation functions. In addition, the system includes means for semiautomatic testing of the logic circuits. See references 3, 5, 6, 7, 8, and 9 for additional background information.

7.2.1.1.8 Isolation Amplifiers

In certain applications, control signals are derived from individual protection channels through isolation amplifiers contained in the protection channel, as permitted by IEEE 279-1971.

In all of these cases, analog signals derived from protection channels for nonprotective functions are obtained through isolation amplifiers located in the analog protection racks. By definition, nonprotective functions include those signals used for control, remote process indication, and computer monitoring. Refer to paragraph 7.1.2.2.1 for a discussion of electrical separation of control and protection functions.

7.2.1.1.9 Power Supply and Environmental Variations

The power supply for the reactor trip system is described in section 7.6 and chapter 8. The environmental variations throughout which the system will perform are given in section 3.11.

7.2.1.1.10 Setpoints

The setpoints that require trip action are given in the Technical Specifications. A detailed discussion on setpoints is found in paragraph 7.1.2.1.9.

7.2.1.1.11 Seismic Design

The seismic design considerations for the reactor trip system are given in section 3.10. This design meets the requirements of General Design Criterion 2.

7.2.1.2 Design Bases Information

The information given below presents the design bases information requested by section 3 of IEEE 279-1971. Functional diagrams are presented in drawings 1X6AA02-225, 1X6AA02-226, 1X6AA02-227, 1X6AA02-228, 1X6AA02-229, 1X6AA02-230, 1X6AA02-231, 1X6AA02-232, 1X6AA02-233, 1X6AA02-234, 1X6AA02-235, 1X6AA02-236, 1X6AA02-237, 1X6AA02-238, 1X6AA02-239, 1X6AA02-240, 1X6AA02-494, 1X6AA02-495, 1X6AA02-496 and 1X6AA02-519.

7.2.1.2.1 Generating Station Conditions

The following are the plant conditions requiring reactor trip.

- DNBR approaching the design basis limit.
- Power density (kW/ft) approaching rated value for Condition II events. (See chapter 4 for fuel design limits.)

- Reactor coolant system overpressure creating stresses approaching the limits specified in chapter 5.

7.2.1.2.2 Generating Station Variables

The following are the variables required to be monitored in order to provide reactor trips. (See table 7.2.1-1.)

- Neutron flux.
- Reactor coolant temperature.
- Reactor coolant system pressure (pressurizer pressure).
- Pressurizer water level.
- Reactor coolant flow.
- Reactor coolant pump operational status (voltage and frequency).
- Steam generator water level.
- Turbine-generator operational status (trip fluid pressure and stop valve position).
- Safety injection signal.

7.2.1.2.3 Spatially Dependent Variables

The reactor coolant temperature is spatially dependent. (See subsection 7.3.1 for a discussion of this variable spatial dependence.)

7.2.1.2.4 Limits, Margins, and Setpoints

The parameter values that will require reactor trip are given in the Technical Specifications and in chapter 15. The accident analyses of chapter 15 demonstrate that the setpoints used in the Technical Specifications are conservative.

The setpoints for the various functions in the reactor trip system have been analytically determined such that the operational limits so prescribed will prevent fuel rod clad damage and loss of integrity of the reactor coolant system as a result of any American Nuclear Society (ANS) Condition II event (anticipated malfunction). As such, during any ANS Condition II event, the reactor trip system limits the following parameters to:

- Minimum DNBR = the design basis limit.
- Maximum system pressure = 2735 psig.
- Fuel rod maximum linear power for determination of protection setpoints = 22.4 kW/ft.

The accident analyses described in section 15.4 demonstrate that the functional requirements, as specified for the reactor trip system, are adequate to meet the above considerations, even assuming, for conservatism, adverse combinations of instrument errors. (Refer to table 15.3.1-

1.) A discussion of the safety limits associated with the reactor core and reactor coolant system, plus the limiting safety system setpoints, are presented in the Technical Specifications.

7.2.1.2.5 Abnormal Events

The malfunctions, accidents, or other unusual events which could physically damage reactor trip system components or could cause environmental changes are as follows:

- Earthquakes. (See chapters 2 and 3.)
- Fire. (See subsection 9.5.1.)
- Explosion - hydrogen buildup inside containment. (See section 6.2.)
- Missiles. (See section 3.5.)
- Flood. (See chapters 2 and 3.)
- Wind and tornadoes. (See section 3.3.)

The reactor trip system fulfills the requirements of IEEE 279-1971 to provide automatic protection and to provide initiating signals to mitigate the consequences of faulted conditions. The reactor trip system is protected against destruction of the system from fires, explosions, floods, wind, and tornadoes. (See each item above.)

7.2.1.2.6 Minimum Performance Requirements

A. Reactor Trip System Response Times

The response time of each reactor trip function shown in Technical Specification Table 3.3.1-1 is shown in FSAR table 7.2.1-4. Response time verification for selected components may use the predetermined allocation values provided in FSAR table 7.2.1-5.

Reactor trip system response time is defined in section 7.1. Typical maximum allowable time delays in generating the reactor trip signal are tabulated in table 7.2.1-3. See paragraph 7.1.2.7 A for a discussion of periodic response time verification.

B. Reactor Trip Accuracies

Accuracy is defined in section 7.1. Reactor trip accuracies are tabulated in table 7.2.1-3. An additional discussion on accuracy is found in subsection 7.1.2.

C. Protection System Ranges

Typical protection system ranges are tabulated in table 7.2.1-3. Range selection for the instrumentation covers the expected range of the process variable being monitored during power operation. Limiting setpoints are at least 5 percent from the end of the instrument span.

7.2.1.3 Final System Drawings

Functional block diagrams, electrical elementaries, and other drawings required to perform a safety review are listed in the safety-related drawing package. (See section 1.7.)

7.2.1.4 References

1. Reid, J. B., "Process Instrumentation for Westinghouse Nuclear Steam Supply Systems," WCAP-7913, January 1973. (Additional background information only.)

2. Lipchak, J. B., "Nuclear Instrumentation System," WCAP-8255, January 1974. (Additional background information only.)

3. Katz, D. N., "Solid State Logic Protection System Description," WCAP-7488-L (Proprietary), March 1971, and WCAP-7672 (Nonproprietary), May 1971. (Additional background information only.)

4. DiTommaso, S. M., Sterrett, C. R., "RTD Bypass Elimination Licensing Report for Vogtle Electric Generating Plant." WCAP-12788 (Proprietary), March 1, 1991. (Additional background information only.)

5. WCAP-16769-P Revision 2, “Westinghouse SSPS Universal Logic Board Replacement Summary Report 6D30225G01/G02/G03/G04.”

6. WCAP-16770-P Revision 0, “Westinghouse SSPS Safeguards Driver Board Replacement Summary Report 6D30252G01/G02.”

7. WCAP-16771-P Revision 1, “Westinghouse SSPS Undervoltage Driver Board Replacement Summary Report 6D30350G01/G02.”

8. WCAP-16772-P Revision 1, “Westinghouse SSPS Semi-Automatic Tester Board Replacement Summary Report 6D30520G01/G02/G03/G04/G05.”

9. WCAP-17867-P-A Revision 1, “Westinghouse SSPS Board Replacement Licensing Summary Report."

7.2.2 ANALYSES

7.2.2.1 Failure Modes and Effects Analyses

An analysis of the reactor trip system has been performed. Results of this study and a fault tree analysis are presented in reference 1.

7.2.2.2 Evaluation of Design Limits

While most setpoints used in the reactor protection system are fixed, there are variable setpoints, most notably the over-temperature ΔT and overpower ΔT setpoints. All setpoints in the reactor trip system have been selected on the basis of engineering design or safety studies. The capability of the reactor trip system to prevent loss of integrity of the fuel cladding and/or reactor coolant system (RCS) pressure boundary during Condition II and III transients is demonstrated in chapter 15. These accident analyses are carried out using those setpoints determined from results of the engineering design studies. Setpoint limits are presented in the Technical Specifications. A discussion of the purpose of each of the various reactor trips and the accident analyses (where appropriate) which utilize this trip are presented below. It should be noted that the selected trip setpoints provide for a margin before protective action is actually required to allow for uncertainties and instrument errors. The design meets the requirements of General Design Criteria (GDC) 10 and 20.

7.2.2.2.1 Trip Setpoint Discussion

The departure from nucleate boiling ratio (DNBR) existing at any point in the core, for a given core design, can be determined as a function of the core inlet temperature, power output, operating pressure, and flow. Below the DNBR design basis limit there is likely to be significant local fuel cladding failure. Consequently, core safety limits, in terms of a DNBR equal to the design basis limit for the hot channel, can be developed as a function of core ΔT, T_{avg}, and pressure for specified flow as illustrated by the solid lines in figure 15.0.6-1. The dashed lines indicate the maximum permissible setpoint (ΔT) as a function of T_{avg} and pressure for the overtemperature and overpower reactor trip. Actual setpoint constants in the equation representing the dashed lines are as given in the Technical Specifications.

These values are conservative to allow for instrument errors. The design meets the requirements of GDC 10, 15, 20, and 29.

The DNBR is not a directly measurable quantity. However, the process variables that determine DNBR are sensed and evaluated. Small isolated changes in various process variables may not, individually, result in violation of a core safety limit. However, the combined variations, over sufficient time, may cause the overpower or overtemperature safety limit to be exceeded. The reactor trip system provides reactor trips associated with individual process variables, in addition to the overpower/overtemperature safety limit trips. Process variable trips prevent reactor operation whenever a change in the monitored value is such that a core or system safety limit could potentially be exceeded, should operation continue. Basically, the high-pressure, low-pressure, and overpower/over-temperature ΔT trips provide sufficient protection for slow transients, as opposed to such trips as low flow or high flux, which will trip the reactor for rapid changes in flow or flux, respectively, that would result in fuel damage before actuation of the slower responding ΔT trips could be effected.

Therefore, the reactor trip system has been designed to provide protection for fuel cladding and RCS pressure boundary integrity where:

A. A rapid change in a single variable or factor will quickly result in exceeding a core or a system safety limit.

B. A slow change in one or more variables will have an integrated effect which will cause safety limits to be exceeded.

Overall, the reactor trip system offers diverse and comprehensive protection against fuel cladding failure and/or loss of RCS integrity for Condition II and III accidents. This is demonstrated by table 7.2.2-1 which lists the various trips of the reactor trip system, the corresponding technical specification on safety limits and safety system settings, and the appropriate accident discussed in the safety analyses in which the trip could be utilized.

In accordance with Branch Technical Position I CSB 12 the reactor trip system automatically provides core protection during nonstandard operating configuration; i.e., operation with a loop out of service. Although operating with a loop out of service over an extended time is considered to be an unlikely event, no protection system setpoints need to be reset. This is because the nominal value of the power (P-8) interlock setpoint restricts the power, such that DNBRs less than the design basis limit will not be realized during any Condition II transients occurring during this mode of operation. This restricted power is considerably below the boundary of permissible values, as defined by the core safety limits for operation with a loop out of service. Thus, the P-8 interlock acts, essentially, as a high nuclear power reactor trip when operating with one loop not in service. By first resetting the coefficient setpoints in the overtemperature ΔT function to more restrictive values, as listed in the Technical Specifications, the P-8 setpoint can then be increased to the maximum value consistent with maintaining DNBR above the design basis limit for Condition II transients in the one-loop shutdown mode. The resetting of the overtemperature ΔT trip and P-8 will be carried out under administrative control and the direction of authorized supervision and with the plant conditions prescribed in the Technical Specifications.

The design meets the requirements of GDC 21.

Preoperational testing is performed on reactor trip system components and systems to determine equipment readiness for startup. This testing serves as a further evaluation of the system design.

Analyses of the results of Condition I, II, III, and IV events, including considerations of instrumentation installed to mitigate their consequences, are presented in chapter 15. The instrumentation installed to mitigate the consequences of load rejection and turbine trip is given in section 7.4.

7.2.2.2.2 Reactor Coolant Flow Measurement

The elbow taps used on each loop in the primary coolant system are instrument devices that indicate the status of the reactor coolant flow. The basic function of devices is to provide information as to whether or not a reduction in flow has occurred. The correlation between flow and elbow tap signal is given by the following equation:

$$\frac{\Delta P}{\Delta P_o} = \left(\frac{W}{W_o}\right)^2$$

where ΔP_o is the pressure differential at the reference flow W_o, and ΔP is the pressure differential at the corresponding flow, W. The full-flow reference point is established during initial plant startup. The low-flow trip point is then established by extrapolating along the correlation curve. The expected absolute accuracy of the channel is within ±10 percent of full flow, and field results have shown the repeatability of the trip point to be within ±1 percent.

7.2.2.2.3 Evaluation of Compliance to Applicable Codes and Standards

The reactor trip system meets the criteria of the GDC, as indicated. The reactor trip system meets the requirements of section 4 of Institute of Electrical and Electronics Engineers (IEEE) 279-1971, as indicated below.

A. General Functional Requirement

   The protection system automatically initiates appropriate protective action whenever a condition monitored by the system reaches a preset level. Functional performance requirements are given in paragraph 7.2.1.1.1. Paragraph 7.2.1.2.4 presents a discussion of limits, margins, and levels; paragraph 7.2.1.2.5 discusses unusual (abnormal) events; and paragraph 7.2.1.2.6 presents minimum performance requirements.

B. Single Failure Criterion

   The protection system is designed to provide two, three, or four instrumentation channels for each protective function and two logic train circuits. These redundant channels and trains are electrically isolated and physically separated. Thus, any single failure within a channel or train will not prevent protective action at the system level, when required. Loss of input power to a channel or logic train, the most likely mode of failure, will result in a signal calling for a trip. This design meets the requirements of GDC 23.

To prevent the occurrence of common mode failures, such additional measures as functional diversity, physical separation, and testing as well as administrative control during design, production, installation, and operation are employed, as discussed in reference 1. The design meets the requirements of GDC 21 and 22.

C. Quality of Components and Modules

For a discussion on the quality of the components and modules used in the reactor trip system, refer to chapter 17. The quality assurance applied conforms to GDC 1.

D. Equipment Qualification

For a discussion of the type of tests made to verify the performance requirements, refer to section 3.11. The test results demonstrate that the design meets the requirements of GDC 4.

E. Channel Integrity

Protection system channels required to operate in accident conditions maintain necessary functional capability under extremes of conditions relating to environment, power supply, malfunctions, and accidents. The power supply for the reactor trip system is described in chapter 8. The environmental variations, throughout which the system will perform, are given in section 3.11.

F. Independence

Channel independence is carried throughout the system, extending from the sensor to the devices actuating the protective function. Physical separation is used to achieve separation of redundant transmitters. Separation of wiring is achieved using separate wireways, cable trays, conduit runs, and containment penetrations for each redundant channel. Redundant analog equipment is separated by locating modules in different protection cabinets. Each redundant protection channel set is energized from a separate ac power feed. This design meets the requirements of GDC 21.

Two reactor trip breakers, which are actuated by two separate logic matrices, interrupt power to the control rod drive mechanisms. The breaker main contacts are connected in series with the power supply, so that opening either breaker interrupts power to all control rod drive mechanisms, permitting the rods to free fall into the core. (See figure 7.1.1-1.)

The design philosophy is to make maximum use of a wide variety of measurements. The protection system continuously monitors numerous diverse system variables. Generally, two or more diverse protection functions would terminate an accident before intolerable consequences could occur. This design meets the requirements of GDC 22.

G. Control and Protection System Interaction

The protection system is designed to be independent of the control system. In certain applications, the control signals and other nonprotective functions are derived from individual protective channels through isolation amplifiers. The isolation amplifiers are classified as part of the protection system and are located in the analog protection racks. Nonprotective functions include those signals used for control, remote process indication, and computer monitoring. The isolation amplifiers are designed, such that a short circuit, open circuit, or the application of credible fault voltages from within the cabinets on the isolated output portion of the circuit (i.e., the nonprotective side of the circuit) will not affect the input (protective) side of the circuit. The signals obtained through the isolation amplifiers are never returned to the protection racks. This design meets the requirements of GDC 24 and section 4.7 of IEEE 279-1971.

The results of applying various malfunction conditions on the output portion of the isolation amplifiers show that no significant disturbance to the isolation amplifier input signal occurred.

H. Derivation of System Inputs

To the extent feasible and practical, protection system inputs are derived from signals which are direct measures of the desired variables. Variables monitored for the various reactor trips are listed in paragraph 7.2.1.2.2.

I. Capability for Sensor Checks

The operational availability of each system input sensor during reactor operation is accomplished by cross-checking between channels that bear a known relationship to each other and that have readouts available. Channel checks are discussed in the Technical Specifications.

J. Capability for Testing

The reactor trip system is capable of being tested during power operation. Where only parts of the system are tested at any one time, the testing sequence provides the necessary overlap between the parts to ensure complete system operation. The testing capabilities are in conformance with Regulatory Guide 1.22, as discussed in paragraph 7.1.2.5.

The protection system is designed to permit periodic testing of the analog channel portion of the reactor trip system during reactor power operation without initiating a protective action, unless a trip condition actually exists. This is because of the coincidence logic required for reactor trip. These tests may be performed at any plant power, from cold shutdown to full power. Before starting any of these tests with the plant at power, all redundant reactor trip channels associated with the function to be tested must be in the normal (untripped) mode in order to avoid spurious trips. Setpoints are referenced in the precautions, limitations, and setpoints portion of the plant technical manual.

1. Analog Channel Tests

Analog channel testing of the process channels which produce the two-out-of-four or two-out-of-three protection logic is performed at the analog instrumentation rack set by individually testing each instrumentation channel. Testing is accomplished through the use of a bypass testing instrumentation test panel installed in each of the 7300 protection channel sets. Use of this panel will prevent the initiation of an unwarranted protective action from that channel during the short period that it is undergoing test. Located on the test panel is a keylock switch which controls the use/operation of the panel during testing and normal operation. Activation of this keylock switch will provide an automatic and continuous indication (alarm and annunciator) in the control room to alert the operators that a 7300 process channel is being tested in the bypass condition. Individual toggle switches are also provided on the test panel for each 7300 bistable. The use of these switches will allow the primary field signal power to be replaced with an imposed test signal power to prevent disruption of the 26-V dc source provided from the protection system bistables to the SSPS input relays. These switches also isolate the 7300 outputs from the BTI panel. The keylock switch provided on the BTI test panel has two operable positions:

- NORMAL - The BTI test panel is disabled, along with all of the toggle switches on that test panel.
- BYPASS ENABLE - The BTI test panel has the capability through the use of the individual toggle switches to place a channel in bypass. When in this mode, automatic and continuous indication of a bypass condition or the potential for a bypass condition is provided to the control room.

When in the bypass enable keylock switch mode of operation, the individual toggle switches on the test panel have two operable positions:

- NORMAL - Live field signal power supplied to SSPS.
- BYPASS - Test signal power supplied to SSPS when an individual process channel toggle switch is placed in the bypass condition. To alert the test technician of this state of operation, a local status light is provided on the BTI test panel, one for each bistable to be tested, to indicate which channel is in test.

Reference 5 provides additional information on this subject.

The following analog channels will be tested as described above:

- T_{avg} and ΔT protection channel testing.
- Pressurizer pressure protection channel testing.
- Pressurizer water level protection channel testing.
- Steam generator water level protection channel testing.
- Reactor coolant low flow.
- Steam pressure protection channels.
- Containment pressure.
- Turbine (anticipatory trip) and trip fluid pressure channel testing.

The underfrequency and undervoltage protection channels are not equipped with a bypass capability for testing. These channels are tested by individually introducing dummy input signals into the instrumentation channels and observing the tripping of the appropriate output bistables. Process analog output to the logic circuitry is interrupted during individual channel testing by a test switch which deenergizes the associated logic input and inserts a proving lamp in the bistable output. Interruption of the bistable output to the logic circuitry for any cause (test, maintenance purposes, or removal from service) will cause that portion of the logic to be actuated (partial trip), accompanied by a partial trip alarm and channel status light actuation in the control room. Each channel contains those switches, test points, etc., necessary to test the channel. See references 2 and 3 for additional background information.

2. Nuclear Instrumentation Channel Tests

The nuclear instrumentation system (NIS) channels which produce a rod stop, permissive, or a reactor trip on one-out-of-two, one-out-of-four, two-out-of-four, or three-out-of four protection logic are provided with a bypass function to prevent the initiation of an unwarranted protective action from that channel during the short period that it is undergoing test. To permit testing of an NIS channel in the bypass mode, a BTI test panel is installed in each of the four NIS protection channel sets (racks). Located on the test panel is a keylock switch which controls the use/operation of the panel during testing and normal operation. Activation of this keylock switch will provide automatic and continuous indication (alarm and annunciator) in the control room to alert the operators that an NIS channel is being tested in the bypass condition. Individual make-before-break toggle switches are also provided on the test panel for each bistable associated with the protection channel set. The make-before-break switch is located on the NIS BTI panels only. Use of these switches will allow the primary field signal power to be replaced by an imposed test signal power to prevent disruption of the 118 V-ac from the protection system bistables to the SSPS input relays. These switches also isolate the NIS drawer outputs from the BTI panel.

The keylock switch provided on the BTI test panel has two operable positions:

- NORMAL - The BTI test panel is disabled, along with all of the toggle switches on that test panel.
- BYPASS ENABLE - The BTI test panel has the capability through the use of the individual toggle switches to place a channel in bypass. When in this mode, automatic and continuous indication of a bypass condition or the potential for a bypass condition is provided to the control room.

When in the bypass enable keylock switch mode of operation, the individual make-before-break toggle switches on the test panel have two operable positions and a transition position:

- NORMAL - Live field signal power supplied to SSPS.

- MID-POSITION (MAKE-BEFORE-BREAK) - Live field signal power and test signal power is supplied to the SSPS.
- BYPASS - Test signal power supplied to SSPS when an individual process channel toggle switch is placed in the bypass condition. To alert the test technician of this state of operation, a local status light is provided on the BTI test panel, one for each bistable to be tested, to indicate which channel is in test.

Since the power provided to the NIS is ac, prior to placing a nuclear instrumentation system channel in bypass, the live signal power signal and the test signal power sources must be in phase to prevent an unwarranted protective action. Alignment of phase is adjusted and verified at the test points provided in the BTI test panel per installation instructions. Once the sources are in phase, the make-before-break switch will be in a position to provide the 118 V-ac bypass voltage. Individual bypass status lights located on the bypass test panels are provided to indicate the bypassed condition of these bistable outputs to the SSPS.

Reference 5 provides additional information on this subject.

It should be noted that a valid trip signal would cause the channel under test to trip at a lower actual reactor power level. A reactor trip would occur when a second bistable trips. No provision has been made in the channel test circuit for reducing the channel signal level below that signal being received from the nuclear instrumentation system detector.

A nuclear instrumentation system channel which can cause a reactor trip through one of two protection logic (source or intermediate range) is provided with a bypass function which prevents the initiation of a reactor trip from that particular channel during the short period that it is undergoing test. Indication of these bypasses are provided locally via status lights on the NIS bypass test panel or remotely via a main control room annunciator.

Periodic tests of the nuclear instrumentation system are performed in accordance with the plant Technical Specifications.

Any deviations noted during the performance of these tests are investigated and corrected in accordance with the established calibration and trouble shooting procedures provided in the plant technical manual for the nuclear instrumentation system. Control and protection trip settings are indicated in the plant technical manual under precautions, limitations, and setpoints.

For additional background information on the nuclear instrumentation system, see reference 3.

3. Solid-State Logic Testing

The reactor logic trains of the reactor trip system are designed to be capable of complete testing at power. After the individual channel analog testing is complete, the logic matrices are tested from the train A and train B logic rack test panels. This step provides overlap between the analog and logic portions of the test program. During this test, all of the logic inputs are actuated automatically in all combinations of trip and nontrip logic. Trip logic is not maintained sufficiently long to permit opening of the reactor trip breakers.

The reactor trip undervoltage coils are "pulsed" in order to check continuity. During logic testing of one train, the other train can initiate any required protective functions. Annunciation is provided in the control room to indicate when a train is in test (train output bypassed) and when a reactor trip breaker is bypassed. Logic testing can be performed in less than 30 min.

A direct reactor trip resulting from undervoltage or underfrequency on the reactor coolant pump buses is provided, as discussed in paragraph 7.2.1.1.2.D and shown in drawings 1X6AA02-228 and 1X6AA02-229. The logic for these trips is capable of being tested during power operation. When parts of the trip are being tested, an overlap is provided between parts so that a complete logic test is provided. Thus, complete testing of protection system equipment is possible.

This design complies with the testing requirements of IEEE 279-1971 and 338-1975, as discussed in subsection 7.1.2.

The permissive and block interlocks associated with the reactor trip system and engineered safety features actuation system are given in tables 7.2.1-2 and 7.2.1-3 and designated protection or "P" interlocks. As a part of the protection system, these interlocks are designed to meet the testing requirements of IEEE 279-1971 and 338-1975.

Testing of all protection system interlocks is provided by the logic testing and semiautomatic testing capabilities of the solid state protection system. In the solid state protection system the undervoltage trip attachment and shunt trip auxiliary relay coils (reactor trip) and master relays (engineered safeguards actuation) are pulsed for all combinations of trip or actuation logic, with and without the interlock signals. For example, reactor trip on low flow (two out of four loops showing two out of three low flow) is tested to verify operability of the trip above P-8 and nontrip below P-7. (See drawing 1X6AA02-229). Interlock testing may be performed at power.

Testing of the logic trains of the reactor trip system includes a check of the input relays and a logic matrix check. The following sequence is used to test the system:

- Check of Input Relays

  During testing of the process instrumentation system and nuclear instrumentation system channels, each channel bistable is placed in a trip mode, causing one input relay in train A and one in train B to deenergize. A contact of each relay is connected to a universal logic printed circuit card. This card performs both the reactor trip and monitoring functions. Each reactor trip input relay contact causes a status lamp and an annunciator on the control board to operate. Either the train A or train B input relay operation will light the status lamp and annunciator.

Each train contains a multiplexing test switch. At the start of a process or nuclear instrumentation system test, this switch (in either train) is placed in the A + B position. The A + B position alternately allows information to be transmitted from the two trains to the control board. A steady status lamp and annunciator indicates that input relays in both trains have been deenergized. A flashing lamp means that both the input relays in the two trains did not deenergize. Contact inputs to the logic protection system, such as reactor coolant pump bus underfrequency relays, operate input relays which are tested by operating the remote contacts, as described above, and use the same type of indications as those provided for bistable input relays.

Actuation of the input relays provides the overlap between the testing of the logic protection system and the testing of those systems supplying the inputs to the logic protection system. Test indications are status lamps and annunciators on the control board. Inputs to the logic protection system are checked one channel at a time, leaving the other channels in service. For example, a function that trips the reactor when two out of four channels trip becomes a one out of three trip when one channel is placed in the trip mode. Both trains of the logic protection system remain in service during this portion of the test.

- Check of Logic Matrices

  Logic matrices are checked, one train at a time. Input relays are not operated during this portion of the test. Reactor trips from the train being tested are inhibited with the use of the input error inhibit switch on the semiautomatic test panel in the train. At the completion of the logic matrix tests, one bistable in each channel of process instrumentation or nuclear instrumentation is tripped to check closure of the input error inhibit switch contacts.

  The logic test scheme uses pulse techniques to check the coincidence logic. All possible trip and nontrip combinations are checked. Pulses from the tester are applied to the inputs of the universal logic card at the same terminals that connect to the input relay contacts. Thus, there is an overlap between the input relay check and the logic matrix check. Pulses are fed back from the reactor trip breaker undervoltage trip attachment and shunt trip auxiliary relay coils to the tester. The pulses are of such short duration that the reactor trip breaker undervoltage coil armature cannot respond mechanically.

  Periodic testing of the solid state protection system includes testing of the master and slave relays from the system's relay test panel.

Test indications that are provided are an annunciator in the control room, indicating that reactor trips from the train have been blocked and that the train is being tested, and green and red lamps on the semiautomatic tester to indicate a good or bad logic matrix test. Protection capability provided during this portion of the test is from the train not being tested.

The testing capability meets the requirements of GDC 21.

- General Warning Alarm Reactor Trip

  Each of the two trains of the solid state protection system is continuously monitored by the general warning alarm reactor trip subsystem. The warning circuits are actuated if undesirable train conditions are set up by improper alignment of testing systems, circuit malfunction or failure, etc., as listed below. A trouble condition in a logic train is indicated in the control room. However, if any one of the conditions exists in train A at the same time any one of the conditions exists in train B, the general warning alarm circuits will automatically trip the reactor.

  - Loss of either of two 48-V dc or either of two 15-V dc power supplies.
  - Printed circuit card improperly inserted.
  - Input error inhibit switch in the inhibit position.
  - Slave relay tester mode selector in test position.
  - Multiplexing selector switch in inhibit position.
  - Train bypass breaker racked in and closed.
  - Permissive or memory test switch not in off position.
  - Logic function test switch not in off position.
  - Loss of power to slave relay output cabinet.

4. Testing of Reactor Trip Breakers

   Normally, reactor trip breakers 52/RTA and 52/RTB are in service, and bypass breakers 52/BYA and 52/BYB are withdrawn (out of service). In testing the protection logic, pulse techniques are used to avoid tripping the reactor trip breakers, thereby eliminating the need to bypass them during this testing (drawing 1X6AA02-226). The following procedure describes the method used for testing the trip breakers:

   - With bypass breaker 52/BYA racked out, manually close and trip it to verify its operation.
   - Rack in and close 52/BYA. Manually trip 52/RTA through a protection system logic matrix while at the same time operating the "Auto Shunt Trip Block" pushbutton on the automatic shunt trip panel. This verifies operation of the undervoltage trip attachment (UVTA) when the breaker trips. After reclosing RTA, trip it again by operation of the

"Auto Shunt Trip Test" pushbutton on the automatic shunt trip panel. This is to verify tripping of the breaker through the shunt trip device.

- Reset 52/RTA.
- Trip and rack out 52/BYA.
- Repeat the above steps to test trip breaker 52/RTB using bypass breaker 52/BYB.

Auxiliary contacts of the bypass breakers are connected into the alarm system of their respective trains such that, if either train is placed in test while the bypass breaker of the other train is closed, both reactor trip breakers and both bypass breakers will automatically trip.

Auxiliary contacts of the bypass breakers are also connected in such a way that if an attempt is made to close the bypass breaker in one train while the bypass breaker of the other train is already closed, both bypass breakers will automatically trip.

Test panels are provided near the reactor trip breakers for verifying auxiliary and cell switch contacts used in the P-4 SSPS and turbine trip signals. In addition, a voltmeter and selector switch are available on the front of each reactor trip switchgear that may be used to determine auxiliary contact position for input to SSPS.

The train A and train B alarm systems operate separate annunciators in the control room. The two bypass breakers also operate an annunciator in the control room. Bypassing of a protection train with either the bypass breaker or with the test switches will result in audible and visual indications.

The complete reactor trip system is normally required to be in service. However, to permit online testing of the various protection channels or to permit continued operation in the event of a subsystem instrumentation channel failure, the Technical Specifications define the minimum number of operable channels. The Technical Specifications also define the required restriction to operation in the event that the channel operability requirements cannot be met.

K. Channel Bypass or Removal from Operation

The protection system is designed to permit periodic testing of the analog channel portion of the reactor trip system during reactor power operation, without initiating a protective action, unless a trip condition actually exists.

L. Operating Bypasses

Where operating requirements necessitate automatic or manual bypass of a protective function, the design is such that the bypass is removed automatically whenever permissive conditions are not met. Devices used to achieve automatic removal of the bypass of a protective function are considered part of the protective system and are designed in accordance with the criteria of this section.

Indication is provided in the control room if some part of the system has been administratively bypassed or taken out of service.

M. Indication of Bypasses

Bypass indication is discussed in paragraph 7.5.5 and section 1.9.

N. Access to Means for Bypassing

The design provides for administrative control of access to the means for manually bypassing channels or protective functions.

O. Multiple Setpoints

For monitoring neutron flux, multiple setpoints are used. When a more restrictive trip setting becomes necessary to provide adequate protection for a particular mode of operation or set of operating conditions, the protective system circuits are designed to provide positive means or administrative control to ensure that the more restrictive trip setpoint is used. The devices used to prevent improper use of less restrictive trip settings are considered part of the protective system and are designed in accordance with the criteria of this section.

P. Completion of Protective Action

The protection system is so designed that, once initiated, a protective action goes to completion. Return to normal operation requires action by the operator.

Q. Manual Initiation

Switches are provided on the control board for manual initiation of protective action. Failure in the automatic system does not prevent the manual actuation of the protective functions. Manual actuation relies on the operation of a minimum of equipment.

R. Access

The design provides for administrative control of access to all setpoint adjustments, module calibration adjustments, and test points.

S. Identification of Protective Actions

Protective channel identification is discussed in paragraph 7.1.2. Indication is discussed in item T below.

T. Information Readout

The protective system provides the operator with complete information pertinent to system status and safety. All transmitted signals (flow, pressure, temperature, etc.) which can cause a reactor trip will either be indicated or recorded for every channel, including all neutron flux power range currents (top detector, bottom detector, algebraic difference, and average of bottom and top detector currents).

Any reactor trip will actuate an alarm and an annunciator. Such protective actions are indicated and identified down to the channel level.

Alarms and annunciators are also used to alert the operator of deviations from normal operating conditions, so that he may take appropriate corrective action to avoid a reactor trip. Actuation of any rod stop or trip of any reactor trip channel will actuate an alarm.

U. System Repair

The system is designed to facilitate the recognition, location, replacement, and repair of malfunctioning components or modules. Refer to the discussion in item J above.

7.2.2.3 <u>Specific Control and Protection Interactions</u>

7.2.2.3.1 Neutron Flux

Four power range neutron flux channels are provided for overpower protection. An isolated auctioneered high signal is derived by auctioneering of the four channels for automatic rod control. If any channel fails in such a way as to produce a low output, that channel is incapable of proper overpower protection but will not cause control rod movement because of the auctioneer. Two out of four overpower trip logic will ensure an overpower trip if needed, even with an independent failure in another channel.

In addition, channel deviation signals in the control system will give an alarm if any neutron flux channel deviates significantly from the average of the flux signals. Also, the control system will respond only to rapid changes in indicated neutron flux; slow changes or drifts are compensated by the temperature control signals. Finally, an overpower signal from any nuclear power range channel will block manual rod withdrawal. Automatic rod withdrawal capability of the rod control system has been disabled. The setpoint for this rod stop is below the reactor trip setpoint.

7.2.2.3.2 Coolant Temperature

The accuracy of the resistance temperature detector (RTD) loop temperature measurements is demonstrated during plant preoperational tests by comparing temperature measurements from all loop RTDs with one another, as well as with the temperature measurements obtained from the wide range RTDs located in the hot leg and cold leg piping of each loop. The comparisons are done with the RCS in an isothermal condition. The linearity of the ΔT measurements obtained from the hot leg and cold leg loop RTDs, as a function of plant power, is also checked during plant startup tests. The absolute value of ΔT versus plant power is not important, per se, as far as reactor protection is concerned. Reactor trip system setpoints are based upon percentages of the indicated ΔT at nominal full power rather than on absolute values of ΔT. This is done to account for loop differences which are inherent. Therefore, the percent ΔT scheme is relative, not absolute, and therefore provides better protective action without the expense of accuracy. For this reason, the linearity of the ΔT signals as a function of power is of importance rather than the absolute values of the ΔT. As part of the plant preoperational tests, the loop RTD signals will be compared with the core exit thermocouple signals.

Reactor control is based upon signals derived from protection system channels after isolation by isolation amplifiers, such that no feedback effect can perturb the protection channels.

Since control is based on the average temperature of the loop with the highest temperature, the control rods are always moved based upon the most pessimistic temperature measurement with respect to margins to departure from nucleate boiling. A spurious low average temperature measurement from any loop temperature control channel will cause no control action. A spurious high average temperature measurement will cause rod insertion (safe direction).

Channel deviation signals in the control system will give an alarm if any temperature channel deviates significantly from the auctioneered (highest) value. Manual rod withdrawal blocks and turbine runback (power demand reduction) will also occur if any two out of the four overtemperature or overpower ΔT channels indicate an adverse condition.

7.2.2.3.3 Pressurizer Pressure

The pressurizer pressure protection channel signals are used for high- and low-pressure protection and as inputs to the overtemperature ΔT trip protection function. Isolated output signals from these channels are used for pressure control. These are used to control pressurizer spray and heaters and power-operated relief valves. Pressurizer pressure is sensed by fast response pressure transmitters.

A spurious high-pressure signal from one channel can cause decreasing pressure by actuation of either spray or relief valves. Additional redundancy is provided in the low pressurizer pressure reactor trip and in the logic for safety injection to ensure low pressure protection.

Overpressure protection is based upon the positive surge of the reactor coolant produced as a result of turbine trip under full load, assuming the core continues to produce full power. The self-actuated safety valves are sized on the basis of steam flow from the pressurizer to accommodate this surge at a setpoint of 2485 psig and an accumulation of 3 percent. Note that no credit is taken for the relief capability provided by the power-operated relief valves during this surge.

In addition, operation of any one of the power-operated relief valves can maintain pressure below the high-pressure trip point for most transients. The rate of pressure rise achievable with heaters is slow, and ample time and pressure alarms are available to alert the operator of the need for appropriate action.

Redundancy is not compromised by having a shared tap (paragraph 7.2.1.1.2), since the logic for this trip is two out of four. If the shared tap is plugged, the affected channels will remain static. If the impulse line bursts, the indicated pressure will drop to zero. In either case the fault is easily detectable, and the protective function remains operable.

7.2.2.3.4 Pressurizer Water Level

Three pressurizer water level channels are used for reactor trip. Isolated signals from these channels are used for pressurizer water level control. A failure in the level control system could fill or empty the pressurizer at a slow rate (on the order of 1/2 h or more).

The high water level trip setpoint provides sufficient margin, such that the undesirable condition of discharging liquid coolant through the safety valves is avoided. Even at full- power conditions, which would produce the worst thermal expansion rates, a failure of the water level control would not lead to any liquid discharge through the safety valves. This is due to the automatic high pressurizer pressure reactor trip actuating at a pressure sufficiently below the safety valve setpoint.

For control failures which tend to empty the pressurizer, two out of four logic for safety injection action on low pressure ensures that the protection system can withstand an independent failure in another channel. In addition, ample time and alarms exist to alert the operator of the need for appropriate action.

7.2.2.3.5 Steam Generator Water Level

The basic function of the reactor protection circuits associated with low-low steam generator water level is to preserve the steam generator heat sink for removal of long-term residual heat. Should a complete loss of feedwater occur, the reactor would be tripped on low-low steam generator water level. In addition, redundant auxiliary feedwater pumps are provided to supply feedwater in order to maintain residual heat removal after trip. This reactor trip acts before the steam generators are dry. This reduces the required capacity, increases the time interval before auxiliary feedwater pumps are required, and minimizes the thermal transient on the reactor coolant system and steam generators. Therefore, a low-low steam generator water level reactor trip circuit is provided for each steam generator to ensure that sufficient initial thermal capacity is available in the steam generator at the start of the transient. Two out of four low-low steam generator water level trip logic ensures a reactor trip if needed, even with an independent failure in another channel used for control, and when degraded by an additional second postulated random failure.

A spurious low signal from the feedwater flow channel being used for control would cause an increase in feedwater flow. The mismatch between steam flow and feedwater flow produced by the spurious signal would actuate alarms to alert the operator of the situation in time for manual correction. If the condition continues, a two out of four high-high steam generator water level signal in any loop, independent of the indicated feedwater flow, will cause feedwater isolation and trip the turbine. The turbine trip will result in a subsequent reactor trip if power is above the P-9 setpoint. The high-high steam generator water level trip is an equipment protective trip, preventing excessive moisture carryover which could damage the turbine blading.

In addition, the three-element feedwater controller incorporates reset action on the level error signal, such that with expected controller settings, a rapid increase or decrease in the flow signal would cause only a small change in level, before the controller would compensate for the level error. A slow change in the feedwater signal would have no effect at all. A spurious low or high steam flow signal would have the same effect as high or low feedwater signal, as discussed above.

A spurious high steam generator water level signal from the protection channel used for control will tend to close the feedwater valve. A spurious low steam generator water level signal will tend to open the feedwater valve. Before a reactor trip would occur, two out of four channels in a loop would have to indicate a low-low water level. Any slow drift in the water level signal will permit the operator to respond to the level alarms and to take corrective action.

Automatic protection is provided in case the spurious high level reduces feedwater flow sufficiently to cause low-low level in the steam generator. Automatic protection is also provided in case the spurious low-level signal increases feedwater flow sufficiently to cause high level in the steam generator. A turbine trip and feedwater isolation would occur on two out of four high-high steam generator water level in any loop.

7.2.2.4 Additional Postulated Accidents

Loss of plant instrument air or loss of component cooling water is discussed in subsection 7.3.1. Load rejection and turbine trip are discussed in further detail in section 7.7.

The control interlocks, called rod stops, that are provided to prevent abnormal power conditions which could result from excessive control rod withdrawal are discussed in paragraph 7.7.1.4 and listed on table 7.7.1-1. Excessively high-power operation (which is prevented by blocking of manual rod withdrawal), if allowed to continue, might lead to a safety limit (as given in the Technical Specifications) being reached. The automatic rod withdrawal capability of the rod control system has been disabled.

Before such a limit is reached, protection will be available from the reactor trip system. At the power levels of the rod block setpoints, safety limits have not been reached. Therefore, these rod withdrawal stops do not come under the scope of safety-related systems and are considered control systems.

7.2.2.5 Tests and Inspections

The reactor trip system meets the testing requirements of IEEE 338-1975, as discussed in paragraph 7.1.2.7. The testability of the system is discussed in paragraph 7.2.2.2.3. The initial and subsequent test intervals are specified in the Technical Specifications. Written test procedures and documentation, conforming to the requirements of IEEE 338-1975, will be available for audit by responsible personnel. Periodic testing conforms with Regulatory Guide 1.22, as discussed in subsections 7.1.2 and 7.2.2.

7.2.2.6 References

1. Gangloff, W. C., and Loftus, W. D., "An Evaluation of Solid State Logic Reactor Protection in Anticipated Transients," WCAP-7706-L (Proprietary) and WCAP-7706 (Nonproprietary), February 1971.
2. Reid, J. B., "Process Instrumentation for Westinghouse Nuclear Steam Supply Systems," WCAP-7913, January 1973. (Additional background information only.)
3. Lipchak, J. B., "Nuclear Instrumentation System," WCAP-8255, January 1974. (Additional background information only.)
4. Katz, D. N., "Solid State Logic Protection System Description," WCAP-7488-L (Proprietary), March 1971, and WCAP-7672 (Nonproprietary), May 1971. (Additional background information only.)
5. Mermigos, J. F., "Bypass Test Instrumentation for the Vogtle Electric Generating Plant, Units 1 and 2," WCAP-13376, Revision 2, September 1992.
6. WCAP-16769-P Revision 2, “Westinghouse SSPS Universal Logic Board Replacement Summary Report 6D30225G01/G02/G03/G04.”
7. WCAP-16770-P Revision 0, “Westinghouse SSPS Safeguards Driver Board Replacement Summary Report 6D30252G01/G02.”
8. WCAP-16771-P Revision 1, “Westinghouse SSPS Undervoltage Driver Board Replacement Summary Report 6D30350G01/G02.”
9. WCAP-16772-P Revision 1, “Westinghouse SSPS Semi-Automatic Tester Board Replacement Summary Report 6D30520G01/G02/G03/G04/G05.”
10. WCAP-17867-P-A Revision 1, “Westinghouse SSPS Board Replacement Licensing Summary Report.”

TABLE 7.2.1-1 (SHEET 1 OF 2)

LIST OF REACTOR TRIPS

Reactor Trips	Coincidence Logic	Interlocks	Comments
Power range high neutron flux	2/4	Manual block of low setting permitted by P-10	High and low setting; manual block and automatic reset of low setting by P-10
Intermediate range high neutron flux	1/2	Manual block permitted by P-10	Manual block and automatic reset
Source range high neutron flux	1/2	Manual block permitted by P-6; interlocked with P-10	Manual block and automatic reset; automatic block above P-10
Power range high positive neutron flux rate	2/4	No interlocks	-
Overtemperature ΔT_{avg}	2/4	No interlocks	-
Overpower ΔT_{avg}	2/4	No interlocks	-
Pressurizer low pressure	2/4	Interlocked with P-7	Blocked below P-7
Pressurizer high pressure	2/4	No interlocks	-
Pressurizer high water level	2/3	Interlocked with P-7	Blocked below P-7
Low reactor coolant flow	2/3 in any loop	Interlocked with P-7	Low flow in one loop and P-8 will cause a reactor trip when above P-8, and a low flow in two loops will cause a reactor trip when above P-7; blocked below P-7
Reactor coolant pump bus undervoltage	Low voltage sensed for pumps 1 or 2 and 3 or 4.	Interlocked with P-7	Blocked below P-7

TABLE 7.2.1-1 (SHEET 2 OF 2)

Reactor Trips	Coincidence Logic	Interlocks	Comments
Reactor coolant pump bus underfrequency	Underfrequency sensed for pumps 1 or 2 and 3 or 4	Interlocked with P-7	Blocked below P-7
Solid state protection system general warning alarm	Both trains	No interlocks	-
Low-low steam generator water level	2/4 per loop	No interlocks	-
Turbine-generator		Interlocked with P-9	Blocked below P-9
a. Low auto stop oil pressure b. Turbine stop valve close	2/3 4/4		
Safety injection signal	coincident with actuation of safety injection	No interlocks	See section 7.3 for engineering safety features actuation conditions
Manual	1/2 per train	No interlocks	

TABLE 7.2.1-2 (SHEET 1 OF 2)

PROTECTION SYSTEM INTERLOCKS

Designation	Derivation	Function
Power Escalation Permissives		
P-6	Presence of P-6: 1/2 neutron flux (intermediate range) above approximately 2.0 x 10^{-5} % rated thermal power	Allows manual block of source range reactor trip
	Absence of P-6: 2/2 neutron flux (intermediate range) below setpoint	Defeats the block of source range reactor trip
P-10	Presence of P-10: 2/4 neutron flux (power range) above setpoint	Allows manual block of power range (low setpoint) reactor trip
		Allows manual block of intermediate range reactor trip and intermediate range rod stops (C-1)
		Blocks source range reactor trip (backup for P-6)
	Absence of P-10: ¾ neutron flux (power range) below setpoint	Defeats the block of power range (low setpoint) reactor trip
		Defeats the block of intermediate range reactor trip and intermediate range rod stops (C-1)
		Inputs to P-7

TABLE 7.2.1-2 (SHEET 2 OF 2)

Designation	Derivation	Function
Blocks of Reactor Trips		
P-11	2/3 pressurizer pressure below setpoint	Allows manual block of safety injection actuation on low pressurizer pressure signal and low steam line pressure signal (lead/lag compensated)
	2/3 pressurizer pressure above setpoint	Defeats manual block of safety injection actuation
P-7	Absence of P-7: ¾ neutron flux (power range) below setpoint (from P-10) and 2/2 turbine impulse chamber pressure below setpoint (from P-13)	Blocks reactor trip on low reactor coolant flow in more than one loop, undervoltage, underfrequency, pressurizer low pressure, and pressurizer high level
P-8	Absence of P-8: ¾ neutron flux (power range) below setpoint	Blocks reactor trip on low reactor coolant flow in a single loop
P-9	Absence of P-9: ¾ neutron flux (power range) below 40 percent power	Blocks reactor trip on turbine trip
P-13	Absence of P-13: 2/2 turbine impulse chamber pressure below 10 percent of full load	Input to P-7

TABLE 7.2.1-3 (SHEET 1 OF 3)

REACTOR TRIP SYSTEM INSTRUMENTATION

Reactor Trip Signal	Typical Range	Typical Trip Accuracy	Typical Time Response (s)
Power range high neutron flux	1 to 120% of full power	1% of full power	≤ 0.5[a]
Intermediate range high neutron flux	8 decades of neutron flux overlapping source range by 2 decades	± 5% of full scale; ± 1% of full scale from 10^{-4} to 50% full power	N/A
Source range high neutron flux	6 decades of neutron flux (1 to 10^6 counts/s)	± 5% of full scale	≤ 0.5[a]
Power range high positive neutron flux rate	+ 15% of full power	± 5%	≤ 0.65[a]
Overtemperature ΔT	T_{hot} 530° to 630°F T_{cold} 530° to 630°F T_{avg} 530° to 630°F P_{PRZR} 1700 to 2500 psig $F(\Delta\Phi)$ -50 to +50 $\Delta T_{setpoint}$ 0° to 100°F	± 3.2°F	[a] [c]
Overpower ΔT	T_{hot} 530° to 650°F T_{cold} 530° to 630°F T_{avg} 530° to 630°F $\Delta T_{setpoint}$ 0° to 100°F	± 2.7°F	[a] [c]
Pressurizer low pressure	1700 to 2500 psig	± 18 psi (compensated signal)	≤ 2
Pressurizer high pressure	1700 to 2500 psig	± 18 psi (noncompensated signal)	≤ 2
Pressurizer high water level	Entire cylindrical portion of pressurizer (distance between taps)	± 2.3% of full range ΔP between taps at design temperature and pressure	N/A

TABLE 7.2.1-3 (SHEET 2 OF 3)

Reactor Trip Signal	Typical Range	Typical Trip Accuracy	Typical Time Response (s)
Low reactor coolant flow	0 to 120% of rated flow	± 2.5% of full flow within range of 70 to 100% of full flow[a] ± 1%	a. Single loop (above P-8) b. Two loops (above P-7
Reactor coolant pump undervoltage	0 to 100% rated voltage		≤ 1.5
Reactor coolant pump underfrequency	3 to 80 Hz	± 0.1 Hz	≤ 0.6
Low-low steam generator water level[b]	±~6 ft from nominal full load water level	± 2.3% of ΔP signal overpressure range of 700 to 1200 psig	≤ 2
Turbine trip oil pressure	0 to 2000 psig		N/A

a. 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. (This provision is not applicable to construction permits docketed after January 1, 1978. See Regulatory Guide 1.118, June 1978.)

b. See also Technical Specification 3.3.3.

c. RTD time constants are verified by measurement. The following channel response times are calculated for narrow range RTD time constants ≤ 5.5 seconds. In both conditions, sensor (RTD) response times have been mathematically removed such that only electronic delays are included. The choice between"without dynamics" and "with dynamics" depends on the method chosen to verify response time. When using allocation times in table 7.2.1-5, the withoutdynamics values are utilized. When using actual measurements, the values chosen must match the test conditions. Dynamics refers to functions usually performed by NLL cards in the 7300 Process Control System and include lead-lag, rate-lag, and lag functions.

	Function	Without Dynamics	With Dynamics
1	Overtemperature ΔT, T_{avg} input	2.000 s	2.469 s
2	Overtemperature ΔT, pressurizer pressure input	8.000 s	8.000 s
3	Overtemperature ΔT, nuclear flux input	8.000 s	8.000 s
4	Overtemperature ΔT, ΔT input	2.000 s	6.159 s
5	Overpower ΔT, T_{avg} input	2.000 s	2.341 s
6	Overpower ΔT, ΔT input	2.000 s	6.159 s

TABLE 7.2.1-3 (SHEET 3 OF 3)

For measured RTD time constants (plus 10% uncertainty) of more than 5.5 seconds, adjust the channel response times as follows:

	Function	**Reduction**
1	Overtemperature ΔT, T_{avg} input	Reduce by amount RTD time constant plus 10% uncertainty exceeds 5.5 s.
2	Overtemperature ΔT, pressurizer pressure input	No adjustment.
3	Overtemperature ΔT, nuclear flux input	No adjustment.
4	Overtemperature ΔT, ΔT input	Reduce by amount RTD time constant plus 10% uncertainty exceeds 5.5 s.
5	Overpower ΔT, T_{avg} input	Reduce by amount RTD time constant plus 10% uncertainty exceeds 5.5 s.
6	Overpower ΔT, ΔT input	Reduce by amount RTD time constant plus 10% uncertainty exceeds 5.5 s.

TABLE 7.2.1-4 (SHEET 1 OF 3)

REACTOR TRIP SYSTEM INSTRUMENTATION RESPONSE TIMES

FUNCTIONAL UNIT		RESPONSE TIME
1.	Manual Reactor Trip	N/A
2.	Power Range, Neutron Flux (N-0041, N-0042, N-0043, N-0044)	≤ 0.5 s[(a)]
3.	Power Range, Neutron Flux, High Positive Rate (N-0041, N-0042, N-0043, N-0044)	≤ 0.65 s[(a)]
5.	Intermediate Range, Neutron Flux (N-0035, N-0036)	N/A
6.	Source Range, Neutron Flux (N-0031, N-0032)	N/A
7.	Overtemperature ΔT (TE-0411, TE-0421, TE-0431, TE-0441)	[(a)(c)]
8.	Overpower ΔT (TE-0411, TE-0421, TE-0431, TE-0441)	[(a)(c)]
9.	Pressurizer Pressure--Low (PI-0455, PI-0456, PI-0457, PI-0458)	≤ 2 s
10.	Pressurizer Pressure--High (PI-0455, PI-0456, PI-0457, PI-0458)	≤ 2 s
11.	Pressurizer Water Level--High (LI-0459, LI-0460, LI-0461)	N/A
12.	Reactor Coolant Flow--Low	

Loop 1	Loop 2	Loop 3	Loop 4
FI-0414	FI-0424	FI-0434	FI-0444
FI-0415	FI-0425	FI-0435	FI-0445
FI-0416	FI-0426	FI-0436	FI-0446

a. Single Loop (Above P-8)	≤ 1 s
b. Two Loops (Above P-7 and below P-8)	≤ 1 s

TABLE 7.2.1-4 (SHEET 2 OF 3)

FUNCTIONAL UNIT	RESPONSE TIME
13. Steam Generator Water Level--Low-Low [(b)]	≤ 2 s

Loop 1	Loop 2	Loop 3	Loop 4
LI-0519	LI-0529	LI-0539	LI-0549
LI-0518	LI-0528	LI-0538	LI-0548
LI-0517	LI-0527	LI-0537	LI-0547
LI-0551	LI-0552	LI-0553	LI-0554

FUNCTIONAL UNIT	RESPONSE TIME
14. Undervoltage - Reactor Coolant Pumps	≤ 1.5 s
15. Underfrequency - Reactor Coolant Pumps	≤ 0.6 s
16. Turbine Trip	
a. Low Fluid Oil Pressure (PI-6161, PI-6162, PI-6163)	N/A
b. Turbine Stop Valve Closure	N/A
17. Safety Injection Input from ESF	N/A
18. Reactor Trip System Interlocks	N/A
19. Reactor Trip Breakers	N/A
20. Automatic Trip and Interlock Logic	N/A

a. 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. (This provision is not applicable to construction permits docketed after January 1, 1978. See Regulatory Guide 1.118, June 1978.)

b. See also Technical Specification 3.3.3.

c. RTD time constants are verified by measurement. The following channel response times are calculated for narrow range RTD time constants ≤ 5.5 seconds. In both conditions, sensor (RTD) response times were mathematically removed such that only electronic delays are included. The choice between "without dynamics" and "with dynamics" depends on the method chosen to verify response time. When using allocation times in table 16.3-3a, the "without dynamics" values are utilized. When using actual measurements, the values chosen must match the test conditions. Dynamics refers to functions usually performed by NLL cards in the 7300 Process Control System and include lead-lag, rate-lag, and lag functions.

TABLE 7.2.1-4 (SHEET 3 OF 3)

Function	Without Dynamics	With Dynamics
Overtemperature ΔT, T_{avg} input	2.000 s	2.469 s
Overtemperature ΔT, pressurizer pressure input	8.000 s	8.000 s
Overtemperature ΔT, nuclear flux input	8.000 s	8.000 s
Overtemperature ΔT, ΔT input	2.000 s	6.159 s
Overpower ΔT, T_{avg} input	2.000 s	2.341 s
Overpower ΔT, ΔT input	2.000 s	6.159 s

For measured RTD time constants (plus 10% uncertainty) of more than 5.5 seconds, adjust the channel response times as follows:

Function	Reduction
Overtemperature ΔT, T_{avg} input	Reduce by amount RTD time constant plus 10% uncertainty exceeds 5.5 s.
Overtemperature ΔT, pressurizer pressure input	No adjustment.
Overtemperature ΔT, nuclear flux input	No adjustment.
Overtemperature ΔT, ΔT input	Reduce by amount RTD time constant plus 10% uncertainty exceeds 5.5 s.
Overpower ΔT, T_{avg} input	Reduce amount RTD time constant plus 10% uncertainty exceeds 5.5 s.
Overpower ΔT, ΔT input	Reduce by amount RTD time constant plus 10% uncertainty exceeds 5.5 s.

TABLE 7.2.1-5 (SHEET 1 OF 2)

REACTOR TRIP ALLOCATION TIMES

Function	Sensor	Time	7300/NIS String	Time	SSPS Relays	Time
PZR PRESS HI	Tobar 32PG	200 ms	NLP + NAL	65 ms	Input	20 ms
	Veritrak 76PH	200 ms				
	Rosemount 1154SH9	200 ms				
PZR PRESS LO	Tobar 32PG	200 ms	NLP + NAL	65 ms	Input	20 ms
	Veritrak 76PH	200 ms				
	Rosemount 1154SH9	200 ms				
SG LEVEL LO-LO	Tobar 32DP	400 ms	NLP + NAL	65 ms	Input	20 ms
	Veritrak 76DP	400 ms				
	Rosemount 1154DH5	200 ms				
RCS FLOW LO	Tobar 32DP	400 ms	NLP + NAL	65 ms	Input	20 ms
	Veritrak 76DP	400 ms				
	Rosemount 1153HB5	200 ms				
OPDT (Vary T_{avg})	Weed N9004E-2B	(1)	NRA+NSA+NSA+NSA+NSA+NAL	368 ms	Input	20 ms
OPDT (Vary ΔT)	Weed N9004E-2B	(1)	NRA+NSA+NSA+NAL	293 ms	Input	20 ms
OTDT (Vary T_{avg})	Weed N9004E-2B	(1)	NRA+NSA+NSA+NSA+NSA+NAL	368 ms	Input	20 ms
OTDT (Vary ΔT)	Weed N9004E-2B	(1)	NRA+NSA+NSA+NAL	293 ms	Input	20 ms
OTDT (Vary Press)	Tobar 32PG	200 ms	NLP+NSA+NSA+NAL	140 ms	Input	20 ms
	Veritrak 76PH	200 ms				
	Rosemount 1154SH9	200 ms				

TABLE 7.2.1-5 (SHEET 2 OF 2)

Function	Sensor	Time	7300/NIS String	Time	SSPS Relays	Time
OTDT (Vary Flux)	Detectors Exempt	N/A	NIS (1 ms)+NSA+NCH+ NSA+NAL	148.5 ms	Input	20 ms
RCP VOLTAGE LO	GE NGV/SAM	(1)	N/A	N/A	Input	20 ms
RCP FREQ LO	ABB	(1)	N/A	N/A	Input	20 ms
NIS LEVEL HI	Detectors Exempt	N/A	NIS FEMA	65 ms	Input	20 ms
NIS RATE HI	Detectors Exempt	N/A	NIS FEMA	200 ms	Input	20 ms
CNMT PRESS REACTOR TRIP FROM SI	Barton 764/351	1.0 s	NLP+NAL	65 ms	Input	20 ms
SEAMLINE PRESS REACTOR TRIP FROM SI	Tobar 32PA	200 ms	NLP+NAL	65 ms	Input	20 ms
	Veritrak 76PG	200 ms				
	Rosemount 1154SH9	200 ms				
	Rosemount 1153GB9	200 ms				

Note 1: Allocated sensor times are not used for these variables. These components will continue to be tested as required.

Allocated sensor times are derived from method (3), section (9), WCAP-13632, revision 2 (Vendor Engineering Specifications). Tobar, Veritrak, and Barton times were provided in table 9-1. Rosemount times are from Rosemount manuals 4302 and 4631. The Rosemount response time specifications may also be found in NUREG/CR-5383. Transmitter FMEAs are based upon EPRI report NP-7243 revision 1.

Values for 7300 cards are from tables 4-7 through 4-12 of WCAP-14036, revision 1. Cards installed are 4NCH, 4NRA, 6NLP, 4NSA, and 9NAL or older artwork levels. NIS components installed are summing and level Amp (3359C48G01), isolation Amp (6065D75G01), rate circuit assembly (3359C41G01), and bistable relay driver assembly (3359C39G01). These were evaluated per NIS FMEA schematic diagram 6065D99.

SSPS input and master relays are Potter & Brumfield KH series relays. SSPS slave relays are Potter & Brumfield MDR relays. Values are tabulated from section 4.8, Westinghouse SSPS FMEA.

TABLE 7.2.2-1 (SHEET 1 OF 5)

REACTOR TRIP CORRELATION

Trip[a]		Accident[b]	Technical Specification
A.	NUCLEAR OVERPOWER TRIPS		
1.	Power range high neutron flux trip (low setpoint)	Uncontrolled rod cluster control assembly bank withdrawal from a subcritical or low-power startup condition (15.4.1)	(c)
		Feedwater system malfunctions that result in a decrease in feedwater temperature (15.1.1)	
		Spectrum of rod cluster control assembly ejection accidents (15.4.8)	
2.	Intermediate range high neutron flux trip	Uncontrolled rod cluster control assembly bank withdrawal from a subcritical or low-power startup condition (15.4.1)	(c)
3.	Source range high neutron flux trip	Uncontrolled rod cluster control assembly bank withdrawal from a subcritical or low-power startup condition (15.4.1)	(c)
4.	Power range high positive neutron flux rate trip	Spectrum of rod cluster control assembly ejection accidents (15.4.8)	(c)
		Uncontrolled rod cluster control assembly bank withdrawal at power (RCS overpressure event only) (15.4.2)	
5.	Power range high neutron flux trip (high setpoint)	Uncontrolled rod cluster control assembly bank withdrawal from a subcritical or low-power startup condition (15.4.1)	(c)
		Uncontrolled rod cluster control assembly bank withdrawal at power (15.4.2)	

TABLE 7.2.2-1 (SHEET 2 OF 5)

Trip[a]	Accident[b]	Technical Specification
	Startup of an inactive reactor coolant pump at an incorrect temperature (15.4.4)	
	Feedwater system malfunctions that result in a decrease in feedwater temperature (15.1.1)	
	Excessive increase in secondary steam flow (15.1.3)	
	Inadvertant opening of a steam generator relief or safety valve (15.1.4)	
	Spectrum of steam system piping failures inside and outside of containment in a PWR (15.1.5) Spectrum of rod cluster control assembly ejection accidents (15.4.8)	
B. CORE THERMAL OVERPOWER TRIPS		
1. Overtemperature ΔT trip	Uncontrolled rod cluster control assembly bank withdrawal at power (15.4.2)	(c)
	Chemical and volume control system malfunction that results in a decrease in the boron concentration in the reactor coolant(15.4.6)	
	Loss of external electrical load (15.2.2)	
	Turbine trip (15.2.3)	
	Feedwater system malfunctions that result in a decrease in feedwater temperature (15.1.1)	
	Excessive increase in secondary steam flow (15.1.3)	
	Inadvertent opening of a pressurizer safety or relief valve (15.6.1)	
	Inadvertent opening of a steam generator relief or safety valve (15.1.4)	

TABLE 7.2.2-1 (SHEET 3 OF 5)

Trip[a]		Accident[b]	Technical Specification
		Loss-of-coolant accidents resulting from the spectrum of postulated piping breaks within the reactor coolant pressure boundary (15.6.5)	
2.	Overpower ΔT trip	Uncontrolled rod cluster control assembly bank withdrawal at power (15.4.2)	(c)
		Feedwater system malfunctions that result in a decrease in feedwater temperature (15.1.1)	
		Excessive increase in secondary steam flow (15.1.3)	
		Inadvertent opening of a steam generator relief or safety valve (15.1.4)	
		Spectrum of steam system piping failures inside and outside of containment in a PWR (15.1.5)	
C.	REACTOR COOLANT SYSTEM PRESSURIZER PRESSURE AND WATER LEVEL TRIPS		
1.	Pressurizer low pressure trip	Inadvertent opening of a pressurizer safety or relief valve (15.6.1)	(c)
		Loss-of-coolant accidents resulting from the spectrum of postulated piping breaks within the reactor coolant pressure boundary (15.6.5)	
		Steam generator tube failure (15.6.3)	
2.	Pressurizer high pressure trip	Uncontrolled rod cluster control assembly bank withdrawal at power (15.4.2)	(c)
		Loss of external electrical load (15.2.2)	
		Turbine trip (15.2.3)	
3.	Pressurizer high water level trip	Uncontrolled rod cluster control assembly bank withdrawal at power (15.4.2)	(c)

TABLE 7.2.2-1 (SHEET 4 OF 5)

Trip[a]		Accident[b]	Technical Specification
		Loss of external electrical load (15.2.2)	
		Turbine trip (15.2.3)	
D.	REACTOR COOLANT SYSTEM LOW FLOW TRIPS		
1.	Low reactor coolant flow	Partial loss of forced reactor coolant flow (15.3.1)	(c)
		Loss of nonemergency ac power to the station auxiliaries (15.2.6)	
		Complete loss of forced reactor coolant flow (15.3.1)	
2.	Reactor coolant pump undervoltage trip	Complete loss of forced reactor coolant flow (15.3.1)	(c)
3.	Reactor coolant pump underfrequency trip	Complete loss of forced reactor coolant flow (15.3.1)	(c)
E.	STEAM GENERATOR TRIP		
	Low-low steam generator water level trip	Loss of normal feedwater flow (15.2.7)	(c)
		Feedwater System Malfunction (15.1.2)	
F.	REACTOR TRIP ON A TURBINE TRIP		
	Reactor trip on turbine trip	Loss of external electrical load (15.2.2)	(c)
		Turbine trip (15.2.3)	
		Loss of nonemergency ac power to the station auxiliaries (15.2.6)	(c)
G.	SAFETY INJECTION SIGNAL ACTUATION TRIP		
	Safety injection signal actuation trip	Inadvertent opening of a steam generator relief or safety valve (15.1.4)	(c)

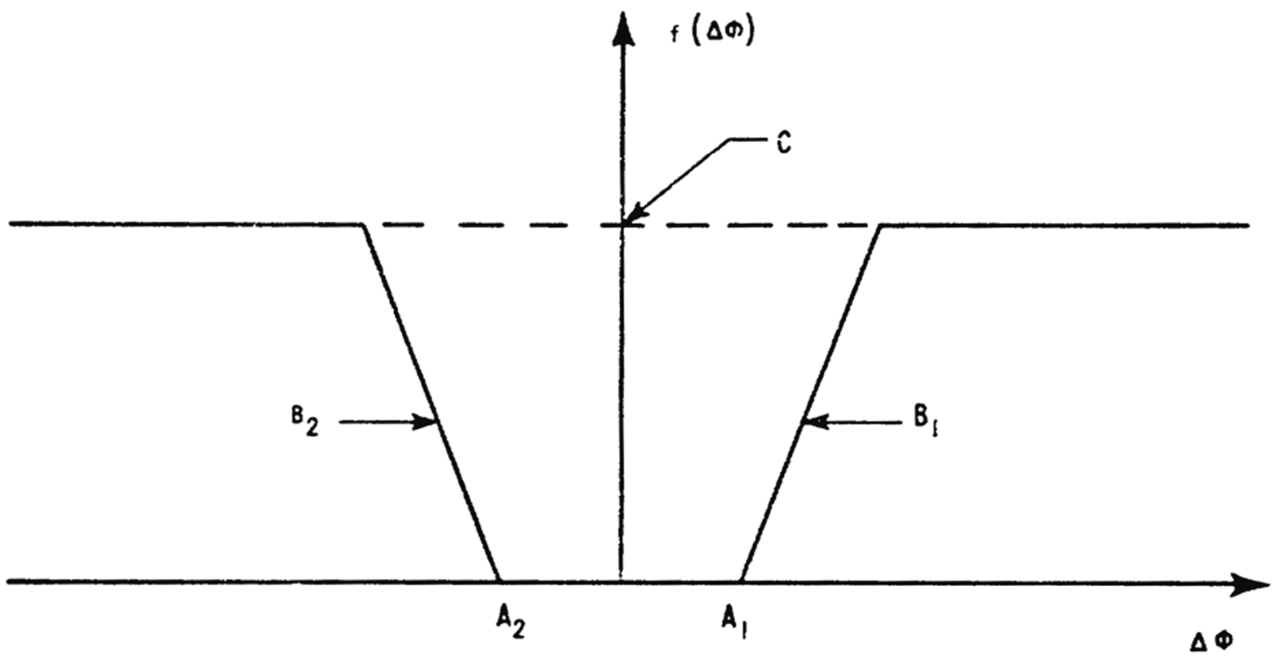
TABLE 7.2.2-1 (SHEET 5 OF 5)

Trip[a]		Accident[b]	Technical Specification
H.	MANUAL TRIP		
	Manual trip	Available for all accidents (chapter 15.)	(c)

a. Trips are listed in order of discussion in section 7.2.

b. References refer to accident analyses presented in chapter 15.

c. Trip safety settings will be incorporated in the Technical Specifications.



$\Delta\Phi$	-	NEUTRON FLUX DIFFERENCE BETWEEN UPPER AND LOWER LONG ION CHAMBERS
A_1, A_2	-	LIMIT OF F ($\Delta\Phi$) DEADBAND
B_1, B_2	-	SLOPE OF RAMP: DETERMINES RATE AT WHICH FUNCTION REACHES IT'S MAXIMUM VALUE ONCE DEADBAND IS EXCEEDED
C	-	MAGNITUDE OF MAXIMUM VALUE THE FUNCTION MAY ATTAIN

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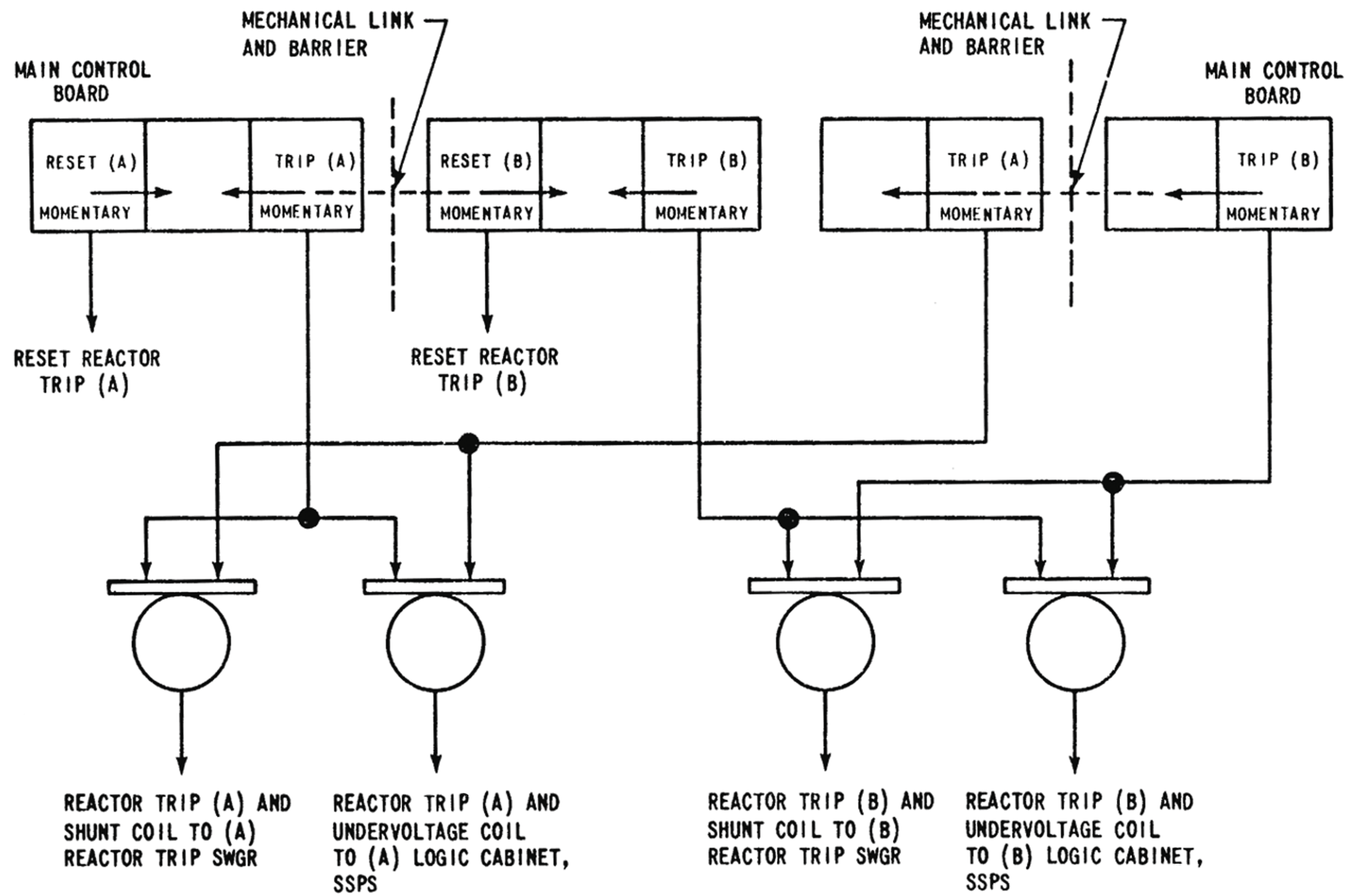

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SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

REACTOR TRIP/ENGINEERED
SAFETY FEATURES
ACTUATION MECHANICAL LINKAGE

FIGURE 7.2.1–2

7.3 ENGINEERED SAFETY FEATURES SYSTEMS

In addition to the requirements for a reactor trip for anticipated abnormal transients, the facility is provided with adequate instrumentation and controls to sense accident situations and initiate the operation of necessary engineered safety features (ESF). The occurrence of a limiting fault, such as a loss-of-coolant accident (LOCA) or a steam line break, requires a reactor trip plus actuation of one or more of the ESF in order to prevent or mitigate damage to the core and reactor coolant system (RCS) components and to ensure containment integrity.

To accomplish these design objectives the ESF system has proper and timely initiating signals which are to be supplied by the sensors, transmitters, and logic components making up the various instrumentation channels of the engineered safety features actuation system (ESFAS).

7.3.1 NUCLEAR STEAM SUPPLY SYSTEM ESFAS

7.3.1.1 Introduction

The ESFAS uses selected plant parameters, determines whether or not predetermined safety limits are being exceeded, and, if they are, combines the signals into logic matrix combinations indicative of primary or secondary system boundary ruptures (Condition III or IV events). Once the required logic combination is completed, the system sends actuation signals to the appropriate ESF components. The ESFAS meets the requirements of General Design Criteria (GDC) 13, 20, 27, 28, and 38.

7.3.1.1.1 System Description

The ESFAS is a functionally defined system described in this section. The equipment which provides the actuation functions identified in paragraph 7.3.1.1.1.1 is listed below and discussed in this section. (For additional background information refer to references 1, 2, 3, 6, 7, 8, 9, and 10.)

A. Process instrumentation and control system.[1]

B. Solid-state logic protection system.[2]

C. ESF test cabinet.[3]

D. Manual actuation circuits.

The ESFAS consists of two discrete portions of circuitry as follows:

A. An analog portion consisting of three to four redundant channels per parameter or variable to monitor various plant parameters such as the RCS and steam system pressures, temperatures, and flows and containment pressures.

B. A digital portion consisting of two redundant logic trains which receive inputs from the analog protection channels and perform the logic needed to actuate the ESF.

Each digital train is capable of actuating the ESF equipment required. The intent is that any single failure within the ESFAS shall not prevent system action when required.

7.3.1.1.1.1 Function Initiation. The specific functions which rely on the ESFAS for initiation are:

A. A reactor trip, provided one has not already been generated by the reactor trip system.

B. Cold leg injection isolation valves which are opened for injection of borated water by centrifugal charging pumps into the cold legs of the RCS.

C. Charging pumps, SI pumps, residual heat removal pumps, and associated valving which provide emergency makeup water to the cold legs of the RCS following a LOCA.

D. Containment air cooling units which cool the containment and limit the potential for release of fission products from the containment by reducing the pressure following an accident.

E. Those pumps which serve as part of the heat sink for containment cooling, e.g., nuclear service cooling water and component cooling water pumps.

F. Motor-driven auxiliary feedwater pumps and steam generator blowdown line isolation valve.

G. Phase A containment isolation which prevents fission product release (isolation of all lines not essential to reactor protection).

H. Steam line isolation to prevent the continuous, uncontrolled blowdown of more than one steam generator and thereby uncontrolled RCS cooldown.

I. Main feedwater line isolation as required to prevent or mitigate the effect of excessive cooldown.

J. Start of the emergency diesels to ensure backup supply of power to emergency and supporting systems components.

K. Isolation of the control room intake ducts and normal heating, ventilation, and air-conditioning (HVAC) units and actuation of the control room emergency HVAC system to meet control room occupancy requirements following a LOCA.

L. Containment spray actuation which initiates containment spray to reduce containment pressure and temperature following a LOCA or steam line break accident inside of containment.

M. Reactor cavity post-accident purge units.

N. Containment purge isolation.

O. Actuation of the control building ESF safety feature electrical equipment room.

P. Isolation of the auxiliary building normal HVAC system and actuation of the auxiliary building emergency ventilation system.

Q. ESF-chilled water pumps and chillers.

R. Auxiliary feedwater pumphouse ESF HVAC systems.

7.3.1.1.1.1.1 Analog Initiating Circuitry. The process analog sensors and racks for the ESFAS are discussed in reference 1. Discussed in this report are the parameters to be measured including pressures, flows, tank and vessel water levels, and temperatures, as well as the measurement and signal transmission considerations. These latter considerations include the transmitter, orifices and flow elements, and resistance temperature detectors, as well as automatic calculations, signal conditioning, and location and mounting of the devices.

The sensors monitoring the primary system are located as shown on the piping flow diagrams in chapter 5. The secondary system sensor locations are shown on the steam system flow diagrams given in chapter 10.

Containment pressure is sensed by four physically separated differential pressure transmitters mounted by strong supports outside of the containment. These are connected to the containment atmosphere by a filled and sealed hydraulic transmission system. The distance from penetration to transmitter is kept to a minimum, and separation is maintained. This arrangement and the pressure sensors external to the containment form a double barrier and conform to GDC 56 and Regulatory Guide 1.11.

7.3.1.1.1.1.2 Digital Initiating Circuitry. The ESF logic racks are discussed in detail in references 2, 6, 7, 8, 9, and 10. The description includes the considerations and provisions for physical and electrical separation as well as details of the circuitry. Reference 2 also covers certain aspects of online test provisions, provisions for test points, considerations for the instrument power source, and considerations for accomplishing physical separation. The outputs from the analog channels are combined into actuation logic as shown in drawings 1X6AA02-228, 1X6AA02-229, 1X6AA02-230, 1X6AA02-231, 1X6AA02-232, and 1X6AA02-519.

To facilitate ESF actuation testing, two-bay cabinets (one per train) are provided which enable operation, to the maximum practical extent, of safety feature loads on a group-by-group basis until actuation of all devices has been checked. Final actuation testing is discussed in detail in this section.

7.3.1.1.1.2 Logic. The outputs from the analog channels are combined into actuation logic as shown in drawings 1X6AA02-229, 1X6AA02-230, 1X6AA02-231, 1X6AA02-232, and 1X6AA02-519. Sensing of the variables by the analog circuitry is discussed in reference 1 and in section 7.2. Tables 7.3.1-1 and 7.3.1-2 give additional information pertaining to logic and functions.

7.3.1.1.1.3 Bypasses, Interlocks, and Sequencing. The interlocks associated with the ESFAS are outlined in table 7.3.1-3. These interlocks satisfy the functional requirements, including those for operational bypasses (Refer to P-11 in table 7.3.1-3.) discussed in subsection 7.1.2. The functions of sequencing electrical equipment are not part of the ESFAS.

7.3.1.1.1.4 Redundancy and Diversity. The redundant concept is applied to both the analog and logic portions of the system. Separation of redundant analog channels begins at the process sensors and is maintained in the field wiring, containment building penetrations, and analog protection racks terminating at the redundant safeguards logic racks. The design meets the requirements of GDC 20, 21, 22, 23, and 24.

7.3.1.1.1.5 Final Actuation Circuitry. The outputs of the solid-state logic protection system (the slave relays) are energized to actuate, as are most final actuators and actuated devices. Examples of these devices are:

A. Safety injection (identified also as emergency core cooling) system pump and valve actuators. See chapter 6 for flow diagrams and additional information.

B. Containment isolation phase A (CIA) signal isolates all nonessential process lines on receipt of SI signal. For further information see subsection 6.2.4.

C. Emergency fan coolers, air handling units, and water chillers. (See section 6.2.)

D. Nuclear service cooling water pump and valve actuators. (See section 9.2.)

E. Auxiliary feedwater pumps start. (See section 10.4.)

F. Emergency diesel generator start. (See section 8.3.)

G. Main feedwater isolation. (See section 10.4.)

H. Ventilation isolation valve and damper actuators. (See section 6.4.)

I. Steam line isolation valve actuators. (See section 10.3.)

J. Containment spray pump and valve actuators. (See section 6.2.)

If an accident is assumed to occur coincident with a loss of offsite power, the ESF loads are sequenced onto the diesel generators to prevent overloading them. This sequence is discussed in chapter 8. The design meets the requirements of GDC 35.

7.3.1.1.2 Design Bases Information

The functional diagrams 1X6AA02-228, 1X6AA02-229, 1X6AA02-230, 1X6AA02-231, 1X6AA02-232, and 1X6AA02-519 provide a graphic outline of the functional logic associated with the ESFAS. Requirements for the ESF system are given in chapter 6. Given below is the design bases information required in Institute of Electrical and Electronics Engineers (IEEE) 279-1971.[(4)]

7.3.1.1.2.1 Plant Conditions. The following is a summary of those plant conditions requiring protective action:

A. Primary System

1. Rupture in small pipes or cracks in large pipes.
2. Rupture of an RCS (LOCA).
3. Steam generator tube rupture.

B. Secondary System

1. Minor secondary system pipe breaks resulting in steam release rates equivalent to the opening of a single dump, relief, or safety valve.
2. Rupture of a major steam pipe.

7.3.1.1.2.2 Plant Variables. The following list summarizes the plant variables required to be monitored for the automatic initiation of SI during each accident identified in the preceding section. Post-accident monitoring requirements are given in table 7.5.2-1.

A. Primary System Accidents

1. Pressurizer pressure.
2. Containment pressure (not required for steam generator tube rupture).

B. Secondary System Accidents

1. Pressurizer pressure.
2. Steam line pressures.
3. Containment pressure.

7.3.1.1.2.3 Spatially Dependent Variables. The only variable sensed by the ESFAS which has spatial dependence is reactor coolant temperature. The effect on the measurement is neutralized by electronic averaging.

7.3.1.1.2.4 Limits, Margins, and Levels. Prudent operational limits, available margins, and setpoints before onset of unsafe conditions requiring protective action are discussed in chapter 15 and the Technical Specifications.

7.3.1.1.2.5 Abnormal Events. The malfunctions, accidents, or other unusual events which could physically damage protection system components or could cause environmental changes are as follows:

A. LOCA. (See chapter 15.)

B. Steam breaks. (See chapter 15.)

C. Earthquakes. (See chapters 2 and 3.)

D. Fire. (See subsection 9.5.1.)

E. Explosion-hydrogen buildup inside containment. (See subsection 6.2.5.)

F. Missiles. (See section 3.5.)

G. Flood. (See chapters 2 and 3.)

7.3.1.1.2.6 Minimum Performance Requirements. Minimum performance requirements are as follows:

A. System Response Times

The response time of each ESFAS function shown in Technical Specification Table 3.3.2-1 is shown in FSAR table 7.3.1-6. Response time verification for selected components may use the predetermined allocation values provided in FSAR table 7.3.1-7.

See paragraph 7.1.2.7A for a discussion of periodic response time verification.

The ESFAS response time is defined as the interval required for the ESF sequence to be initiated subsequent to the time that the appropriate variable(s) exceed the setpoint(s). The ESF sequence is initiated by the output of the ESFAS. This is brought about by the operation of the dry contacts of the slave relays (600 and 700 series relays) in the output cabinets of the solid-state protection system. The response times include the time interval between the time the parameter sensed by the sensor exceeds the safety setpoint and the time the solid-state protection system slave relay dry contacts are operated. These values are maximum allowable values consistent with the safety analyses and the Technical Specifications and are systematically verified during plant preoperational startup tests. These maximum delay times include all compensation and therefore require that any such network be aligned and operating during verification testing.

The ESFAS is always capable of having response time tests performed using the same methods as those tests performed during the preoperational test program or following significant component changes.

Maximum allowable time delays in generating the actuation signal for loss-of-coolant protection are given in table 7.3.1-4.

Maximum allowable time delays in generating the actuation signal for secondary system protection are given in table 7.3.1-5.

B. System Accuracies

Typical accuracies required for generating the required actuation signals for loss-of-coolant protection are given in table 7.3.1-4.

Typical accuracies required in generating the required actuation signals for secondary system protection are given in table 7.3.1-5.

C. Ranges of Sensed Variables

Typical ranges of sensed variables to be accommodated until conclusion of protective action is ensured are given in table 7.3.1-4 for loss-of-coolant protection.

Typical ranges of sensed variables to be accommodated until conclusion of protective action is ensured are given in table 7.3.1-5 for secondary system protection.

7.3.1.1.3 Final System Drawings

The schematic diagrams for the system discussed in this section are identified in section 1.7.

7.3.1.2 <u>Analysis</u>

7.3.1.2.1 Failure Modes and Effects Analyses

Failure modes and effects analyses have been performed on ESF systems equipment within the Westinghouse scope of supply.(5) The balance of plant system interfacing with the ESF system equipment meets the failure modes and effects analyses interface requirements in WCAP-8760.(5) The VEGP balance of plant ESF systems, although not identical, have been designed to equivalent safety design criteria. Other FMEA are included in the pertinent sections of this report.

7.3.1.2.2 Compliance with Standards and Design Criteria

Discussions of GDC are provided in various sections of chapter 7 where a particular GDC is applicable. Conformance with certain IEEE standards is presented in subsection 7.1.2. Conformance with Regulatory Guide 1.22 is discussed in paragraph 7.1.2.5. The discussion given below shows that the ESFAS conforms with IEEE 279-1971.(4)

7.3.1.2.2.1 <u>Single Failure Criteria</u>. The discussion presented in paragraph 7.2.2.2.3 is applicable to ESFAS, with the following exception.

In the ESF, a loss of instrument power calls for actuation of ESF equipment controlled by the specific bistable that lost power (containment spray excepted). The actuated equipment must have power to comply. The power supply for the protection systems is discussed in sections 7.6 and 8.3. For containment spray, the final bistables are energized to trip to avoid spurious actuation. In addition, manual containment spray requires a simultaneous actuation of two manual controls. This is considered acceptable because spray actuation on high-3 containment pressure signal provides automatic initiation of the system via protection channels meeting the criteria of reference 2. Moreover, two sets (two switches per set) of containment spray manual initiation switches are provided to meet the requirements of IEEE 279-1971. Also, it is possible for all ESF equipment (e.g., valves and pumps) to be individually, manually actuated from the control board. Hence, a third mode of containment spray initiation is available. The design meets the requirements of GDC 21 and 23.

7.3.1.2.2.2 Equipment Qualification. Equipment qualifications are discussed in sections 3.10 and 3.11.

7.3.1.2.2.3 Channel Independence. The discussion presented in paragraph 7.2.2.2.3 is applicable. The ESF slave relay outputs from the solid-state logic protection cabinets are redundant, and the actuations associated with each train are energized up to and including the final actuators by the separate ac power supplies which power one logic train each.

7.3.1.2.2.4 Control and Protection System Interaction. The discussions presented in paragraph 7.2.2.2.3 are applicable.

7.3.1.2.2.5 Capability for Sensor Checks and Equipment Test and Calibration. The discussions of system testability in paragraph 7.2.2.2.3 are applicable to the sensor, analog circuitry, and logic trains of the ESFAS.

The following discussions cover those areas in which the testing provisions differ from those for the reactor trip system.

7.3.1.2.2.5.1 Testing of ESFAS. The ESF systems are tested to provide assurance that the systems operate as designed and are available to function properly in the event of an accident. The testing program meets the requirements of GDC 21 and Regulatory Guide 1.22 as discussed in paragraph 7.1.2.5. The tests described herein and further discussed in subsection 6.3.4 meet the requirements on testing of the emergency core cooling system (ECCS) as stated in GDC 37, except for the operation of those components that will cause an actual safety injection. The test, as described, demonstrates the performance of the full operational sequence that brings the system into operation, the transfer between normal and emergency power sources, and the operation of associated cooling water systems. The safety injection and residual heat removal pumps are started and operated and their performance verified in a separate test discussed in subsection 6.3.4. When the pump tests are considered in conjunction with the ECCS test, the requirements of GDC 37 on testing of the ECCS are met as closely as possible without causing an actual safety injection.

Testing, as described in subsections 6.3.4 and 7.2.2 and herein, provides periodic testability during reactor operation of all logic and components associated with the ECCS. This design meets the requirements of Regulatory Guide 1.22 as discussed in the above sections. The program is as follows:

A. Prior to initial plant operations, ESF system tests are conducted.

B. Subsequent to initial startup, ESF system tests are conducted on one train ON A STAGGERED TEST BASIS during each regularly scheduled refueling outage.

C. During online operation of the reactor, all of the ESF analog and digital circuitry are fully tested. In addition, essentially all of the ESF final actuators are fully tested. The remaining few final actuators whose operation is not compatible with continued online plant operation is checked by means of continuity testing.

D. During normal operation, the operability of testable final actuation devices of the ESF systems is tested by manual initiation from the control room.

7.3.1.2.2.5.2 Performance Test Acceptability Standard for the "SI" (Safety Injection Signal) and for the "CS" (Containment Spray Actuation) Actuation Signals Generation. During reactor operation the basis for ESFAS acceptability is the successful completion of the overlapping tests performed on the initiating system and the ESFAS. (See figure 7.3.1-1.) Checks of process indications verify operability of the sensors. Analog checks and tests verify the operability of the analog circuitry from the input of the analog circuits up to and including the logic input relays except for the input relays associated with the containment spray function which are tested during the solid-state logic testing. Solid-state logic testing also checks the digital signal path from and including logic input relay contacts through the logic matrices and master relays and performs continuity tests on the coils of the output slave relays; final actuator testing operates the output slave relays and verifies operability of those devices which require safeguards actuation and which can be tested without causing plant upset. A continuity check is performed on the actuators of the untestable devices. Operation of the final devices is confirmed by control board indication and by visual observation that the appropriate pump motor breakers close and automatic valves have completed their travel.

The basis for acceptability for the ESF interlocks is control board indication of proper receipt of the signal upon introducing the required input at the appropriate setpoint. Maintenance checks (performed during regularly scheduled refueling outages), such as resistance to ground of signal cables in radiation environments are based on qualification test data which identifies what constitutes acceptable radiation degradation.

7.3.1.2.2.5.3 Frequency of Performance of ESFAS. During reactor operation, complete system testing (excluding sensors or those devices whose operation would cause plant upset) is performed periodically as specified in the Technical Specifications. Testing, including the sensors, is also performed during scheduled plant outages for refueling.

7.3.1.2.2.5.4 ESF Actuation Test Description. The following sections describe the testing circuitry and procedures for the online portion of the testing program. The guidelines used in developing the circuitry and procedures are:

A. The test procedures must not involve the potential for damage to any plant equipment.

B. The test procedures must minimize the potential for accidental tripping.

C. The provisions for online testing must minimize complication of ESF actuation circuits so that their reliability is not degraded.

7.3.1.2.2.5.5 Description of Initiation Circuitry. Several systems comprise the total ESF system, the majority of which may be initiated by different process conditions and be reset independently of each other.

The functions listed in paragraph 7.3.1.1.1.1 (excluding items H and L) are initiated by a common signal (Safety Injection) which in turn may be generated by different process conditions.

In addition, operation of all other vital auxiliary support systems, such as auxiliary feedwater, component cooling water, and nuclear service cooling water, is initiated by the safety injection signal.

Each function is actuated by a logic circuit which is duplicated for each of the two redundant trains of ESF initiation circuits.

The output of each of the initiation circuits consists of a master relay which drives slave relays for contact multiplication as required. The logic, master, and slave relays are mounted in two redundant and independent solid-state logic protection cabinets designated train A and train B. The master and slave relay circuits operate various pump and fan circuit breakers or motor starters, motor-operated valve starters, solenoid-operated valves, emergency generator starting equipment, and other ESF actuation devices.

7.3.1.2.2.5.6 Analog Testing. Analog testing is identical to that used for reactor trip circuitry and is described in paragraph 7.2.2.2.3.

An exception to this is containment spray, which is energized to actuate two out of four and reverts to two out of three when one channel is in test.

7.3.1.2.2.5.7 Solid-State Logic Testing. Except for containment spray channels, solid-state logic testing is the same as that discussed in paragraph 7.2.2.2.3. During logic testing of one train, the other train can initiate the required ESF function. For additional details, see references 2, 6, 7, 8, 9, and 10.

7.3.1.2.2.5.8 Actuator Testing. At this point, testing of the initiation circuits through operation of the master relay and its contacts to the coils of the slave relays has been accomplished. The ESFAS logic slave relays in the solid-state protection system output cabinets are subjected to coil continuity tests by the output relay tester in the solid-state protection system cabinets. Slave relays (e.g., K601 and K602) do not operate because of reduced voltage applied to their coils by the mode selector switch (test/operate). A multiple position master relay selector switch selects the master relays and corresponding slave relays to which the coil continuity test voltage is applied. The master relay selector switch is returned to off before the mode selector switch is returned to off. The mode selector switch is placed back in the operate mode. However, failure to do so does not result in defeat of the protective function. The ESFAS slave relays are activated during the testing by the online test cabinet, so that overlap testing is maintained.

The ESFAS final actuation device or actuated equipment testing is performed from the engineered safeguards test cabinets. These cabinets are located near the solid-state logic protection system equipment. There is one set of test cabinets provided for each of the two protection trains A and B. Each set of cabinets contains individual test switches necessary to actuate the slave relays. To prevent accidental actuation, test switches are of the type that must be rotated and then depressed to operate the slave relays. Assignments of contacts of the slave relays for actuation of various final devices or actuators has been made such that groups of devices or actuated equipment can be operated individually during plant operation without causing plant upset or equipment damage. In the unlikely event that a safety injection signal is initiated during the test of the final device that is actuated by this test, the device will already be in its safeguards position.

During this last procedure, close communication between the main control room operator and the tester at the test cabinet is required. Prior to the energizing of a slave relay, the operator in the main control room ensures that plant conditions permit operation of the equipment that is actuated by the relay. After the tester has energized the slave relay, the main control room operator observes that all equipment has operated as desired using the appropriate indicating lamps, monitor lamps, and annunciators on the control board and records all operations. The operator then resets all devices and prepares for operation of the next slave relay actuated equipment.

By means of the procedure outlined above, all ESF devices actuated by ESFAS initiation circuits, with the exceptions noted in paragraph 7.1.2.5 under a discussion of Regulatory Guide 1.22, are operated by the automatic circuitry.

7.3.1.2.2.5.9 Actuator Blocking and Continuity Test Circuits. Those few final actuation devices that cannot be designed to be actuated during plant operation (discussed in paragraph 7.1.2.5) have been assigned to slave relays for which additional test circuitry has been provided to individually block actuation of a final device upon operation of the associated slave relay during testing. Operation of these slave relays, including contact operations and continuity of the electrical circuits associated with the final devices control, is checked in lieu of actual operation. The circuits provide for monitoring of the slave relay contacts, the devices control circuit cabling and control voltage, and the devices control actuation solenoids. Interlocking prevents blocking the output from more than one output relay in a protection train at a time. Interlocking between trains is also provided to prevent continuity testing in both trains simultaneously; therefore, the redundant device associated with the protection train not under test is available in the event protective action is required. If an accident occurs during testing, the automatic actuation circuitry overrides testing as noted above. One exception to this is if the accident occurs while testing a slave relay whose output must be blocked, those few final actuation devices associated with this slave relay are not actuated; however, the redundant devices in the other train are operational and perform the required safety function. Actuation devices to be blocked are identified in paragraph 7.1.2.5.

The continuity test circuits for these components that cannot be actuated online are verified by providing lights on the engineered safeguards test cabinets.

The typical schemes for blocking operation of selected protection function actuator circuits are shown in figure 7.3.1-2 as details A and B. The schemes operate as explained below and are duplicated for each safeguards train.

Detail A shows the circuit for contact closure for protection function actuation. Under normal plant operation with equipment not under test, the test lamps DS* for the various circuits are energized, verifying that the blocking functions are not in use. Typical circuit path is through the normally closed test relay contact K8* and through test lamp connections one to three. Coils X1 and X2 are capable of being energized for protection function actuation upon closure of solid-state logic output relay contacts K*. Coil X1 is typical for a motor control center starter coil, and X2 is typical for a breaker closing auxiliary coil, motor starter master coil, coil of a solenoid valve, auxiliary relay, etc. When the contacts K8* are opened to block energizing of coil X1 or X2, the white lamp is deenergized, and the slave relay K* may be energized to perform continuity testing. The continuity test is performed by depressing the test lamp assembly and observing that the test lamp lights. The circuit path is through test lamp connections two to one (contact K8* open), through relay contact K*, and finally through actuator coil X1 or X2. Sufficient current flows in the circuit to cause the test lamp to light, but the current is insufficient to cause coil X1 or X2 to operate. When the K* relay is reset, depressing the lamp assembly does not cause the lamp to light. After the K8* relay is reset, the test lamp lights, verifying that the blocking action is removed and the circuit is in its normal operable condition.

Detail B shows the circuit for contact opening for protection function actuation. Under normal plant operation with equipment not under test for 125 V-dc actuation devices, the white test lamps DS* for the various circuits are energized, and green test lamps DS* are deenergized.

Typical circuit path for white lamp DS* is through the normally closed solid-state logic output relay contact K*. Coil Y2 is typical for a solenoid valve coil, auxiliary relay, etc. When the contact K8* is closed to block deenergizing of coil Y2, the green test lamp is energized and the slave relay K* may be energized to verify operation (opening of its contacts). Opening of the K* contact is verified by the white lamp DS* deenergizing. When the K* relay is reset, the white lamp DS* reenergizes, verifying that the K* relay contact has closed. After the K8* relay is reset, the green test lamp should be deenergized, which verifies that the circuit is now in its normal (i.e., operable) position.

7.3.1.2.2.5.10 Time Required for Testing. It is estimated that analog testing can be performed at a rate of several channels per hour. Logic testing of both trains A and B can be performed in less than 30 min. Testing of actuated components, including those which can only be partially tested, will be a function of control room operator availability. It is expected to require several shifts to accomplish these tests. Automatic actuation circuitry overrides testing, except for those few devices associated with a single slave relay whose outputs must be blocked and then only while blocked. It is anticipated that continuity testing associated with a blocked slave relay could take several minutes. During this time the redundant devices in the other trains would be functional.

7.3.1.2.2.5.11 Summary of Online Testing Capabilities. The procedures described provide capability for complete checking from the process signal to the logic cabinets and from there to the individual pump and fan circuit breakers or starters, valve starters, pilot solenoid valves, and other equipment including all field cabling actually used in the circuitry called upon to operate for an accident condition. For those few devices whose operation could adversely affect plant or equipment operation, the same procedure provides for checking from the process signal to the logic rack. To check the final actuation device, a continuity test of the individual control circuits is performed.

The procedures require testing at various locations:

A. Analog testing and verification of bistable setpoint are accomplished at process analog racks. Verification of bistable relay operation is done at the main control room status lights.

B. Logic testing through operation of the master relays and low voltage application to slave relays is done at the solid-state protection system logic rack test panel.

C. Testing of pumps, fans, and valves is done at the engineered safeguards cabinet test panel located near the solid-state protection system logic racks in combination with the control room operator.

D. Continuity testing for those circuits that cannot be operated is done at the same test cabinet mentioned in item C above.

The reactor coolant pump essential service isolation valves consist of the isolation valves for the auxiliary component cooling water return and the seal water return header.

The main reason for not testing these valves periodically is that the reactor coolant pumps may be damaged. Although pump damage from this type of test would not result in a situation which endangers the health and safety of the public, it could result in unnecessary shutdown of the reactor for an extended period of time while the reactor coolant pump or any of its components are replaced.

Containment spray system pump tests are performed periodically. The pump tests are performed with the isolation valves in the spray pump discharge lines closed. The valves are tested with the pump stopped.

7.3.1.2.2.5.12 Testing During Shutdown. ECCS tests are performed periodically in accordance with the Technical Specifications with the RCS isolated from the ECCS by closing the appropriate valves. A test safety injection signal will then be applied to initiate operation of active components (pumps and valves) of the ECCS. This is in compliance with GDC 37.

7.3.1.2.2.5.13 Periodic Maintenance Inspections. The maintenance procedures which follow are accomplished in accordance with applicable plant procedures. The frequency depends on the operating conditions and requirements of the reactor power plant. If any degradation of equipment operation is noted, either mechanically or electrically, remedial action is taken to repair, replace, or readjust the equipment. Optimum operating performance must be achieved at all times.

Typical maintenance procedures include the following:

A. Check cleanliness of all exterior and interior surfaces.

B. Check all fuses for corrosion.

C. Inspect for loose or broken control knobs and burned out indicator lamps.

D. Inspect for moisture and check the condition of cables and wiring.

E. Mechanically check all connectors and terminal boards for looseness, poor connection, or corrosion.

F. Inspect the components of each assembly for signs of overheating or component deterioration.

G. Perform complete system operating check.

The balance of the requirements listed in reference 1 (sections 4.11 through 4.22) are discussed in paragraph 7.2.2.2.3. Section 4.20 receives special attention in section 7.5.

7.3.1.2.2.6 Manual Resets and Blocking Features. The manual reset feature is provided in the standard design of the Westinghouse solid-state protection system design for two basic purposes:

A. The feature permits the operator to start an interruption procedure in the event of false actuation.

B. Although system actuation is automatic, the reset feature enables the operator to start a manual takeover of the system to handle unexpected events which can be better dealt with by operator appraisal of changing conditions following an accident.

It is most important to note that manual control of the system does not occur once actuation has begun by just resetting the associated logic devices alone. Components seal in (latch) so that removal of the actuate signal, in itself, neither cancels nor prevents completion of protective action nor provides the operator with manual override of the automatic system by this single action. In order to take complete control of the system to interrupt its automatic operation, the operator must manually unlatch relays which have latched the initial actuation signals in the associated motor control centers, and trip the pump motor circuit breakers.

The manual reset feature therefore, does not perform a bypass function. It is merely the first of several manual operations required to take control of the automatic system should such an action be considered necessary.

In the event that the operator anticipates system actuation and erroneously concludes that it is undesirable or unnecessary and imposes a standing reset condition in one train by operating and holding the corresponding reset switch at the time the actuation signal is transmitted, the other train will automatically carry the protective action to completion. In the event that the reset condition is imposed simultaneously in both trains at the time the actuation signals are generated, the automatic sequential completion of system action is interrupted and control is taken by the operator. Manual takeover will be maintained, even though the reset switches are released, if the original initiate signal exists. Should the initiate signal then clear and return again, automatic system actuation will repeat.

Note also that any time delays imposed on the system action are to be applied after the initiating signals are latched. Delay of actuation signals for fluid systems lineup, load sequencing, and other operations are not sufficient to allow the operator time to interrupt automatic completion with manual reset alone, as would be necessary if the time delay was imposed prior to latching of the initial actuation signal.

The manual block features associated with pressurizer and steam line safety injection signals provide the operator with the means to block initiation of safety injection during plant startup. These block features meet the requirements of section 4.12 of IEEE 279-1971, in that automatic removal of the block occurs when plant conditions require the protection system to be functional.

If a steam line rupture occurs while both of these safety injection actuation signals are blocked, steam line isolation will occur on high negative steam pressure rate. An alarm for steam line isolation will alert the operator of the accident.

For large loss-of-coolant accidents (LOCAs), sufficient mass and energy would be released to the containment to automatically actuate safety injection when the containment high pressure setpoint (high-I) is reached. Additionally, the operator would be alerted to the occurrence of a LOCA by the following safety-related indications:

A. Loss of pressurizer level (a low level alarm is provided).

B. Rapid decrease of reactor coolant system pressure.

C. Increase in containment pressure.

In addition to the above, the following indications are normally available to the operator at the control board:

A. Radiation alarms.

B. Increase in sump water level.

C. Decrease off scale of accumulator water levels and decrease in pressure (a low water level alarm and low pressure alarm is provided for each accumulator).

D. ECCS valve and pump position indication, status lights, and annunciators.

E. Flow from ECCS pumps.

For very small LOCAs (approximately less than 2-in. diameter) in which the containment high pressure setpoint may not be reached, the operator would observe the safety-related indications plus the first two normally available indications. In addition, a charging flow/letdown mismatch would provide the operator with another indication of leakage from the reactor coolant system.

Since the operator would observe the pressurizer level and receive additional indications that a LOCA occurred, a manual safety injection would be initiated immediately. As presented in WCAP-8356, the time to uncover the core following a small break is relatively long (e.g., greater than 10 min for a 2-in. break). The operator would, therefore, have sufficient time to manually initiate safety injection.

As part of WCAP-10599, ERG Validation Program Final Report, June 1984, a simulator response to a LOCA with safety injection blocked is included. Although this was a substantial sized LOCA, the operator actions for this LOCA are more limiting than those for a small-break

LOCA, and therefore bound the small-break LOCA. Sufficient operator action time was available to perform the necessary actions to mitigate the consequences of this event.

7.3.1.2.2.7 Manual Initiation of Protective Actions (Regulatory Guide 1.62). There are eight individual main steam stop valve momentary control switches (two per loop) mounted on the control board. Each switch, when actuated, will isolate one of the main steam lines. In addition, there are two system level switches. Each switch actuates all eight main steam line isolation valves and associated bypass valves at the system level.

Manual initiation of switchover to recirculation is in conformance with section 4.17 of IEEE 279-1971 with the following comment.

Manual initiation of containment isolation consists of two momentary control switches mounted on the control board. Each switch, when actuated, will provide for actuation of containment isolation (as well as containment ventilation isolation).

Manual initiation of containment spray consists of four momentary control switches mounted on the control board. Actuation of containment spray and resultant containment ventilation isolation will occur only if two associated control switches are operated simultaneously.

Manual initiation of either one of two redundant safety injection actuation main control board-mounted switches provides for actuation of the components required for reactor protection and mitigation of adverse consequences of the postulated, modify accident, including delayed actuation of sequence-started emergency electrical loads, as well as for the cold leg recirculation mode following a loss of primary coolant accident. Therefore, once safety injection is initiated, those components of the ECCS (see section 6.3) which are realigned as part of the semiautomatic switchover go to completion on refueling water storage tank low-low water level without any manual action. Manual operation of other components or manual verification of proper position as part of emergency procedures is not precluded nor otherwise in conflict with the above described conformance to section 4.17 of IEEE 279-1971 of the semiautomatic switchover circuits.

No exception to the requirements of IEEE 279-1971 has been taken in the manual initiation circuit of safety injection. Although section 4.17 of IEEE 279-1971 requires that a single failure within common portions of the protective system shall not defeat the protective action by manual or automatic means, the standard does not specifically preclude the sharing of initiated circuitry logic between automatic and manual functions. It is true that the manual safety injection actuation associated with one safety train (e.g., train A) shares portions of the automatic actuation circuitry of the same train; however, a single failure in shared functions does not defeat the protective action of the redundant actuation train (e.g., in this case train B). A single failure in shared functions does not defeat the protective action of the safety function. It is further noted that the sharing of the logic by manual and automatic actuation is consistent with the system level action requirements of section 4.17 of IEEE 279-1971 and with the minimization of complexity.

7.3.1.2.2.8 Further Considerations. In addition to the considerations given above, a loss of instrument air or loss of component cooling water to vital equipment has been considered. Neither the loss of instrument air nor the loss of component cooling water (assuming no other accident conditions) can cause safety limits given in the Technical Specification to be exceeded. Likewise, loss of either one of the two will not adversely affect the core or the reactor coolant system nor will it prevent an orderly shutdown if this is necessary. Furthermore, all pneumatically operated valves and controls will assume a safe operating position upon loss of instrument air. It is also noted that, for conservatism during the accident analysis (chapter 15), credit is not taken for the instrument air system nor any control system being operable.

The design does not provide any circuitry which will directly trip the reactor coolant pumps on a loss of auxiliary component cooling water. Indication in the control room is provided whenever auxiliary component cooling water is lost. The reactor coolant pumps can run about 10 min after a loss of auxiliary component cooling water. This provides adequate time for the operator to correct the problem or trip the plant if necessary.

In regard to the auxiliary feedwater system refer to subsection 7.3.7.

7.3.1.2.3 Summary

The effectiveness of the ESFAS is evaluated in chapter 15, based on the ability of the system to contain the effects of condition III and IV events, including loss-of-coolant and steam break accidents. The ESFAS parameters are based upon the component performance specifications which are given by the manufacturer or verified by test for each component. Appropriate factors to account for uncertainties in the data are factored into the constants characterizing the system.

The ESFAS must detect Condition III and IV events and generate signals which actuate the ESF. The system must sense the accident condition and generate the signal actuating the protection function reliably and within a time determined by and consistent with the accident analyses in chapter 15.

The ESF actuating signals, once generated, are latched in the actuation logic output relays and remain active until the manual reset is performed by the operator. Such reset will not reverse the actuation of any ESF equipment, all of which will remain in its emergency mode until deenergized by the operator on an individual basis. For details see the logic diagrams referenced in section 1.7.

Much longer times are associated with the actuation of the mechanical and fluid system equipment associated with ESF. This includes the time required for switching and bringing pumps and other equipment to speed and the time required for them to take load.

Operating procedures require that the complete ESFAS normally be operable. However, redundancy of system components is such that the system operability assumed for the safety analyses can still be met with certain instrumentation channels out of service. Channels that are out of service are to be placed in the tripped mode or in the case of containment spray, in the bypass mode.

7.3.1.2.3.1 Loss-of-Coolant Protection. By the analysis of LOCA and in system tests, it has been verified that except for very small reactor coolant system breaks which can be protected against by the charging pumps followed by an orderly shutdown, the effects of various LOCAs are reliably detected by the low pressurizer pressure signal; the ECCS is actuated in time to prevent or limit core damage.

For large coolant system breaks the passive accumulators inject first, because of the rapid pressure drop. This protects the reactor during the unavoidable delay associated with actuating the active ECCS equipment.

High containment pressure also actuates the ECCS. Therefore, emergency core cooling actuation can be brought about by sensing this other direct consequence of a primary system break; that is, the ESFAS detects the leakage of the reactor coolant into the containment. Then generation time of the actuation signal of about 1.5 s after detection of the consequences of the accident is adequate.

Containment spray will provide additional emergency cooling of containment and also limit fission product releases upon sensing elevated containment pressure (high-3) to mitigate the effects of a LOCA.

The delay time between detection of the accident condition and the generation of the actuation signal for the system is assumed to be about 1.0 s. However, this time is short as compared to that required for startup of the fluid systems.

The analyses in chapter 15 show that the diverse methods of detecting the accident condition and the time for generation of the signals by the protection systems are adequate to provide reliable and timely protection against the effects of loss-of-coolant.

7.3.1.2.3.2 Steam Line Break Protection. The ECCS is also actuated to protect against a steam line break. About 2.0 s elapse between sensing low steam line pressure and generation of the actuation signal. Analysis of steam line break accidents assuming this delay for signal generation shows that the ECCS is actuated for a steam line break in time to limit or prevent further core damage for steam line break cases.

Additional protection against the effects of steam line break is provided by feedwater isolation which occurs upon actuation of the ECCS. Feedwater line isolation is initiated to prevent excessive cooldown of the reactor vessel and thus protect the reactor coolant system.

Additional protection against a steam line break accident is provided by closure of all steam line isolation valves to prevent uncontrolled blowdown of all steam generators. The generation of the protection system signal (from high negative steam pressure rate) (about 2.0 s) is again short as compared to the time required to close the fast acting steam line isolation valves (approximately 7 s for the events analyzed).

In addition to actuation of the ESF, the steam line break accident results in a reactor trip. The core reactivity is further reduced by borated water injected by the ECCS.

The analyses in chapter 15 of the steam line break accidents and an evaluation of the protection system instrumentation and channel design show that the ESFAS is effective in preventing or mitigating the effects of a steam line break accident.

7.3.1.3 References

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7.3.2 EMERGENCY CORE COOLING SYSTEM

7.3.2.1 Description

7.3.2.1.1 System Description

An important engineered safety feature (ESF) is the emergency core cooling system which includes a collection of fluid system components described as the safety injection system (SIS). Refer to section 6.3 for a description and analysis of the system. Portions of the SIS which are actuated by the ESFAS include these components:

A. Residual heat removal/low-head safety injection (SI) pumps in both trains.

B. Charging pumps/high-head SI pumps in both trains.

C. Air-operated isolation valves. These include isolation valves for accumulators fill line, test.

D. Motor-operated isolation valves. These include 8808A, 8808B, 8808C, and 8808D for the accumulators.

E. A flow diagram description is shown in figure 6.3.2-1. The principal description and evaluation of this system is provided in section 6.3.

7.3.2.1.1.1 Initiating Circuits and Logic. The function of initiation of SI is described in paragraph 7.3.1.1.1 with specific functions identified in table 7.3.1-2. The logic for the initiation of SI is shown in drawings 1X6AA02-232 and 1X6AA02-519.

7.3.2.1.1.2 Bypass, Interlocks, and Sequencing. There are no operating or online testing bypasses provided for the SI pump motors or valve operators. The associated interlocks are described in section 7.6. The pump motors for high-head SI and low-head SI are sequenced as shown in drawings 1X3D-AA-K02A and 1X3D-AA-K02B.

7.3.2.1.1.3 Redundancy and Diversity. The system is composed of redundant trains A and B. The instrumentation and controls of the components and equipment in train A are physically and electrically separate and independent of the instrumentation and controls of the components and equipment in train B. The redundancy and independence provided between safety trains A and B are adequate to maintain equipment functional capabilities following design bases events.

7.3.2.1.1.4 Status Indication and Display. Pumps and valves which are an integral part of or associated with the engineered safeguards (used for injection, containment spray, and recirculation) have an operation/position status light.

ESF remote-operated valves have position indication on the control board in two places to show proper positioning of the valves. Red and green indicator lights are located next to the manual control station showing open and closed positions. The ESF (SI) positions of these valves are displayed by an energized light on the monitor light panels, which consist of an array of white lights which are off when the valves are in their normal or required positions for power operations. The monitor lights for automatically actuated valves are energized when the valve is in the automatically actuated position. For the centrifugal charging pump alternate minimum flow valves (HV-8508A and B), the monitor panel lights indicate that the valves are in the enabled mode; therefore, valve position is indicated only at the handswitches. These monitor lights thus enable the operator to quickly assess the status of the ESF systems. These indications are derived from contacts integral to the valve operators. The circuits for the ESF monitor lights are classified as associated circuits and have electrical and physical separation. In the cases of the accumulator isolation valves, redundancy of position indication is provided by valve stem-mounted limit switches which actuate annunciators on the control board when the valves are not correctly positioned for ESF actuation.

The stem-mounted switches for the accumulator isolation valves are independent of the limit switches in the motor operator.

7.3.2.1.1.5 Support Systems. The following systems are required for support of the ESF:

A. Nuclear service cooling water system. (See subsection 9.2.1.)

B. Component cooling water system. (See subsection 9.2.2.)

C. Electrical power distribution systems. (See chapter 8.)

7.3.2.1.2 Design Basis Information.

Refer to section 6.3.

7.3.2.1.3 Final System Drawings.

Refer to section 6.3.

7.3.2.2 Analysis

Refer to chapter 15 and section 6.3.

7.3.3 CONTAINMENT COMBUSTIBLE GAS CONTROL SYSTEM

7.3.3.1 Description

The concentration of hydrogen in the containment atmosphere is monitored by the hydrogen monitor system described in subsection 6.2.5. The containment combustible gas control equipment (described briefly below and more completely in subsection 6.2.5) maintains this hydrogen concentration below the minimum concentration capable of combustion.

7.3.3.1.1 System Description

A. Subsystems

1. Hydrogen monitors.
2. Hydrogen recombiners.
3. Post-loss-of-coolant accident (post-LOCA) purge exhaust system.
4. Post-LOCA cavity purge system.
5. Containment cooling system fans.

B. Initiating Circuits

The containment combustible gas control equipment (table 7.3.3-1) is operated manually from control switches located in the main control room or at local stations. It is not necessary for the monitor, recombiner, or purge equipment to be initiated automatically because it would take approximately 7 days for the hydrogen concentration to reach the control limit of 4-percent hydrogen by volume with no hydrogen reduction system in operation. The containment cooler fans start automatically and run at slow speed upon receipt of a safety injection signal (SIS). (See subsection 7.3.11.) The post-LOCA cavity purge system starts automatically on SIS.

C. Logic

The combustible gas control system is manually controlled, except for items under automatic start mentioned in paragraph 7.3.3.1.1.B above, as shown in drawings 1X5DN013-4, 1X5DN015-1, 1X5DN017-2, 1X5DN013-1, 1X5DN013-2 and 1X5DN013-4.

D. Bypass

Indication of system bypass is provided as described in section 7.5. The containment isolation system (CIS) isolates the purge exhaust lines which can manually be reopened when necessary.

E. Interlocks

There are no interlocks on these controls.

F. Sequencing

On SIS or loss of offsite power coincident with SIS, the containment fan coolers are sequenced on at low speed at the 30.5-s sequencer step. On loss of offsite power only, the fans are sequenced on at high speed at the same step.

G. Redundancy

Controls are provided on a one-to-one basis with the mechanical equipment so that the controls preserve the redundancy of the mechanical equipment.

H. Diversity

Diversity of control is provided in that the combustible gas control equipment may be controlled from local controls at the power distribution equipment, as well as from the main control room panels.

I. Actuated Devices

Table 7.3.3-1 lists the actuated devices.

J. Supporting Systems

The supporting systems required for these controls are the Class 1E ac power system (described in section 8.3) and the containment atmosphere monitoring system (described in subsection 6.2.5).

7.3.3.1.2 Design Basis

Design bases for the containment combustible gas control system are such that operation is controlled manually from the main control room and no single failure prevents the containment combustible gas control system from functioning. In addition, the following conditions are considered for the control system components:

A. Range of Transient and Steady-State Conditions and Circumstances

The electrical power supply characteristics for the controls on this system are as described in section 8.3. The range of possible environmental conditions for these controls is as described in section 3.11.

B. Malfunctions, Accidents, or Other Unusual Events

1. Fire protection is discussed in subsection 9.5.1.
2. Missile protection is discussed in section 3.5.
3. Earthquake protection is discussed in sections 3.7.B and 3.7.N.

7.3.3.1.3 Drawings

There is no automatic actuation signal for this system, although the equipment controls include interfaces with sensors and with other devices. However, at the device level, the containment cooler fans and the post-LOCA cavity purge fans automatically start upon receipt of SIS, and the containment post-LOCA purge exhaust isolation valves automatically close on receipt of CVI. References to the drawings associated with this system are provided as described in the introductory material for this section.

Control logic diagrams for the individual devices are shown in drawings 1X5DN013-4, 1X5DN015-1, 1X5DN017-2, 1X5DN019-1, 1X5DN019-2, 1X5DN013-1, 1X5DN013-2 and 1X5DN013-4. These compare with the Preliminary Safety Analysis Report (PSAR) as follows:

A. Recombiner Controls

For recombiners, there is no functional change, but fault protection is added.

B. Mixing Fan Controls

Functionally the containment cooler fans operate as shown in drawings 1X5DN013-1, 1X5DN013-2 and 1X5DN013-4. Details of motor overload protection have been added since the PSAR. The containment cooler fans are loaded onto the diesel generators as indicated in drawings 1X3D-AA-K02A, 2X3D-AA-K02A, 1X3D-AA-K02B and 2X3D-AA-K02B.

The electrical schematic diagrams listed in section 1.7 are in accordance with the control logic diagrams.

7.3.3.2 Analysis

A. Conformance to Nuclear Regulatory Commission (NRC) General Design Criteria

The applicable criteria are listed in table 7.1.1-1. No deviations or exceptions to those criteria are taken. (See section 3.1.)

B. Conformance to Regulatory Guide 1.7

Conformance is described in subsection 6.2.5 and summarized in section 1.9.

C. Conformance to Institute of Electrical and Electronics Engineers (IEEE) Standard 279-1971

The design of the control system is based on the applicable requirements of IEEE Standard 279-1971, as follows:

1. General Functional Requirement - Paragraph 4.1

   The containment cooler fans and the post-LOCA cavity purge fans are able to function automatically and reliably over the full range of transients for all plant conditions for which credit was taken in the analyses. The rest of the system functions for all of these plant conditions when manually initiated. The system response time and accuracy are as required in the accident analyses. The hydrogen sampling line is manually actuated.

2. Single Failure Criterion - Paragraph 4.2

   Through use of redundant, independent systems, as previously described, any single failure or multiple failures resulting from a single credible event will not prevent the system from performing its intended function when required.

3. Quality of Components and Modules - Paragraph 4.3

   Components and modules used in the construction of the system exhibit a quality consistent with the nuclear power plant design life objective, require minimum maintenance, and have low failure rates. The program for quality assurance is described in chapter 17.

4. Equipment Qualification - Paragraph 4.4

   The system is qualified to perform its intended functions under the environmental conditions specified in sections 3.10.B, 3.10.N, 3.11.B, and 3.11.N.

5. Channel Integrity - Paragraph 4.5

   All channels maintain functional capability under all conditions described in paragraph 7.3.3.1.2.

6. Channel Independence - Paragraph 4.6

   Discussions of the means used to ensure channel independence are given in paragraphs 7.1.2.2 and 8.3.1.4.

7. Control and Protection System Interaction - Paragraph 4.7

   No credible failure at the output of an isolation device will prevent the associated channel from performing its intended function. No single random failure in one channel will prevent the other channel from performing the intended function.

8. Derivation of System Outputs - Paragraph 4.8

   To the extent feasible, the system inputs are from direct measurement of the desired variable.

9. Capability of Sensor Checks - Paragraph 4.9

   Sufficient means have been provided to check the operational availability of the system.

10. Testing and Calibration - Paragraph 4.10

    The control system has the capability of testing the devices used to derive the final system output. No jumpers are used for testing.

11. Channel Bypass or Removal from Operation - Paragraph 4.11

    Testing of one channel can be accomplished during reactor operation without initiating a protective action at the system level.

12. Operating Bypasses - Paragraph 4.12

    There are no permissive conditions on bypasses. Bypass of one channel will not bypass the other channel. Bypass of one system will not bypass any other system.

13. Indication of Bypass - Paragraph 4.13

    If the protective action of any part of the system has been bypassed or deliberately rendered inoperative, the fact will be continuously indicated in the control room, as described in section 7.5.

14. Access to Means for Bypassing - Paragraph 4.14

    Appropriate administrative controls will be applied to ensure that access to the means for manually bypassing the system is adequately protected.

15. Multiple Setpoints - Paragraph 4.15

    The system is designed so that there are no multiple setpoints.

16. Completion of Protective Action Once It Is Initiated - Paragraph 4.16

    The system is designed so that once protective action is initiated, it is carried through to completion.

17. Manual Initiation - Paragraph 4.17

    Manual initiation of each function is provided in the control system with a minimum of equipment by direct control of power distribution equipment and solenoid valves from panel-mounted control switches. System level actuation of the safety function is not provided since the time required for operation of these functions allows the station operator to take individual action for each controlled device.

18. Access to Setpoint Adjustments, Calibration, and Test Points - Paragraph 4.18

    Appropriate administrative controls are applied to ensure that access to the means for adjusting, calibrating, and testing the system is adequately protected.

19. Identification of Protective Actions - Paragraph 4.19

    System protective actions are described and identified down to the channel level.

20. Information Readout - Paragraph 4.20

    Sufficient information is provided to allow the station operator to make a prompt decision regarding the system operating requirements. The indications required for these decisions are provided by device status lights, the systems status monitor panel, and supporting systems, as listed in the system description discussed in paragraph 7.3.3.1.1.J.

21. System Repair - Paragraph 4.21

    The system is designed to facilitate the recognition, location, replacement, repair, and adjustment of malfunctioning components or modules.

22. Identification - Paragraph 4.22

    Protection system components are identified, as described in paragraph 7.1.2.3.

D. Conformance to Nuclear Regulatory Commission (NRC) Regulatory Guides

   The applicability of regulatory guides is as shown in table 7.1.1-1 and summarized in section 1.9. References to the discussions of these regulatory guides are presented in paragraphs 7.1.2.5, 7.1.2.6, and 7.1.2.7.

E. Periodic Testing

   Periodic testing of the mechanical equipment associated with this system is discussed in subsection 6.2.5. There is no automatic actuation equipment for the entire system, but there is automatic device actuation, as described in paragraph 7.3.3.1.3. Provisions for periodic testing of the actuation system are discussed in the Technical Specifications.

F. Failure Modes and Effects Analysis

   See table 6.2.5-2.

7.3.4 CONTAINMENT PURGE ISOLATION SYSTEM

7.3.4.1 <u>Description</u>

The containment purge isolation system detects any abnormal amount of radioactivity in the containment and initiates appropriate action to ensure that any release of radioactivity to the environs is controlled. The containment purge systems are isolated by containment ventilation isolation (CVI) signals. A detailed description of those systems is given in subsection 6.2.4.

7.3.4.1.1 System Description

A. Initiating Circuits

Redundant area radiation monitors in the containment and an independent radiation monitor in the purge line consisting of gaseous, particulate, and iodine radiation monitors measure the radioactivity levels in the containment. These monitors, through their data processing modules, provide digital radioactivity signals to the engineered safety features actuation system (ESFAS) logic. The logic generates redundant CVI actuation signals.

B. Logic

Logic diagrams for the ESFAS are provided in drawings 1X6AA02-225, 1X6AA02-226, 1X6AA02-227, 1X6AA02-228, 1X6AA02-229, 1X6AA02-230, 1X6AA02-231, 1X6AA02-232, 1X6AA02-233, 1X6AA02-234, 1X6AA02-235, 1X6AA02-236, 1X6AA02-237, 1X6AA02-238, 1X6AA02-239, 1X6AA02-240, 1X6AA02-494, 1X6AA02-495, 1X6AA02-496, 1X6AA02-519, 1X5DN019-1 and 1X5DN019-2. These diagrams show the actuation systems and bypass interlock provisions. The logic for the containment purge isolation subsystem is included in these figures.

C. Bypass

Switches are provided to bypass defective monitors to preclude spurious actuation.

D. Interlocks

There are no interlocks on these controls.

E. Sequencing

The system is energized on the first step of load sequencing.

F. Redundancy

Controls are provided on a one-to-one basis with the mechanical equipment so that the controls preserve the redundancy of the mechanical equipment.

G. Diversity

Diversity of sensing is provided in that containment purge isolation can be actuated by the containment vent gaseous iodine, air particulate radiation monitors, or containment area radiation monitors.

H. Actuated Devices

Table 7.3.4-1 lists the actuated devices.

I. Supporting Systems

Supporting systems for the containment purge isolation are the four Class 1E 125-V dc power supplies, the Class 1E ac power system discussed in section 8.3, and the instrument air system described in section 9.3. The isolation function is fail-safe with respect to all of these support systems; that is to say, loss of any one of these support systems will not prevent isolation.

7.3.4.1.2 Design Bases

The design bases for the containment purge isolation system are described in paragraphs 6.2.4.1.1 and 7.3.3.1.2.

7.3.4.1.3 Drawings

The logic for the containment purge isolation system is shown in the ESFAS logic diagrams, drawings 1X6AA02-225, 1X6AA02-226, 1X6AA02-227, 1X6AA02-228, 1X6AA02-229, 1X6AA02-230, 1X6AA02-231, 1X6AA02-232, 1X6AA02-233, 1X6AA02-234, 1X6AA02-235, 1X6AA02-236, 1X6AA02-237, 1X6AA02-238, 1X6AA02-239, 1X6AA02-240, 1X6AA02-494, 1X6AA02-495, 1X6AA02-496, 1X6AA02-519, 1X5DN019-1 and 1X5DN019-2.

7.3.4.2 Analysis

A. Conformance to Nuclear Regulatory Commission (NRC) General Design Criteria

   The applicable criteria are listed in table 7.1.1-1. No deviations or exceptions to those criteria are taken. Compliance is summarized in section 3.1.

B. Conformance to Institute of Electrical and Electronics Engineers (IEEE) Standard 279-1971

   The design of the control system conforms to the applicable requirements of IEEE Standard 279-1971, as listed and discussed in paragraph 7.3.3.2C. The ranges and setpoints are given in the Technical Specifications.

C. Conformance to NRC Regulatory Guides

   The applicability of the regulatory guides is as shown in table 7.1.1-1 and summarized in section 1.9. References to the discussions of these regulatory guides are presented in subsection 7.1.2.

D. Periodic Testing

   Periodic testing of the mechanical equipment associated with this system is discussed in section 9.4. Periodic testing of the actuation system is discussed in the Technical Specifications.

7.3.5 FUEL HANDLING BUILDING VENTILATION ISOLATION

7.3.5.1 Description

A description of the entire fuel handling building ventilation system is given in subsection 9.4.2.

7.3.5.1.1 Initiating Circuits

A. Four redundant two-channel-oriented and train-oriented gaseous radioactivity monitors, together with their data processing modules, provide a digital signal to the balance of plant (BOP) safety actuation system when preset radiation levels are exceeded.

B. Two manual actuation switches also are wired into the BOP safety actuation system.

C. Upon receipt of the inputs from items A through C above, the BOP safety actuation system logic circuitry produces a fuel handling building isolation signal for both train A and train B (FHBI-A and FHBI-B). This signal in turn causes the post-accident filter units, train A and train B, fans to start. Starting these fans then causes the inlet and discharge dampers to open. Isolation dampers are closed automatically.

D. When radiation signals return to normal conditions, the post-accident heating, ventilation and air-conditioning (HVAC) systems continue to operate until reset manually.

E. Switches are provided to bypass defective monitors to preclude spurious actuation. The FHBI signal may be blocked using the normal channel test blocks. Channel bypass is indicated in the control room.

F. There are no interlocks on these controls.

G. The system is energized on the first step of load sequencing.

H. Controls are provided on a one-to-one basis with the mechanical equipment so that the controls preserve the redundancy of the mechanical equipment. There are two channels of actuation initiated by redundant radioactivity monitors, and redundant manual initiation switches.

I. Diversity of control is provided in that the fuel handling building ventilation isolation system can be actuated by either automatic signals or manual control.

J. Table 7.3.5-1 lists the actuated devices.

K. Supporting systems for the fuel handling building ventilation isolation system actuation are the two Class IE 125-V dc power supplies, the two Class-IE vital 120-V ac power systems discussed in section 8.3, and the instrument air system described in subsection 9.3.1. Loss of any one of these support systems will not prevent isolation.

7.3.5.2 Design Bases

The design bases for the fuel handling building ventilation isolation system are discussed in paragraph 9.4.2.2.1.1. Additionally, the design bases described in paragraph 7.3.1.1.2 are applicable for the control system components.

7.3.5.3 Drawings

The logic diagrams for the fuel handling building ventilation isolation actuation system are included in drawings AX5DN020-1, AX5DN020-2, AX5DN020-3, AX5DN027-1, AX5DN028-1, AX5DN029-1 and AX5DN029-3.

The control logic diagrams, the electrical schematic diagrams, the piping and instrument diagrams, and the physical location drawings for this system are included in the references in section 1.7.

7.3.5.4 Analysis

A. Conformance to Nuclear Regulatory Commission (NRC) General Design Criteria

The applicable criteria are listed in table 7.1.1-1. No deviations or exceptions to those criteria are taken. Compliance is summarized in section 3.1.

B. Conformance to Institute of Electrical and Electronics Engineers (IEEE) Standard 279-1971

The design of the control system conforms to the applicable requirements of IEEE Standard 279-1971, as listed and discussed in paragraph 7.3.3.2C.

C. Conformance to NRC Regulatory Guides

The applicability of the regulatory guides is as shown in table 7.1.1-1 and summarized in section 1.9. References to the discussions of conformance to these regulatory guides are presented in paragraph 7.1.2.

D. Failure Mode and Effects Analysis

See table 9.4.2-2.

E. Periodic Testing

Periodic testing of the mechanical equipment associated with this system is discussed in subsection 9.4.2.

7.3.6 CONTROL ROOM VENTILATION ISOLATION

7.3.6.1 Description

Upon detection of high gaseous radioactivity levels in the control room outside air intake, the normal HVAC system is isolated as described in sections 6.4 and 9.4. The control room HVAC system switches to the emergency mode of operation where a small supply of outside air is provided to maintain a set positive pressure in the control room. This positive pressure will prevent the ingress of the local ambient atmosphere. Normal ventilation is restored only by manual operation by the plant operator and is maintained only if the local ambient atmosphere poses none of the monitored hazards.

7.3.6.1.1 System Description

A. Actuating Circuits

The gaseous radioactivity level of the air provided to the main control room from the local ambient atmosphere is monitored by four redundant monitors (two per each intake duct).

The signals from these monitors are transmitted to bistables in the engineered safety features actuation system. If acceptable levels are exceeded, the control room is isolated, as described above.

The sensitivities and response times of these monitors are listed in table 7.3.6-1.

In addition to the above, control room isolation is initiated manually.

B. Logic

The control room ventilation isolation actuation system logic is included in drawings AX5DN020-4, AX5DN020-5, AX5DN020-6, AX5DN020-8, AX5DN020-10, AX5DN031-1, AX5DN031-2, AX5DN031-4, AX5DN032-3, AX5DN032-1, AX5DN034-2 and AX5DN037-1. For emergency operation, both trains of the affected unit receive a start signal. However, a permissive is provided which does not allow the lag unit to start unless there is a low-flow condition in the lead unit. The actuation signal is transmitted to each actuated device and, subject to the provisions of bypass or override, causes each device to assume its safe state.

C. Bypass

Channel selector switches, with a test block feature, are provided in the instrumentation control circuit to enable testing of the instrument control circuit independently of the redundant control circuit. Channel bypass is indicated at the system level in the control room.

Manual override is available by means of pull-to-lock switches on the fans.

D. Interlocks

Operational interlocks are as shown in drawings AX5DN020-4, AX5DN020-5, AX5DN020-6, AX5DN020-8, AX5DN020-10, AX5DN031-1, AX5DN031-2, AX5DN031-4, AX5DN032-3, AX5DN032-1, AX5DN034-2 and AX5DN037-1 and as identified in section 6.4.

E. Sequencing

The control room ventilation isolation system is powered from the Class 1E power system and energized on the first (0.5 s) step of the load sequencing, except for the control room filter units which start automatically after the 30.5 s step.

F. Redundancy

Controls are provided on a one-to-one basis with the mechanical equipment so that the controls preserve the redundancy of the mechanical equipment. Redundancy is provided in the gaseous radioactivity monitors, the actuation signals, and manual actuation switches.

G. Diversity

Diversity of actuation is provided in that the control room ventilation system may be isolated by either an automatic system or by operator manual actuation. Diversity is provided by actuation from the gaseous radioactivity and manual switches.

H. Actuated Devices

Table 7.3.6-2 lists the actuated devices.

I. Supporting System

The supporting system required for the controls are the four Class 1E 125 V-dc power supplies, vital Class 1E ac system described in section 8.3, and instrument air system described in section 9.3.1.

7.3.6.1.2 Design Bases

The design bases for the control room ventilation isolation system are such that no single failure can prevent the isolation of the control room ventilation system. The trip points are provided in the Technical Specifications.

Additionally, the design bases described in subsection 6.4.1 are applicable to the control system components.

7.3.6.1.3 Drawings

The logic diagram for the control room ventilation isolation actuation system is included in drawings AX5DN020-4, AX5DN020-5, AX5DN020-6, AX5DN020-8, AX5DN020-10, AX5DN031-1, AX5DN031-2, AX5DN031-4, AX5DN032-3, AX5DN032-1, AX5DN034-2 and AX5DN037-1.

Other drawings pertaining to this system are included in the references in section 1.7.

7.3.6.2 Analysis

A. Conformance to Nuclear Regulatory Commission (NRC) General Design Criteria

   The applicable criteria are listed in table 7.1.1-1. No deviations or exceptions to those criteria are taken. Compliance is summarized in section 3.1.

B. Conformance to Institute of Electrical and Electronics Engineers (IEEE) Standard 279-1971

   The design of the control system conforms to the applicable requirements of IEEE Standard 279-1971, as listed and discussed in paragraph 7.3.3.2.C. The setpoints are provided in the Technical Specifications.

C. Conformance to NRC Regulatory Guides

   The applicability of regulatory guides is as shown in table 7.1.1-1 and summarized in section 1.9. References to the discussions of these regulatory guides are presented in table 7.1.1-1.

D. Failure Mode and Effects Analysis

   This analysis is given in table 6.4.4-1.

E. Periodic Testing

   Periodic testing of the mechanical equipment associated with this system is discussed in subsection 9.4.1. Provisions for the periodic testing of the actuation system are discussed in the Technical Specifications.

7.3.7 AUXILIARY FEEDWATER SYSTEM

7.3.7.1 Description

The auxiliary feedwater system (AFWS) consists of two motor-driven pumps, one steam turbine-driven pump, and piping, valves, instruments, and controls, as shown in drawings 1X4DB161-2 and 1X4DB161-3. The pumps are started automatically on receipt of signals from the actuation logic, as shown in drawings 1X5DN117-1, 1X5DN117-2, 1X5DN117-3, 1X5DN120-1, 1X5DN120-2, 1X5DN120-3, 1X5DN120-5, 1X5DN120-6, 1X5DN121-1, 1X5DN121-2, 1X5DN122-1 and 1X5DN122-2. The two motor-driven pumps can also be started manually from control switches in the control room or at the remote shutdown control panel. The turbine-driven pump can also be started manually from the control room or at the local control panels located in the auxiliary feedwater pumphouse.

The preferred source of water for the AFWS is the condensate storage tank (CST). This tank is Seismic Category 1.

Each motor-driven pump feeds two steam generators through individual motor-operated flow control valves. AFWS flow can be regulated manually from the control room or from the remote shutdown panels.

The turbine-driven pump feeds all four steam generators through individual dc motor-operated control valves. AFWS valves can be operated manually from the control room or from the local control panels located in the auxiliary feedwater pumphouse.

AFWS flow indication is provided for each steam generator in the control room and at the remote shutdown control panel.

The AFWS pump turbine is supplied steam from two of the four main steam lines. Each of the steam supply lines to the turbine driver is equipped with a check valve and a normally open motor-operated gate valve. These steam lines join to form a header which leads to the turbine through a normally closed supply valve and normally open trip/throttle valve, both of which are dc motor-operated, and a normally open electro-hydraulically operated speed governing valve. Control of these valves, as well as manual speed control for the turbine-driven pump, is provided in the control room and at the local control panels located in the auxiliary feedwater pumphouse.

The status of the motor-driven pumps, the turbine-driven pump, the turbine steam supply valves, and the turbine stop valves is indicated in the control room.

The AFWS equipment is described in subsection 10.4.9.

In addition to initiating functions described above, the auxiliary feedwater actuation signal (AFWAS) closes the steam generator blowdown and sample isolation valves, when auxiliary feedwater is required by plant conditions. However, the steam generator sample isolation valves may be opened 30 seconds after closure due to an auxiliary feedwater auto-start signal to allow operators to obtain a sample. All remote manually operated valves in the normal suction from the CST and in the discharge to the steam generators are normally open.

7.3.7.1.1 System Description

A. Initiating Circuits

The AFWAS motor-driven (AFWAS-M) starting the motor-driven auxiliary feedwater pumps is generated on the occurrence of any one of the following signals:

1. Manual start.
2. Trip of both main feedwater pumps.
3. The two out of four low-low water level signals in any one steam generator.
4. Safety injection (SI).
5. Loss of offsite power.
6. Anticipated Transient Without SCRAM (ATWS) Mitigation System Actuation Circuitry (AMSAC).

All automatic actuations of the motor-driven pumps are subject to load sequencing. The AFWAS turbine-driven (AFWAS-T) starting the turbine-driven auxiliary feedwater pumps is generated on the occurrence of any one of the following signals:

1. Manual start.

2. The two out of four low-low water level signals on any two steam generators.
3. Loss of offsite power.
4. AMSAC.

The steam generator sample line isolation valves and the steam generator blowdown isolation valves are all automatically closed on the occurrence of a steam generator low-low water level, safety injection signal, a loss of offsite power signal, trip of both main feedwater pumps, or AMSAC actuation.

B. Logic

See drawings 1X5DN117-1, 1X5DN117-2, 1X5DN117-3, 1X5DN120-1, 1X5DN120-2, 1X5DN120-3, 1X5DN120-5, 1X5DN120-6, 1X5DN121-1, 1X5DN121-2, 1X5DN122-1 and 1X5DN122-2.

C. Bypass

Control switches in the control room to modulate the feedwater pump discharge valves have override features to maintain the required steam generator water levels. This also permits manual closure of the valves if necessary to isolate the flow to a faulted steam generator. (See FSAR paragraph 10.4.9.2.2.3 and drawings 1X5DN121-1 and 1X5DN121-2.)

D. Interlocks

There are no other interlocks other than those shown in drawings 1X5DN117-1, 1X5DN117-2, 1X5DN117-3, 1X5DN120-1, 1X5DN120-2, 1X5DN120-3, 1X5DN120-5, 1X5DN120-6, 1X5DN121-1, 1X5DN121-2, 1X5DN122-1 and 1X5DN122-2.

E. Redundancy

Sufficient actuation and control channels are provided throughout the AFWS to ensure the required flow to at least two steam generators in the event of a single failure.

F. Diversity

The AFWS is diversified by utilizing a turbine-driven pump with dc motor-operated valves and two ac motor-driven pumps with ac motor-operated valves. Diversity in initiating signals can be seen in drawings 1X5DN117-1, 1X5DN117-2, 1X5DN117-3, 1X5DN120-1, 1X5DN120-2, 1X5DN120-3, 1X5DN120-5, 1X5DN120-6, 1X5DN121-1, 1X5DN121-2, 1X5DN122-1 and 1X5DN122-2.

G. Actuated Devices

1. Auxiliary feedwater pump turbine steam supply valves (two).
2. Auxiliary feedwater pump turbine stop valve.
3. Auxiliary feedwater motor-operated valves (eight).
4. Auxiliary feedwater pump electric motors (two).
5. Steam turbine-driven AFWS pump drain line to condenser HV-5178.
6. Vacuum degasifier isolation valve HV-5087.
7. Steam generator blowdown isolation valves (four).

8. Steam generator blowdown sample isolation valves (eight).
9. Auxiliary feedwater pump recirculation valves (two).

H. Supporting Systems

The Class 1E ac and dc power systems are required for auxiliary feedwater control.

I. Portion of System Not Required for Safety

Instrumentation provided for monitoring system performance is not required for safety, except for the instrumentation that is shown on table 7.5.2-1.

7.3.7.1.2 Design Bases

Auxiliary feedwater is required, as described in subsection 10.4.9. No single failure shall prevent this system from operating.

The system must provide full auxiliary feedwater flow within 1 min of the detection of any condition requiring auxiliary feedwater.

7.3.7.1.3 Drawings

The logic diagram for the AFWAS is included in drawings 1X5DN117-1, 1X5DN117-2, 1X5DN117-3, 1X5DN120-1, 1X5DN120-2, 1X5DN120-3, 1X5DN120-5, 1X5DN120-6, 1X5DN121-1, 1X5DN121-2, 1X5DN122-1 and 1X5DN122-2.

Other drawings pertaining to this system are referenced in section 1.7.

7.3.7.2 Analysis

A. Compliance to Nuclear Regulatory Commission (NRC) General Design Criteria (GDC)

Compliance is summarized in section 3.1.

1. GDC 13

   Instrumentation necessary to monitor station variables associated with hot shutdown is provided in the main control room and on the auxiliary shutdown control panel. Controls for the AFWS are provided at each location. A description of the surveillance instrumentation is provided in section 7.5.

2. GDC 19

   All controls and indications required for safe shutdown of the reactor are provided in the main control room. In the event that the main control room must be evacuated, adequate controls and indications are located outside the main control room to bring to and maintain the reactor in a hot standby condition and provide capability to achieve cold shutdown.

   The remote shutdown control panels, located outside the main control room, are described in section 7.4.

3. GDC 34

The AFWS provides an adequate supply of feedwater to the steam generators to remove reactor decay heat following reactor trip. Two steam generators with auxiliary feedwater supply are sufficient to remove reactor decay heat without exceeding design conditions of the reactor coolant system.

4. Other GDC

   The remaining applicable general design criteria are listed in table 7.1.1-1 and subsection 10.4.9.

B. Conformance to Institute of Electrical and Electronics Engineers (IEEE) Standard 279-1971

   The design of the control system conforms to the applicable requirements of IEEE Standard 279-1971, as listed and discussed in paragraph 7.2.2.3 and subsection 7.3.2, except that this system is automatically actuated. The setpoints are provided in the Technical Specifications.

C. Conformance to NRC Regulatory Guides

   The applicability of regulatory guides is shown in table 7.1.1-1 and summarized in section 1.9. References to the discussions of these regulatory guides are presented in table 7.1.1-1.

D. Failure Modes and Effects Analysis

   See table 10.4.9-4.

E. Periodic Testing

   Periodic testing of the mechanical equipment associated with this system is discussed in paragraph 10.4.9.4. Provisions for the periodic testing of the actuation system are discussed in the Technical Specifications.

7.3.8 MAIN STEAM AND FEEDWATER ISOLATION

7.3.8.1 Description

The signals that initiate automatic closure of the main steam isolation, main steam isolation valve bypass, feedwater isolation, and feedwater isolation bypass valves are generated in the engineered safety features actuation system (ESFAS) described in subsection 7.3.1. The logic diagrams for the generation of these signals are shown in drawings 1X6AA02-225, 1X6AA02-226, 1X6AA02-227, 1X6AA02-228, 1X6AA02-229, 1X6AA02-230, 1X6AA02-231, 1X6AA02-232, 1X6AA02-233, 1X6AA02-234, 1X6AA02-235, 1X6AA02-236, 1X6AA02-237, 1X6AA02-238, 1X6AA02-239, 1X6AA02-240, 1X6AA02-494, 1X6AA02-495, 1X6AA02-496, and 1X6AA02-519. The remainder of this section concentrates on the non-Westinghouse portion of the main steam and feedwater isolation system.

The main steam and main feedwater isolation valves are operated by hydraulic actuators, except for the Unit 2 Train A MSIV actuators which are operated by system media actuators. The hydraulic actuators are powered by compressed gas accumulators, which are controlled by electrically operated solenoid valves. The system media actuators use system media as the motive force to open and close the valve which is controlled by electrically operated solenoid valves. Each main feedwater isolation valve has two actuators. Each actuator is controlled from a separate Class 1E electrical system, and each is capable of closing the valve independently of the other. Each main steam isolation valve has one separate Class 1E electrical system actuator.

The main steam isolation valve bypass valves are operated by a pneumatic diaphragm operator, each with one separate Class 1E electrical system actuator; the bypass feedwater isolation valves are pneumatic piston operator, each with two separate 1E electrical system actuators.

7.3.8.1.1 System Description

A. Initiating Circuits

   The main steam isolation, main steam isolation valve bypass, feedwater isolation, and feedwater isolation bypass valves close automatically upon receipt of automatic close signals (steam line isolation signal for steam isolation and feedwater isolation signal for feedwater isolation) from the Westinghouse solid-state protection system.

   The steam line isolation signal is generated by any of the following:

   1. High steam pressure rate.
   2. Low steam line pressure.
   3. High containment pressure.

   A feedwater isolation signal is generated by the following:

   1. Steam generator high level (two out of four for each steam generator).
   2. Safety injection.
   3. Reactor trip coincident with low T_{avg}.

   Manual operation is also provided.

B. Logic

   Refer to drawings 1X6AA02-225, 1X6AA02-226, 1X6AA02-227, 1X6AA02-228, 1X6AA02-229, 1X6AA02-230, 1X6AA02-231, 1X6AA02-232, 1X6AA02-233, 1X6AA02-234, 1X6AA02-235, 1X6AA02-236, 1X6AA02-237, 1X6AA02-238, 1X6AA02-239, 1X6AA02-240, 1X6AA02-494, 1X6AA02-495, 1X6AA02-496, 1X6AA02-519, 1X5DN149-1, 1X5DN149-2, 1X5DN149-3, 1X5DN150-1, 1X5DN150-2, 1X5DN150-3, 1X5DN149-4 and 1X5DN150-4.

C. Bypass

   See subsection 7.3.1.

D. Interlocks

   See subsection 7.3.1.

E. Redundancy

   Two isolation valves in series (train oriented) are provided, ensuring steam line isolation.

F. Diversity

   See subsection 7.3.1 for a discussion of diversity with regard to the automatic actuation signal.

G. Actuated Devices

   The actuated devices are the main steam and feedwater isolation valves. Refer to table 7.3.8-1.

H. Supporting Systems

   The system makes use of the Class 1E dc power systems and of the compressed air system.

I. Portions of the System Not Required for Safety

   The operator for each valve includes provisions for manually opening the valve. Instrumentation is provided for measuring the accumulator pressures. Neither of these provisions is required for safety.

7.3.8.1.2 Design Bases

The design bases for the main steam and feedwater isolation actuation system are provided in subsection 7.3.1. The design bases for the remainder of the main steam and feedwater isolation system are that the system isolates the main steam and feedwater when required and that no single failure can prevent isolation from occurring. See subsection 7.3.1 for additional discussion.

In addition, paragraph 7.3.3.1.2 is applicable to the control system components.

7.3.8.1.3 Drawings

See drawings 1X6AA02-225, 1X6AA02-226, 1X6AA02-227, 1X6AA02-228, 1X6AA02-229, 1X6AA02-230, 1X6AA02-231, 1X6AA02-232, 1X6AA02-233, 1X6AA02-234, 1X6AA02-235, 1X6AA02-236, 1X6AA02-237, 1X6AA02-238, 1X6AA02-239, 1X6AA02-240, 1X6AA02-494, 1X6AA02-495, 1X6AA02-496, 1X6AA02-519, 1X5DN149-1, 1X5DN149-2, 1X5DN149-3, 1X5DN150-1, 1X5DN150-2, 1X5DN150-3, 1X5DN149-4 and 1X5DN150-4.

7.3.8.2 Analysis

A. Compliance to Nuclear Regulatory Commission (NRC) General Design Criteria

   Compliance is summarized in section 3.1.

B. Conformance to Institute of Electrical and Electronics Engineers (IEEE) Standard 279-1971. The design of the valve control system conforms to the applicable requirements of IEEE Standard 279-1971, as listed and discussed in subsection 7.3.2, except that the system is automatically actuated. The setpoints are provided in the Technical Specifications.

C. Conformance to NRC Regulatory Guides

   The applicability of regulatory guides is shown in table 7.1.1-1 and summarized in section 1.9.

D. Periodic Testing

The main steam isolation valve control system includes provisions for verifying the proper operation of the electronic logic circuits, checking the accumulator pressure in each actuator, and for performing a 10-percent close test of each valve. The frequency of control system testing is provided in the Technical Specifications. The mechanical system testing provisions are given in subsection 10.3.4. This periodic testing is not applicable to the MSIVs with system media actuators.

7.3.9 NUCLEAR SERVICE COOLING WATER

7.3.9.1 <u>Description</u>

The nuclear service cooling water (NSCW) consists of the ultimate heat sink and the NSCW pumps, piping, valves, exchangers, and other components. The NSCW system is described in subsection 9.2.1. The ultimate heat sink is described in subsection 9.2.5.

The referenced sections also state the safety design bases and the power generation design bases for their respective systems.

7.3.9.1.1 System Description

A. Initiating Circuits

For train A, two of the three NSCW cooling tower pumps are normally operating during power generation, with one spare. In the event of an accident requiring safety injection, the safety injection signal A ensures that two out of three remain in operation. If any one pump drops out, pump discharge manifold low pressure and the pump interlock circuitry starts the spare pump. The design is similar for the train B NSCW cooling tower pumps. For either train, the load sequencer must also be in operation. Manual initiation is also provided from the control room and remote shutdown panels.

Transfer pumps in each basin are used to transfer water between basins; they are powered by the same source as the train power source for the basin into which they pump. The operation of these pumps is manual only.

The first fan to start in each NSCW tower is interlocked to start when the tower's spray valve opens and will stop when the spray valve closes. The spray valve begins to open when the NSCW return temperature is above 75°F and begins to close when the temperature falls below 65°F.

The other three fans in each NSCW tower are controlled by independent temperature switches that are dependent on the NSCW return header temperatures. These fans are set to start sequentially through a range of 79°F to 87°F. Automatic trip of the three tower fans on decreasing temperature is provided, with the fans set to trip sequentially through a range of 77°F to 71°F.

To protect against tower icing in the event of low ambient temperature, two motor-operated interlocked valves function to bypass the cooling spray headers and return water directly to the cooling tower basin. Manual initiation is also provided from the control room and remote shutdown panels.

B. Logic

Drawings 1X5DN086-1, 1X5DN087-1, 1X5DN087-2, 1X5DN087-3, 1X5DN087-4, 1X5DN089-1, 1X5DN089-2, 1X5DN089-3, 1X5DN090-1, 1X5DN090-2, 1X5DN090-3, 1X5DN087-5, and 1X5DN090-6 show the logic for NSCW engineered safety features.

C. System Bypass

System bypass, nonauto, power failure, or overload are indicated and alarmed at the systems status monitor panel (QBPS).

D. Interlocks

Interlocks are described in subsection 9.2.1 and 9.2.5 and are shown in drawings 1X5DN086-1, 1X5DN087-1, 1X5DN087-2, 1X5DN087-3, 1X5DN087-4, 1X5DN089-1, 1X5DN089-2, 1X5DN089-3, 1X5DN090-1, 1X5DN090-2, 1X5DN090-3, 1X5DN087-5, and 1X5DN090-6.

E. Redundancy

Redundancy is provided by trains A and B and controls on a one-to-one basis with the mechanical equipment, so that controls preserve the redundancy of the mechanical equipment.

F. Diversity

Diversity is provided by trains A and B, as well as by control from the control room and the remote safe shutdown panels.

G. Radiation Monitoring

Radiation monitoring is provided by a radiation monitor in the return line to each NSCW cooling tower.

H. Actuated Devices

Table 7.3.9-1 lists the actuated devices.

I. Supporting Systems

   a. The Class 1E ac power system (described in chapter 8).

   b. Makeup water wells.

   c. Makeup from river.

7.3.9.1.2 Drawings

Drawings 1X4DB133-1, 1X4DB133-2, 1X4DB134, 1X4DB135-1, and 1X4DB135-2 show the NSCW system and the ultimate heat sink. Drawings 1X5DN086-1, 1X5DN087-1, 1X5DN087-2, 1X5DN087-3, 1X5DN087-4, 1X5DN089-1, 1X5DN089-2, 1X5DN089-3, 1X5DN090-1, 1X5DN090-2, 1X5DN090-3, 1X5DN087-5, and 1X5DN090-6 show the systems actuation logic.

7.3.9.2 <u>Analysis</u>

A. Compliance with Nuclear Regulatory Commission General Design Criteria

Compliance is summarized in section 3.1. See subsection 7.3.1.

B. Conformance to Institute of Electrical and Electronics Engineers (IEEE) Standard 279-1971

   The design of the NSCW control system conforms to the applicable requirements of IEEE Standard 279-1971 as listed and discussed in subsection 7.3.2 and paragraph 7.3.7.2. The setpoints which result in Engineered Safety Features Actuation System (ESFAS) actuation of NSCW system are in the Technical Specifications.

C. Failure Modes and Effects Analysis

   See table 9.2.1-2.

7.3.10 COMPONENT COOLING WATER SYSTEM

7.3.10.1 Description

The component cooling water system (CCWS) consists of three pumps in each of two trains (A and B), heat exchangers, surge tank, interconnecting pipes, valves, and fittings. The CCWS is described in subsection 9.2.2. Subsection 9.2.2 also addresses the safety design bases and the power generation design bases.

7.3.10.1.1 Engineered Safety Features Initiating Circuits

A. One or two out of three 50-percent capacity CCWS pumps are normally operated in one train. The appearance of a safety injection signal A or loss of offsite power starts train A pumps via the load sequencer.

B. A pump discharge header low pressure signal will also start any pump not running.

C. Pumps can also be started manually from the control room or the remote shutdown panels.

D. Should any pump drop out, the continued presence of the safety injection signal A automatically ensures that two pumps are operating.

E. The safety injection signal B starts train B similarly to train A.

F. Low-low level switches on the surge tank are provided to automatically stop the CCWS pumps before insufficient net positive suction head (NPSH) conditions occur in the pump suction. Each train has its own, separate surge tank, thus maintaining separation.

G. Radiation monitoring is provided in the return line to the CCWS pumps suctions, which would include any return to the surge tanks.

H. Power failure, bypass for test or maintenance, switches in local mode are monitored; alarms and system inoperable lights occur on system status monitoring panel (QBPS) in the control room.

I. Table 7.3.10-1 lists the actuated devices.

J. Supporting systems

   1. The Class 1E ac power system.
   2. Nuclear service cooling water system.

3. Nuclear steam supply system-balance of plant engineered safety features actuation system.
4. Reactor makeup water storage tanks.
5. Demineralized water storage tank.
6. CCWS surge tanks.

   Makeup to the component cooling water surge tanks is provided automatically from the Seismic Category 1 reactor makeup water storage tank or the demineralized water storage tank.

7.3.10.1.2 Design Bases

Subsection 9.2.2 covers the safety design bases and the power generation design bases.

7.3.10.1.3 Drawings

Drawings 1X5DN091-1, 1X5DN091-2, 1X5DN091-3, 1X5DN092-1, and 1X5DN092-2 show the logic diagrams for the CCWS.

7.3.10.2 Analysis

A. Conformance to Nuclear Regulatory Commission general design criteria is discussed in subsection 7.3.1 and section 3.1.
B. Conformance to Institute of Electrical and Electronics Engineers 279-1971 is listed and discussed in paragraphs 7.3.1.2, and 7.3.7.2.
C. A failure modes and effects analysis is given in table 9.2.2-3.

7.3.11 CONTAINMENT HEAT REMOVAL SYSTEM

7.3.11.1 Description

The containment heat removal system consists of eight train- oriented, fan-operated cooling units and the containment spray system. The cooling unit and the spray system are described in subsection 6.2.2.

7.3.11.1.1 Design Bases

A. Safety design bases for the cooling units are described in paragraph 6.2.2.1.1.1 and for the spray system in paragraph 6.2.2.2.1.1.1.
B. Power generation bases are described in paragraph 6.2.2.1.1.2 for the cooling units. The containment spray system has no power generation design bases.

7.3.11.1.2 Actuating Signals and Circuits

A. The containment safety-related cooling units start via the load sequencer on the receipt of a safety injection signal. All fans are energized on the 30.5 s sequencer step following the receipt of a safety injection signal. The cooling units can also be started and stopped from the control room and from the remote shutdown panels.

B. The containment spray system is initiated by the receipt of a high containment pressure signal (high-3).

C. The safety evaluation is covered in paragraph 6.2.2.1.3.

D. Actuated devices that are tested are listed in table 7.3.11-1.

7.3.11.2 Analysis

The analysis for the engineered safety features, including the systems covered by this section, is covered in paragraph 7.3.1.2. The failure modes and effects analysis of the containment heat removal system is given in table 6.2.2-3. The containment spray failure modes and effects analysis is given in table 6.2.2-5.

7.3.11.3 Summary

The summary is covered in paragraph 7.3.1.

7.3.11.4 Loss-of-Coolant Protection

This analysis is covered in paragraph 7.3.1.

7.3.11.5 Drawings

A. Drawings 1X5DN013-1, 1X5DN013-2, and 1X5DN013-4 show the logic for the containment coolers.

B. Drawings 1X3D-BD-J01A, 1X3D-BD-J01B, 1X3D-BD-J02A, 1X3D-BD-J02B, 1X3D-BD-J02C, and 1X3D-BD-J02D show the electrical elementary diagrams for the containment spray system. The containment spray system starts independently of the sequence to load the safety injection signal. This makes it possible to start within the required time independently of the safety injection signal status.

7.3.12 CONTROL BUILDING ENGINEERED SAFETY FEATURES HEATING, VENTILATION, AND AIR-CONDITIONING SYSTEM

7.3.12.1 Description

The control building engineered safety features (ESF) heating, ventilation, and air-conditioning (HVAC) system provides a proper environment and temperature for the Class 1E electrical equipment and personnel, both during normal operations and under postulated accident conditions. It also serves to reduce or limit the release of fission products to the control building following a postulated loss-of-coolant accident or fuel handling accident. Except for the control room essential HVAC system described in detail in section 6.4 and subsection 7.3.6, the other subsystems of the control building ESF HVAC system are as follows:

A. Control building safety feature electrical equipment rooms HVAC system.

B. Control building HVAC equipment rooms ESF ventilation system (level 3).

C. Control building auxiliary relay rooms ESF air-conditioning units.

A detailed description of these systems is given in subsection 9.4.5.

7.3.12.1.1 System Description

A. Actuating Circuits

1. Control building safety feature electrical equipment rooms HVAC system components (air-conditioning units, exhaust fans, and associated dampers) are actuated upon:

    a. Safety injection (signal A and signal B).

    b. Manual initiation.

2. Control building HVAC equipment rooms ESF ventilation system components (control room ESF chiller rooms exhaust fans) are actuated upon:

    a. Control room ESF chiller room high temperature.

    b. Manual actuation.

3. Control building auxiliary relay rooms ESF air-conditioning units are actuated upon:

    a. Safety injection (signal A and signal B).

    b. Manual initiation.

B. Logic

The control building ESF HVAC system logic is shown in drawings AX5DN008-1, AX5DN056-6, 1X5DN044-1, 1X5DN045-1, and AX5DN056-2. Logic is designed in such a manner that a momentary loss of the control power will not prevent or reverse the safety actuation of any equipment and the reset of the safety injection signal will not trip the actuated equipment without deliberate subsequent operator action.

C. Bypass

Bypass of each subsystem (except the auxiliary relay rooms ESF air-conditioning) comprising the control building ESF HVAC system is indicated in the control room. Such bypass may result from either control power failure, system component failure, manual override at the component level, or transfer to local control. The bypass indication logic is shown in drawings AX5DN008-1, AX5DN056-6, 1X5DN044-1, 1X5DN045-1, and AX5DN056-2. The manual override capability is provided only for the control building control room ESF chiller rooms exhaust fans.

D. Interlocks

There are no interlocks other than those shown in drawings AX5DN008-1, AX5DN056-6, 1X5DN044-1, 1X5DN045-1, and AX5DN056-2.

E. Sequencing

All loads other than the supporting ESF chiller compressor motors (item J) are energized on the first step of load sequencing. The ESF chiller compressor motors start automatically after the 30.5-s sequencer step.

F. Redundancy

All equipment, instruments, and controls are fully redundant and arranged in two completely independent trains (A and B).

G. Seismic Qualification

All components comprising the control building ESF HVAC system are Seismic Category 1 and remain functional during and after a safe shutdown earthquake.

H. Diversity

Diversity of actuation is provided in that the control building ESF HVAC system can be operated either manually from any one of the two physically separated locations (i.e., main control room and the shutdown panels) or automatically.

I. Actuated Devices

Table 7.3.12-1 lists the actuated devices.

J. Supporting Systems

The following systems are required to be operational for proper functioning of the control building ESF HVAC system:

1. Class 1E 480-V ac system.
2. Class 1E 120-V ac system.
3. Class 1E 125-V dc system.
4. Class 1E 4160-V ac system.
5. Essential chilled water system.

Under emergency conditions (safety injection or loss of offsite power) the Class 1E electric power systems remain operational, as described in section 8.3. The essential chilled water system is described in subsection 9.2.9. It is automatically actuated by the safety injection signal.

7.3.12.1.2 Design Bases

The design bases for the control building ESF HVAC system are such that no single failure within that system nor any supporting system shall prevent it from performing its safety function. A detailed description of the system's design bases is provided in subsection 9.4.5.

7.3.12.1.3 Drawings

The drawings pertaining to the control building ESF HVAC system (including logic diagrams shown in drawings AX5DN008-1, AX5DN056-6, 1X5DN044-1, 1X5DN045-1, and AX5DN056-2) are included in the references in section 1.7.

7.3.12.2 Analysis

The analysis presented in subsection 7.3.1 for the ESF pertains also to the system discussed herein. The failure mode and effects analyses of the control building ESF HVAC systems are given in table 9.4.5-2.

7.3.12.3 Summary

The summary is covered in paragraph 7.3.1.

7.3.13 AUXILIARY BUILDING ENGINEERED SAFETY FEATURES HEATING, VENTILATION, AND AIR-CONDITIONING SYSTEM

7.3.13.1 Description

The auxiliary building engineered safety features (ESF) heating, ventilation, and air conditioning (HVAC) system performs the following safety functions:

- Maintains proper temperatures in safety-related switchgear, motor control center (MCC), pump and heat exchanger rooms during postulated accident conditions, station blackout, and manual conditions.

- Minimizes the release of airborne radioactivity to the outside atmosphere resulting from recirculation line and component leakage into the piping penetration area ECCS and ESF pump rooms during an accident condition.

The system maintains a negative pressure in the piping penetration area and ESF pump rooms and filters the exhaust from the negative pressure boundary. The auxiliary building ESF HVAC system is comprised of the following two systems:

- Auxiliary building ESF room coolers.

- Piping penetration area filtration and exhaust system.

Both systems are described in detail in subsection 9.4.3.

7.3.13.1.1 System Description

A. Activity Circuits

1. The ESF room coolers are actuated upon:

   - Safety injection signal (signal A and signal B) or an automatic actuation signal generated by actuation of the corresponding equipment (pump or heat exchanger).
   - Room temperature high signal.
   - Manual actuation.

   For details see drawings 1X5DN030-1, 1X5DN030-3, 1X5DN030-4, 1X5DN030-5, and 1X5DN065-1.

2. The piping penetration area filtration and exhaust unit motors and their associated dampers and heaters are actuated upon:

   - Containment ventilation isolation signal (signal A and signal B).
   - Manual actuation.

   Upon automatic actuation of the piping penetration area filtration exhaust system, the piping penetration area is automatically isolated from the auxiliary building normal HVAC system.

B. Logic

The auxiliary building ESF HVAC system logic is shown in drawings 1X5DN030-1, 1X5DN030-3, 1X5DN030-4, 1X5DN030-5, and 1X5DN065-1. Logic is designed in such a manner that a momentary loss of the control power will not prevent or reverse the safety actuation of any equipment, and it is designed such that the reset of the safety injection signal will not trip the actuated equipment without deliberate subsequent operator action.

C. Bypass

Bypass of either subsystem comprising the auxiliary building ESF HVAC system is indicated in the control room. Such bypass may result from control power failure, system component failure, manual override at the component level, or transfer to local control. The bypass indication logic is shown in drawings 1X5DN030-1, 1X5DN030-3, 1X5DN030-4, 1X5DN030-5, and 1X5DN065-1. The manual override capability is provided only for the piping penetration area filtration and exhaust units.

D. Interlocks

There are no interlocks other than those shown in drawings 1X5DN030-1, 1X5DN030-3, 1X5DN030-4, 1X5DN030-5, and 1X5DN065-1.

E. Sequencing

The piping penetration area filtration and exhaust units are permitted to start on the containment ventilation isolation signal during the 15.5-s sequencer step for (1-s) or after sequencing is complete (after 30.5 s). All other loads are energized on the first step of load sequencing. The supporting ESF chiller compressor motors start automatically after sequencing is complete. Heaters may be manually loaded after sequencing is completed.

F. Redundancy

All equipment, instruments, and controls are fully redundant and arranged in two completely independent trains (A and B).

G. Seismic Qualification

All components comprising the auxiliary building ESF HVAC system are Seismic Category 1 and remain operational during and after a safe shutdown earthquake.

H. Diversity

Diversity of actuation is provided in that the auxiliary building ESF room coolers can be operated either manually from any one of the two physically separated locations (i.e., main control room and the shutdown panels) or automatically. The automatic actuation occurs upon either high room temperature or safety injection; this also enhances system diversity. The penetration area filtration and exhaust units can be actuated either manually from the control room or automatically.

I. Actuated Devices

Table 7.3.13-1 lists the actuated devices.

J. Supporting Systems

The following systems are required to be operational for proper functioning of the auxiliary building ESF HVAC system:

- Class 1E 480-V ac system.
- Class 1E 120-V ac system.
- Class 1E 125-V dc system.
- Essential chilled water system.

Under emergency conditions (safety injection or loss of offsite power) the Class IE electric power system remains operational, as described in section 8.3. The essential chilled water system is described in subsection 9.2.9. It is automatically actuated by the safety injection signal.

7.3.13.1.2 Design Bases

The design bases for the auxiliary building ESF HVAC system are such that no single failure within that system nor any supporting system can prevent it from performing its safety function. A detailed description of system design bases is provided in subsection 9.4.3.

7.3.13.1.3 Drawings

The drawings pertaining to the auxiliary building ESF HVAC system (including logic diagrams shown in drawings 1X5DN030-1, 1X5DN030-3, 1X5DN030-4, 1X5DN030-5, and 1X5DN065-1) are included in the references in section 1.7.

7.3.13.2 Analysis

The analysis presented in subsection 7.3.1 for the ESF pertains also to the systems discussed herein. The failure modes and effects analysis of the auxiliary building ESF HVAC system is given in table 9.4.3-3.

7.3.13.3 Summary

The summary is covered in paragraph 7.3.1.

7.3.14 AUXILIARY FEEDWATER PUMPHOUSE ENGINEERED SAFETY FEATURES HEATING, VENTILATION, AND AIR-CONDITIONING SYSTEM

7.3.14.1 Description

The auxiliary feedwater pumphouse engineered safety features (ESF) heating, ventilation, and air-conditioning (HVAC) system provides a suitable environment for equipment and maintenance personnel within the auxiliary feedwater pump rooms. It consists of one wall-mounted air supply fan and damper in each of the two motor-driven auxiliary feedwater pump rooms and two dampers facilitating natural convection in the turbine-driven auxiliary feedwater pump room. A detailed description of this system is given in subsection 9.4.8.

7.3.14.1.1 System Description

A. Actuating Circuits

1. The motor-driven auxiliary feedwater pump room air supply fans and dampers are actuated upon:

- Room temperature high signal.
- Manual actuation.

2. The turbine-driven auxiliary feedwater pump room dampers are actuated upon:
   - Turbine-driven auxiliary feedwater pump automatic start signal.
   - Manual actuation.

B. Logic

The auxiliary feedwater pumphouse ESF HVAC system logic is shown in drawings 1X5DN068-1 and 1X5DN068-3. Logic is designed so that a momentary loss of control power can not prevent or reverse the safety actuation of any equipment.

C. Bypass

Bypassed/inoperable status for the motor-driven auxiliary feedwater pump room air supply fans and dampers is indicated in the control room.

The manual override capability is provided only for the motor-driven auxiliary feedwater pump room air supply fans.

D. Interlocks

There are no interlocks other than those shown in drawings 1X5DN068-1 and 1X5DN068-3.

E. Sequencing

All equipment comprising the auxiliary feedwater pumphouse ESF HVAC system is energized on the first (0.5-s) sequencer step.

F. Redundancy

There is no redundancy in the auxiliary feedwater pumphouse ESF HVAC system.

G. Seismic Qualification

All components comprising the auxiliary feedwater pumphouse ESF HVAC system are Seismic Category 1 and remain functional during and after a safe shutdown earthquake.

H. Diversity

Diversity of actuation is provided in that the equipment can be operated either automatically or manually from any one of the two physically separated locations.

I. Actuated Devices

Table 7.3.14-1 lists the actuated devices.

J. Supporting Systems

The following systems are required to be operational for proper functioning of the auxiliary feedwater pumphouse ESF HVAC system:

- Class 1E 480-V ac system.

- Class 1E 125-V dc system.

These systems remain operational under emergency conditions. (See section 8.3.)

7.3.14.1.2 Design Bases

The design bases for the auxiliary feedwater pumphouse ESF HVAC system are outlined in subsection 9.4.8.

7.3.14.1.3 Drawings

The drawings pertaining to the auxiliary feedwater pumphouse ESF HVAC system (including logic diagrams shown in drawings 1X5DN068-1 and 1X5DN068-3) are included in the references in section 1.7.

7.3.14.2 Analysis

The analysis presented in subsection 7.3.1 generally applies. Although the auxiliary feedwater pumphouse ESF HVAC system is not redundant, its malfunctioning poses no threat to safety functions of the auxiliary feedwater system, due to the excessive redundancy of the latter. A loss of either of the three auxiliary feedwater pumps that might potentially result from the malfunction of its respective ventilation equipment does not impair the auxiliary feedwater supply function. (See subsection 10.4.9.) The failure modes and effects analysis of the auxiliary feedwater pumphouse ESF HVAC system is given in table 9.4.8-2.

7.3.14.3 Summary

The summary covered in subsection 7.3.1 generally applies. All specific features of the auxiliary feedwater pumphouse ESF HVAC system are discussed above and in subsection 9.4.8.

7.3.15 DIESEL GENERATOR BUILDING ENGINEERED SAFETY FEATURES HEATING, VENTILATION, AND AIR-CONDITIONING SYSTEM

7.3.15.1 Description

The diesel generator building engineered safety features (ESF) heating, ventilation, and air-conditioning (HVAC) system is designed to remove the heat added to the building atmosphere by operating diesel generators, their associated equipment, and solar load. The system is comprised of two identical and completely independent trains, each serving one diesel generator.

Each such subsystem includes two 50-percent capacity ESF fan units connected in parallel to common ductwork. For a detailed description of the diesel generator building ESF HVAC system, see subsection 9.4.7.

7.3.15.1.1 System Description

A. Actuating Circuits

   As noted above, each of the two diesel generator building ESF HVAC system trains includes two ESF fan units. The first ESF fan unit is actuated upon:

   - Diesel generator running signal.

- Manual actuation.

The second (standby) unit is actuated upon:

- Diesel generator running and room temperature high signal.
- Manual actuation.

Following its actuation, the system maintains the air temperature within the recommended range by modulating appropriate dampers. For details see drawings 1X5DN058-1, 1X5DN058-3, 1X5DN058-4, and 1X5DN058-5.

B. Logic

The diesel generator building ESF HVAC system logic is shown in drawings 1X5DN058-1, 1X5DN058-3, 1X5DN058-4, and 1X5DN058-5. Logic is designed in such a manner that a momentary loss of the control power does not prevent or reverse the safety actuation of any equipment. Once actuated, the system operates until the actuating signals disappear. The first ESF fan is stopped manually. The second (standby) ESF fan stops when room temperature drops below setpoint.

The dampers then automatically return to normal position. Should the diesel generator restart, the ESF HVAC system actuates again without operator intervention.

C. Bypass

Bypass of the diesel generator building ESF HVAC system is indicated in the control room. Such bypass may result from either system control power loss, fan motor breaker inoperable position, component failure, transfer to local control, or manual override of the fan motor actuating signal. The bypass indication logic is shown in drawings 1X5DN058-1, 1X5DN058-3, 1X5DN058-4, and 1X5DN058-5.

D. Interlocks

There are no interlocks other than those shown in drawings 1X5DN058-1, 1X5DN058-3, 1X5DN058-4, and 1X5DN058-5.

E. Sequencing

The ESF fan motors may be energized after the 30.5-s sequencer step based on process requirements. All other loads are energized at the first of load sequencing.

F. Redundancy

The diesel generator building ESF HVAC system is not redundant, since each of its trains (A and B) serves the corresponding diesel generator. Nevertheless, such arrangement preserves redundancy at the diesel generator system level.

G. Seismic Qualification

All components of the diesel generator ESF HVAC system are Seismic Category 1 and remain operational during and after a safe shutdown earthquake.

H. Diversity

Diversity of actuation is provided in that the diesel generator building ESF HVAC system can be operated either manually from any one of the two physically separated locations (i.e., main control room and the shutdown panels) or automatically with each of the two fans in either train being actuated by different signals. (See item A.)

I. Actuated Devices

Table 7.3.15-1 lists the actuated devices.

J. Supporting Systems

The following systems are required to be operational for proper functioning of the diesel generator building ESF HVAC system:

- Class 1E 480-V ac system.
- Class 1E 120-V ac system.
- Class 1E 125-V dc system.

As described in chapter 8, all systems remain operational under emergency conditions.

7.3.15.1.2 Design Bases

The design bases for the diesel generator building ESF HVAC system are given in subsection 9.4.7.

7.3.15.1.3 Drawings

The drawings pertaining to the diesel generator building ESF HVAC system (including logic diagrams shown in drawings 1X5DN058-1, 1X5DN058-3, 1X5DN058-4, and 1X5DN058-5) are included in references in section 1.7.

7.3.15.2 Analysis

The analysis presented in subsection 7.3.1 generally applies. Although the diesel generator building ESF HVAC system is not redundant, its malfunction does not impair the performance and redundancy at the diesel generator system level. (See item F.) The failure modes and effects analysis of the diesel generator building ESF HVAC system is given in table 9.4.7-2.

7.3.15.3 Summary

The summary covered in subsection 7.3.1 generally applies. All specific features of the diesel generator building ESF HVAC system are discussed above and in subsection 9.4.7.

7.3.16 ELECTRICAL TUNNEL ENGINEERED SAFETY FEATURES HEATING, VENTILATION, AND AIR-CONDITIONING SYSTEM

7.3.16.1 Description

The safety function of the electrical tunnel engineered safety features (ESF) heating, ventilation, and air-conditioning (HVAC) system is to provide adequate environment for the Class 1E cables routed through electrical tunnels. The tunnels serviced by this system are as follows:

- Two diesel power cable tunnels (trains A and B).
- Two nuclear service cooling water (NSCW) tower cable tunnels (trains A and B).
- Turbine building and auxiliary building train A tunnel. (The corresponding train B tunnel is ventilated by convection only.)

Each of the above tunnels has a single fan unit. The electrical tunnel ESF HVAC system is described in detail in subsection 9.4.9.

7.3.16.1.1 System Description

A. Actuating Circuits

The fan motor in every fan unit is actuated upon:

1. Tunnel temperature high signal, with the exception of fans 1-1540-B7-005-000 and 2-1540-B7-005-000, the turbine building to auxiliary building train A tunnel ventilation fans. As described in subsection 9.4.9, this fan does not automatically start on high temperature.
2. Manual actuation.

   For details see drawing 1X5DN069-1.

B. Logic

The electrical tunnel ESF HVAC system logic is shown in drawing 1X5DN069-1. The logic is designed in such a manner that a momentary loss of the control power does not prevent or reverse the safety actuation of any equipment.

C. Bypass

Bypass of either fan comprising the electrical tunnel ESF HVAC system is indicated in the control room. Such bypass may result from control power failure, system component failure, or manual override at the component level. Bypass indication for manual override of the turbine building to auxiliary building train A electrical tunnel HVAC system is not indicated in the control room. As described in subsection 9.4.9, the train A electrical tunnel ventilation fan is manually started. The manual override capability is provided on all five fan units.

D. Interlocks

There are no interlocks other than those shown in drawing 1X5DN069-1.

E. Sequencing

The electrical tunnel ESF HVAC fan motors are energized on the first (0.5-s) step of load sequencing, except for the train A tunnel fan which is manually actuated.

F. Redundancy

The electrical tunnel ESF HVAC system is comprised of five completely independent subsystems, each serving a different tunnel. Although these subsystems are not redundant, it does not impair the redundancy at the system level. (Each tunnel and its respective fan unit belong to the same train.)

G. Seismic Qualification

All components comparing the electrical tunnel ESF HVAC system are Seismic Category 1 and remain operational during and after a safe shutdown earthquake.

H. Diversity

Diversity of actuation is provided in that the electrical tunnel ESF fan units can be operated either manually or automatically with the exception of the turbine building to auxiliary building train A tunnel. The fan unit in that tunnel is started manually.

I. Actuated Devices

Table 7.3.16-1 lists the actuated devices.

J. Supporting Systems

The only supporting system that has to be operational for the electrical tunnel ESF HVAC system to function properly is the Class 1E 480-V ac power system. As described in chapter 8, this system remains operational under any postulated emergency conditions.

7.3.16.1.2 Design Bases

The design bases for the electrical tunnel ESF HVAC system are discussed in subsection 9.4.9.

7.3.16.1.3 Drawings

The drawings pertaining to the electrical tunnel ESF HVAC system (including logic diagrams shown in drawing 1X5DN069-1) are included in the references in section 1.7.

7.3.16.2 Analysis

The analysis presented in subsection 7.3.1 generally applies. As noted in item F above, redundancy of the vital diesel generator power system is not compromised by the lack of redundancy in the electrical tunnel ESF HVAC system. The failure modes and effects analysis of the latter system is given in table 9.4.9-3.

7.3.16.3 Summary

The summary covered in paragraph 7.3.1 generally applies. All specific features of the electrical tunnel ESF HVAC system are discussed above and in subsection 9.4.9.

7.3.17 DIESEL GENERATOR FUEL OIL SYSTEM

7.3.17.1 Description

A separate diesel generator fuel oil system provides sufficient and independent fuel oil supply for each diesel generator engine under all conditions and plant operating modes. Each such system consists of a diesel fuel oil storage tank, a diesel fuel oil day tank, two diesel fuel oil storage tank pumps, an engine-driven fuel oil pump, associated pipes, valves, filters, instrumentation, and controls. The diesel generator fuel oil system is described in detail in subsection 9.5.4.

7.3.17.1.1 System Description

A. Actuating Circuits

Each diesel generator has two 100-percent capacity diesel fuel oil storage tank pumps operating alternately for greater reliability. Each pump is actuated upon:

1. Day tank fuel oil level low signal.
2. Low pressure at the discharge of the other operating pump.
3. Manual actuation.

The details of the actuation logic are drawn in drawing 1X5DN107-1.

B. Logic

The diesel generator fuel oil system logic is shown in drawing 1X5DN107-1. The logic is designed in such a manner that a momentary loss of the control power does not prevent or reverse the actuation of the pumps.

C. Bypass

Bypass of each diesel fuel oil storage pump is indicated in the control room. Such bypass may result from either control power failure, system component failure, or manual override of the pump automatic actuation capability. The bypass indication logic is shown in drawing 1X5DN107-1.

D. Interlocks

There are no interlocks other than those shown in drawing 1X5DN107-1.

E. Sequencing

The diesel generator fuel oil storage pumps are energized on the first (0.5 s) step of load sequencing.

F. Redundancy

The fuel oil system for each diesel generator is partially redundant. The fuel oil storage pumps are fully redundant, as there are two of these for each diesel generator. All other portions of each diesel generator fuel oil system are not redundant. This, however, does not impair the redundancy of the diesel generator onsite power system, which consists of two completely independent and redundant trains A and B for each nuclear power generating unit.

G. Seismic Qualification

All components comprising the diesel generator fuel oil system are Seismic Category 1 and remain operational during and after a safe shutdown earthquake.

H. Diversity

Diversity of actuation is provided in that the diesel generator fuel oil system can be operated either automatically or manually.

I. Actuated Device

Actuated devices are listed in table 7.3.17-1.

J. Supporting Systems

The following systems are required to be operational for the diesel generator fuel oil system to function properly:

1. Class 1E 480-V ac system.
2. Class 1E 120-V ac system.

As described in chapter 8, all Class 1E power systems remain operational under emergency conditions.

7.3.17.1.2 Design Bases

The design bases for the diesel generator fuel oil system are given in subsection 9.5.4.

7.3.17.1.3 Drawings

The drawings pertaining to the diesel generator fuel oil system (including logic diagrams drawn in drawing 1X5DN107-1) are included in the references in section 1.7.

7.3.17.2 Analysis

The failure mode and effects analysis of the diesel generator fuel oil system is given in table 9.5.4-2.

7.3.17.3 Summary

The summary covered in paragraph 7.3.1 generally applies. All specifics of the diesel generator fuel oil system are discussed above in subsection 9.5.4.

TABLE 7.3.1-1

INSTRUMENTATION OPERATING CONDITIONS FOR ENGINEERED SAFETY FEATURES

No.	Functional Unit	No. of Channels	No. of Channels to Trip
1	Safety injection		
	Manual	2	1
	High containment pressure (high-1)	3	2
	Low steam line pressure lead-lag compensated	12 (3 per steam line)	2 in any one steam line
	Pressurizer low pressure [(a)]	4	2
2	Containment spray		
	Manual[(b)]	4	2
	Containment pressure (high-3)	4	2

a. Permissible bypass if reactor coolant pressure is less than 2000 psig.

b. Manual actuation of containment spray system requires the simultaneous operation of two separate switches. The requirements for the simultaneous operation of two switches is desirable to prevent inadvertent spray actuation.

TABLE 7.3.1-2 (SHEET 1 OF 2)

INSTRUMENTATION OPERATING CONDITIONS FOR ISOLATION FUNCTIONS

No.	No. of Functional Unit	No. of Channels	No. of Channels to Trip
1	Containment isolation		
	Automatic safety injection (phase A)	See items 1b through 1d of table 7.3.1-1	
	Manual (phase A)	2	1
2	Steam line isolation		
	High steam line negative pressure rate	12 (3 per steam line)	2 per steam line in any steam line
	Containment pressure (high-2)	3	2
	Low steam line pressure	12 (3 per steam line)	2 per steam line in any steam line
	Manual[(a)]	2 per steam line	1 per steam line

TABLE 7.3.1-2 (SHEET 2 OF 2)

No.	Functional Unit	No. of Channels	No. of Channels to Trip
3	Feedwater line isolation		
	Safety injection	See items 1a through 1d of table 7.3.1-1	
	Steam generator high-high level 2/4 on any steam generator	16 (4 per steam generator)	2 per steam generator
	Reactor trip coincident with	2 (reactor trip)	1
	low T_{avg}	4 (low T_{avg})	2
	Manual	1 per feedwater line	1 per feedwater line

a. Two tandem switches (one for train A and one for train B) will simultaneously close all main steam line and main steam bypass isolation valves at the system level.

TABLE 7.3.1-3 (SHEET 1 OF 2)

INTERLOCKS FOR ENGINEERED SAFETY FEATURES ACTUATION SYSTEM

Designation	Input	Function Performed
P-4	Reactor trip	Actuates turbine trip. Closes main and bypass feedwater valves on low T_{avg} below set point. Prevents opening of main and bypass feedwater valves which were closed by safety injection or high-high steam generator water level. Allows manual block of the automatic reactuation of safety injection. Transfers steam dump control from the load rejection controller to the plant trip controller.
	Reactor not tripped	Defeats the block preventing automatic reactuation of safety injection.
P-11	2/3 pressurizer pressure below setpoint	Allows manual block of safety injection actuation on low pressurizer pressure signal. Allows manual block of safety injection actuation and steam line isolation on low compensated steam line pressure signal and allows steam line isolation on high steam line negative pressure rate.

TABLE 7.3.1-3 (SHEET 2 OF 2)

Designation	Input	Function Performed
	2/3 pressurizer pressure above setpoint	Defeats manual block of safety injection actuation on low pressurizer pressure and safety injection and steam line isolation on low steam line pressure and defeats steam line isolation on high steam line negative pressure rate.
P-12[a]	2/4 low-low T_{avg} below setpoint	Blocks steam during except cooldown condenser dump valves. Allows manual bypass of steam dump block for the cooldown valves only.
	2/4 low-low T_{avg} above setpoint	Defeats the manual bypass of steam dump block.
P-14	2/4 steam generator high-high water level above setpoint on any steam generator	Closes all feedwater regulating valves and isolation valves. Trips all main feedwater pumps which close the pump discharge valves. Actuates turbine trip.

a. ESF interlock not applicable.

TABLE 7.3.1-4

PRIMARY SYSTEM ACCIDENTS AND REQUIRED INSTRUMENTATION
RUPTURES IN SMALL PIPES, CRACKS IN LARGE PIPES,
RUPTURES OF LARGE PIPES, AND STEAM GENERATOR TUBE RUPTURE

Channel	Response Time(s)[a]	Accuracy[a]	Range
Pressurizer pressure	(c)	$\pm$1.75 percent of span	1700 to 2500 psig
Containment pressure[b]	(d)	$\pm$1.75 percent of span	0 to 115 percent of containment design pressure

a. See section 7.1 for definitions of engineered safety features actuation system response time and accuracy.

b. Not required for steam generator tube rupture.

c. Total time from step change in pressurizer pressure until start of safety injection pumps is 27 s with offsite power available and 40 s with offsite power unavailable.

d. Total time from step change in containment pressure until full containment spray is obtained is 94 s (includes 29 s for diesel start and sequencing and 65 s for filling the spray header).

TABLE 7.3.1-5

SECONDARY SYSTEM ACCIDENTS AND REQUIRED INSTRUMENTATION,
MINOR SECONDARY SYSTEM PIPE BREAK, AND
MAJOR SECONDARY SYSTEM PIPE BREAK

Item	Channel	Response Time(s)[a]	Accuracy [a]	Range
1	Containment pressure[b]	(b)	±1.75 percent of full scale	0 to 115 percent of containment design pressure
2	Steam line pressure	10.0[c]	±2.25 percent of span	0 to 1300 psig
3	Steam line pressure rate	See item 2 for sensor characteristics		
4	T_{avg}	N/A	±2°F	530 to 630°F
5	Pressurizer pressure	(d)	±1.75 percent of span	1700 to 2500 psig

a. See section 7.1 for definitions of engineered safety features actuation system response time and accuracy.

b. Total time from step change in containment pressure until full containment spray is obtained is 94 s (includes 29 s for diesel start and sequencing and 65 s for filling the spray header).

c. Total time from step change in steam pressure until steam line isolation valves are fully closed.

d. Total time from step change in pressurizer pressure until start of safety injection pumps is 27 s with offsite power available and 40 s with offsite power unavailable.

TABLE 7.3.1-6 (SHEET 1 OF 6)

ENGINEERED SAFETY FEATURES RESPONSE ITEMS

INITIATION SIGNAL AND FUNCTION		RESPONSE TIME IN SECONDS
1.	Manual Initiation	
a.	Safety Injection (ECCS)	N/A
	Feedwater Isolation	N/A
	Component Cooling Water	N/A
	Containment Cooling Fans	N/A
	Nuclear Service Cooling Water	N/A
	Containment Ventilation Isolation	N/A
b.	Containment Spray	N/A
c.	Phase "A" Isolation	N/A
d.	Auxiliary Feedwater	N/A
e.	Steam Line Isolation	N/A
f.	Control Room Ventilation Emergency Mode Actuation	N/A
g.	Reactor Trip	N/A
h.	Start Diesel Generators	N/A
2.	Containment Pressure--High-1	
a.	Safety Injection (ECCS)	$\leq 39^{(1)}/27^{(5)}$
b.	Reactor Trip (from SI)	≤ 2
c.	Feedwater Isolation	≤ 7
d.	Phase "A" Isolation	$\leq 2^{(6)}$

TABLE 7.3.1-6 (SHEET 2 OF 6)

INITIATION SIGNAL AND FUNCTION		RESPONSE TIME IN SECONDS
e.	Containment Ventilation Isolation	≤ 1.5[6]
f.	Auxiliary Feedwater	≤ 60
g.	Nuclear Service and Component Cooling Water	≤ 100[1]/88.5[2]
h.	Containment Cooling Fans	≤ 48[1]/36.5[2]
i.	Control Room Ventilation Emergency Mode Actuation	69.3[12]/99.3[13]
j.	Start Diesel Generators	≤ 13.5[7]
3.	Pressurizer Pressure--Low	
a.	Safety Injection (ECCS)	≤ 39[1]/27[5]
b.	Reactor Trip (from SI)	≤ 2
c.	Feedwater Isolation	≤ 7
d.	Phase "A" Isolation	≤ 2[6]
e.	Containment Ventilation Isolation	≤ 1.5[6]
f.	Auxiliary Feedwater	≤ 60
g.	Nuclear Service and Component Cooling Water	≤ 100[1]/88.5[2]
h.	Containment Cooling Fans	≤ 48[1]/36.5[2]
i.	Control Room Ventilation Emergency Mode Actuation	69.3[12]/99.3[13]
j.	Start Diesel Generators	≤ 13.5[7]
4.	Steam Line Pressure--Low	
a.	Safety Injection (ECCS)	≤ 39[1]/27[5]

TABLE 7.3.1-6 (SHEET 3 OF 6)

INITIATION SIGNAL AND FUNCTION		RESPONSE TIME IN SECONDS
b.	Reactor Trip (from SI)	≤ 2
c.	Feedwater Isolation	≤ 7
d.	Phase "A" Isolation	$\leq 2^{(6)}$
e.	Containment Ventilation Isolation	$\leq 1.5^{(6)}$
f.	Auxiliary Feedwater	≤ 60
g.	Nuclear Service and Component Cooling Water	$\leq 100^{(1)}/88.5^{(2)}$
h.	Containment Cooling Fans	$\leq 48^{(1)}/36.5^{(2)}$
i.	Control Room Ventilation Emergency Mode Actuation	$69.3^{(12)}/99.3^{(13)}$
j.	Start Diesel Generators	$\leq 13.5^{(7)}$
k.	Steam Line Isolation	$\leq 10^{(3)}$
5.	Containment Pressure--High-3	
	Containment Spray	$\leq 82.5^{(2)}/94^{(1)}$
6.	Containment Pressure--High-2	
	Steam Line Isolation	$\leq 10^{(3)}$
7.	Steam Line Pressure — Negative Rate—High	
	Steam Line Isolation	$\leq 10^{(3)}$
8.	Steam Generator Water Level--High-High	
a.	Turbine Trip	N/A
b.	Feedwater Isolation	≤ 7

TABLE 7.3.1-6 (SHEET 4 OF 6)

INITIATION SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
9. Steam Generator Water Level--Low-Low	
a. Motor-Driven Auxiliary Feedwater Pumps	≤ 60
b. Turbine-Driven Auxiliary Feedwater Pump	≤ 60
10. Loss of or Degraded 4.16 kV ESF Bus Voltage	
Auxiliary Feedwater	≤ 60(14)
11. Trip of All Main Feedwater Pumps	
Motor Driven Pumps	N/A
Auxiliary Feedwater	N/A
12. RWST Level—Low-Low Coincident with Safety Injection	N/A
a. Semi-Automatic Switchover to Containment Emergency Sump	≤ 60
13. Loss of Power	
a. 4.16 kV ESF Bus Undervoltage-Loss of Voltage; Start Signal to Diesel Generator	≤ 2.0(9)
b. 4.16 kV ESF Bus Undervoltage – Grid Degraded Voltage; Start Signal to Diesel Generator	≤ 21.2(10)
14. Control Room Intake Radiogas	
Control Room Ventilation Emergency Mode Actuation	≤ 72.0(15)/102.0(16)
15. Containment Radioactivity	
a. Area Radiation Low Range- Containment Ventilation Isolation	≤ 5(8, 11)
b. Containment Ventilation Radiation-Containment Ventilation Isolation	≤ 5(8, 11)

TABLE 7.3.1-6 (SHEET 5 OF 6)

INITIATION SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
16. Fuel Handling Building Exhaust Duct Radiation	
a. Fuel Handling Building Post Accident Ventilation Actuation	N/A

TABLE 7.3.1-6 (SHEET 6 OF 6)

TABLE NOTATIONS

(1) Time to full ECCS flow. Signal sensing, diesel generator starting, and sequencer loading delays included.

(2) Diesel generator starting delay not included. Offsite power available.

(3) Electrohydraulic or system media actuated valves.

(4) Deleted.

(5) Time to full ECCS flow. Diesel generator starting delay not included.

(6) Does not include valve closure time.

(7) Signal sensing, diesel generator starting and diesel generator breaker delay included.

(8) Does not include valve closure time and relates to post-accident radiation sources as specified in FSAR subsection 15.7.4.

(9) The response time shall include the time delay associated with the loss of voltage relays plus the delay associated with operation of the respective SF sequencer output relays.

(10) The response time shall include the time delay associated with the undervoltage relays plus the delay associated with operation of the respective SF sequencer output relays.

(11) Radiation detectors time response not included.

(12) Signal sensing, sequencer loading, and flow establishment delays included for the train B lead filter unit.

(13) Signal sensing, sequencer loading, train B lead fan failure, and flow establishment delays included for the train A lag filter unit.

(14) For loss of voltage, the response time begins when the loss of voltage trip setpoint of Surveillance Requirement (SR) 3.3.5.2.A has been exceeded. For degraded voltage, the response time begins when the degraded voltage trip setpoint of SR 3.3.5.2.B has been exceeded continuously for the time delay specified in SR 3.3.5.2.B.

(15) Signal sensing and flow establishment delays included for the train B lead filter unit. Response time criteria permit detection of degradation; however, analysis of record allows up to 138 s.

(16) Signal sensing, train B lead fan failure and flow establishment delays included for the train A lag filter unit. Response time permits detection of degradation; however, analysis of record allows up to 138 s.

TABLE 7.3.1-7 (SHEET 1 OF 2)

ENGINEERED SAFETY FEATURES ALLOCATION TIMES

Function	Sensor	Time	7300/NIS String	Time	SSPS Relays	Time
CNMT PRESS HI-1	Barton 764/351	1.0 s	NLP+NAL	65 ms	Input+Master+Slave	88 ms
CNMT PRESS HI-2	Barton 764/351	1.0 s	NLP+NAL	65 ms	Input+Master+Slave	88 ms
CNMT PRESS HI-3	Barton 764/351	1.0 s	NLP+NAL	65 ms	Input+Master+Slave	88 ms
STEAMLINE PRESS LO	Tobar 32PA	200 ms	NLP+NAL	65 ms	Input+Master+Slave	88 ms
	Veritrak 76PG	200 ms				
	Rosemount 1154SH9	200 ms				
	Rosemount 1153GB9	200 ms				
STEAMLINE HI NEG RATE	Tobar 32PA	200 ms	NLP+NAL	65 ms	Input+Master+Slave	88 ms
	Veritrak 76PG	200 ms				
	Rosemount 1154SH9	200 ms				
	Rosemount 1153GB9	200 ms				
PZR PRESS LO SI	Tobar 32PG	200 ms	NLP+NAL	65 ms	Input+Master+Slave	88 ms
	Veritrak 76PH	200 ms				
	Rosemount 1154SH9	200 ms				
RWST LEVEL LO-LO	Tobar 32DP	400 ms	NLP+NAL	65 ms	Input+Master+Slave	88 ms
	Veritrak 76DP	400 ms				
	Rosemount 1153DB5	200 ms				
SG LEVEL LO-LO	Tobar 32DP	400 ms	NLP+NAL	65 ms	Input+Master+Slave	88 ms
	Veritrak 76DP	400 ms				
	Rosemount 1154DH5	200 ms				

TABLE 7.3.1-7 (SHEET 2 OF 2)

Function	Sensor	Time	7300/NIS String	Time	SSPS Relays	Time
SG LEVEL HI-HI	Tobar 32DP	400 ms	NLP+NAL	65 ms	Input+Master+Slave	88 ms
	Veritrak 76DP	400 ms				
	Rosemount 1154DH5	200 ms				
CNMT AREA RADIATION LEVEL HI	Westinghouse	(1)	N/A	N/A	Input+Master+Slave	88 ms
CNMT VENT RADIATION LEVEL HI	Westinghouse	(1)	N/A	N/A	Input+Master+Slave+Slave	124 ms

Note 1: Allocated sensor times are not used for these variables. These components will continue to be tested as required.

Allocated sensor times are derived from method (3), section (9), WCAP-13632, revision 2 (Vendor Engineering Specifications). Tobar, Veritrak, and Barton times were provided in Table 9-1. Rosemount times are from Rosemount manuals 4302 and 4631. The Rosemount response time specifications may also be found in NUREG/CR-5383. Transmitter FMEAs are based upon EPRI report NP-7243, revision 1.

Values for 7300 cards are from tables 4-7 through 4-12 of WCAP-14036, revision 1. Cards installed are 4NCH, 4NRA, 6NLP, 4NSA, and 9NAL or older artwork levels.

SSPS input and master relays are Potter & Brumfield KH series relays. SSPS slave relays are Potter & Brumfield MDR relays. Values are tabulated from section 4.8, Westinghouse SSPS FMEA.

TABLE 7.3.3-1 (SHEET 1 OF 2)

CONTAINMENT COMBUSTIBLE GAS CONTROL SYSTEM
ACTUATED EQUIPMENT LIST[a]

Description	Actuating Train A	Actuating Train B
Post-LOCA purge exhaust inside valve	X	
Post-LOCA purge exhaust inside valve		X
Containment hydrogen monitor A supply inside valves	X	
Containment hydrogen monitor B supply inside valves		X
Containment hydrogen monitor A supply outside valve		X
Containment hydrogen monitor B supply outside valve	X	
Containment hydrogen monitor A supply return valve		X
Containment hydrogen monitor B supply return valve	X	
Containment cooler fan 1	X	
Containment cooler fan 2	X	
Containment cooler fan 3		X
Containment cooler fan 4		X
Containment cooler fan 5	X	
Containment cooler fan 6	X	
Containment cooler fan 7		X
Containment cooler fan 8		X
Containment hydrogen thermal recombiner 1	X	

TABLE 7.3.3-1 (SHEET 2 OF 2)

Description	Actuating Train A	Actuating Train B
Containment hydrogen thermal recombiner 2		X
Post-LOCA cavity purge system fan 1	X	
Post-LOCA cavity purge system fan 2		X

a. Additional details are provided on the electrical schematic diagrams and the control logic diagrams referenced in section 1.7.

TABLE 7.3.4-1

CONTAINMENT PURGE ISOLATION SYSTEM ACTUATED DEVICES[a]

Containment post-loss-of-coolant accident (post-LOCA) purge isolation valve, Train A, inside reactor containment (IRC)	HV-2624A
Containment post-LOCA purge isolation valve, Train B, IRC	HV-2624B
Containment preaccess purge supply valve, Train A, IRC	HV-2626A
Containment minipurge supply valve, Train A, IRC	HV-2626B
Containment preaccess purge supply valve, Train B, outside reactor containment (ORC)	HV-2627A
Containment minipurge supply valve, Train B, ORC	HV-2627B
Containment preaccess purge exhaust valve, Train A, IRC	HV-2628A
Containment minipurge exhaust valve, Train A, IRC	HV-2628B
Containment preaccess purge exhaust valve, Train B, ORC	HV-2629A
Containment minipurge exhaust valve, Train B, ORC	HV-2629B

a. Refer to appropriate logic diagrams for additional actuated devices.

TABLE 7.3.5-1

FUEL HANDLING BUILDING VENTILATION POST-ACCIDENT ACTUATED EQUIPMENT[a]

Description	Actuating Train
Emergency HVAC system fan motor A-1542-N7-001-M01	A
Emergency HVAC system fan motor A-1542-N7-002-M01	B
Emergency HVAC system inlet damper HV-12510	A
Emergency HVAC system inlet damper HV-12511	B
Emergency HVAC system discharge damper HV-12512	A
Emergency HVAC system discharge damper HV-12513	B
Normal HVAC system supply isolation HV-2528	B
Normal HVAC system supply isolation HV-2529	A
Normal HVAC system supply isolation HV-2534	B
Normal HVAC system supply isolation HV-2535	A
Normal HVAC system exhaust isolation HV-12479	A
Normal HVAC system exhaust isolation HV-12480	B
Normal HVAC system to equipment building isolation HV-12481	A
Normal HVAC system to equipment building isolation HV-12482	B

a. Refer to appropriate logic diagrams for additional actuated devices.

TABLE 7.3.6-1

CONTROL ROOM VENTILATION ISOLATION CONTROL SYSTEM
MONITOR SENSITIVITIES AND RESPONSE TIMES

Type	Concentration Setpoint for Isolation		Limiting Isotope	Response Time
	μmCi/cm^3	ppm		
Gaseous Radioactivity	$3x10^{-6}$	-	Kr 85	(a)
Smoke	-	-	-	Manual actuation

a. Response time is radiation-level dependent.

TABLE 7.3.6-2

CONTROL ROOM VENTILATION ISOLATION CONTROL SYSTEM ACTUATED EQUIPMENT LIST[a]

Description	Actuation Channel or Train
Control room (CR) filter unit fan motor (1-1531-N7-001-M01)	A
CR filter unit fan motor (1-1531-N7-002-M01)	B
Emergency supply outlet damper HV-12128	A
Emergency supply outlet damper HV-12129	B
Emergency return fan motor (1-1531-B7-005-M01)[b]	A
Emergency return fan motor (1-1531-B7-006-M01)[b]	B
Emergency return air damper HV-12130	A
Emergency return air damper HV-12131	B
Outside air isolation damper HV-12114[c]	A
Outside air isolation damper HV-12115[c]	B
Normal CR A/C unit fan motor A-1531-A7-001-M01	Nontrain
Normal CR A/C unit fan motor A-1531-A7-002-M01	Nontrain
Normal CR A/C unit inlet damper HV-12143	Nontrain
Normal CR A/C unit inlet damper HV-12144	Nontrain
Normal CR A/C unit discharge damper 1HV-12146	A
Normal CR A/C unit discharge damper 1HV-12147	B
Normal CR A/C unit return air 1HV-12148	B
Normal CR A/C unit return air 1HV-12149	A
CR kitchen, toilet, and conference room exhaust fan motor A-1531-B7-008-M01	Nontrain
CR kitchen, toilet, etc., fan inlet damper HV-12162	A
CR kitchen, toilet, etc., fan inlet damper HV-12163	B
Normal CR A/C unit discharge damper 2HV-12146	A
Normal CR A/C unit discharge damper 2HV-12147	B
Normal CR A/C unit return damper 2HV-12148	B
Normal CR A/C unit return damper 2HV-12149	A
Normal CR A/C return and exhaust fan motor A-1531-B7-009-M01	Nontrain
Normal CR A/C return and exhaust fan motor A-1531-B7-010-M01	Nontrain

a. Refer to appropriate logic diagrams for additional actuated devices.
b. Return air fans are disabled and abandoned in place as their function is not required.
c. Manual actuation only.

TABLE 7.3.8-1 (SHEET 1 OF 2)

MAIN STEAM, MAIN STEAM BYPASS, AND MAIN FEEDWATER AND FEEDWATER BYPASS ISOLATION ACTUATED DEVICES[a]

	Train
Main steam isolation valve HV-3006A SG 001	A
Main steam isolation valve bypass isolation valve HV-13005A SG 001	A
Main steam isolation valve HV-3006B SG 001	B
Main steam isolation valve bypass isolation valve HV-13005B SG 001	B
Main steam isolation valve HV-3016A SG 002	A
Main steam isolation valve bypass isolation valve HV-13007A SG 002	A
Main steam isolation valve HV-3016B SG 002	B
Main steam isolation valve bypass isolation valve HV-13007B SG 002	B
Main steam isolation valve HV-3026A SG 003	A
Main steam isolation valve bypass isolation valve HV-13008A SG 003	A
Main steam isolation valve HV-3026B SG 003	B
Main steam isolation valve bypass isolation valve HV-13008B SG 003	B
Main steam isolation valve HV-3036A SG 004	A
Main steam isolation valve bypass isolation valve HV-13006A SG 004	A
Main steam isolation valve HV-3036B SG 004	B
Main steam isolation valve bypass isolation valve HV-13006B SG 004	B
Main feedwater isolation valve HV-5227 SG 001	A and B
Main feedwater isolation valve HV-5228 SG 002	A and B

TABLE 7.3.8-1 (SHEET 2 OF 2)

	Train
Main feedwater isolation valve HV-5229 SG 003	A and B
Main feedwater isolation valve HV-5230 SG 004	A and B
Main feedwater isolation bypass valve HV-15196 SG 001	A and B
Main feedwater isolation bypass valve HV-15197 SG 002	A and B
Main feedwater isolation bypass valve HV-15198 SG 003	A and B
Main feedwater isolation bypass valve HV-15199 SG 003	A and B
Main feedwater regulating valve FV-0510 SG 001	A and B
Main feedwater regulating valve FV-0520 SG 002	A and B
Main feedwater regulating valve FV-0530 SG 003	A and B
Main feedwater regulating valve FV-0540 SG 004	A and B
Bypass feedwater regulating valve LV-5243 SG 001	A and B
Bypass feedwater regulating valve LV-5244 SG 002	A and B
Bypass feedwater regulating valve LV-5245 SG 003	A and B
Bypass feedwater regulating valve LV-5242 SG 004	A and B

a. Refer to appropriate logic diagrams for additional actuated devices.

TABLE 7.3.9-1

NSCW ACTUATED DEVICES[a]

		Train
1.	NSCW pump 1-1202-P4-001-M01	A
2.	NSCW pump 1-1202-P4-002-M01	B
3.	NSCW pump 1-1202-P4-003-M01	A
4.	NSCW pump 1-1202-P4-004-M01	B
5.	NSCW pump 1-1202-P4-005-M01	A
6.	NSCW pump 1-1202-P4-006-M01	B
7.	NSCW pump 1-1202-P4-007-M01	B
8.	NSCW pump 1-1202-P4-008-M01	A
9.	NSCW fan 1-1202-W4-001-F01	A
10.	NSCW fan 1-1202-W4-002-F01	B
11.	NSCW fan 1-1202-W4-001-F02	A
12.	NSCW fan 1-1202-W4-002-F02	B
13.	NSCW fan 1-1202-W4-001-F03	A
14.	NSCW fan 1-1202-W4-002-F03	B
15.	NSCW fan 1-1202-W4-001-F04	A
16.	NSCW fan 1-1202-W4-002-F04	B

a. Refer to appropriate logic diagrams for additional actuated devices.

TABLE 7.3.10-1

COMPONENT COOLING WATER SYSTEM
ACTUATED DEVICES[a]

	Train
Component cooling water pump 1-1203-04-001	A
Component cooling water pump 1-1203-04-003	A
Component cooling water pump 1-1203-04-005	A
Component cooling water pump 1-1203-04-002	B
Component cooling water pump 1-1203-04-004	B
Component cooling water pump 1-1203-04-006	B

a. Refer to appropriate logic diagrams for additional actuated devices.

TABLE 7.3.11-1

CONTAINMENT HEAT REMOVAL SYSTEM ACTUATED DEVICES[a]

Component	Train
Containment building cooling unit fan 1-1501-A7-001-M001	A
Containment building cooling unit fan 1-1501-A7-002-M01	A
Containment building cooling unit fan 1-1501-A7-003-M01	B
Containment building cooling unit fan 1-1501-A7-004-M01	B
Containment building cooling unit fan 1-1501-A7-005-M01	A
Containment building cooling unit fan 1-1501-A7-006-M01	A
Containment building cooling unit fan 1-1501-A7-007-M01	B
Containment building cooling unit fan 1-1501-A7-008-M01	B

a. Refer to appropriate logic diagrams for additional actuated devices.

TABLE 7.3.12-1 (SHEET 1 OF 2)

CONTROL BUILDING ESF HVAC SYSTEM
ACTUATED EQUIPMENT LIST[(a)]

Description	Actuation Channel or Train
Control building safety feature electrical equipment ac unit fan motor (1-1532-A7-001-M01)	A
Control building safety feature electrical equipment ac unit fan motor (1-1532-A7-002-M01	B
Control building safety feature battery room exhaust fan motor (1-1532-B7-001-M01)	A
Control building safety feature battery room exhaust fan motor (1-1532-B7-003-M01)	A
Control building safety feature battery room exhaust fan discharge dampers (HV-12742)	A
Control building safety feature battery room exhaust fan discharge damper (HV-12748)	A
Control building safety feature battery room exhaust fan motor (1-1532-B7-002-M01)	B
Control building safety feature battery room exhaust fan motor (1-1532-B7-004-M01)	B
Control building safety feature battery room exhaust fan discharge damper (HV-12727)	B
Control building safety feature battery room exhaust fan discharge damper (HV-12749)	B

TABLE 7.3.12-1 (SHEET 2 OF 2)

Description	Actuation Channel or Train
Control building control room ESF chiller room exhaust fan motor (1-1531-B7-002-M01)	A
Control building control room ESF chiller room exhaust fan motor (1-1531-B7-004-M01)	B
Control building electrical penetration filter unit heater (1-1562-N7-001-H01)	A
Control building electrical penetration filter unit heater (1-1562-N7-002-H01)	B
Control building auxiliary relay room ESF air-conditioning unit fan motor (1-1539-A7-001-M01)	A
Control building auxiliary relay room ESF air-conditioning unit fan motor (1-1539-A7-002-M01)	B

a. Refer to appropriate logic diagrams for additional actuated devices.

TABLE 7.3.13-1 (SHEET 1 OF 2)

AUXILIARY BUILDING ESF HVAC SYSTEM
ACTUATED EQUIPMENT LIST[a]

Description	Actuation Channel or Train
Electrical switchgear and MCC room cooler motors:	
1-1555-A7-001-M01	A
1-1555-A7-002-M01	B
1-1555-A7-003-M01	A
1-1555-A7-004-M01	B
1-1555-A7-005-M01	A
1-1555-A7-006-M01	B
Residual heat removal pump room cooler motors:	
1-1555-A7-007-M01	A
1-1555-A7-008-M01	B
Containment spray pump room cooler motors:	
1-1555-A7-009-M01	A
1-1555-A7-010-M01	B
Component cooling water pump room cooler motors:	
1-1555-A7-011-M01	A
1-1555-A7-012-M01	B
Charging pump room cooler motors:	
1-1555-A7-013-M01	A
1-1555-A7-014-M01	B
Safety injection pump room cooler reactors:	
1-1555-A7-015-M01	A
1-1555-A7-016-M01	B
Spent fuel pool heat exchanger and pump room cooler motors:	

TABLE 7.3.13-1 (SHEET 2 OF 2)

Description	Actuation Channel or Train
1-1555-A7-017-M01	A
1-1555-A7-018-M01	B
Piping penetration room filtration and exhaust unit motors:	
1-1561-N7-001-M01	A
1-1561-N7-002-M01	B
Piping penetration room filtration and exhaust unit heaters:	
1-1561-N7-001-H01	A
1-1561-N7-002-H01	B
Piping penetration room filtration and exhaust unit dampers:	
HV-12614 and PV-2550A and PV-2550B	A
HV-12616 and PV-2551A and PV-2551B	B
Piping penetration area isolation dampers:	
HV-12605 (controlled by SO-V HY-12605)	A
HV-12606 (controlled by SO-V HY-12606)	B
HV-12604 (controlled by SO-V HY-12604)	A
HV-12607 (controlled by SO-V HY-12607)	B

a. Refer to appropriate logic diagrams for additional actuated devices.

TABLE 7.3.14-1

AUXILIARY FEEDWATER PUMPHOUSE ESF HVAC SYSTEM
ACTUATED EQUIPMENT LIST[a]

Description	Actuation Channel or Train
Motor-driven auxiliary feedwater pump A room air supply fan motor (1-1593-B7-001-M01)	A
Motor-driven auxiliary feedwater pump A room air shutoff damper (HV-12006)	A
Motor-driven auxiliary feedwater pump B room air supply fan motor (1-1593-B7-002-M01)	B
Motor-driven auxiliary feedwater pump B room air shutoff damper (HV-12005)	B
Turbine-driven auxiliary feedwater pump room air intake damper (HV-12010 controlled by HY-12010 solenoid valve)	C

a. Refer to appropriate logic diagrams for additional actuated devices.

TABLE 7.3.15-1 (Sheet 1 of 2)

DIESEL GENERATOR BUILDING ESF HVAC SYSTEM
ACTUATED EQUIPMENT LIST[a]

Description	Actuations Train or Channel
ESF supply fan motors:	
1-1566-B7-001-M01	A
1-1566-B7-002-M01	B
1-1566-B7-003-M01	A
1-1566-B7-004-M01	B
Recirculation dampers:	
TV-12100A (controlled by I/P converter TY-12100A)	A
TV-12100 (controlled by I/P converter TY-12100A)	A
TV-12101A (controlled by I/P converter TY-12101A)	B
TV-12101 (controlled by I/P converter TY-12101A)	B
Air intake dampers:	
TV-12094C (controlled by I/P converter TY-12094A)	A
TV-12094A (controlled by I/P converter TY-12094A)	A
TV-12094B (controlled by I/P converter TY-12094B)	A
TV-12094D (controlled by I/P converter TY-12094B)	A
TV-12095A (controlled by I/P converter TY-12095A)	B
TV-12095C (controlled by I/P converter TY-12095A)	B
TV-12095B (controlled by I/P converter TY-12095B)	B
TV-12095D (controlled by I/P converter TY-12095B)	B
Exhaust dampers:	
TV-12086 (controlled by SOL valve TY-12086)	A
TV-12086A (controlled by SOL valve TY-12086)	A
TV-12099 (controlled by SOL valve TY-12099)	B
TV-12099A (controlled by SOL valve TY-12099)	B
TV-12096 (controlled by SOL valve TY-12096)	A
TV-12096A (controlled by SOL valve TY-12096)	A
TV-12097 (controlled by SOL valve TY-12096)	A
TV-12097A (controlled by SOL valve TY-12096)	A
TV-12098 (controlled by SOL valve TY-12098)	B
TV-12098A (controlled by SOL valve TY-12098)	B
TV-12085 (controlled by SOL valve TY-12098)	B
TV-12085A (controlled by SOL valve TY-12098)	B

TABLE 7.3.15-1 (Sheet 2 of 2)

DIESEL GENERATOR BUILDING ESF HVAC SYSTEM
ACTUATED EQUIPMENT LIST[a]

Description	Actuations Train or Channel
Non-ESF fan unit isolation dampers:	
HV-12052	A
HV-12055	B
ESF supply fan discharge dampers:	
HV-12050	A
HV-12051	A
HV-12053	B
HV-12054	B

a. Refer to appropriate logic diagrams for additional actuated devices.

TABLE 7.3.16-1

ELECTRICAL TUNNEL ESF HVAC SYSTEM
ACTUATED EQUIPMENT LIST[a]

Description	Actuation Train or Channel
Diesel power cable tunnel exhaust fan motors:	
1-1540-B7-001-M01	A
1-1540-B7-002-M01	B
NSCW tower cable tunnel exhaust fan motors:	
1-1540-B7-003-M01	A
1-1540-B7-004-M01	B
Turbine building and auxiliary building exhaust fan motor:	
2-1540-B7-005-M01 (Unit 2 only)	A
1-1540-B7-005-M01 (Unit 1 only)	A

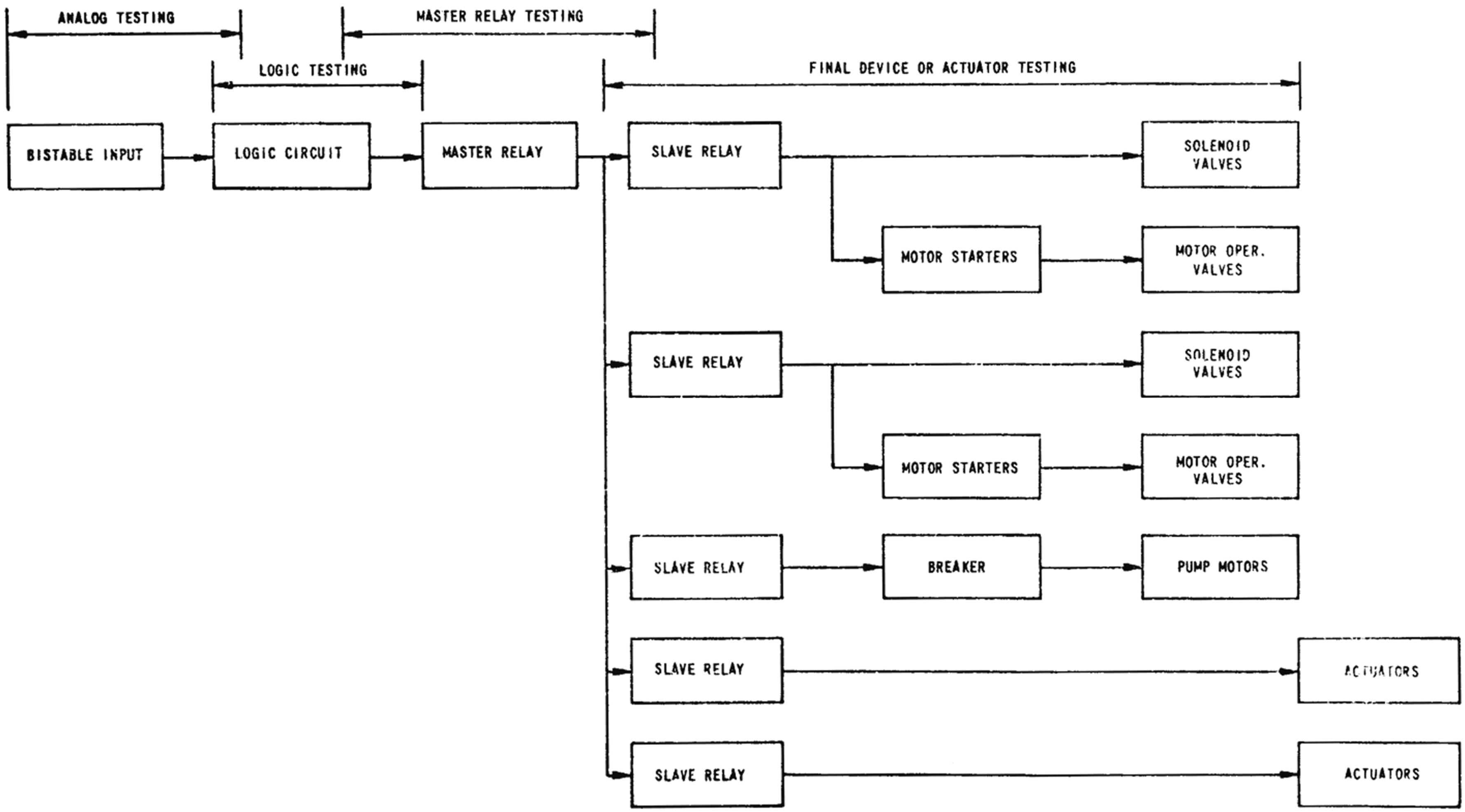
a. Refer to appropriate logic diagrams for additional actuated devices.

TABLE 7.3.17-1

DIESEL GENERATOR FUEL OIL SYSTEM
ACTUATED EQUIPMENT LIST[a]

Description	Actuation Train or Logic
Diesel fuel oil storage tank pumps:	
1-2403-P4-001	A
1-2403-P4-002	A
1-2403-P4-003	B
1-2403-P4-004	B

a. Refer to appropriate logic diagrams for additional actuated devices.



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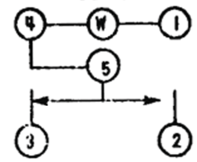
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

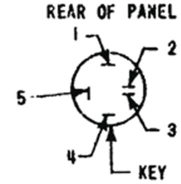
TYPICAL ENGINEERED SAFETY FEATURES TEST CIRCUITS

FIGURE 7.3.1–1



ILLUMINATED PUSHBUTTON SWITCH
WITH 28V LAMP NO. 327
(EXCEPT AS NOTED)

REAR OF PANEL



CONTACT LOCATION SCHEME

GENERAL NOTES: *

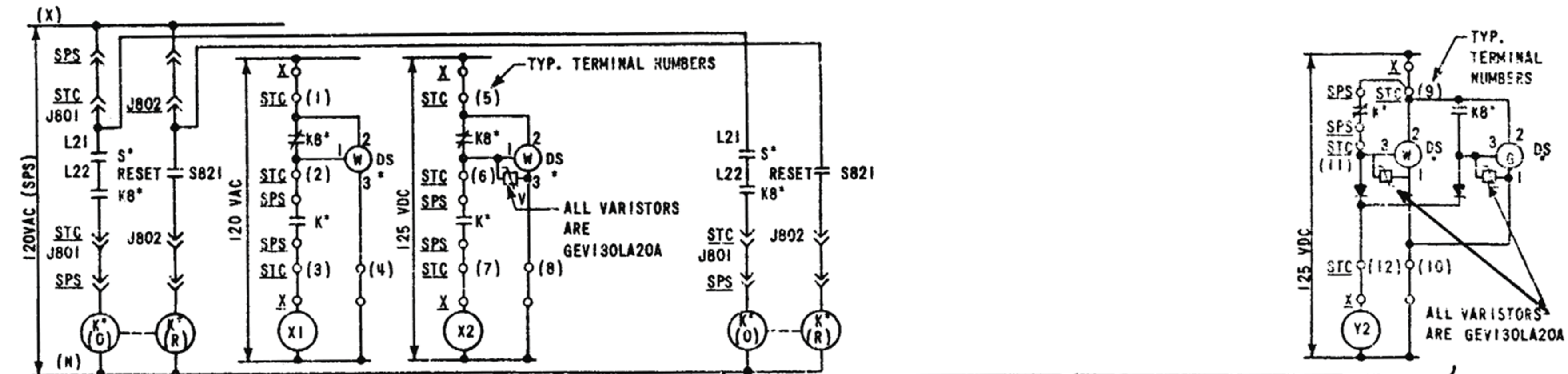
1. CIRCUITRY AND HARDWARE FOR REDUNDANT PROTECTION TRAINS "A" AND "B" TEST CABINETS ARE DUPLICATE EXCEPT AS NOTED
   - A - TRAIN "A" ONLY
   - B - TRAIN "B" ONLY
2. IN DETAILS A & B THE SYMBOL * REPRESENTS THE SUFFIX NUMBERS OF THE DEVICE REFERENCED.

   EXAMPLE:

   K* - SPS RELAY, K601, K602, ETC.
   K(O) - OPERATING COIL
   K(R) - RESET COIL
   S* - STC TEST SWITCH, S802, S834 ETC.
   K8* - STC RELAY, K811, K817, ETC.
   DS* - STC LIGHT, DS8C09, DS8077, ETC.
3. "DETAIL A" & "B" TYPE CIRCUITS ARE DETAILED ON THE SCHEMATICS. "DETAIL B" CIRCUITS WILL BE SUBSTITUTED FOR "DETAIL A" CIRCUITS WHERE REQUIRED.

LOCATION LEGEND

SPS - SOLID STATE PROTECTION SYSTEM
STC - SAFEGUARDS TEST CABINET
X - SWGR, MCC, AUXILIARY RELAY RACK, ETC.



DETAIL A TYPICAL PROTECTION ACTUATION CIRCUIT BLOCKING SCHEMES
(CONTACT CLOSURE FOR ACTUATION)

DETAIL B TYPICAL PROTECTION ACTUATION CIRCUIT BLOCKING SCHEMES
(CONTACT OPENING FOR ACTUATION)

*DETAILS A AND B OF THIS FIGURE ARE NOT TO BE CONFUSED WITH ALPHA DESIGNATION OF LOGIC TRAINS A AND B.

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SOUTHERN COMPANY *Energy to Serve Your World®*	**VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2**	ENGINEERED SAFEGUARDS TEST CABINET (INDEX, NOTES, AND LEGEND) FIGURE 7.3.1–2

7.4 SYSTEMS REQUIRED FOR SAFE SHUTDOWN

The functions necessary for safe shutdown are available through instrumentation and control channels associated with the major systems in both the primary and secondary plant. These channels are normally aligned to serve a variety of operational functions, including startup and shutdown, as well as protective functions. There are no systems specifically and solely dedicated as safe shutdown systems. However, procedures for securing and maintaining the plant in a safe condition can be instituted by appropriate alignment of selected plant systems. The discussion of these systems, together with the applicable codes, criteria, and guidelines, is found in other sections of this safety analysis report. In addition, the alignment of systems associated with the engineered safety features, which are invoked under postulated limiting fault situations, is discussed in section 6.3, paragraphs 7.3.1.1.1.1 and 7.3.1.1.1.5, and tables 7.3.1-1, 7.3.1-2, and 7.3.1-3. In the event of a turbine or reactor trip, the plant is placed in a hot standby condition. During the hot standby condition, an adequate heat sink is provided to remove reactor core residual heat. Boration capability is provided to compensate for xenon decay and to maintain the required core shutdown margin. Redundancy of systems and components is provided to enable continued maintenance of the hot standby condition. Redundant systems and components exist for taking the plant to the cold shutdown condition, if required.

The instrumentation and control systems required to be aligned for maintaining safe shutdown of the reactor, which are discussed in this section, are the minimum needed under nonaccident conditions. These systems permit the necessary operations that:

- Prevent the reactor from returning to criticality.
- Provide an adequate heat sink so that design and safety limits on reactor coolant system (RCS) temperature and pressure are not exceeded.

The designation of systems required for safe shutdown depends on identifying those systems which provide the following capabilities for maintaining a safe shutdown:

- Coolant circulation.
- Boration.
- Heat removal.
- Depressurization.

The specific systems, together with the necessary associated instrumentation and controls, are identified for both hot standby and cold shutdown in subsections 7.4.1 and 7.4.2. Table 7.4.1-1 tabulates systems available for safe shutdown.

Maintenance of a shutdown with these systems and associated instrumentation and controls has included consideration of the accident consequences that might jeopardize safe shutdown conditions. The accident consequences that are germane are those that would tend to degrade the capabilities for coolant circulation, boration, heat removal, and depressurization.

The results of the accident analysis are presented in chapter 15. Of these, the following produce consequences that might jeopardize safe shutdown conditions:

- Chemical and volume control system malfunction that results in a decrease in the boron concentration in the reactor coolant (uncontrolled boron dilution) (15.4.6).
- Loss of normal feedwater flow (15.2.7).
- Loss of external electrical load and/or turbine trip (15.2.2 and 15.2.3).
- Loss of offsite ac power to the station auxiliaries (15.2.6).

These analyses show that safety is not adversely affected by these incidents, with the associated assumptions being that one train of the instrumentation and controls discussed in subsections 7.4.1 and 7.4.2 are available to control and/or monitor shutdown. These required systems will allow the maintenance of safe shutdown even under the accident conditions listed above, which would tend toward a return to criticality or a loss of heat sink.

In addition to the operation of systems required for safe shutdown, as described below, the following are assumed:

- The turbine is tripped. (Note that this can be accomplished at the turbine as well as inside the control room.)
- The reactor is tripped. (Note that this can be accomplished at the shutdown panels as well as inside the control room.)
- All automatic systems continue functioning as long as offsite power and the plant compressed air system are available. With a loss of either, components relying on these systems are assumed to take their fail-safe position unless failure to do so is the most limiting single failure.

7.4.1 HOT STANDBY

To effect a unit shutdown, the unit is initially brought to a hot standby condition under control from the main control room or the shutdown panels. Hot standby is defined as the condition in which the reactor is subcritical (K_{eff} <0.99) and the RCS temperature and pressure are in the normal operating range. To accomplish a hot standby, the following functions are required: coolant circulation, boration, and heat removal. The portions of the reactor trip system required to achieve the shutdown condition are described in section 7.2. The system and component controls and monitoring indicators provided on the shutdown panels are listed in subsection 7.4.3. The minimum controls and monitoring indicators required to maintain a hot standby under a nonaccident condition are tabulated and discussed below. Table 7.4.2-1 lists the instrumentation and controls available for hot standby and hot or cold shutdown and provides the location of controls and indication.

A. Required Systems and Component Controls

   1. Auxiliary feedwater system.
   2. Condensate storage facility.
   3. Main steam power-operated atmospheric relief valves.
   4. Centrifugal charging pumps.
   5. Nuclear service cooling water (NSCW) pumps.

6. NSCW fans.
7. Component cooling water pumps.
8. Containment fan coolers.
9. Emergency diesel generators (and associated onsite electrical distribution system).
10. Control room ventilation.
11. Emergency ventilation systems for those areas housing equipment required for safe shutdown.
12. Essential chilled water.

B. Required Monitoring Indicators

1. Steam generators
   - Water level for each steam generator.
2. Pressurizer
   - Water level.
3. Reactor Coolant System
   - Hot leg temperatures.
   - Cold leg temperatures.
   - Pressure.

7.4.1.1 Auxiliary Feedwater Control

The auxiliary feedwater pumps start automatically as described in subsection 7.3.7 or can be started manually. Start/stop motor controls are located at the shutdown panels (trains A and B) and the turbine-driven pump auxiliary feedwater local panel (train C), as well as at the main control board. Control of the motor-operated valves in the auxiliary feedwater system is provided at the shutdown panels, auxiliary feedwater local panel, and the main control board.

7.4.1.2 Power-Operated Atmospheric Steam Relief Valves

7.4.1.2.1 Description

The instrumentation and controls for the atmospheric steam relief system consist of controls, transmitters, and indicators to provide automatic or manual actuation of the power-operated atmospheric steam relief valves to remove decay heat from the RCS.

Both the main steam safety valves and the power-operated atmospheric steam relief valves are located upstream of the main steam isolation valves, outside of the containment; and both provide a means of removing decay heat in a hot standby condition. The safety valves are full-capacity, spring-loaded valves actuated by high main steam line pressure. They are described more fully in chapter 10. The power-operated atmospheric steam relief valves, however, are the preferred mode of steam relief to avoid prolonged operation of the safety valves. The power-operated portion of the relief system is safety related, except as specifically noted otherwise in paragraph I below.

A pressure transmitter and pressure controller are provided for each of the steam generators to actuate the power-operated atmospheric steam relief valve and control the steam pressure at a predetermined setting. Manual control capability is provided both in the control room and on the shutdown panels for power-operated atmospheric steam relief valve regulation. The status of the power-operated atmospheric steam relief valves is indicated by open and closed indicating lights and by the controller output indication provided in the main control room and on the shutdown panels.

A. Initiating Circuits

No initiating circuits are required for the self-actuated, spring-loaded safety valves. Each power-operated atmospheric steam relief valve is automatically actuated to regulate the steam generator pressure via the pressure controller and can be manually actuated by selecting the manual control mode. The required instrumentation readout for manual system control is described in section 7.5.

B. Logic

No logic is required for the spring-loaded safety valves. Each power-operated atmospheric steam relief valve is individually controlled by its own pressure control loop. Normally atmospheric steam relief valve operation is automatic, but it may be operated manually.

C. Bypass

No bypass is provided. Placement of the power- operated atmospheric steam relief valve controller in the manual mode does not preclude the steam relief functional requirement, since the spring-loaded safety valves provide the code-required relief capability.

D. Interlock

No interlock is provided for the power-operated atmospheric steam relief valve system.

E. Redundancy

Any one of the four power-operated atmospheric steam relief valves provides sufficient steam relief for hot shutdown requirements. Redundancy is accomplished on a system basis, since any one of the four associated steam generators is adequate for the heat removal requirements.

F. Diversity

Diversity is accomplished by the spring-loaded safety valves operating as backup to the power-operated atmospheric steam relief valves.

G. Actuated Devices

The safety valves are self-actuated.

The power-operated atmospheric steam relief valves are electrohydraulic valves designed to fail closed.

H. Supporting Systems

The controls and power for the power-operated atmospheric steam relief valves are powered from the Class 1E power system (chapter 8).

I. Portion of System Not Required for Safety

The alarms to the station annunciator and computer are not required for safety.

J. Design Bases Information

The design bases of the power-operated atmospheric steam relief system (in accordance with Section 3 of Institute of Electric and Electronic Engineers (IEEE) Standard 279-1971) are:

1. The plant condition which requires protective action is hot standby heat removal at controlled steam generator pressure, with or without loss of offsite power.
2. The equipment is located outside the containment and is designed to withstand the temperature range, relative humidity, and atmospheric pressure for that location. (Refer to table 3.11.B.1-1 for specific values.)
3. The power-operated atmospheric steam relief system is designed to withstand the effects of earthquake without loss of function. The system is designed and its components are physically located to prevent loss of function from missile damage.
4. The power-operated atmospheric steam relief controls are analog in nature, and the response of conventional process control equipment adjusted for stable pressure controlling operation is adequate. The power-operated atmospheric steam relief valves are not intended to prevent safety valve operation when the turbine bypass system is not available. The requirement is for the power-operated steam relief valves to relieve the safety valves from a sustained pressure-controlling function in the hot standby mode. Thus, response time and accuracy are not critical for the required performance. The steam generator pressure will be relatively constant (no load steam pressure), with no rapid change required in the mass flowrate from the atmospheric steam relief valves.

7.4.1.2.2 Analysis

A. Conformance to Nuclear Regulatory Commission (NRC) General Design Criteria (GDC)

1. GDC 13 and 19

   Instrumentation necessary to monitor station variables associated with hot standby is provided with adequate indication in the main control room and on the shutdown panels. Controls for the power-operated atmospheric steam relief are provided at each location. A description of the surveillance instrumentation is provided in section 7.5.

2. GDC 34

   The power-operated atmospheric steam relief valves provide an adequate means of venting the steam generators to remove reactor decay heat following reactor trip. Modulation of the power-operated atmospheric steam relief valves provides the desired rate of heat removal from the RCS to maintain the hot standby condition. The power-operated atmospheric steam relief system has sufficient redundancy to ensure its intended function, assuming a single failure.

B. Conformance to NRC Regulatory Guides

1. Regulatory Guide 1.22

   The power-operated atmospheric steam relief controls can be tested periodically.

2. Regulatory Guide 1.29

   The power-operated atmospheric steam relief controls are designed to withstand the effects of a safe shutdown earthquake (SSE) without loss of function. The power-operated atmospheric steam relief controls are classified Seismic Category 1, in accordance with the guide.

C. Conformance to IEEE Standard 279-1971

The controls for the power-operated atmospheric steam relief system conform to the applicable requirements of IEEE Standard 279-1971. The control circuits are designed so that any single failure will not prevent proper protective action (removal of reactor decay heat) when required. This is accomplished by redundant steam relief systems in that only one of the four valves is needed to provide sufficient capacity. The power-operated atmospheric relief valves utilize control power from independent Class 1E power systems. The controllers for the valves are powered from separate independent Class 1E control channels. In order to prevent interaction between the redundant systems, the control channels are wired independently and separated with no electrical connections between them.

D. Conformance to Other Criteria and Standards

Conformance to other criteria and standards is given in table 7.1.1-1.

7.4.1.3 Centrifugal Charging System Controls

7.4.1.3.1 Description

If the unit is maintained in a hot standby condition for a prolonged time, a centrifugal charging pump is required to maintain the reactor coolant inventory so that the level in the pressurizer is maintained above the heaters and to borate to compensate for xenon decay. At the time the charging pump is brought into operation to replenish the RCS, the boron concentration of the RCS may be increased, if desired. Normal operation of the charging system is automatic, as described in paragraph 7.7.1.6. Manual control is also provided both at the main control board and the shutdown panels. Control of major power-operated valves associated with establishing a charging path to the RCS is provided in the main control room and at the shutdown panels.

The following discussion is limited to the manual centrifugal charging pump controls. A detailed description of the charging system, its operation, and safety evaluation is provided in section 6.3 and subsection 9.3.4.

A. Initiating Circuits

The charging pumps can be controlled manually by the plant operator for hot standby service. For other initiating circuits, see section 7.3.

B. Logic

The control logic provides for both automatic and manual control features. The pumps can be started under manual control at any time. Refer to section 1.7 for a list of elementary and logic diagrams.

C. Bypass

No bypass of the manual controls, other than maintenance provisions, is provided.

D. Interlocks

When the shutdown panel transfer switch is in the local position, automatic start of the pump on a safety signal is defeated.

E. Redundancy

Two independent centrifugal charging pumps and control circuits are provided, either of which can provide the necessary input to the primary system for the hot standby condition.

F. Diversity

There is no diversity in the manual control circuits or power supplies for the two centrifugal charging pumps.

G. Actuated Devices

The charging pumps and associated valves are the actuated devices.

H. Supporting Systems

The charging pump controls are powered from the Class 1E power system.

I. Portion of System Not Required for Safety

The instrumentation used to monitor the charging pump operation (other than indicating lights for hand switches as an integral part of the control circuit), alarms on the station annunciator and computer, and automatic charging pump control via the pressurizer level control channels are not required for safety.

J. Design Bases Information

The design bases of the charging pump manual controls (in accordance with Section 3 of IEEE Standard 279-1971) are as follows:

1. The generating station condition that requires protective action is low pressurizer level following a reactor trip with or without loss of offsite power.
2. The equipment is located outside the containment and is designed to withstand the temperature range, relative humidity, and atmospheric pressure for its location. Refer to table 3.11.B.1-1 for specific values.

3. The charging pump manual control system is designed to withstand the effects of an SSE without loss of function. The system is designed and its components located to prevent loss of function from missile damage.

7.4.1.3.2 Analysis

A. Conformance to NRC GDC

1. GDC 13 and 19

   Instrumentation necessary to monitor station variables associated with hot standby is provided with adequate indication in the main control room and on the shutdown control panels. Manual controls for the centrifugal charging pumps are provided both inside and outside of the control room. A description of the surveillance instrumentation is provided in section 7.5.

2. GDC 33

   The centrifugal charging pump manual controls provide adequate control of the pressurizer level to preclude use of the pressurizer heaters below low-low level. One centrifugal charging pump is sufficient to provide the necessary makeup to the RCS to maintain the hot standby condition.

B. Conformance to NRC Regulatory Guides

1. Regulatory Guide 1.22

   The centrifugal charging pump manual controls can be tested periodically during operation, since the charging pumps are used during normal operation.

2. Regulatory Guide 1.29

   The centrifugal charging pump manual controls are designed to withstand the effects of an SSE without loss of function or physical damage. The centrifugal charging pump manual controls are classified Seismic Category 1, in accordance with the guide.

C. Conformance to IEEE Standard 279-1971

   The centrifugal charging pump manual controls are designed to meet the portions of IEEE Standard 279-1971 applicable to manual controls. The manual control circuits are designed so that any single failure will not prevent protective action (makeup to the RCS) when required. This is accomplished by two redundant centrifugal charging pumps. The control circuit of each charging pump utilizes controls powered from an independent Class 1E power system. To prevent interaction between the redundant systems, the manual control channels are wired independently and separated with no electrical connections between them.

   The normal automatic control circuits are electrically isolated from the manual controls to ensure manual control system independence.

D. Conformance to Other Criteria and Standards

   Conformance to other criteria and standards is given in table 7.1.1-1.

7.4.1.4 Coolant Circulation

The preferred method of coolant circulation is forced circulation with the reactor coolant pumps supplying the driving head. With loss of offsite power, the pumps are not available; however, the RCS is designed to provide sufficient natural circulation to reach and maintain hot standby. Natural circulation flow is verified by noting the various RCS temperatures.

7.4.1.5 Other Systems Required for Hot Standby

The other major equipment and systems required to maintain the unit in the hot standby condition are listed below. For a more comprehensive and detailed listing, refer to tables 7.4.1-1 and 7.4.2-1.

A. NSCW system (subsection 9.2.1).

B. Component cooling water system (subsection 9.2.2).

C. Containment fan coolers (subsection 6.2.2).

D. Emergency diesel generators (and associated onsite electrical distribution system) (subsection 8.3.1).

E. Control room ventilation system (subsection 9.4.1).

F. Emergency ventilation system (for those areas housing equipment required for safe shutdown) (section 9.4)

G. Essential chilled water (subsection 6.2.2).

Systems A through F above are either normally operating continuously or start automatically when required. The instrumentation and controls for these systems are described in the particular section of this document where each system is described. (See A through F above.) Further discussion of the actuation and controls for the engineered safety feature systems is provided in section 7.3.

7.4.2 COLD SHUTDOWN

To perform a unit cold shutdown, the unit is brought from hot standby conditions to nearly ambient conditions from the main control room or shutdown panels. The ability to reach cold shutdown under control from the main control room utilizing safety-related components is further discussed in this section; the ability to reach cold shutdown under control from the shutdown panels is discussed in detail in subsection 7.4.3.

Cold shutdown is defined by the Technical Specifications as the condition in which the reactor is subcritical, the reactor coolant system (RCS) temperature is ≤ 200°F, and the RCS is depressurized. To accomplish a cold shutdown, the following functions are required:

- Coolant circulation.
- Boration.
- Heat removal.
- Depressurization.

The systems required for hot standby are also required for cold shutdown. In addition, the following systems, components, and indication are required:

A. Required Systems and Component Controls

1. Vessel head letdown and vent system.
2. Pressurizer power-operated relief valve complex.
3. Residual heat removal system.
4. Boric acid storage tank.
5. Boric acid transfer pumps.
6. Accumulator vent system.
7. Manual block of safety injection signal.
8. Pressurizer backup heaters.

The components in these systems are fully qualified and safety grade with power from a Class 1E electrical bus except the pressurizer heaters. (Two groups of pressurizer backup heaters can be administratively loaded on the non-1E emergency bus.) All control switches for these items are safety grade.

B. Required Monitoring Indicators

1. Boric acid storage tank level.
2. Boric acid charging flowrate.

Table 7.4.2-1 lists the instrumentation and controls available for hot standby and hot or cold shutdown and provides the locations of controls and indication.

Hot standby is a stable plant condition for a reactor plant that incorporates a Westinghouse nuclear steam supply system. Examination of Condition II, III, or IV events for the Westinghouse nuclear steam supply system reveals no events that require cooldown to cold shutdown conditions for safety reasons. Eventual achievement of cold shutdown conditions may be required for long-term recovery. However, there is no safety reason why this must be accomplished in some limited period of time. While the plant is in the hot standby condition, the auxiliary feedwater system and the power-operated atmospheric steam relief valves are used to remove residual heat to meet all safety requirements. The long-term safety grade supply of auxiliary feedwater allows extended operation at hot standby conditions. Additionally, the plant design includes provisions for achieving cold shutdown, even assuming a safe shutdown earthquake, a loss of offsite power, and the most limiting single failure with limited operator action outside the control room.

7.4.3 SAFE SHUTDOWN FROM OUTSIDE THE CONTROL ROOM

7.4.3.1 Description

If temporary evacuation of the control room is required because of some abnormal plant condition, the operators can establish and maintain the plant in a hot standby and hot or cold shutdown condition from outside the control room through the use of controls located at the shutdown panels. Hot standby is a stable plant condition which can be maintained safely for an extended period of time. In the event that access to the control room is restricted, the plant can be safely kept at hot standby until the control room can be reentered, by the use of the monitoring indicators and the controls listed in subsection 7.4.1. Although the prime intent of the shutdown panels is to maintain hot standby from outside the control room, the panels are also used for implementing cold shutdown from outside the control room.

7.4.3.1.1 Shutdown Panels

Hot standby and hot or cold shutdown can be established and maintained from the shutdown panels. The panels are designed to allow control of a shutdown following an evacuation of the control room, coincident with the loss of offsite power and a single active failure. No other design basis event is postulated. (See 9.5.1 for a discussion of shutdown in the event of a fire.) Remote control station equipment is designed to the same standards as the corresponding equipment in the main control room.

Two shutdown panels are provided for each unit. The train A panel is located adjacent to train A 4160-V switchgear room on level A of the control building. The train B panel is adjacent to the lower cable spreading room also located on level A. Access to each is administratively controlled. Each panel contains the control switches for the associated train's safety-grade equipment required to accomplish hot standby and hot or cold shutdown. Additionally, control of selected nonsafety-grade components is provided to accomplish a shutdown if offsite power remains available. Table 7.4.2-1 lists the instrumentation and controls available for hot and/or cold shutdown and provides the location for the various control switches and indicators.

The shutdown panels are provided for use following an evacuation of the control room only. No actions are anticipated from the shutdown panels during normal, routine shutdown, refueling, or maintenance operations. Each control switch and controller on the shutdown panel is accompanied by a transfer switch. When a transfer switch is turned to the local position, the following occur:

- Common alarm in the control room is actuated.
- Control from the control room is defeated.
- Automatic features in control circuits originated from the control room are defeated.
- Manual control from shutdown panel is possible.

Because automatic features are defeated, manual action is required if a safety signal is generated while performing a shutdown from these panels.

The shutdown panels are provided with sufficient communication circuits to ensure that the operator can safely perform a hot standby and hot or cold shutdown. Communication is available between the following stations (see subsection 9.5.2):

- Control room.
- Shutdown panels.
- Onsite technical support center.
- Diesel generator local control station.
- Auxiliary feedwater local control station.

7.4.3.1.2 Controls at Other Locations

In addition to the controls and indicators provided on the shutdown panels, the following controls are provided outside the control room:

A. Reactor trip capability at the reactor trip switchgear.

B. Start/stop controls for the diesel generators, located on each diesel generator local control panel.

C. Start/stop controls for the turbine-driven auxiliary feedwater pump and position controls for valves in lines to the steam generators, located on auxiliary feedwater local control panel.

D. Close/trip of the Class 1E bus feeder breakers and the diesel-backed non-1E bus feeder breakers (1NB01 and 1NB10) located at the switchgear.

7.4.3.1.3 Design Bases Information

In accordance with Nuclear Regulatory Commission (NRC) General Design Criterion (GDC) 19, the capability of establishing a shutdown condition and maintaining the station in a safe status in that mode is considered an essential function. The controls and indications essential to this function are identified in subsection 7.4.1. To ensure the availability of the shutdown panels after control room evacuation, the following design features have been utilized:

A. The shutdown panels, including all safety-grade controls and indications mounted on them, are designed to withstand the safe shutdown earthquake (SSE) with no loss of essential functions.

B. The shutdown panels are designed to conform with the applicable portions of Institute of Electrical and Electronics Engineers (IEEE) Standard 279-1971.

C. The shutdown panels are designed to achieve and maintain hot standby conditions and to achieve cold shutdown from full power conditions and maintain cold shutdown conditions thereafter.

D. The shutdown panels are designed to achieve cold shutdown where offsite power is available and where offsite power is not available for 72 h.

E. The shutdown panels are designed to utilize only safety-related systems independent from the main control room except for indications and operator-interface modules (OIMs) for train A head vent throttle valve, centrifugal charging pump discharge throttle valves, power-operated atmospheric steam relief valves (steam generators 2 and 3 can be controlled independent of the control room at shutdown panel B by a portable plug-in signal generating device), train A accumulator tank gas vent valve and residual heat removal heat exchanger outlet and bypass valves (refer to paragraph 7.4.3.3 for a discussion on alternate shutdown indication).

F. The shutdown panels are designed for a coincident single failure. When a random event such as a fire or allowable technical specification maintenance results in one safety grade train being unavailable, a single failure in the redundant train is not postulated. When a random event other than fire causes a control room evacuation, a coincident single failure in the systems controlled from the local shutdown panel is considered.

G. The shutdown panel design allows credit for remedial operator action as discussed in paragraph 7.4.3.1.2 but minimizes the need for operator action outside of the shutdown panel area.

H. Design basis events do not occur simultaneous with nor as a consequence of any event which initiates control room evacuation.

I. The shutdown panel design minimizes the potential for inadvertent use of or sabotage of the plant from the shutdown panel.

J. Access to the shutdown panels is under administrative controls.

K. An alarm is provided in the control room to provide an indication when a component or components on the shutdown panel is/are bypassed from the main control boards to the shutdown panel.

L. Controls, switches, and indications on the shutdown panels are designed to be consistent with the design requirement for similar devices located in the main control room.

7.4.3.2 Analysis

The analysis of the control systems required for safe shutdown is found in subsection 7.4.1. The discussion below is limited to the shutdown panels.

A. Conformance to NRC GDC

1. GDC 19

   The shutdown panels provide adequate controls and indications located outside the main control room to establish and maintain the reactor and the reactor coolant system in the hot standby and hot or cold shutdown condition in the event that the main control room must be evacuated.

B. Conformance to NRC Regulatory Guides

1. Regulatory Guide 1.22

   The shutdown panels are designed to be tested periodically during station operation.

2. Regulatory Guide 1.29

   The shutdown panels are designed to withstand the effects of an SSE without loss of function or physical damage. The shutdown panels are classified Seismic Category 1. Selected instrumentation and control devices are not safety related but are qualified for seismic integrity to prevent compromising the function of safety- related devices during or after an SSE.

C. Conformance to IEEE Standard 279-1971

The shutdown panels are designed to conform to applicable portions of IEEE Standard 279-1971. The control circuits at the shutdown panels are designed so that any single failure will not prevent maintaining safe shutdown when required. This is accomplished by fully redundant controls for the systems required for hot standby and hot or cold shutdown, utilizing independent Class 1E power systems.

To prevent interaction between the redundant systems, the redundant control channels are wired independently and separated with no electrical connections between them. Non-Class 1E circuits available for safe shutdown are electrically isolated from Class 1E circuits.

D. Conformance to Other Guides, Criteria, and Standards

The additional guides, criteria, and standards listed in table 7.1.1-1 apply only to the essential instrumentation and control required for safe shutdown from outside the control room.

7.4.3.3 Alternate Shutdown Indication System

7.4.3.3.1 Description

The alternate shutdown indication system is designed to provide indication and controllers; i.e., OIMs, necessary for cold shutdown that are independent from the control room in the event of a control room fire. No other events are postulated to occur either during or after a control room fire; consequently, the design is exempted from the single failure criteria, Seismic Category 1 criteria, and the other design basis accident criteria, except where required for other reasons (e.g., due to interfacing with or impacting on existing systems).

The plant safety monitoring system (PSMS) (refer to paragraph 7.5.3.6) and the alternate shutdown indication system cabinet are used to process and output isolated signals which go to the control room and the train B shutdown panel. The PSMS provides isolated signals for the alternate shutdown indication parameters for which the PSMS performs data acquisition and display. The alternate shutdown indication system cabinet isolates signals which are required in the process cabinets and the OIM control loops.

The reactor may be tripped from the main control board before leaving the control room or tripped from either of the shutdown panels immediately after entering the shutdown panel rooms. Both shutdown panels are fully equipped panels that may act as the point of control for performing a shutdown and cooldown of the plant given that the control room is inaccessible. However, only the train B shutdown panel is provided with electrically isolated instrumentation and controls for use as the alternate shutdown point of control following a control room fire.

7.4.3.3.2 Design Bases Information

The alternate shutdown indication system is designed to meet Branch Technical Position CMEB 9.5-1 requirement C.5.C (see appendix 9B).

7.4.3.3.2.1 Safety Design Bases. The alternate shutdown indication system shall not compromise safety-related systems and associated inputs nor prevent safe shutdown.

7.4.3.3.2.2 Power Generation Design Basis. The alternate shutdown indication system provides electrically isolated signals into the control room during power generation. It is designed to function during and after a control room fire.

A. The alternate shutdown indication system controls, in conjunction with remote shutdown panel B controls, are used to achieve and maintain hot standby condition and achieve cold shutdown from full power conditions in 72 h following a control room fire and maintain cold shutdown conditions thereafter.

B. The alternate shutdown indication system instrumentation, in conjunction with remote shutdown panel B instrumentation, provides direct readings and controls to monitor the process variables necessary to perform and control the following shutdown functions:

   1. Reactivity control.
   2. Reactor coolant makeup/inventory.
   3. Reactor heat removal.

C. The alternate shutdown indication system consists of the following required parameters and OIMs (see table 7.4.2-1):

1. Neutron flux.
2. Reactor coolant system wide range T_{cold} - (loops 2 and 3).
3. Incore thermocouples in the quadrants corresponding to loops 2 and 3 (Unit 1) and loops 1 and 4 (Unit 2).
4. Reactor coolant system wide range pressure.
5. Steam generator wide range level (loops 2 and 3).
6. Pressurizer level.
7. Head vent throttle valve (OIM).
8. Accumulator tank gas vent valve (OIM).

D. The alternate shutdown indication system accommodates post-fire conditions where offsite power is available and where offsite power is not available for 72 h.

E. The alternate shutdown indication system is not damaged by a control room fire.

F. The alternate shutdown indication system and associated circuits design are exempted from Seismic Category I criteria, single failure criteria, or other design basis accident criteria, except where required for other reasons (e.g., because of interface with or impact on existing safety systems).

G. The alternate shutdown indication system is electrically isolated from the control room so that a fire-induced, hot short, open circuit, or short to ground in the alternate shutdown control room indication circuits will not prevent operation of the alternate shutdown indication at the shutdown panel.

H. Access to the alternate shutdown indication system is under administrative control.

I. The alternate shutdown indication system OIMs are activated manually following evacuation of the control room. This actuation does not disturb control, process, protection, or nuclear instrumentation circuits except those associated with the alternate shutdown indication system.

J. The alternate shutdown indication system is electrically isolated from the control room so that a fire-induced hot short, open circuit, or short to ground in any of the Class 1E circuits will not prevent operation of the alternate shutdown equipment from the shutdown panel.

K. An alarm is provided in the control room to provide an indication in the event that the alternate shutdown OIMs are bypassed from the main control board to the shutdown panel.

7.4.3.3.2.3 Guides, Criteria, and Standards. The alternate shutdown indication system conforms to GDC 19, the applicable portions of IEEE Standards 279-1971, 323-1974, and 344-1975, Regulatory Guide 1.22, and Branch Technical Position CMEB 9.5-1.

TABLE 7.4.1-1

SYSTEMS AVAILABLE FOR SAFE SHUTDOWN

Auxiliary feedwater system

Condensate storage facility

Chemical and volume control system (boration and makeup functions)

Pressurizer power-operated relief valve complex

Reactor vessel head letdown system

Residual heat removal system

Main steam power-operated atmospheric relief valve complex

Component cooling water system

NSCW system

Onsite standby power supply (diesel generators and associated outside electrical distribution system)

Ventilation systems (control room and engineered safety features rooms)

Associated instrumentation and controls

Safety injection system (accumulator vents systems)

Containment fan coolers

Essential chilled water

ACCW

TABLE 7.4.2-1 (SHEET 1 OF 9)

INSTRUMENTATION AND CONTROLS AVAILABLE
FOR HOT STANDBY AND HOT OR COLD SHUTDOWN

Valve/ Switch/ Indicator	Function[a]	Location[b] CR	PSDA	PSDB	Local	ASI[c]
PV456A	Primary PORV	X		X		
PV455A	Primary PORV	X	X			
HV8000A	PORV block valve	X	X			
HV8000B	PORV block valve	X		X		
HV8875A	Accumulator No. 1 vent	X	X			
HV8875B	Accumulator No. 2 vent	X	X			
HV8875C	Accumulator No. 3 vent	X	X			
HV8875D	Accumulator No. 4 vent	X	X			
HV8875E	Accumulator No. 1 vent	X		X		
HV8875F	Accumulator No. 2 vent	X		X		
HV8875G	Accumulator No. 3 vent	X		X		
HV8875H	Accumulator No. 4 vent	X		X		
HV943A	Accumulator vent	X	X			
HV943B	Accumulator vent	X		X		X
PI960	Accumulator No. 1 press	X	X			
PI962	Accumulator No. 2 press	X	X			
PI964	Accumulator No. 3 press	X	X			
PI966	Accumulator No. 4 press	X	X			
PI961	Accumulator No. 1 press	X		X		
PI963	Accumulator No. 2 press	X		X		
PI965	Accumulator No. 3 press	X		X		
PI967	Accumulator No. 4 press	X		X		
FV121	Charging Flow	X			X	
HV8146	Normal charge	X	X			
HV8147	Alternate charge	X		X		
HV8105	Charging isolation	X		X		
HV8106	Charging isolation	X	X			
HV8116	Charge pump A bypass	X	X			
HV190A	Charge pump A throttle	X	X			
HV8485A	Charge pump A discharge	X	X			
HV8471A	Charge pump A suction	X	X			
HV190B	Charge pump B throttle	X		X		
HV8485B	Charge pump B discharge	X		X		
HV8438	Charge pump B discharge	X		X		
HV8471B	Charge pump B suction	X		X		
LV112D	RWST to charge	X	X			

TABLE 7.4.2-1 (SHEET 2 OF 9)

Valve/ Switch/ Indicator	Function[a]	Location[b] CR	PSDA	PSDB	Local	ASI[c]
LV112E	RWST to charge	X		X		
LV112B	VCT to charge	X	X			
LV112C	VCT to charge	X		X		
HV8104	Boric acid to charge	X	X			
HV8801A	BIT outlet (Unit 1) Charging pump high head cold leg injection (Unit 2)	X	X			
HV8801B	BIT outlet (Unit 1) Charging pump high head cold leg injection (Unit 2)	X		X		
FI138	Charge pump A flow	X	X			
FI917	BIT flow path (Unit 1) Charging pump high head cold leg injection (Unit 2)	X		X		
HS273	Charge pump A	X	X			
HS274	Charge pump B	X		X		
HS276	BAT pump A	X	X			
HS277	BAT pump B	X		X		
LI185	VCT level	X	X			
LI112	VCT level	X[e]		X	X	
LI102	BAST level	X	X			
LI104	BAST level	X		X		
PI10115	BAST level				X	
HV8095A	Head vent	X	X			
HV8096A	Head vent	X	X			
HV442A	Letdown to PRT	X	X			
FI406	Letdown flow	X	X			
LI459	Pressurizer level	X	X		X	
HV8095B	Head vent	X		X		
HV8096B	Head vent	X		X		
HV442B	Letdown to PRT	X		X		X
FI407	Letdown flow	X		X		
LI460	Pressurizer level	X		X	X	X
HV5119	CST No. 2 to AFW A	X	X			
HV5137	AFW A to SG No. 4	X	X			
HV5139	AFW A to SG No. 1	X	X			
FI5150	Flow to SG No. 4	X	X		X	
FI5152	Flow to SG No. 1	X	X		X	
LI5100	CST No. 1 Level				X	
LI5111	CST No. 1 level	X	X		X	
LI5115	CST No. 2 level				X	
LI5116	CST No. 2 level	X	X		X	
LI501	SG No. 1 level	X	X		X	
LI504	SG No. 4 level	X	X		X	
PI514	SG No. 1 press	X	X			

TABLE 7.4.2-1 (SHEET 3 OF 9)

Valve/ Switch/ Indicator	Function[a]	Location[b] CR	PSDA	PSDB	Local	ASI[c]
PI544	SG No. 4 press	X	X			
HS5131	AFW pump A	X	X			
PIC3000	SG No. 1 press control	X	X			
PIC3030	SG No. 4 press control	X	X			
HV5118	CST No. 2 to AFW B	X		X		
HV5132	AFW B to SG No. 2	X		X		
HV5134	AFW B to SG No. 3	X		X		
FI5151	Flow to SG No. 2	X		X	X	
FI5153	Flow to SG No. 3	X		X	X	
LI502	SG No. 2 level	X		X	X	X
LI503	SG No. 3 level	X		X	X	X
PI455	Pressurizer pressure	X	X		X	
PI456	Pressurizer pressure	X		X		
PI457	Pressurizer pressure	X	X			
PI458	Pressurizer pressure	X		X		
PI514	SG No. 1 pressure	X			X	
PI524	SG No. 2 pressure	X			X	
PI525	SG No. 2 pressure	X		X		
PI534	SG No. 3 pressure	X			X	
PI535	SG No. 3 pressure	X		X		
PI544	SG No. 4 pressure	X			X	
HS5130	AFW pump B	X		X		
PIC3010	SG No. 2 press containment	X		X		
PIC3020	SG No. 3 press containment	X		X		
HV5113	CST No. 2 to AFW C	X			X	
HV5120	AFW C to SG No. 4	X			X	
HV5122	AFW C to SG No. 1	X			X	
HV5125	AFW C to SG No. 2	X			X	
HV5127	AFW C to SG No. 3	X			X	
HV3009	SG No. 1 to AFW C	X			X	
LI5101	CST No. 1 level			X		
LI5104	CST No. 2 level			X		
HV3019	SG No. 2 to AFW C	X			X	
HV5106	Steam to AFW C	X			X	
SI15109	AFW C speed	X			X	
PI5105	Main Steam to AFW C turbine press	X			X	
HS15111	AFW C trip and throttle	X			X	
PDIC5180	AFW C speed control	X			X	
TI413	LOOP No.1 cold	X	X			
TI413	LOOP No.1 hot	X	X			
TI443	LOOP No.4 cold	X	X			
TI443	LOOP No.4 hot	X	X			
TI423	LOOP No.2 cold	X		X		X
TI423	LOOP No.2 hot	X		X		
TI433	LOOP No.3 cold	X		X		X

TABLE 7.4.2-1 (SHEET 4 OF 9)

Valve/ Switch/ Indicator	Function[a]	Location[b]				
		CR	PSDA	PSDB	Local	ASI[c]
TI433	LOOP No.3 hot	X		X		
TI10055	Core exit temperature (loop 2 core quadrant on Unit 1) (loop 1 core quadrant on Unit 2)			X		X
TI10056	Core exit temperature (loop 3 core quadrant on Unit 1) (loop 4 core quadrant on Unit 2)			X		X
HS10469	Pressurizer backup heater	X	X			
HS10470	Pressurizer backup heater	X		X		
HS4516	DG A	X			X	
HS4517	DG B	X			X	
HS9045	DG B fuel oil transfer pump 3	X			X	
HS9047	DG B fuel oil transfer pump 4	X			X	
HS998	SI pump A	X	X			
HS999	SI pump B	X		X		
HV8701A	RHR suction	X	X			
HV8701B	RHR suction	X	X			
HV8812A	RWST to RHR	X	X			
HV606	RHR HX outlet	X	X			
ZLB40107	HV606 valve position		X	X		
FV610	RHR pump miniflow	X	X			
FV618	RHR HX bypass	X	X			
HS620	RHR pump A	X	X			
HV8809A	RHR A to SI	X	X			
HV8702A	RHR suction	X		X		
HV8702B	RHR suction	X		X		
HV8812B	RWST to RHR	X		X		
HV607	RHR HX outlet	X		X		
ZLB40108	HV607 valve position	X			X	
FV611	RHR pump miniflow	X		X		
FV619	RHR HX bypass	X		X		
HS621	RHR pump B	X		X		
FV5155	AFW pump A miniflow		X			
FV5154	AFW pump B miniflow			X		
HV8809B	RHR B to SI	X		X		
TI604	RHR A temperature	X[e]			X	
TI605	RHR B temperature	X[e]			X	
FI618	RHR A flow	X	X			
FI619	RHR B flow	X		X		
LI990	RWST level	X	X		X	
LI991	RWST level	X		X		
HS1852	CCW pump No. 1	X	X			
HS1854	CCW pump No. 3	X	X			
HS1856	CCW pump No. 5	X	X			
HS1853	CCW pump No. 2	X		X		

TABLE 7.4.2-1 (SHEET 5 OF 9)

Valve/ Switch/ Indicator	Function[a]	Location[b] CR	PSDA	PSDB	Local	ASI[c]
HS1855	CCW pump No. 4	X		X		
HS1857	CCW pump No. 6	X		X		
HS1602	NSCW pump No. 1	X	X			
HS1634	NWCW pump No. 3	X	X			
HS1608	NSCW pump No. 5	X	X			
HS1603	NSCW pump No. 2	X		X		
HS1635	NSCW pump No. 4	X		X		
HS1609	NSCW pump No. 6	X		X		
HS1610	NSCW fan No. 1A	X	X			
HS1616	NSCW fan No. 2A	X	X			
HS1622	NSCW fan No. 3A	X	X			
HS1628	NSCW fan No. 4A	X	X			
HS1611	NSCW fan No. 1B	X		X		
HS1617	NSCW fan No. 2B	X		X		
HS1623	NSCW fan No. 3B	X		X		
HS1629	NSCW fan No. 4B	X		X		
HV1668	NSCW tower bypass	X	X			
HV1669	NSCW tower bypass	X		X		
FI1876	CCW A flow	X	X			
FI1877	CCW B flow	X		X		
FI1640	NSCW A flow	X	X			
FI1641	NSCW B flow	X		X		
TI1676	NSCW A temperature	X	X			
TI1677	NSCW B temperature	X		X		
LI1606	NSCW A level	X	X			
LI1607	NSCW B level	X		X		
HS22412	CB essential chilled water pump A	X	X			
HS22413	CB essential chilled water pump B	X		X		
FI22425	CB essential chilled water A flow	X	X			
FI22426	CB essential chilled water B flow	X		X		
HS22442	CB essential chiller A	X	X			
HS22443	CB essential chiller B	X		X		
HS12200	ESF room cooler No. 1	X	X			
LI518	SG 1 narrow range	X	X			
LI527	SG 2 narrow range	X		X		
LI537	SG 3 narrow range	X		X		
LI548	SG 4 narrow range	X	X			
HS12201	ESF room cooler No. 2	X		X		
HS12202	ESF room cooler No. 3	X	X			
HS12203	ESF room cooler No. 4	X		X		
HS12204	ESF room cooler No. 5	X	X			
HS12205	ESF room cooler No. 6	X		X		
HS12206	ESF room cooler No. 7	X	X			
HS12212	ESF room cooler No. 8	X		X		
HS12208	ESF room cooler No. 11	X	X			

TABLE 7.4.2-1 (SHEET 6 OF 9)

Valve/ Switch/ Indicator	Function[a]	Location[b] CR	PSDA	PSDB	Local	ASI[c]
HS12214	ESF room cooler No. 12	X		X		
HS12209	ESF room cooler No. 13	X	X			
HS12215	ESF room cooler No. 14	X		X		
HS12050	DG-A exhaust fan	X	X			
HS12051	DG-A exhaust fan	X	X			
HS12053	DG-B exhaust fan	X		X		
HS12054	DG-B exhaust fan	X		X		
HS13150	CB Normal AC room ESF AC unit	X	X			
HS13152[d]	Electrical Equipment room ESF AC unit	X		X		
HS12823	CB auxiliary relay room AC	X	X			
HS12918	CB auxiliary relay room AC	X		X		
HS12733	CBSF fan No. 1	X	X			
HS12718	CBSF fan No. 2	X		X		
HS12742	CBSF batt fan	X	X			
HS12748	CBSF batt fan	X	X			
HS12727	CBSF batt fan	X		X		
HS12749	CBSF batt fan	X		X		
HS40002	Reactor trip switch	X	X	X		
ZL40045	Trip breaker A	X	X			
ZL40044	Trip breaker B	X		X		
NI31	Source range flux	X	X			
NI32	Source range flux	X		X		
NI35	Intermediate range flux	X	X			
NI36	Intermediate range flux	X		X		
NI-13135C	Neutron flux (upper range)	X		X		X
NI-13135D	Neutron flux (lower range)	X		X		X
II40090-2	DG-A amps	X	X			
II40093-5	DG-B amps	X		X		
ZLB40104	1AA02 energized (DG breaker)	X	X			
ZLB40105	1BA03 energized (DG breaker)	X		X		
HS40012, 40068	SI block A (2 switches)	X	X			
HS40013, 40069	SI block B (2 switches)	X		X		
HS2166	NSCW transfer pump A	X		X		
HS2167	NSCW transfer pump B	X	X			
HS2582	CTB cooler	X	X			
HS12582	CTB cooler	X	X			
HS2583	CTB cooler	X		X		
HS12583	CTB cooler	X		X		
HS2584	CTB cooler	X	X			
HS12584	CTB cooler	X	X			
HS2585	CTB cooler	X		X		
HS12585	CTB cooler	X		X		

TABLE 7.4.2-1 (SHEET 7 OF 9)

Valve/ Switch/ Indicator	Function[a]	Location[b] CR	PSDA	PSDB	Local	ASI[c]
PI-403	RCS wide-range pressure	X		X		X
PI-405	RCS wide-range pressure	X	X			
HV8110	Charge pump miniflow	X	X			
HV8111A	Charge pump miniflow	X		X		
HV8111B	Charge pump miniflow	X		X		
HS1/2AA0201	Feeder from 1/2NXRB or SAT	X			X	
HS1/2AA0205	Feeder from 1/2NXRA	X			X	
HS1/2AA0219	Feeder from DG-A	X			X	
HS1/2AA0210	Feeder to 480 V SWGR 1/2AB15	X			X	
HS1/2AA0221	Feeder to 480 V SWGR1/2AB05	X			X	
HS1/2AA0220	Feeder to 480 V SWGR1/2AB04	X			X	
HS1/2AA0222	Feeder to 480 V SWGR1/2NB01	X			X	
HS1/2AB0401	SWGR 1/2AB04 feeder from 1/2AA02	X			X	
HS1/2AB0501	SWGR 1/2AB05 feeder from 1/2AA02	X			X	
HS1/2AB1501	SWGR 1/2AB15 feeder from 1/2AA02	X			X	
HS1/2NB0101	SWGR 1/2NB01 feeder from 1/2AA02	X			X	
HS1/2BA0305	Feeder from 1/2NXRA or SAT	X			X	
HS1/2BA0301	Feeder from 1/2NXRB	X			X	
HS1/2BA0319	Feeder from DG-B	X			X	
HS1/2BA0306	Feeder to 480 V SWGR 1/2BB06	X			X	
HS1/2BA0304	Feeder to 480 V SWGR 1/2BB07	X			X	
HS1/2BA0309	Feeder to 480 V SWGR 1/2BB16	X			X	
HS1/2BA0318	Feeder to 480 V SWGR 1/2NB10	X			X	
HS1/2BB0601	SWGR 1/2BB06 feeder from 1/2BA03	X			X	
HS1/2BB0701	SWGR 1/2BB07 feeder from 1/2BA03	X			X	
HS1/2BB1601	SWGR 1/2BB16 feeder from 1/2BA03	X			X	
HS1/2NB1001	SWGR 1/2NB10 feeder from 1/2BA03	X			X	
HS8000	Cold overpressure arm/block	X	X			
HS8000	Cold overpressure	X		X		
LV-459	Letdown isolation	X	X			
LV-460	Letdown isolation	X	X			
FI-132	Letdown flow	X	X			
PI-131	Letdown pressure	X	X			
HV8145	Charge auxiliary spray	X	X			
HS495	RCP No. 1	X	X			
HS555	Oil lift pump No. 1	X	X			
HS496	RCP No. 2	X		X		
HS556	Oil lift pump No. 2	X		X		
HS497	RCP No. 3	X		X		
HS557	Oil lift pump No. 3	X		X		
HS498	RCP No. 4	X	X			
HS558	Oil lift pump No. 4	X	X			
PV-455B	Normal spray	X	X			
PV-455C	Normal spray	X	X			
ZLB40106	Pressurizer spray valve position	X				

TABLE 7.4.2-1 (SHEET 8 OF 9)

Valve/ Switch/ Indicator	Function[a]	Location[b] CR	PSDA	PSDB	Local	ASI[c]
HV8098	Head letdown to excess letdown HX	X	X			
TIC12001	AFW heater				X	
HS12005	AFW supply fan	X		X		
TIC12002	AFW heater				X	
HS12006	AFW supply fan	X	X			
TIC12000	AFW heater				X	
TIC12013	AFW heater				X	
HV12010	AFW damper	X			X	
PI-5129	AFW pump A suction	X	X			
PI-5141	AFW pump A discharge	X	X			
PI-5128	AFW pump B suction	X		X		
PI-5140	AFW pump B discharge	X		X		
HS12273	CTB CRDM Fan 1	X	X			
HS12274	CTB CRDM Fan 2	X		X		
HS12275	CTB CRDM Fan 3	X	X			
HS12276	CTB CRDM Fan 4	X		X		

TABLE 7.4.2-1 (SHEET 9 OF 9)

____

a.	AC	air conditioner
	AFW	auxiliary feedwater
	BAST	boric acid storage tank
	BAT	boric acid transfer
	BIT	boron injection tank
	CB	control building
	CBSF	control building safety feature
	CCW	component cooling water
	CRDM	control rod drive mechanism
	CST	condensate storage tank
	CTB	containment building
	DG	diesel generator
	ESF	engineered safety features
	HX	heat exchanger
	NSCW	nuclear service cooling water
	PORV	power-operated relief valve
	PRT	pressurizer relief tank
	RCP	reactor coolant pump
	RCS	reactor coolant system
	RHR	residual heat removal
	RWST	refueling water storage tank
	SG	steam generator
	SI	safety injection
	VCT	volume control tank
b.	CR	control room
	PSDA	shutdown panel A
	PSDB	shutdown panel B
	ASI	alternate shutdown indication

c. The items identified in this column are provided with control room circuitry isolation, via the alternate shutdown indication panel, to provide the ability for shutdown from remote shutdown panel B in the event of a control room fire.

d. Unit 1 only.

e. Available only on plant computer in control room.

7.5 INFORMATION SYSTEMS IMPORTANT TO SAFETY

7.5.1 SAFETY-RELATED DISPLAY INSTRUMENTATION INTRODUCTION

An analysis was conducted to identify the appropriate variables and to establish the appropriate design bases and qualification criteria for instrumentation employed by the operator for monitoring conditions in the reactor coolant system, the secondary heat removal system, and the containment, including engineered safety functions and the systems employed for attaining a safe shutdown condition.

The instrumentation is used by the operator to monitor the VEGP throughout all operating conditions including anticipated operational occurrences and accident and post-accident conditions.

The emergency response facilities and support systems consisting of the onsite technical support center, emergency operations facility, operational support center, safety parameter display system, and the emergency response data system (ERDS) are discussed in the VEGP Emergency Plan, section H. Table 7.5.2-1 indicates the specific plant parameters which are associated with ERDS. Modifications to these parameters in the plant may require NRC notification per 10 CFR 50, Appendix E, Part VI.

7.5.2 DESCRIPTION OF INFORMATION SYSTEMS

The plant safety analyses and evaluations define the design basis accident (DBA) event scenarios for which preplanned operator actions are required. Accident monitoring instrumentation is necessary to permit the operator to take required actions to address these analyzed situations. However, instrumentation is also necessary for unforeseen situations (i.e., to ensure that, should plant conditions evolve differently than predicted by the safety analyses, the control room operating staff has sufficient information to evaluate and monitor the course of the event). Additional instrumentation is also needed to indicate to the operating staff whether the integrity of the fuel cladding, the reactor coolant pressure boundary (RCPB), or the reactor containment has degraded beyond the prescribed limits defined as a result of the plant safety analyses and other evaluations.

Five classifications of variables have been identified to provide this instrumentation:

A. Those variables that provide information needed by the operator to perform manual actions identified in the operating procedures that are associated with DBA events are designated type A. These variables are restricted to preplanned actions for DBA events. The basis for selecting type A variables is given in paragraph 7.5.2.2.1.

B. Those variables needed to assess that the plant critical safety functions are being accomplished or maintained, as identified in the plant safety analysis and other evaluations, are designated type B.

C. Those variables used to monitor for the gross breach or the potential for gross breach of the fuel cladding, the RCPB, or the containment are designated type C.

D. Those variables needed to assess the operation of individual safety systems and other systems important to safety are designated type D.

E. Those variables that are required for use in determining the magnitude of the postulated releases and continually assessing any such releases of radioactive materials are designated type E.

The five classifications of variable are not mutually exclusive, in that a given variable (or instrument) may be included in one or more types. When a variable is included in one or more of the five classifications, the equipment monitoring this variable meets the requirements of the highest category identified.

Three categories of design and qualification criteria have been identified. The differentiation is made in order that an importance of information hierarchy can be recognized in specifying accident monitoring instrumentation. Category 1 instrumentation has the highest performance requirements and should be utilized for information which cannot be lost under any circumstances. Category 2 and Category 3 instruments are of lesser importance in determining the state of the plant and do not require the same level of operational assurance.

The primary differences between category requirements are in qualification, application of single failure, power supply, and display requirements. Category 1 requires seismic and environmental qualification, the application of a single failure criteria, utilization of emergency power, and an immediately accessible display. Category 2 requires environmental and seismic qualification commensurate with the required function but does not require the single failure criteria, emergency power, or an immediately accessible display. Category 2 requires, in effect, a rigorous performance verification for a single instrument channel. Category 3, which is high quality commercial grade, does not require qualification, single failure criteria, emergency power, or an immediately accessible display.

Table 7.5.2-1 summarizes the following information for each variable identified:

A. Instrument range or status.

B. Type and category.

C. Environmental qualification.

D. Seismic qualification.

E. Number of channels.

F. Display methodology.

G. Implementation date.

7.5.2.1 Definitions

7.5.2.1.1 Design Basis Accident Events

Those events, any one of which could occur during the lifetime of a particular unit, and those events not expected to occur but postulated because their consequences would include the potential for release of significant amounts of radioactive gaseous, liquid, or particulate material to the environment are DBA events. Excluded are those events (defined as normal and anticipated operational occurrences in 10 CFR 50) expected to occur more frequently than once during the lifetime of a particular unit.

The limiting accidents that were used to determine instrument functions are:

- Loss-of-coolant accident (LOCA).

- Steam line break.
- Feedwater line break.
- Steam generator tube rupture.

7.5.2.1.2 Hot Standby

Hot standby is the state of the plant in which the reactor is subcritical such that k_{eff} is less than or equal to 0.99 and the reactor coolant system (RCS) temperature is greater than or equal to 350°F.

7.5.2.1.3 Cold Shutdown

Cold shutdown is the state of the plant in which the reactor is subcritical such that k_{eff} is less than or equal to 0.99, the RCS temperature is less than 200°F, and the RCS pressure is less than or equal to 10 CFR 50, Appendix G limits.

7.5.2.1.4 Controlled Condition

A controlled condition is the state of the plant that is achieved when the "subsequent action" portion of the plant emergency procedures is implemented and the critical safety functions are being accomplished or maintained by the control room operating staff.

7.5.2.1.5 Critical Safety Functions

Critical safety functions are those safety functions that are essential to prevent a direct and immediate threat to the health and safety of the public. These are the accomplishing or maintaining of:

- Reactivity control.
- RCS pressure control.
- Reactor coolant inventory control.
- Reactor core cooling.
- Heat sink maintenance.
- Reactor containment environment.

7.5.2.1.6 Immediately Accessible Information

Immediately accessible information is information that is visually available to the control room operating staff immediately (i.e., within human response time requirements), once they have made the decision that the information is needed.

7.5.2.1.7 Primary Information

Primary information is information that is essential for the direct accomplishment of the preplanned manual actions necessary to bring the plant into a safe condition in the event of a DBA event; it does not include those variables that are associated with contingency actions.

7.5.2.1.8 Contingency Actions

Contingency actions are those manual actions that address conditions beyond the DBA events.

7.5.2.1.9 Key Variables

Key variables are those variables which provide the most direct measure of the information required.

7.5.2.1.10 Backup Information

Backup information is that information, made up of additional variables beyond those classified as key, that provide supplemental and/or confirmatory information to the control room operating staff. Backup variables do not provide indication which is as reliable or complete as that provided by primary variables and are not usually relied upon as the sole source of information.

7.5.2.2 Variable Types

These accident monitoring variables and information display channels are those that are required to enable the control room operating staff to perform the functions defined by type A, B, C, D, and E classifications as follows.

7.5.2.2.1 Type A

Type A variables provide the primary information required to permit the control room operating staff to:

A. Perform the diagnosis specified in the VEGP emergency operating instructions.

B. Take the specified, preplanned, manually controlled actions for which no automatic control is provided that are required for safety systems to accomplish their safety function in order to recover from the DBA.

C. Attain and maintain a cold shutdown condition.

The verification of the actuation of safety-related systems has been excluded from the type A definition. The variables which provide this verification are included in the definition of type D.

Type A variables are restricted to preplanned actions for DBA events. Variables used for contingency actions and additional variables which might be utilized are of types B, C, D, and E.

7.5.2.2.2 Type B

Type B variables provide to the control room operating staff information to assess the process of accomplishing or maintaining critical safety functions (i.e., reactivity control, RCS pressure control, RCS inventory control, reactor core cooling, heat sink maintenance, and reactor containment environment).

7.5.2.2.3 Type C

Type C variables provide the control room operating staff information to monitor:

A. The extent to which variables that indicate the potential for causing a gross breach of a fission product barrier have exceeded the design basis values.

B. The incore fuel cladding, the RCPB, or the primary reactor containment which may have been subject to gross breach.

   These variables include those required to initiate the early phases of the emergency plan. Excluded are those associated with monitoring of radiological release from the plant which are included in type E.

Type C variables used to monitor the potential for breach of a fission product barrier have an arbitrarily determined extended range. The extended range was chosen to minimize the probability of instrument saturation even if conditions exceed those predicted by the safety analysis.

Although variables selected to fulfill type C functions may rapidly approach the values that indicate an actual gross failure, it is the final steady-state value reached that is important. Therefore, a high degree of accuracy and a rapid response time are not necessary for type C information display channels.

7.5.2.2.4 Type D

Type D variables provide the control room operating staff sufficient information to monitor the performance of:

A. Plant safety systems employed for mitigating the consequences of an accident and subsequent plant recovery to attain a cold shutdown condition. These include verification of the automatic actuation of safety systems.

B. Other systems normally employed for attaining a cold shutdown condition.

7.5.2.2.5 Type E

Type E variables provide the control room operating staff information to:

A. Monitor the habitability of the control room.

B. Monitor the plant areas where access may be required to service equipment necessary to monitor or mitigate the consequences of an accident.

C. Estimate the magnitude of release of radioactive material through identified pathways and continually assess such releases.

D. Monitor radiation levels and radioactivity in the environment surrounding the plant.

7.5.2.3 Variable Categories

The qualification requirements of the type A, B, C, D, and E accident monitoring instrumentation are subdivided into three categories. Descriptions of the three categories are given below. Table 7.5.2-2 briefly summarizes the selection criteria for type A, B, C, D, and E variables into each of the three categories. Table 7.5.2-3 briefly summarizes the design and qualification requirements of the three designated categories.

7.5.2.3.1 Category 1

7.5.2.3.1.1 Selection Criteria for Category 1. The selection criteria for Category 1 variables have been subdivided according to the variable type. For type A, those key variables used for diagnosis or providing information for necessary operator action have been designated Category 1. For type B, those key variables used for monitoring the process of accomplishing or maintaining critical safety functions have been designated Category 1. For type C, those key variables used for monitoring the potential for breach of a fission product barrier have been designated Category 1. There are no type D or type E Category 1 variables.

7.5.2.3.1.2 Qualification Criteria for Category 1. The instrumentation is environmentally and seismically qualified in accordance with sections 3.11 and 3.10, respectively. Instrumentation shall continue to read within the required accuracy following but not necessarily during a seismic event.

At least one instrumentation channel is qualified from the sensor up to and including the display. For the other instrumentation channels, qualification as a minimum is applied up to and includes the channel isolation device. (Refer to paragraph 7.5.2.3.4 in regard to extended range instrumentation qualification.)

7.5.2.3.1.3 Design Criteria for Category 1.

A. No single failure within either the accident-monitoring instrumentation, its auxiliary supporting features, or its power sources, concurrent with the failures that are a cause of or result from a specific accident, will prevent the control room operating staff from being presented the required information. Where failure of one accident-monitoring channel results in information ambiguity (e.g., the redundant displays disagree), the additional information is provided to allow the control room operating staff to analyze the actual conditions in the plant. This may be accomplished by providing additional independent channels of information of the same variable (addition of an identical channel) or by providing independent channels which monitor different variables which bear known relationships to the channels (addition of a diverse channel(s)). Redundant or diverse channels are electrically independent and physically separated from each other with two-train separation and from equipment not classified important to safety in accordance with Regulatory Guide 1.75, Physical Independence of Electric Systems.

If ambiguity does not result from failure of the channel, then a third redundant or diverse channel is not required.

B. The instrumentation is energized from station emergency standby power sources, battery backed where momentary interruption is not tolerable, as discussed in Regulatory Guide 1.32, Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants.

C. The out-of-service interval is based on normal Technical Specification requirements for the system it serves where applicable or where specified by other requirements.

D. Servicing, testing, and calibration programs are specified to maintain the capability of the monitoring instrumentation. For those instruments where the required interval between testing is less than the normal time interval between generating station shutdowns, a capability for testing during power operation is provided.

E. Whenever means for removing channels from service are included in the design, the design facilitates administrative control of the access to such removal means.

F. The design facilitates administrative control of the access to all setpoint adjustments, module calibration adjustments, and test points.

G. The monitoring instrumentation design minimizes the development of conditions that would cause meters, annunciators, recorders, alarms, etc., to give anomalous indications that could be potentially confusing to the control room operating staff.

H. The instrumentation is designed to facilitate the recognition, location, replacement, repair, or adjustment of malfunctioning components or modules.

I. To the extent practicable, monitoring instrumentation inputs are from sensors that directly measure the desired variables. An indirect measurement is made only when it can be shown by analysis to provide unambiguous information.

J. Periodic checking, testing, calibration, and calibration verification are performed in accordance with the applicable portions of Regulatory Guide 1.118, Periodic Testing of Electric Power and Protection Systems.

K. The range selected for the instrumentation encompasses the expected operating range of the variable being monitored to the extent that saturation does not negate the required action of the instrument in accordance with the applicable portions of Regulatory Guide 1.105, Instrument Setpoints.

7.5.2.3.1.4 Information Processing and Display Interface Criteria for Category 1. The interface criteria specified here provide requirements to be implemented in the processing and displaying of the information.

A. The control room operating staff have immediate access to the information from redundant or diverse channels in units of measure familiar to the staff; i.e. for temperature readings, degrees should be used, not volts. Where two or more instruments are needed to cover a particular range, overlapping instrument spans are provided.

B. A historical record of at least one instrumentation channel for each process variable is maintained. A recorded pre-event history for these channels is required for a minimum of 1 h, and continuous recording of these channels is required following an accident until continuous recording of such information is no longer deemed necessary. The term "continuous recording" is not intended to exclude the use of discrete time sample data storage systems. This recording is available when required and does not need to be immediately accessible.

The time period of 1 h was selected based on a representatively slow transient which bounds this time requirement. A 1/2-in.- equivalent break area LOCA was selected since the reactor trip occurs at approximately 50 min after the break. Where direct and immediate trend or transient data is essential for operator information or action, the recording is immediately accessible.

7.5.2.3.2 Category 2

7.5.2.3.2.1 Selection Criteria for Category 2. The selection criteria for Category 2 variables are subdivided according to the variable type. For types A, B, and C, those variables which provide preferred backup information are designated Category 2. For type D, those key variables that are used for monitoring the performance of safety systems have been designated Category 2. For type E, those key parameters to be monitored for use in determining the magnitude of the release of radioactive materials and for continuously assessing such releases have been designated Category 2.

7.5.2.3.2.2 Qualification Criteria for Category 2. Category 2 instrumentation is qualified from the sensor up to and including the channel isolation device for at least the environment (seismic and/or environmental) in which it must operate to serve its intended function.

7.5.2.3.2.3 Design Criteria for Category 2.

A. Category 2 instrumentation that is required to operate following a safe shutdown earthquake to mitigate a consequential plant incident is energized from a seismically qualified power source, which is battery backed where momentary interruption is not tolerable. The instrumentation required to function after a seismic event is the safety-related cold shutdown instrumentation described in section 7.4. Otherwise, the instrumentation is energized from a highly reliable onsite power source, not necessarily the emergency standby power, which is battery backed where momentary interruption is not tolerable.

B. The out-of-service interval is based on paragraph 7.5.2.4, Post Accident Monitoring Program.

C. Servicing, testing, and calibration programs are specified to maintain the capability of the monitoring instrumentation. For those instruments where the required interval between testing is less than the normal time interval between generating station shutdowns, a capability for testing during power operation is provided.

D. Whenever means for removing channels from service are included in the design, the design facilitates administrative control of the access to such removal means.

E. The design facilitates administrative control of the access to all setpoint adjustments, module calibration adjustments, and test points.

F. The monitoring instrumentation design minimizes the potential for the development of conditions that would cause meters, annunciators, recorders, and alarms, etc., to give anomalous indications that could be potentially confusing to the operator.

G. The instrumentation is designed to facilitate the recognition, location, replacement, repair, or adjustment of malfunctioning components or modules.

H. To the extent practicable, monitoring instrumentation inputs are from sensors that directly measure the desired variables. An indirect measurement is made only when it can be shown by analysis to provide unambiguous information.

I. Periodic checking, testing, calibration, and calibration verification are in accordance with applicable portions of Regulatory Guide 1.118, Periodic Testing of Electric Power and Protection Systems.

J. The range selected for the instrumentation encompasses the expected operating range of the variable being monitored to the extent that saturation does not negate the required action of the instrument in accordance with the applicable portions of Regulatory Guide 1.105, Instrument Setpoints.

7.5.2.3.2.4 Information Processing and Display Interface Criteria for Category 2. The instrumentation signal is, as a minimum, processed for display on demand. Recording requirements are variable specific and are determined on a case-by-case basis.

7.5.2.3.3 Category 3

7.5.2.3.3.1 Selection Criteria for Category 3. The selection criteria for Category 3 variables have been subdivided according to the variable type. For types B and C, those variables which provide backup information have been designated Category 3. For types D and E, those variables which provide preferred backup information have been designated Category 3. There are no Category 3 type A variables.

7.5.2.3.3.2 Qualification Criteria for Category 3. The instrumentation is high quality, commercial grade which is not required to provide information when exposed to a post-accident adverse environment.

7.5.2.3.3.3 Design Criteria for Category 3.

A. Servicing, testing, and calibration programs are specified to maintain the capability of the monitoring instrumentation. For those instruments where the required interval between testing is less than the normal time interval between generating station shutdown, a capability for testing during power operation is provided.

B. Whenever means for removing channels from service are included in the design, the design facilitates administrative control of the access to such removal means.

C. The design facilitates administrative control of the access to all setpoint adjustments, module calibration adjustments, and test points.

D. The monitoring instrumentation design minimizes the potential for the development of conditions that would cause meters, annunciators, recorders, and alarms, etc., to give anomalous indications that could be potentially confusing to the operator.

E. The instrumentation is designed to facilitate the recognition, location, replacement, repair, or adjustment of malfunctioning components or modules.

F. To the extent practicable, monitoring instrumentation inputs are from sensors that directly measure the desired variables. An indirect measurement is made only when it can be shown by analysis to provide unambiguous information.

7.5.2.3.3.4 Information Processing and Display Interface Criteria for Category 3. The instrumentation signal is, as a minimum, processed for display on demand. Recording requirements are variable specific and are determined on a case-by-case basis.

7.5.2.3.4 Extended Range Instrumentation Qualification Criteria

The qualification environment for extended range instrumentation is based on the DBA events; the assumed maximum qualification value of the monitored variable shall be equal to the specified maximum range for the variable. The monitored variable is assumed to approach this peak by extrapolating the most severe initial ramp associated with the DBA events. The decay is considered proportional to the decay for this variable associated with the DBA events. No additional qualification margin needs to be added to the extended range variable. All environmental envelopes, except those pertaining to the variable measured by the information display channel, are those associated with the DBA events. The environmental qualification requirement for extended range instrument does not account for steady-state elevated levels that may occur in other environmental parameters associated with the extended range variable. For example, a sensor measuring containment pressure must be qualified for the measured process variable range (i.e., three times design pressure for concrete containments), but the corresponding ambient temperature is not mechanistically linked to that pressure. Rather, the ambient temperature value is the bounding value for DBA events analyzed in chapter 15. The extended range requirement is to ensure that the instrument will continue to provide information if conditions degrade beyond those postulated in the safety analysis. Since extended variable ranges are nonmechanistically determined, extension of associated parameter levels is not justifiable and is therefore not required.

7.5.2.4 Post Accident Monitoring Instrumentation Program

A program shall be maintained, the post accident monitoring instrumentation program, which ensures the capability to monitor plant variables and systems operating status during and following an accident. This program shall include those instruments provided to indicate system operating status and furnish information regarding the release of radioactive materials (Category 2 and 3 instrumentation as defined in Regulatory Guide 1.97 Revision 2) and provide the following:

A. Preventive maintenance and/or periodic surveillance of instrumentation.

B. Preplanned operating procedures and backup instrumentation to be used if one or more monitoring instruments become inoperable.

C. Administrative procedures for returning inoperable instruments to operable status as soon as practicable.

7.5.3 DESCRIPTION OF VARIABLES

7.5.3.1 Type A Variables

Type A variables are defined in paragraph 7.5.2.2.1. They are the variables which provide primary information required to permit the control room operating staff to:

A. Perform the diagnosis specified in the VEGP emergency operating procedures.

B. Take specified preplanned manually controlled actions for which no automatic control is provided that are required for safety systems to accomplish their safety function to recover from a design basis accident (DBA) event. (Verification of actuation of safety systems is excluded from type A and is included as type D.)

C. Attain and maintain a cold shutdown condition.

Key type A variables have been designated Category 1. These are the variables which provide the most direct measure of the information required. The key type A variables are:

- Reactor coolant system (RCS) wide-range (WR) pressure.
- WR hot leg reactor coolant temperature (T_{hot}).
- WR cold leg reactor coolant temperature (T_{cold}).
- WR steam generator level.
- Narrow-range (NR) steam generator level.
- Pressurizer level.
- Containment pressure.
- Steam line pressure.
- Containment water level (WR).

- Containment water level (NR).
- Condensate storage tank level.
- Refueling water storage tank level.
- Auxiliary feedwater flow.
- Containment radiation level (high range).
- Core exit temperature.
- Steam line radiation.
- RCS subcooling.

No type A variable has been designated Category 2 or 3. A summary of type A variables is provided in table 7.5.3-1.

7.5.3.2 Type B Variables

Type B variables are defined in paragraph 7.5.2.2.2. They are the variables that provide information to the control room operating staff to assess the process of accomplishing or maintaining critical safety functions, i.e.:

- Reactivity control.
- RCS pressure control.
- Reactor coolant inventory control.
- Reactor core cooling.
- Heat sink maintenance.
- Primary reactor containment environment.

Variables which provide the most direct indication (i.e., key variable) to assess each of the six critical safety functions have been designated Category 1. Preferred backup variables have been designated Category 2. These are listed in table 7.5.3-2.

7.5.3.3 Type C Variables

Type C variables are defined in paragraph 7.5.2.2.3. Basically, they are the variables that provide to the control room operating staff information to monitor the potential for breach or actual gross breach of:

- Incore fuel clad.
- RCS boundary.

- Containment boundary.

(Variables associated with monitoring of radiological release from the plant are included in type E.)

Those type C key variables which provide the most direct measure of the potential for breach of one of the three fission product boundaries have been designated Category 1. Backup information indicating potential for breach is designated Category 2. Variables which indicate actual breach and have been designated as preferred backup information are designated Category 2. All other backup variables have been designated Category 3.

Table 7.5.3-3 summarizes the selection of type C variables.

7.5.3.4 Type D Variables

Type D variables are defined in paragraph 7.5.2.2.4. They are those variables that provide sufficient information to the control room operating staff to monitor the performance of:

A. Plant safety systems employed for mitigating the consequences of an accident and subsequent plant recovery to attain a safe shutdown condition, including verification of the automatic actuation of safety systems.

B. Other systems normally employed for attaining a cold shutdown condition.

Type D key variables are designated Category 2. Preferred backup information is designated type D Category 3.

The following systems or major components have been identified as requiring type D information to be monitored:

A. Pressurizer level and pressure control (assess status of the pressurizer following return to normal pressure and level control under certain post-accident conditions).

B. Chemical and volume control system (CVCS) (employed for attaining a safe shutdown under certain post-accident conditions).

C. Secondary pressure and level control (employed for restoring/maintaining a secondary heat sink under post-accident conditions).

D. Emergency core cooling system (ECCS).

E. Auxiliary feedwater.

F. Containment systems.

G. Component cooling water (CCW).

H. Nuclear service cooling water.

I. Residual heat removal (RHR).

J. Heating, ventilation, and air-conditioning (HVAC) (if required for engineered safety features operation).

K. Electric power to vital safety systems.

L. Verification of automatic actuation of safety systems.

M. Reactor coolant system status.

N. Reactivity control.

Table 7.5.3-4 lists the key variables identified for each system listed above.

For the purpose of specifying seismic qualification for type D Category 2 variables, it is assumed that a seismic event and a break in Seismic Category 1 piping will not occur concurrently. As a result, the limiting event is an unisolated (single failure of a main steam isolation valve) break in Nuclear Safety Class 2 main steam piping. Instrumentation necessary to monitor this event and associated with the safety systems which are required to mitigate should be seismically qualified. Similarly, the environmental qualification of type D Category 2 variables depends on whether the instrumentation is subject to a high-energy line break when required to provide information.

7.5.3.5 Type E Variables

Type E variables are defined in paragraph 7.5.2.2.5. They are those variables that provide the control room operating staff with information to:

A. Monitor the habitability of control room.

B. Monitor the plant areas where access may be required to service equipment necessary to monitor or mitigate the consequences of an accident.

C. Estimate the magnitude of release of radioactive materials through identified pathways.

D. Monitor radiation levels and radioactivity in the environment surrounding the plant.

Key type E variables are qualified to Category 2 requirements. Preferred backup type E variables are qualified to Category 3 requirements.

Table 7.5.3-5 lists the key type E variables.

7.5.3.6 Plant Safety Monitoring System

The plant safety monitoring system (PSMS) is a microprocessor-based monitoring system used to process and output many of the Regulatory Guide 1.97, Revision 2 variables in proper format to internal plasma displays and external indicators, displays, cabinets and other equipment. The PSMS consists of three types of modular components: the remote processing unit, the display processing unit, and the plasma display. These components perform the data acquisition and processing, the data base consolidation and comparison, and the data selection and display, respectively.

The system is seismically and environmentally qualified and is configured to address single failure criteria. Qualification details are available in sections 3.10 and 3.11. In addition, the PSMS has the capability for online testing without affecting reactor protection and control.

The configuration of the PSMS on VEGP consists of a remote processing unit associated with each protection channel set and a remote processing unit assigned to the monitoring of non-Class 1E signals. Each remote processing unit acts independently to perform data acquisition, engineering unit conversion, and limit checking. Through this independence, the system is immune to common mode failures. The remote processing units associated with the four protection channel sets are powered by the same vital buses as the protection sets.

The remote processing units also provide an additional function: isolated data links from each remote processing unit serve as inputs to the integrated plant computer for transfer of the Regulatory Guide 1.97 data set.

The plasma display modules are redundant, qualified graphic/alphanumeric modules for displaying Category 1 and certain Category 2 variables on demand (as indicated in table 7.5.2-1). The displays have been human factor engineered in order to provide to the operator a concise display of plant conditions. Access to particular information is via functional keys integral to the PSMS. These displays will be used in conjunction with other control room instrumentation to monitor the VEGP throughout all operating conditions including anticipated operational occurrences and accident and post-accident conditions.

Additional discussions on the features of PSMS are provided in paragraphs 7.4.3.3, Alternate Shutdown Indication System, 7.7.2.7, Core Cooling Monitor, and 7.7.2.8, Reactor Vessel Level Instrumentation System.

7.5.4 ADDITIONAL INFORMATION

A cross-reference of variables and categories for each instrument identified in the VEGP survey is included in table 7.5.4-1.

Table 7.5.4-2 is included as a cross-reference to identify post-accident monitoring systems instruments utilized at VEGP which also address the recommendations of NUREG-0737. The instruments identified meet the intent of the guidance provided in NUREG-0737.

7.5.5 BYPASSED AND INOPERABLE STATUS INDICATION FOR ENGINEERED SAFETY FEATURES SYSTEMS

7.5.5.1 Description

In accordance with the guidance of Regulatory Guide 1.47, means are provided for automatic system level indication of the plant's engineered safety features (ESF) systems which are bypassed or inoperable. The system status monitoring panel (QBPS) serves the purpose of such indication and is located in the control room, next to the main control board. The QBPS panel is safety grade and seismically qualified and hence remains functional during and after a design basis event. However, no credit is taken in the accident analysis (chapter 15) for the QBPS indications being available to the operator. Most of the information displayed on the QBPS panel can be derived by the operator from other safety-grade instrumentation in the control room, such as:

- Individual ESF equipment status indicating lights and controls' position.
- ESF equipment monitor (light boxes on the main control board), light groups 1 through 5.
- Lights indicating the status and manual override of the automatic actuation signals for the control room and fuel handling building ESF heating, ventilation, and air-conditioning (HVAC) systems.

The bypasses that are applied manually to test-block the automatic safety actuation signal for either train of the two latter HVAC systems are monitored only on the QBPS panel.

Each ESF system monitored on the QBPS panel (table 7.5.5-1) has one monitoring light and an adjacent selector handswitch for each of its trains. The light-switch pairs belonging to each train are grouped together for easy train identification. Under normal circumstances, i.e., when no bypass condition has been detected, all monitoring lights are off. A detection of such condition in any monitored component in either train of an ESF system causes the corresponding light on the panel to illuminate. The engraving on the light readily identifies the bypassed system; the location of the light on the panel determines the train. Each system monitoring light can be illuminated either automatically or manually by its corresponding selector handswitch. The QBPS panel circuitry automatically detects any of the following conditions as applicable in each monitored component of the ESF systems:

- Loss of control power.
- Control handswitch in pull-to-lock position.
- Overcurrent lockout relay tripped (process-control loads).
- Circuit breaker not in operating position.
- Control transferred from the control room to a local panel.
- Manual block of the actuation of one safety train to test the other train.[a]
- Loss of power to the relay actuation logic.[a]
- Manual override of an automatic actuation signal.[a]
- Incorrect status of a hand-operated component, defeating the safety function of an ESF system.[b]

The components monitored by the system status monitoring circuits are the ESF pumps, fans, compressors, valves, dampers, and relay logic circuits.

In accordance with Regulatory Guide 1.47, the automatic system level indication of bypass and inoperable status is provided only for automatically actuated systems, including those systems that directly support the automatically initiated systems but may not be automatically initiated because they are normally in the operating mode. No automatic indication is provided for the bypasses that are expected to occur less frequently than once per year or when the system is not required to be operable. These may include such maintenance features as manual valves provided for isolation of equipment for repairs, electrical cable connections, or other manual disconnects. However, manual initiation of ESF equipment bypass indication on a system level basis is provided; each status monitoring light on the QBPS panel can be manually lit by its adjacent selector handswitch. Under administrative control, manual bypass indication can be set up or removed to further enhance the operator's awareness of the current status of the ESF systems. The automatic indication feature cannot be removed by operator action.

[a] Applies only to the control room and fuel-handling building ESF HVAC systems.
[b] Applies only to the reactor water storage tank main drain isolation valve No. 1204-207, which, if closed, disables the safety injection system.

The illumination of any monitoring light on the QBPS panel will activate the annunciator alarm on the main control board and will also be registered by the plant computer. Annunciator response procedures are discussed in subsection 13.5.2. In accordance with Institute of Electrical and Electronics Engineers (IEEE) Standard 384 and Regulatory Guide 1.75, proper isolation is provided between Class 1E circuits in different trains and between the Class 1E and non-Class 1E circuits.

The QBPS monitoring lights and circuits are powered from the same train as the ESF equipment they monitor. The operability of each train of the systems status monitoring system can be readily verified by pressing a test pushbutton for that train, which activates all status monitoring lights, annunciator, and the computer input in that train.

The availability of power to the ESF system status monitoring circuitry is indicated on the QBPS panel (one normally lit indicating light per train). Loss of power is immediately annunciated.

7.5.5.2 Conformance to Regulatory Guide 1.47

As required by Nuclear Regulatory Commission Regulatory Guide 1.47, the ESF status monitoring system comprising the QBPS panel and related circuitry provides the following functions:

A. Bypassed and inoperable status is automatically indicated at the system level for protection systems and systems actuated or controlled by protection systems (i.e. for primary ESF systems). Automatic status indication for primary ESF systems does not occur for the bypassing or inoperable condition of auxiliary or supporting systems which must be operable for the primary ESF systems to perform their safety-related functions. However, the intent of Position C.2 of RG 1.47 is met in that automatic indication is provided for bypassed and inoperable status for these auxiliary and supporting systems; and in that VEGP procedures will include steps to ensure that an operator, in responding to the annunciator alarm for inoperable indication of a support system, will manually activate the inoperable status indication for the appropriate primary ESF systems.

B. The automatic indication discussed in A is highly reliable and provided in the control room, while manual activation of the system level indicators is also provided in the control room.

C. Automatic indication is provided for all those bypasses or deliberately induced inoperable conditions that are expected to occur more frequently than once per year, have significant bearing upon the ability to perform safety functions, and are expected to occur when the affected system is normally required to be operable.

7.5.5.3 Conformance to Branch Technical Position ICSB-21

The guidelines set forth in Branch Technical Position ICSB-21, Revision 2, are complied with by the following:

A. Bypass indicators are arranged to enable the operator to determine the status of each safety system to determine if continued reactor operation is permissable.

B. The operator cannot cancel erroneous bypass indications.

C. The ESF status monitoring system is not used to perform functions that are essential to safety.

D. The ESF status monitoring system is designed and installed in a manner that precludes the possibility of adverse effects on plant safety systems and does not reduce the required independence between redundant safety systems.

E. The design of the ESF status monitoring system provides the capability of assuming its operable status during normal plant operation by means of verifying its indicating and annunciating functions.

F. The ESF status monitoring system is designed with shared system bypass condition(s) monitored in both units.

7.5.5.4 System Drawings

The logic and elementary diagrams pertaining to the ESF systems status monitoring system are included in the tables in subsection 1.7.1.

TABLE 7.5.2-1 (SHEET 1 OF 14)

POST-ACCIDENT MONITORING INSTRUMENTATION

Variable	Range/ Status	Type/ Category	Qualification Environmental	Qualification Seismic	Number of Instruments	Control Room Indication	Implementation Date	Power Supply	EOF Indication	TSC Indication	Conformance	ERDS Parameter[ae]
Reactor coolant pressure (wide range)	0 to 3000 psi	A1, B1, B2, C1, C2, D2	Yes	Yes	4 per unit	Plasma display 4 meters 1 dual recorder	Core load	1E	Yes	Yes	Conforms to Reg Guide 1.97, Rev 2	Yes
RCS wide range T_{hot}	0° to 700°F	A1, B1, B2	Yes	Yes	1 per loop	Plasma display 4 meters 1 dual recorder	Complete	1E	Yes	Yes	Conforms to Reg Guide 1.97, Rev 2	Yes
RCS wide range T_{cold}	0° to 700°F	A1, B1, B2	Yes	Yes	1 per loop	Plasma display 4 meters 1 dual recorder	Complete	1E	Yes	Yes	Conforms to Reg Guide 1.97, Rev 2	Yes
Wide range steam generator water level	0 to 100 percent of span	A1, B1, B2, D2	Yes	Yes	1 per steam generator	Plasma display 4 meters 2 dual recorders	Complete	1E	Yes	Yes	Conforms to Reg Guide 1.97, Rev 2	Yes
Narrow range steam generator water level	0 to 100 percent of span	A1, B1, D2	Yes	Yes	3 per steam generator	Plasma display 12 meters	Complete	1E	Yes	Yes	Conforms to Reg Guide 1.97, Rev 2	No
Pressurizer level	0 to 100 percent of span	A1, B1, D2	Yes	Yes	3 per unit	Plasma display 3 meters 1 recorder	Complete	1E	Yes	Yes	Conforms to Reg Guide 1.97, Rev 2	Yes
Containment pressure	0 to 75 psig	A1, B1, B2, C2, D2	Yes	Yes	4 per unit	Plasma display 4 meters 1 dual recorder	Complete	1E	Yes	Yes	Conforms to Reg Guide 1.97, Rev 2	Yes

TABLE 7.5.2-1 (SHEET 2 OF 14)

Variable	Range/ Status	Type/ Category	Qualification Environmental	Qualification Seismic	Number of Instruments	Control Room Indication	Implementation Date	Power Supply	EOF Indication	TSC Indication	Conformance	ERDS Parameter[ae]
Steam line pressure	0 to 1300 psig	A1, B1, D2	Yes	Yes	3 per loop	Plasma display 12 meters 2 dual recorders	Complete	1E	Yes	Yes	Conforms to Reg Guide 1.97, Rev 2	Yes
Refueling water storage tank level	0 to 100 percent of span	A1, D2	Yes	Yes	4 per unit	Plasma display 4 meters 1 dual recorder	Complete	1E	Yes	Yes	Conforms to Reg Guide 1.97, Rev 2	Yes
Containment water level (narrow range)	0 to 48 in.[z]	A1, B1, B2, C2, D2	Yes	Yes	2 per unit	Plasma display	Core load	1E	Yes	Yes	Conforms to Reg Guide 1.97, Rev 2	Yes
Containment water level (wide range)	0 to 120 in.[z]	A1, B1, B2, C2, D2	Yes	Yes	2 per unit	Plasma display 2 meters	Complete	1E	Yes	Yes	Conforms to Reg Guide 1.97, Rev 2	Yes
Condensate storage tank level	0 to 100 percent of span	A1, B1, D2	Yes	Yes	2 per tank	Plasma display 4 meters 1 dual recorder	Complete	1E	Yes	Yes	Conforms to Reg Guide 1.97, Rev 2	No
Auxiliary feedwater flow	0 to 600 gal/min	A1, B1, D2	Yes	Yes	2 per loop	Plasma display 4 meters	Core load	1E	Yes	Yes	Conforms to Reg Guide 1.97, Rev 2	Yes
Containment radiation level (wide range)	1 to 10^8R/h	A1, B1, B2, E2	Yes	Yes	2 per unit	Safety-related display console	Complete	1E	Yes	Yes	Conforms to Reg Guide 1.97, Rev 2	Yes
Steamline radiation monitor	10^{-1} to $10^3 \mu Ci/cm^3$	A1, B2, E2	Yes	Yes	1 per loop	Safety-related display console	Core load	1E	Yes	Yes	Conforms to Reg Guide 1.97, Rev 2	Yes
Core exit temperature	200 to 2300°F	A1, B1, C1	Yes	Yes	2 per core quadrant per train	Plasma display	Core load	1E	Yes	Yes	Conforms to Reg Guide 1.97, Rev 2	Yes
RCS subcooling	600°F subcooling to 350°F superheat	A1, B1, D2	Yes	Yes	2 per unit	Plasma display	Core load	1E	Yes	Yes	Conforms to Reg Guide 1.97, Rev 2	Yes

TABLE 7.5.2-1 (SHEET 3 OF 14)

Variable	Range/ Status	Type/ Category	Qualification Environmental	Qualification Seismic	Number of Instruments	Control Room Indication	Implementation Date	Power Supply	EOF Indication	TSC Indication	Conformance	ERDS Parameter[ae]
Neutron flux (Extended range)	Lower: 10^{-1} to 10^{6} CPS Upper: 10^{-3} to 200 percent power	B1, D2	Yes	Yes	2 per unit	Plasma display	Core load	1E	Yes	Yes	Conforms to Reg Guide 1.97, Rev 2[a g]	No
Reactor vessel water level	Upper range: 60-120 percent Full range: 0-120 percent Dynamic Head: 0-120 percent liquid	B1, C2, D2	Yes	Yes	2 per unit	Plasma display	Core load	1E	Yes	Yes	Conforms to Reg. Guide 1.97, Rev. 2	Yes
Containment isolation valve status	Open/ closed	C1,[ai] C2, D2	Yes	Yes	1 per valve	1 pair of[ak] lights per valve	Complete	1E	Yes	Yes	(a)	No
Containment hydrogen concentration	0 to 10 percent partial pressure	B3, C3	Yes	Yes	2 per unit	2 meters 1 recorder plasma display	Complete	1E	Yes	Yes	Conforms to Reg. Guide 1.97, Rev. 2	Yes
Containment pressure (extended range)	-5 to 160 psig	C1, C2	Yes	Yes	2 per unit	Plasma display	Core load	1E	Yes	Yes	Conforms to Reg. Guide 1.97, Rev. 2	Yes
Plant vent[t] level radiogas	10^{-6} to $10^{4}\mu Ci/cm^{3}$	C2, E2	Yes[o]	Yes[x]	1 per unit	Communication console	Core load	Non-1E[p]	Yes	Yes	Conforms to Reg. Guide 1.97, Rev. 2	Yes
Plant vent particulates and halogen (passive filters)	NA	C2, E2	Yes	Yes	NA	NA	Complete	NA	NA	NA	Conforms to Reg. Guide 1.97, Rev. 2	No

TABLE 7.5.2-1 (SHEET 4 OF 14)

Variable	Range/ Status	Type/ Category	Qualification Environmental	Qualification Seismic	Number of Instruments	Control Room Indication	Implementation Date	Power Supply	EOF Indication	TSC Indication	Conformance	ERDS Parameter[ae]
Auxiliary building radiation level (portable sampling)	NA	C3	No	No	NA	NA	Complete	NA	NA	NA	Conforms to Reg. Guide 1.97, Rev. 2	No
Site environmental radiation level (portable sampling)	NA	C3, E3	No	No	NA	NA	Complete	NA	NA	NA	Conforms to Reg. Guide 1.97, Rev. 2	No
RCS activity	N/A	C3	No	No	NA	No	Complete	NA	No	No	(b)	No
Reactor coolant Pump status	Running/ stopped	D2	Yes	Yes	1 per pump	1 pair of lights per pump plasma display	Complete	1E	Yes	Yes	(d)	No
Pressurizer pressure	1700/ 2500 psig	D2	Yes	Yes	4 per unit	4 meters	Complete	1E	Yes	Yes	(d)	No
Power-operated relief (PORV) valve status	Open/ closed	D2	Yes	Yes	1 per valve	1 pair of lights per valve	Complete	1E	Yes	Yes	Conforms to Reg. Guide 1.97, Rev. 2	No
Primary safety valve status	Open/ Closed	D2	Yes	Yes	1 per valve	Plasma display[q]	Core load	1E	Yes	Yes	Conforms to Reg. Guide 1.97, Rev. 2	No
Pressurizer heater current	0-800 amps	D2	Yes[o]	No	2 per unit	[q]	Core load	Non-1E UPS	Yes	Yes	Conforms to Reg. Guide 1.97, Rev. 2	No
Pressurizer relief tank temperature	50° to 350°F	D3	No	No	1 per unit	1 meter	8/1/86	Non-1E UPS	Yes	Yes	(w)	No
Charging system flow	0 to 200 gal/min	D2	Yes[o]	No	1 per path	1 meter	Core load	Non-1E UPS	Yes	Yes	Conforms to Reg. Guide 1.97, Rev. 2	Yes
Emergency charging flow	0 to 150 gal/min	D2	Yes	Yes	1 per path	2 meters	Core load	Non-1E UPS	Yes	Yes	Conforms to Reg. Guide 1.97, Rev. 2	No

TABLE 7.5.2-1 (SHEET 5 OF 14)

Variable	Range/ Status	Type/ Category	Qualification Environmental	Qualification Seismic	Number of Instruments	Control Room Indication	Implementation Date	Power Supply	EOF Indication	TSC Indication	Conformance	ERDS Parameter[ae]
Letdown flow	0 to 200 gal/min	D2	Yes[a]	No	1 per path	1 meter	Core load	Non-1E UPS	Yes	Yes	Conforms to Reg. Guide 1.97, Rev. 2	No
Emergency letdown	0 to 80 gal/min	D2	Yes[a]	No	1 per path	2 meters	Core load	Non-1E UPS	Yes	Yes	Conforms to Reg. Guide 1.97, Rev. 2	No
Volume control tank level	0 to 100 percent of span	D2	Yes[a]	No	1 per tank	1 meter	Complete	Non-1E UPS	Yes	Yes	Conforms to Reg. Guide 1.97, Rev. 2	No
Chemical and volume control system valve status	Open/ closed	D2	Yes	Yes	1 per valve	1 pair of[ab] lights per valve	Complete	1E/Non-1E UPS	Yes	Yes	(d)	No
Chemical and volume control system pump status	Running/ stopped	D2	Yes	Yes	1 per pump	1 pair of lights per pump	Complete	1E	Yes	Yes	(d)	No
Reactor coolant pump seal injection flow	0 to 20 gal/min	D2	Yes	Yes	1 per pump	4 meters	Complete	Non-1E UPS	Yes	Yes	(d)	No
Steam generator atmospheric PORV status	Open/ closed	D2	Yes	Yes	1 per valve	1 pair of lights per valve	Complete	Non-1E UPS	Yes	Yes	Conforms to Reg. Guide 1.97, Rev. 2	No
Main steam line isolation valve status	Open/ closed	B2, D2	Yes	Yes	1 per valve	1 pair of lights per valve	Complete	1E	Yes	Yes	(d)	No
Main steam isolation valve bypass isolation valve status	Open/ closed	B2, D2	Yes	Yes	1 per valve	1 pair of[ab] lights per valve	Complete	1E	Yes	Yes	(d)	No
Steam generator system status main steam flow	0 to 4.8 million lb/h	D2	Yes	Yes	2 per steam generator	8 meters 4 recorders	Complete	Non-1E UPS	Yes	Yes	Conforms to Reg. Guide 1.97, Rev. 2	No

TABLE 7.5.2-1 (SHEET 6 OF 14)

Variable	Range/ Status	Type/ Category	Qualification Environmental	Qualification Seismic	Number of Instruments	Control Room Indication	Implementation Date	Power Supply	EOF Indication	TSC Indication	Conformance	ERDS Parameter[ae]
Main feedwater regulating valve status	Open/ closed	D2	Yes	Yes	1 per valve	1 pair of[ab] lights per valve	Complete	1E	Yes	Yes	(d)	No
Main feedwater bypass valve status	Open/ closed	D2	Yes	Yes	1 per valve	1 pair of[ab] lights per valve	Complete	1E	Yes	Yes	(d)	No
Main feedwater flow	0 to 4.8 million lb/h	D2	Yes[o]	Yes[aa]	2 per steam generator	8 meters 4 recorders	Complete	Non-1E UPS	Yes	Yes	Conforms to Reg. Guide 1.97, Rev. 2	Yes
Steam generator blowdown isolation valve status	Open/ closed	D2	Yes	Yes	1 per valve	1 pair of lights per valve	Complete	1E	Yes	Yes	(d)	No
Steam generator sample line isolation valve status	Open/ closed	D2	Yes	Yes	1 per valve	1 pair of lights per valve	Complete	1E	Yes	Yes	(d)	No
High-head safety injection	0 to 1000 gal/min	D2	Yes	Yes	1 per valve	1 meter	Complete	1E	Yes	Yes	Conforms to Reg. Guide 1.97, Rev. 2	Yes
Low-head safety injection	0 to 800 gal/min	D2	Yes	Yes	1 per train	2 meters	Complete	1E	Yes	Yes	Conforms to Reg. Guide 1.97, Rev. 2	No
Main feedwater isolation valve status	Open/ closed	D2	Yes	Yes	1 per valve	2 pair of lights per valve	Complete	1E	Yes	Yes	(d)	No
Emergency core[u] cooling system valve status	Open/ closed	D2	Yes	Yes	1 per valve	1 pair of lights per valve	Complete	1E	Yes	Yes	(d)	No
Accumulator pressure	0 to 700 psig	D3	No	No	1 per tank	4 meters	Core load	Non-1E UPS	Yes	Yes	(aj)	No

TABLE 7.5.2-1 (SHEET 7 OF 14)

Variable	Range/ Status	Type/ Category	Qualification Environmental	Qualification Seismic	Number of Instruments	Control Room Indication	Implementation Date	Power Supply	EOF Indication	TSC Indication	Conformance	ERDS Parameter[(ae)]
Safety injection pump status	Running/ stopped	D2	Yes	Yes	1 per pump	1 pair of lights per pump	Complete	1E	Yes	Yes	(d)	No
Auxiliary feedwater valve status	Open/ closed	D2	Yes	Yes	1 per valve	1 pair of lights per valve	Complete	1E	Yes	Yes	(d)	No
Feedwater isolation bypass valve status	Open/ closed	D2	Yes	Yes	1 per valve	1 pair of lights[(ab)] per valve	Complete	1E	Yes	Yes	(d)	No
Auxiliary feedwater pump status	Running/ stopped	D2	Yes	Yes	1 per pump	1 pair of lights per pump	Complete	1E	Yes	Yes	Conforms to Reg. Guide 1.97, Rev. 2	No
Containment spray valve status	Open/ closed	D2	Yes	Yes	1 per valve	1 pair of lights per valve	Complete	1E	Yes	Yes	(d)	No
Containment spray pump status	Running/ stopped	D2	Yes	Yes	1 per pump	1 pair of lights per pump	Complete	1E	Yes	Yes	(d)	No
Containment fan cooler damper position	Open/ closed	D2	Yes	Yes	1 per damper	1 pair of lights per damper	Complete	1E	Yes	Yes	(d)	No
Containment fan cooler breaker position	High/low speed, on/off	D2	Yes	Yes	1 per breaker	1 pair of lights per breaker	Complete	1E	Yes	Yes	(d)	No
Component cooling water header pressure	0 to 200 psig	D2	Yes[(o)]	Yes[(aa)]	1 per train	2 meters	Complete	Non-1E UPS	Yes	Yes	(d)	No
Component cooling water header temperature	0 to 300°F	D2	Yes[(o)]	Yes[(aa)]	1 per train	IPC	Complete	Non-1E UPS	Yes	Yes	Conforms to Reg. Guide 1.97, Rev 2	No

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Variable	Range/ Status	Type/ Category	Qualification Environmental	Qualification Seismic	Number of Instruments	Control Room Indication	Implementation Date	Power Supply	EOF Indication	TSC Indication	Conformance	ERDS Parameter[ae]
Component cooling water surge tank level	0 to 100 percent	D2	Yes[o]	Yes[aa]	1 per train	IPC	Complete	Non-1E UPS	Yes	Yes	(d)	No
Component cooling water flow to engineered safety features components	0 to 15,000 gal/min	D2	Yes[ah]	Yes[aa]	1 per train	2 meters	Complete	Non-1E UPS	Yes	Yes	Conforms to Reg. Guide 1.97, Rev 2	No
Component cooling water pump status	Running/ stopped	D2	Yes	Yes	1 per pump	1 pair of lights per pump	Complete	1E	Yes	Yes	(d)	No
Auxiliary component cooling water flow from RCP seals	0-400 gal/min	D2	Yes	Yes	2 per path	2 meters	Complete	1E	No	No	(d)	No
Nuclear service cooling water system flow	0 to 25,000 gal/min	D2	Yes[o]	Yes[aa]	1 per train	2 meters	Complete	Non-1E UPS	Yes	Yes	(d)	No
Nuclear service cooling water valve status	Open/ closed	D2	Yes	Yes	1 per valve	1 pair of lights per valve	Complete	1E	Yes	Yes	(d)	No
Nuclear service cooling water pump status	Running/ stopped	D2	Yes	Yes	1 per pump	1 pair of lights per pump	Complete	1E	Yes	Yes	(d)	No
Nuclear service cooling water fan status	On/off	D2	Yes	Yes	1 per fan	1 pair of lights per fan	Complete	1E	Yes	Yes	(d)	No

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Variable	Range/ Status	Type/ Category	Qualification Environmental	Qualification Seismic	Number of Instruments	Control Room Indication	Implementation Date	Power Supply	EOF Indication	TSC Indication	Conformance	ERDS Parameter[ae]
Heating, ventilation, and air-conditioning system status[v][am]	Open/ closed	D2	Yes	Yes	1 per damper	1 pair of lights per damper	Complete	1E	Yes[ac]	Yes[ac]	(d)	No
Engineered safety features (ESF) environment temperature	High/ normal	D2	Yes	Yes	1 per ESF component	1 alarm per channel	Complete	1E/ Non-1E	Yes[ad]	Yes[ad]	(d, n)	No
ESF environment cooler fan status	On/off	D2	Yes	Yes	1 per ESF component	1 pair of lights per channel	Complete	1E	Yes	Yes	(d)	No
ac, dc, vital instrument voltage	Bus specific	D2	Yes	Yes	1 per bus	1 meter per bus	Complete	1E	Yes	Yes	Conforms to Reg. Guide 1.97, Rev 2	No
Residual heat removal (RHR) heat exchanger discharge temperature	50° to 400°F	D2	Yes	Yes	1 per train	IPC	Core load	Non-1E UPS	Yes	Yes	Conforms to Reg. Guide 1.97, Rev 2	No
RHR flow	0 to 5000 gal/min	D2	Yes	Yes	1 per train	2 meters	Complete	1E	Yes	Yes	Conforms to Reg. Guide 1.97, Rev 2	Yes
RHR valve status	Open/ closed	D2	Yes	Yes	1 per valve	1 pair of lights per valve	Complete	1E	Yes	Yes	(d)	No
RHR pump status	Running/ stopped	D2	Yes	Yes	1 per pump	1 pair of lights per pump	Complete	1E	Yes	Yes	(d)	No
Control rod position indication	0 to 228 steps	D3	No	No	2 per control rod	Light-emitting diodes	Complete	Non-1E	No	No	Conforms to Reg. Guide 1.97, Rev 2	No
Reactor trip breaker position	Tripped/ not tripped	D2	Yes	Yes	1 per breaker	1 pair of lights per breaker	Complete	1E	Yes	Yes	(d)	No

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Variable	Range/ Status	Type/ Category	Qualification Environmental	Qualification Seismic	Number of Instruments	Control Room Indication	Implementation Date	Power Supply	EOF Indication	TSC Indication	Conformance	ERDS Parameter(ae)
SI actuation	Actuated/ not actuated	D2	Yes	Yes	1 per train	1 light per unit	Complete	1E	Yes	Yes	(d)	No
Turbine stop valve status	Closed/ not closed	D2	No(o)	No	1 per valve	1 light per valve	Complete	Non-1E	Yes	Yes	(d)	No
First stage turbine pressure	0 to 120% power	D2	Yes	Yes	1 per train	2 meters	Complete	1E	Yes	Yes	(d)	No
Plant vent airflow rate	Unit 1 3200 to 160,000 Sft^3/min Unit 2 2000 to 100,000 Sft^3/min	E2	Yes(o)	Yes(x)	1 per unit	(q)	Core load	Non-1E(p)		Yes	(y)	No
Condenser air ejector radiation	$5.0E^{-7}$ to $1.0E^{+5}$ $\mu Ci/cm^3$	E3	No	No	1 per unit	Communication console	Complete	Non-1E	Yes	Yes	Conforms to Reg Guide 1.97, Rev 2	Yes
Area radiation monitors												
Control room monitor	10^{-2} to 10^3 mr/h	E3	No	No	1 per plant	Communication console	Complete	Non-1E diesel-backed	Yes	Yes	(e)	No
Fuel handling building monitor	10^{-1} to 10^4 mr/h	E3	No	No	1 per plant	Communication console	Complete	Non-1E diesel-backed	Yes	Yes	(e)	No
Sampling room monitor	10^{-1} to 10^4 mr/h	E3	No	No	1 per plant	Communication console	Complete	Non-1E diesel-backed	Yes	Yes	(e)	No
Accident sampling capability Primary coolant and sump		E3	No	No	NA		Complete	NA			al.	No
• Grab Sample												

TABLE 7.5.2-1 (SHEET 11 OF 14)

Variable	Range/ Status	Type/ Category	Qualification Environmental	Qualification Seismic	Number of Instruments	Control Room Indication	Implementation Date	Power Supply	EOF Indication	TSC Indication	Conformance	ERDS Parameter[ae]
Containment air • Grab Sample		E3	No	No	NA		Complete	NA			al.	No
High level radioactive liquid tank	0 to 100 percent of span	D3	No	No	1 per tank	High level alarm	Complete	Non-1E	No	No	(r)	No
Radioactive gas holdup tank pressure	0 to 150 psig	D3	No	No	1 per tank	High pressure alarm	Complete	Non-1E	No	No	(s)	No
Meteorological parameters	NA	E3	No	No	20 per plant	[q]	Complete	Non-1E	Yes	Yes	Conforms to Reg Guide 1.97, Rev 2	Yes[af]
Containment sump radiation	NA	E3	No	No	NA	NA	Complete	NA	NA	NA	(i)	No
Containment atmospheric temperature											(f)	Yes
Containment sump water temperature	0-400°F	D2	Yes	Yes	1 per unit	1 meter	Core load	Non-1E	No	No	Conforms to Reg Guide 1.97, Rev 2	No
Heat removal by the containment fan system											(h)	No
Containment sump and containment atmospheric sampling											(i)	No
Boric acid charging flow											(j)	No
RCS extended range pressure											(k)	No

TABLE 7.5.2-1 (SHEET 12 OF 14)

Variable	Range/ Status	Type/ Category	Qualification Environmental	Qualification Seismic	Number of Instruments	Control Room Indication	Implementation Date	Power Supply	EOF Indication	TSC Indication	Conformance	ERDS Parameter(ae)
Accumulator tank level											(m)	No

a. Containment Isolation Valve Status - Containment isolation valves in series are provided with a single indication on each valve. The indications for the two valves in series are powered from different trains.

b. RCS Activity - Normal sampling system can be used to sample the RCS for later activity analysis.

c. Deleted

d. The plant specific study performed on VEGP indicated that these parameters were included in the minimum set of parameters necessary to monitor the performance of:

1. Plant safety systems employed for mitigating the consequences of an accident and subsequent plant recovery to attain a cold shutdown condition, including verification of the automatic actuation of safety systems.
2. Other systems normally employed for attaining a cold shutdown condition.

e. Area Radiation - VEGP will use health physics plant survey monitoring to determine radiation levels in the areas or locations where post accident access may be required or which may contain a significant post-accident radiation source.

f. Containment Atmospheric Temperature - The VEGP emergency response guidelines do not require the operator to take an action that would result in adverse consequences if the containment temperature was indicating an erroneous value. As such, the containment temperature indication is considered a Category 3 parameter.

g. Deleted

h. Heat Removal by the Containment Fan/Heat Removal System - Other parameters were designated as VEGP type D variables to demonstrate that the containment heat removal systems are operating properly. These include the following:

- Containment spray flow.
- Containment spray system valve status.
- Containment pressure.
- Containment water level.
- Containment spray pump status.
- Fan cooler damper position.
- Fan cooler breaker position.

i. Containment Sump and Atmospheric Sampling - Data obtained from containment sump and atmospheric sampling are not used by the operator to take any manual action to mitigate the consequences of an accident. Hence, these parameters are considered backup variables (Category 3) and the capability to obtain grab samples is maintained. See Note al.

j. Boric Acid Charging Flow - For monitoring the performance of the emergency core cooling system (ECCS), VEGP has designated refueling water storage tank level, high-head safety injection flow, low-head safety injection flow, containment water level, and ECCS valve status. Since the ECCS does not normally take suction from the boric acid tank (BAT), the boric acid charging flow was not designated a key variable. If the operator uses the BAT for boration following an accident, normal charging flow and reactor coolant system (RCS) sampling is used to demonstrate that the RCS is being borated.

k. RCS Extended Range Pressure - RCS wide-range pressure will be used.

l. Deleted

TABLE 7.5.2-1 (SHEET 13 OF 14)

m. Reactor coolant system pressure indication and valve position indication for the accumulator discharge isolation and accumulator vent valves provide adequate status of the accumulators.

n. The environment/temperature for the diesel generator building is monitored by instrumentation that is designed for a mild environment, nonseismic, and powered from a non-Class 1E UPS.

o. These devices are backup verification to qualified system status parameters. These devices are purchased to perform in their anticipated service environments for the plant conditions for which they must function.

p. The alternate (auxiliary) power supply will be either battery-backed or powered by the diesel generator.

q. These parameters may be displayed on the integrated plant computer monitor display in the control room.

r. The liquid radwaste system is not required following an event. The containment normal sumps and the reactor coolant drain tank discharge lines are isolated by a containment isolation signal. These lines will be isolated subsequent to any LOCA. ECCS pumps are located in flood retaining rooms that prevent the spread of post-LOCA recirculation fluid if a pump were to fail. The recycle holdup tank level is alarmed (at 95 percent volume) in the control room as part of the liquid radwaste system trouble alarm. An operator would be dispatched to the local control panel to clear the annunciated signal.

s. The design pressure of each of the waste gas decay tanks (WGDT) is 150 psig. There are seven WGDTs per unit and two shared shutdown decay tanks. Each tank is provided with a pressure transmitter and a high pressure alarm in the control room as part of the gaseous waste processing system trouble alarm. An operator would be dispatched to the local control panel to clear the annunciated signal. The alarms for the WGDTs are set at 100 psig. All of the WDGTs are provided with relief valves set at or below the tanks design pressure. The relief valves for the WGDTs discharge to the shutdown decay tanks which are normally at low pressure. Should an extended discharge to the shutdown decay tank occur a high alarm would be received prior to lifting of the shutdown decay tank relief valve. The relief valves for the shutdown decay tanks discharge to the plant vent which is monitored by the plant vent monitor. Failure of one of these tanks was analyzed in subsection 15.7.1. Based upon the protection afforded by the installed tank relief valves and the potential eventual release to the plant vent, the gaseous waste processing system trouble alarm in the control room is adequate for providing information concerning the status of the WGDTs.

t. The containment effluent radioactivity is monitored by the plant vent monitor. The plant vent receives the discharges from the containment purge system, auxiliary building, control building, and the fuel handling building.

u. Accumulator isolation valve status is a part of the ECCS valve status.

v. Emergency ventilation damper position is part of the heating, ventilation, and air conditioning system status.

w. The upper range of pressurizer relief tank temperature indication was chosen to envelope the maximum expected temperature in the tank. The rupture disk on the relief tank has a blowout pressure of 92 psig, corresponding to a saturation temperature of 331°F.

x. Seismic qualification is limited to the isokinetic nozzles, flow transmitter, monitoring skid, and associated data processing module.

y. Additional flow instrumentation is available that provides a range of 3,000-190,000 Sft^3/min for Unit 1 and 1,200-120,000Sft^3/min for Unit 2.

z. Containment narrow range water level has a 0-48 in. instrument span starting at 6 in. above the sump bottom and ending at 6 in. above the top of the sump. Containment wide range water level has a 0-120 in. instrument span starting at 9 in. above the containment floor and ending at 10 ft.-9 in. above the containment floor.

aa. Applies to the seismic integrity of the pressure boundary only.

ab. Other position indication (via the system status monitoring panel and/or monitoring light boxes) is available if the pair of lights associated with the valve hand switch which is powered from the same source as the solenoid valve is lost due to intrusion of a harsh environment on the unsealed solenoid.

ac. The auxiliary feedwater turbine driven pump room pneumatic damper position is not available in the TSC and EOF. This damper receives an open signal on auxiliary feedwater turbine driven pump start and fails open in the event of loss of offsite power to provide ventilation via natural circulation. Damper position indication may be obtained from the control room.

TABLE 7.5.2-1 (SHEET 14 OF 14)

ad. Indications of ESF environmental temperatures in the TSC and EOF are high alarms. High temperatures are of concern for equipment operability in these environments following an accident; therefore, alarms of low temperatures are not needed.

ae. Changes to these parameters may require NRC notification per 10 CFR 50, Appendix E, Section VI. Additional parameters transmitted, but not shown in the table, are NIS Source, Intermediate, and Power Range Detectors; RCS flows; liquid effluent radiation; CVCS letdown radiation; and Steam Generator Blowdown Radiation.

af. Meteorological parameters transmitted through ERDS are 10-meter wind speed, 10-meter wind direction, and 60- to 10-meter delta temperature.

ag. Due to post LOCA flooding of the reactor cavity/incore instrument tunnel, the extended range neutron flux monitors could possibly be submerged and thus become inoperable. These detectors are required from the time of event initiation, until a stabilized subcritical condition is established, return to critical is no longer credible, and manual sampling is established. This is consistent with Regulatory Guide 1.97, Revision 2 which indicates the function of the excore neutron flux detectors is "function detection; accomplishment of mitigation," and the function of boron concentration measurement is "verification"; and with NUREG-0737 (item II.B.3) which requires the capability to obtain and analyze boron samples within approximately 1 hour, i.e., well before the excore neutron detectors may become inoperable.

ah. Procured for mild environment.

ai. Only one channel of positive indication is provided per valve, but the NRC determined that with this one exception, containment isolation valve position indication meets all other category 1 criteria. See NUREG-1137.

aj. Per NRC letter from C. E. Carpenter, Jr. to C. K. McCoy dated November 19, 1993, the accumulator pressure variable is Category 3 not Category 2.

ak. Several containment isolation valves are operated by both the A-Train and the B-Train. In this case, the control room indication for these valves is 2 pair of lights per valve.

al. With License Amendments 123 and 101, the NRC staff approved elimination of the post-accident sampling system (PASS). However, pursuant to the NRC safety evaluation for WCAP-14986 which provided the basis for NRC approval of PASS elimination, contingency plans have been developed for obtaining and analyzing highly-radioactive samples of reactor coolant, containment sump liquid, and containment atmosphere.

am. The Containment Cooler dampers (HV-2582A, HV-2582B, HV-2583A, HV-2583B, HV-2584A, HV-2584B, HV-2585A, HV-2585B) are deenergized open with their associated breakers locked off. As such, these damper indications are not required to be monitored and are not included in the heating, ventilation, and air-conditioning system status.

TABLE 7.5.2-2

SUMMARY OF SELECTION OF CRITERIA

Type	Category 1	Category 2	Category 3
A	Key variables that are used for diagnosis or providing information necessary for operator action	Variables which provide preferred backup information	None
B	Key variables that are used for monitoring the process of accomplishing or maintaining critical safety functions	Variables which provide preferred backup information	Variables which provide backup information
C	Key variables that are used for monitoring the potential for breach of a fission product barrier	Variables which provide preferred backup information	Variables which provide backup information
D	None	Key variables which are used for monitoring the performance of plant systems	Variables which provide preferred backup information which are used for monitoring the performance of plant systems
E	None	Key variables to be monitored for use in determining the magnitude of the release of radioactive materials and for continuously assessing such releases.	Variables to be monitored which provide preferred backup information for use in determining the magnitude of the release of radioactive materials and for continuously assessing such releases.

TABLE 7.5.2-3

SUMMARY OF DESIGN, QUALIFICATION, AND INTERFACE REQUIREMENTS

Qualification	Category 1	Category 2	Category 3
Environmental	Yes	As appropriate (See paragraph 7.5.2.3.2.2.)	No
Seismic	Yes	As appropriate (See paragraph 7.5.2.3.2.2.)	No
Design			
Single failure	Yes	No	No
Power supply	Emergency diesel generator	Onsite	As required
Channel out of service	Technical Specifications	Technical LAM Specifications	As required
Testability	Yes	Yes	As required
Interface			
Minimum indication	Immediately accessible	Demand	Demand
Recording	Yes	As required (See paragraph 7.5.2.3.2.4.)	As required (See paragraph 7.5.2.3.3.4.)

(a) As defined in paragraph 7.5.2.4, Post Accident Monitoring Instrumentation Program.

TABLE 7.5.3-1

SUMMARY OF TYPE A VARIABLES

Variable	Variable Function	Type/ Category
RCS pressure (wide range (WR))	Key	A1
T_{hot} (WR)	Key	A1
T_{cold} (WR)	Key	A1
Steam generator level (WR)	Key	A1
Steam generator level (narrow range (NR))	Key	A1
Pressurizer level	Key	A1
Containment pressure	Key	A1
Steam line pressure	Key	A1
Containment water level (WR)	Key	A1
Containment water level (NR)	Key	A1
Condensate storage tank level	Key	A1
Refueling water storage tank level	Key	A1
Auxiliary feedwater flow	Key	A1
Containment area radiation level (WR)	Key	A1
Core exit temperature	Key	A1
Steam line radiation monitor	Key	A1
RCS subcooling	Key	A1

TABLE 7.5.3-2 (SHEET 1 OF 2)

SUMMARY OF TYPE B VARIABLES

Function Monitored	Variable	Variable Function	Type/ Category
Reactivity control	Extended range Neutron Flux	Key	B1
	WR T_{hot}	Backup (P)	B2
	WR T_{cold}	Backup (P)	B2
RCS pressure control	RCS pressure (WR)	Key	B1
	WR T_{hot}	Key	B1
	WR T_{cold}	Key	B1
	Containment pressure	Backup (P)	B2
	Containment area radiation (WR)	Backup (P)	B2
	Stream line radiation	Backup (P)	B2
Reactor coolant inventory control	Pressurizer level	Key	B1
	Reactor vessel water level	Key	B1
	Containment water level (NR)	Backup (P)	B2
	Containment water level (WR)	Backup (P)	B2
	WR steam generator level	Backup (P)	B2
Reactor core cooling	Core exit temperature	Key	B1
	RCS subcooling	Key	B1
	CST level	Key	B1
	Reactor vessel water level	Key	B1
	WR T_{hot}	Backup (P)	B2
	WR T_{cold}	Backup (P)	B2
	RCS pressure (WR)	Backup (P)	B2
Heat sink maintenance	NR steam generator level	Key	B1
	WR steam generator level	Key	B1
	Auxiliary feedwater flow	Key	B1
	Core exit temperature	Key	B1
	Steam line pressure	Key	B1
	Main steam line isolation and bypass valve status	Backup (P)	B2

TABLE 7.5.3-2 (SHEET 2 OF 2)

Function Monitored	Variable	Variable Function	Type/ Category
Containment environment	Containment pressure	Key	B1
	Containment area radiation	Key	B1
	Containment water level (NR)	Key	B1
	Containment water level (WR)	Key	B1
	Containment hydrogen concentration	Key	B1

TABLE 7.5.3-3

SUMMARY OF TYPE C VARIABLES

Function Monitored	Variable	Condition	Variable Function	Type/ Category
Incore fuel clad	Core exit temperature	Potential for breach	Key	C1
	Reactor vessel water level	Potential for breach	Backup (P)	C2
	RCS activity	Actual breach	Backup	C3
RCS boundary	RCS pressure (WR)	Potential for breach	Key	C1
	RCS pressure (WR)	Actual breach	Backup (P)	C2
	Containment pressure	Actual breach	Backup (P)	C2
	Containment water level (NR)	Actual breach	Backup (P)	C2
	Containment water level (WR)	Actual breach	Backup (P)	C2
Containment boundary	Containment pressure (extended range)	Potential for breach	Key	C1
	Containment hydrogen concentration	Potential for breach	Key	C1
	Plant vent radiation level	Actual breach	Backup (P)	C2
	Containment isolation valve status	Actual breach	Key	C2
	Containment pressure (extended range)	Actual breach	Backup (P)	C2
	Site environmental radiation	Actual breach	Backup	C3
	Auxiliary building radiation	Actual breach	Backup	C3

TABLE 7.5.3-4 (SHEET 1 OF 4)

SUMMARY OF TYPE D VARIABLES

System	Variable	Variable Function	Type/ Category
Pressurizer level and pressure control	Power-operated relief valve (PORV) status	Key	D2
	Safety valve status	Key	D2
	Pressurizer level	Key	D2
	RCS pressure (WR)	Key	D2
	Pressurizer heater power availability	Key	D2
	Pressurizer pressure	Key	D2
CVCS	Charging system flow	Key	D2
	Letdown flow	Key	D2
	Volume control tank level	Key	D2
	Seal injection flow	Key	D2
	CVCS valve status	Key	D2
Secondary pressure and level control	Steam generator atmospheric steam dump valve status	Key	D2
	Main steam flow	Key	D2
	Main steam isolation valve and bypass valve status	Key	D2
	Steam generator blowdown isolation valve status	Key	D2
	Steam line pressure	Key	D2
	Auxiliary feedwater flow	Key	D2
	Steam generator level (WR)	Key	D2
	Steam generator level (NR)	Key	D2
	Main feedwater control and bypass valve status	Key	D2
	Main feedwater isolation valve and bypass valve status	Key	D2
	Main feedwater flow	Key	D2
	SG sample line isolation valve status	Key	D2

TABLE 7.5.3-4 (SHEET 2 OF 4)

System	Variable	Variable Function	Type/ Category
Reactor coolant	RCS subcooling	Key	D2
System status	Reactor coolant pump status	Key	D2
	Reactor vessel water level	Key	D2
ECCS	Refueling water storage tank level	Key	D2
	HHSI and LHSI flow	Key	D2
	Containment water level (NR)	Key	D2
	Containment water level (WR)	Key	D2
	ECCS valve status	Key	D2
	Accumulator pressure	Backup	D3
Auxiliary feedwater	Auxiliary feedwater flow	Key	D2
	Auxiliary feedwater valve status	Key	D2
	Condensate storage tank level	Key	D2
Containment	Containment spray flow	Key	D2
	Containment water level (WR and NR)	Key	D2
	Containment spray valve status	Key	D2
	Containment spray pump status	Key	D2
	Containment pressure	Key	D2
	Containment fan cooler damper position	Key	D2
	Containment fan cooler breaker position	Key	D2
	Containment isolation valve status	Key	D2
	Containment sump water temperature	Key	D2
CCW	Header pressure	Key	D2
	Header temperature	Key	D2
	Surge tank level	Key	D2
	CCW flow	Key	D2
	CCW pump status	Key	D2
	A flow from RCP seals	Key	D2

TABLE 7.5.3-4 (SHEET 3 OF 4)

System	Variable	Variable Function	Type/ Category
Nuclear service cooling water system	Valve status	Key	D2
	System flow	Key	D2
	Fan status	Key	D2
	Pump status	Key	D2
Reactor coolant	RCS subcooling	Key	D2
System status	Reactor coolant pump status	Key	D2
	Reactor vessel water level	Key	D2
RHR	Heat exchanger discharge temperature	Key	D2
	Flow	Key	D2
	Valve status	Key	D2
	RCS pressure (WR)	Key	D2
	Pump status	Key	D2
HVAC	Environment for ESF components	Key	D2
	System status	Key	D2
	ESF environment cooler status	Key	D2
Electric power	ac/dc vital instrument voltage	Key	D2
Verification of automatic actuation of safety systems	Reactor trip breaker position	Key	D2
	Reactor trip bypass breaker position	Key	D2
	Rod position indication	Backup	D3
	SI activation	Key	D2
	Turbine stop valve position	Key	D2
	First-stage turbine pressure	Key	D2
	Main feedwater control bypass valve status	Key	D2
	Main feedwater isolation valve status	Key	D2
	Auxiliary feedwater pump status	Key	D2

TABLE 7.5.3-4 (SHEET 4 OF 4)

System	Variable	Variable Function	Type/ Category
	Safety injection pump status	Key	D2
	Nuclear service cooling water pump status	Key	D2
	CCW pump status	Key	D2
	Containment isolation valve status	Key	D2
	Containment fan cooler status	Key	D2
	RHR pump status	Key	D2
	Containment spray pump status	Key	D2
	CVCS pump status	Key	D2
Reactivity control system	Extended range neutron flux	Key	D2
	Control rod position indication	Backup	D3

TABLE 7.5.3-5

SUMMARY OF TYPE E VARIABLES

Variable	Variable Function	Type/ Category
Containment area radiation (WR)	Key	E2
Plant vent radiation level	Key	E2
Steam line radiation	Key	E2
Plant vent air flow rate	Key	E2
Condenser air ejector radiation	Backup (P)	E3
Area radiation monitors		
Control room monitor	Backup (P)	E3
Radiochemistry lab monitor	Backup (P)	E3
Fuel handling building monitor	Backup (P)	E3
Sampling room monitor	Backup (P)	E3
Decontamination station (large parts)	Backup (P)	E3
Decontamination station (small parts)	Backup (P)	E3
Instrument decontamination station	Backup (P)	E3
Site environmental radiation level	Backup (P)	E3
Meteorological parameters	Backup (P)	E3
Containment sump radiation	Backup (P)	E3

TABLE 7.5.4-1 (SHEET 1 OF 5)

SUMMARY OF VARIABLES AND CATEGORIES

Variable	Type A	Type B	Type C	Type D	Type E
	Type and Category				
Reactor coolant system (RCS) pressure (wide range (WR))	1	1,2	1,2	2	
WR T_{hot}	1	1,2			
WR T_{cold}	1	1,2			
WR steam generator level	1	1,2		2	
Narrow range (NR) steam generator level	1	1		2	
Pressurizer level	1	1		2	
Containment pressure	1	1,2	2	2	
Steam line pressure	1	1		2	
Refueling water storage tank level	1			2	
Containment water level (WR and NR)	1	1,2	2	2	
Condensate storage tank level	1	1		2	
Auxiliary feedwater flow	1	1			2
Containment radiation level (high range)	1	1,2			2
Steam line radiation monitor	1	2		2	
Core exit temperature	1	1		1	
RCS subcooling	1	1		2	
Condenser air ejector					3
Extended range neutron flux		1		2	

TABLE 7.5.4-1 (SHEET 2 OF 5)

Variable	Type and Category Type A	 Type B	 Type C	 Type D	 Type E
Reactor vessel water level		1	2	2	
Containment isolation valve status			1,2	2	
Control rod position				3	
Containment hydrogen concentration		1	1		
Containment pressure (extended range)			1,2		
RCS activity			3		
Plant vent radiogas level			2		2
Auxiliary building radiation level (portable sample)			3		
Site environmental radiation level			3		3
Reactor coolant pump status				2	
Pressurizer pressure				2	
Power-operated relief valve (PORV) status				2	
Primary safety valve status				2	
Pressurizer heater current				2	
Pressurizer relief tank temperature				3	
Charging system flow				2	
Emergency charging flow				2	
Letdown flow				2	
Emergency letdown				2	
Volume control tank level				2	
Chemical and volume control system (CVCS) valve status				2	
CVCS pump status				2	

TABLE 7.5.4-1 (SHEET 3 OF 5)

Variable	Type and Category: Type A	Type B	Type C	Type D	Type E
Reactor coolant pump seal injection flow				2	
Steam generator atmospheric PORV status				2	
Main steam line isolation valve status		2		2	
Main steam line isolation valve bypass isolation valve status		2		2	
Steam generator system status-main steamflow				2	
Main feedwater control valve status				2	
Main feedwater control bypass valve status				2	
Main feedwater isolation bypass valve status				2	
Main feedwater isolation valve status				2	
Main feedwater flow				2	
Steam generator blowdown isolation valve status				2	
Steam generator sample line isolation valve status				2	
High-head safety injection flow				2	
Low-head safety injection flow				2	
Emergency core cooling system valve status				2	
Accumulator pressure				3	
Auxiliary feedwater valve status				2	
Containment spray valve status				2	
Containment spray pump status				2	

TABLE 7.5.4-1 (SHEET 4 OF 5)

Variable	Type and Category				
	Type A	Type B	Type C	Type D	Type E
Containment fan cooler damper position				2	
Containment fan cooler breaker position				2	
Component cooling water (CCW) header pressure				2	
CCW header temperature				2	
CCW surge tank level				2	
CCW flow				2	
Auxiliary component cooling water from RCP seals				2	
Nuclear service cooling water system flow				2	
Nuclear service cooling water system valve status				2	
Residual heat removal (RHR) heat exchanger discharge temperature				2	
RHR flow				2	
RHR valve status				2	
RHR pump status				2	
Engineered safety features (ESF) environment temperature				2	
ESF environment cooler status				2	
Heating, ventilation, and air-conditioning system status				2	
ac and dc vital instrument voltage				2	
SI actuation				2	
Reactor trip breaker position				2	

TABLE 7.5.4-1 (SHEET 5 OF 5)

Variable	Type and Category Type A	 Type B	 Type C	 Type D	 Type E
Turbine stop valve position				2	
First-stage turbine pressure				2	
Auxiliary feedwater pump status				2	
Safety injection pump status				2	
Nuclear service cooling water pump status				2	
Nuclear service cooling water fan status				2	
CCW pump status				2	
Area radiation					
Control room monitor					3
Fuel handling building area radiation					3
Sampling room monitor					3
Plant vent airflow rate					2
Meteorological parameters					3
Containment sump radiation					3
Accident sampling capability					3
Containment sump water temperature				2	

TABLE 7.5.4-2

NUREG-0737 CONFORMANCE

Applicable Section of NUREG-0737	Variable
II.D.3	Pressurizer PORV status
II.F.1, Attachment 4	Containment pressure (extended range)
II.F.1, Attachment 5	Containment water level (NR and WR)
II.F.1, Attachment 6[2]	Containment H@ concentration
II.F.2	Core exit temperature
	Reactor vessel level RCS subcooling
I.D.2	Safety parameter display system
II.E.1.2	Auxiliary feedwater flow
II.F.1, Attachment 3[1]	Containment area radiation (high range)
II.F.1, Attachment 2	Sampling and analysis of plant effluent (See section 11.5.)
II.F.1, Attachment 1	Noble gas effluent monitors (See section 11.5.)
II.K.1.5	ECCS and other system valve status

1. Calibration of high-range monitors is performed in accordance with the manufacturer's recommendation.

2. Accurate indication of containment hydrogen concentration is available to the operators within 90 minutes of initiating safety injection following a LOCA.

TABLE 7.5.5-1

ESF SYSTEMS MONITORED ON THE SYSTEM STATUS
MONITORING PANEL

System Name	System No.	Monitored Train
Nuclear service cooling water system	1202	A, B
Component cooling water system	1203	A, B
Spent fuel pit cooling system	1213	A, B
Auxiliary component cooling water system	1217	A, B
Safety injection system	1204	A, B
Chemical and volume control system	1208	A, B
Auxiliary feedwater system (motor driven)	1302	A, B
Auxiliary feedwater system (turbine driven)	1302	C
Containment spray system	1206	A, B
Residual heat removal system	1205	A, B
Containment building air cooling system	1501	A, B
Essential chilled water system	1592	A, B
Auxiliary building ESF equipment room coolers and auxiliary feedwater pumphouse HVAC system	1555, 1593	A, B
Control building ESF electrical equipment room HVAC system	1532	A, B
Control building control room HVAC system	1531	A, B
Fuel handling building ESF HVAC system	1542	A, B
Piping penetration filtration and exhaust system	1561	A, B
Electrical tunnel ventilation system	1540	A, B
Diesel generator standby power system and diesel generator, fuel oil, air start and diesel generator building HVAC systems	1566, 1821, 2403	A, B
Containment hydrogen recombiner system and CTB post LOCA cavity purge system	1513, 1516	A, B

7.6 INTERLOCK SYSTEMS IMPORTANT TO SAFETY

7.6.1 INSTRUMENTATION AND CONTROL POWER SUPPLY SYSTEM

7.6.1.1 Description

The following is a description of the vital instrumentation and control power supply system. Further information is provided in paragraph 8.3.1.1.5.

A. Refer to drawing 1X3D-AA-G01A for a single-line diagram of the vital instrumentation and control power supply system.

B. There are six Class 1E inverters, six distribution panels, four manual transfer switches, and four Class 1E batteries, each with two battery chargers. The manual transfer switches installed for one of the two battery chargers per train allow for incoming power connection from a FLEX diesel generator following BDBEE (Beyond Desgin Basis External Event) but are normally aligned to their Class 1E power sources. Each inverter is connected independently to one distribution panel. Channels I and II have two inverters each; channels III and IV each have only one inverter.

C. The six Class 1E inverters provide a source of 120-V, 60-Hz power for the reactor protection system, the engineered safety feature actuation system, and the nuclear steam supply system control and instrumentation, the post-accident monitoring system, and the safety-related radiation monitoring system. The power for the channel I, II, III, and IV inverters is from the Class 1E 125-V dc Train A, B, C, and D station batteries, respectively. The station batteries ensure continued operation of instrumentation systems in the event of a station blackout.

D. Each distribution panel may be connected to a backup source of 120-V ac power. The tie is through a local, manually operated breaker, which is mechanically interlocked with the breaker connecting the inverter to the distribution panel such that the distribution panel cannot be connected to both sources simultaneously. The backup 120-V ac power is derived from the train A and B 480-V ac distributing system via 480-120-V regulating transformers that are qualified as isolation devices.

7.6.1.2 Analysis

Since the inverters for each of the four channels are connected to independent battery systems, a loss of a single dc bus can only affect the dc power supply to one of the four channels.

Each inverter is independently connected to its respective instrument distribution panel so that the loss of an inverter cannot affect more than one of the six distribution panels.

Therefore no single failure in the instrumentation and control power supply system or its associated power supplies can cause a loss of power to more than one of the redundant loads.

The inverters are designed to maintain their outputs within acceptable limits. The loss of the dc input is alarmed in the control room, as is the loss of an inverter's output.

A more complete description of the instrumentation and control power supply system, including physical separation and provisions to protect against fire, is discussed in chapter 8.

Based on the scope definitions presented in references 1 through 3, the criteria which are applicable to the instrumentation and control power supply system is Institute of Electrical and Electronics Engineers (IEEE) Standard 308-1974. The design is in compliance with IEEE Standard 308-1974 and Regulatory Guide 1.6. Availability of this system is continuously indicated by the operational status of the systems it serves (drawing 1X3D-AA-G01A) and is verified by periodic testing performed on the served systems. The inverters have been seismically and environmentally qualified as discussed in sections 3.10 and 3.11.

7.6.1.3 References

1. The Institute of Electrical and Electronic Engineers, Inc., "IEEE Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations," IEEE Standard 308-1974.
2. The Institute of Electrical and Electronic Engineers, Inc., "IEEE Standard: Criteria for Protection Systems for Nuclear Power Generating Stations," IEEE Standard 279-1971.
3. The Institute of Electrical and Electronic Engineers, Inc., "IEEE Trial-Use Criteria for the Periodic Testing of Nuclear Power Generating Station Protection System," IEEE Standard 338-1975.

7.6.2 RESIDUAL HEAT REMOVAL ISOLATION VALVES

7.6.2.1 Description

The residual heat removal system (RHRS) isolation valves are normally closed and are only opened for residual heat removal (RHR) after system pressure is reduced to approximately 365 psig and system temperature has been reduced to approximately 350°F.

There are two motor-operated valves in series in each of the two RHR pump suction lines from the reactor coolant system (RCS) hot legs. The two valves nearest the RCS (valves HV8701B and HV8702B) are designated as the inner isolation valves, while the two valves nearest the RHR pumps (valves HV8701A and HV8702A) are designated as the outer isolation valves. The interlock logic provided for the isolation valves is shown in figure 7.6.2-1. Logic for the outer valves is identical to that provided for the inner isolation valves, except that equipment diversity is employed by virtue of the fact that the pressure transmitter set used for valve interlocks on the inner valves is manufactured differently from the pressure transmitter set used for the outer valve interlocks.

Each valve is interlocked so that it cannot be opened at the main control board unless the RCS pressure is below a preset pressure. This interlock prevents the valve from being opened at the main control board when the RCS pressure plus the RHR pump pressure would be above the RHRS design pressure. A second pressure interlock is provided which initiates a control room alarm to alert the operators if one or both of the valves are not fully closed and the RCS pressure is greater than 420 psig.

The interlock table for the inner and outer isolation valves is shown in table 7.6.2-1. Inner isolation valve HV8701B (in train C) and outer isolation valve HV8702A (in train D) are interlocked by valve position signals derived from stem-mounted switches on valves in the opposite train. The valves themselves are identified in table 7.6.2-1. These switches (designated limit switches No. 2) are operated by the position of the valve stem and are separate from the switches supplied with the valve motor operator (designated No. 1). The motor-operated limit switch on each valve is connected to the same electrical train as the valve motor with which it is interlocked.

Reactor coolant system pressure control during low temperature operation is discussed in paragraph 5.2.2.10.

7.6.2.2 Analysis

Based on the scope definitions presented in references 1 and 2, these criteria do not apply to the RHR isolation valve interlocks; however, in order to meet Nuclear Regulatory Commission (NRC) requirements and because of the possible severity of the consequences of loss of function, the requirements of Institute of Electrical and Electronic Engineers (IEEE) Standard 279-1971 will be applied with the following comments:

A. For the purpose of applying IEEE Standard 279-1971 to this circuit, the following definitions will be used:

   1. Protection System

      The two valves in series in each line and all components of their interlocking and closure circuits.

   2. Protective Action

      The initiation of an alarm in the main control room when RCS pressures are above the preset value and one or both valves are open.

B. IEEE Standard 279-1971, Section 4.10

   The above mentioned pressure interlock signals and logic will be tested online to the maximum extent possible without adversely affecting safety. This test will include the analog signal through to the train signal which activates the slave relays. (The slave relays provide the final output signal to the valve control circuit.) This is done in the best interests of safety, since an actual actuation to permit opening the valve or to test the automatic closing of an open valve could potentially leave only one remaining valve to isolate the low-pressure RHRS from the RCS.

C. IEEE Standard 279-1971, Section 4.15

   This requirement does not apply, as the setpoints are independent of mode of operation and are not changed.

D. IEEE Standard 279-1971, Section 4.12

   This requirement does not apply to these interlocks because bypass of the interlocks at the local station is under strict administrative control with the valves power removed (breaker locked in the open position) to prevent unauthorized opening of the valves.

Environmental qualification of the valves and wiring is discussed in section 3.11.

In those cases where nuclear steam supply system-furnished valves for engineered safety features (table 7.6.2-1) are in one train with interlocking provisions by valve position signals derived from stem-mounted switches on valves in the opposite train, the field wiring as well as motor control center wiring are in the balance of plant scope. They are wired and installed to ensure the following conditions:

A. Electrical independence of and separation of the switch(es) designated No. 2 (stem mounted) from the control circuit of the valve whose position is being sensed.

B. Separation of the field wiring of the valves switch(es) designated No. 2 (stem mounted) from the field wiring of the valves control circuit in accordance with IEEE Standard 384-1974.

Under the above conditions, a single failure analysis of either the controlling valves or the controlled valves train-oriented control circuitry will show that a single failure in the train-oriented control circuitry will not defeat the protective action of the redundant train-oriented control circuitry. Other than the cases where a stem-mounted limit switch No. 2 is used for position signals between valves assigned to the redundant train, there are no cases where interlocks mounted on equipment of one train are used in the circuitry of the redundant train.

7.6.2.3 References

1. The Institute of Electrical and Electronic Engineers, Inc., "IEEE Standard: Criteria for Protection Systems for Nuclear Power Generating Stations," IEEE Standard 279-1971.

2. The Institute of Electrical and Electronic Engineers, Inc., "IEEE Trial-Use Criteria for the Periodic Testing of Nuclear Power Generating Station Protection System," IEEE Standard 338-1975.

3. The Institute of Electrical and Electronics Engineers, Inc., "Trial-Use Standard Criteria for Separation of Class 1E Equipment and Circuits," IEEE Standard 384-1974.

7.6.3 REFUELING INTERLOCKS

Electrical interlocks (i.e., limit switches) as discussed in subsection 9.1.4 are provided for minimizing the possibility of damage to the fuel during fuel handling operations.

7.6.4 ACCUMULATOR MOTOR-OPERATED VALVES

The design of the interconnection of these signals to the accumulator isolation valve meets the following criteria established in previous Nuclear Regulatory Commission (NRC) positions on this matter:

A. Automatic opening of the accumulator valves when:

   1. The primary coolant system pressure exceeds a preselected value (specified in the Technical Specifications).

   2. A safety injection (SI) signal has been initiated.

   Both signals shall be provided to the valves.

B. Utilization of an SI signal to automatically remove (override) any bypass features that are provided to allow an isolation valve to be closed for short periods of time when the reactor coolant system (RCS) is at pressure (in accordance with the provisions of the Technical Specifications). As a result of the confirmatory SI signal, isolation of an accumulator with the reactor at pressure is acceptable.

The control circuit for these valves is shown in figure 7.6.4-1. The valves and control circuits are further discussed in subsections 6.3.2 and 6.3.5.

The SI system accumulator discharge isolation valves are motor- operated, normally open valves, which are controlled from the main control board. Technical Specifications require these valves to be open with power removed in mode 3 when RCS pressure is above 1000 psig.

These valves are also interlocked such that:

A. They open automatically on receipt of an SI signal with the main control board switch in either the "auto" or "close" position.

B. They open automatically whenever the RCS pressure is above the SI unblock pressure (P-11) specified in the Technical Specifications only when the main control board switch is in the "auto" position.

C. They cannot be closed as long as an SI signal is present.

The four main control board position switches for these valves provide a "spring return to auto" when placed in the open position and a "maintain position" when placed in the closed position.

The "maintain closed" position is required to provide an administratively controlled manual block of the automatic opening of the valve at pressure above the SI unblock pressure (P-11). The manual block or "maintain closed" position is required when performing periodic check valve leakage tests when the reactor is at pressure. The maximum permissible time that an accumulator valve can be closed when the reactor is at pressure is specified in the Technical Specifications.

Administrative control is required to ensure that any accumulator valve, which has been closed at pressures above the SI unblocking pressure, is returned to the "auto" position. Verification that the valve automatically returns to its normal full open position is also required.

During plant shutdown, the accumulator valves are closed. To prevent an inadvertent opening of these valves during that period, the accumulator valve motor circuit breakers are opened or withdrawn. Administrative control is again required to ensure that these valve circuit breakers are closed during the prestartup procedures.

Power lockout is provided for these valves as discussed in paragraph 8.3.1.1.11.

These normally open motor-operated valves have alarms, indicating a malpositioning (with regard to their emergency core cooling system function during the injection phase). The alarms sound in the main control room.

An alarm will sound for any accumulator isolation valve under the following conditions when the RCS pressure is above the SI unblocking pressure.

A. Valve motor-operated limit switch indicates valve not open.

B. Valve stem-operated limit switch indicates valve not open. The alarm on this switch will repeat itself at given intervals.

7.6.5 SWITCHOVER FROM INJECTION TO RECIRCULATION

The details of achieving cold leg recirculation following safety injection (SI) and after a loss-of-coolant accident (LOCA) are given in paragraph 6.3.2.8.

7.6.5.1 Description of Instrumentation Used for Switchover

Protection logic is provided to automatically open the two residual heat removal (RHR) containment emergency sump isolation valves (HV8811A in train A and HV8811B in train B) when two of four refueling water storage tank (RWST) level sensors indicate less than the low-low level setpoint in conjunction with the maintained SI signal. The SI signal is maintained by the contact of a slave relay in the solid-state protection system (SSPS) output cabinet that closes on SI and remains closed until manually reset from the control board. This manual reset switch is separate from the main SI reset switch, which is not associated with this circuit. The sump valve automatic open circuit reset switch permits the operator to remove the actuation signal if the corresponding sump isolation valve must be closed and retained in a closed position following a LOCA, e.g., for maintenance purposes.

7.6.5.2 Initiation Circuit

The two out of four low-low RWST level is the trip signal which, in coincidence with the SI signal, provides the initiation function to automatically open the containment sump isolation valves.

7.6.5.3 Logic

The logic function derived from the RWST level sensors and the SI signal is depicted on sheet 1, figure 7.6.5-1.

7.6.5.4 Bypass

The manual reset logic function is shown on sheet 2, figure 7.6.5-1; its purpose and action are described in paragraph 7.6.5.1. As noted, the SI signal is retained by latching it; it is not removed by action of the main SI reset used by the operator per emergency procedures to remove the SI signal to other equipment prior to realignment for switchover to the recirculation mode following a postulated LOCA.

7.6.5.5 Interlocks

The trip signal logic consists of four RWST water level transmitters, each of which provides a level signal to one of the four RWST level channel bistables. The RWST level channel bistables are:

- Normally deenergized.
- Deenergized on loss of power.
- Energized on low-low setpoint.

Each level channel bistable is assigned to a separate instrumentation and control power supply. A trip signal is provided from both train A and train B SSPS cabinets to the corresponding sump isolation valves logic, should two of the four water level channel bistables receive a RWST level signal lower than the low-low level setpoint, following the generation of an SI signal.

The following valve in the A electrical train (HV8811A SI recirculation sump to RHR pump No. 1 isolation valve) will be interlocked with the following valve in the C electrical train (HV-8701B loop 1 RHR suction line from reactor coolant system isolation valve).

The following valve in the B electrical train (HV8811B SI recirculation sump to RHR pump No. 2 isolation valve) will be interlocked with the following valve in the D electrical train (HV-8702A loop 2 RHR suction line from RCS isolation valve).

Note that in the case of these RHR containment emergency sump isolation valves, the protective action is independent of the position of the interlocking valves. The sump valve is opened automatically by the two out of four low-low RWST water level signal and the control from the inner and outer RHR pump suction isolation valves, and RWST/RHR suction valve positions are bypassed. The valve position interlocking is used only during online testing of the SI recirculation sump isolation valves.

7.6.5.6 Sequence

This circuit is energized directly from the SSPS output cabinet and is not sequenced following an accident that requires its functioning. The SSPS output cabinet is powered from the Class 1E 120-V vital ac distribution panels as discussed in subsections 7.6.1 and 8.3.1. Power is available for operation of all valves on the first step of the diesel generator sequencing.

7.6.5.7 Redundancy

The function of this semiautomatic switchover is available from both train A and train B down to the actuated equipment. The function including the actuated equipment is therefore redundant, and train separation and independence is maintained from sensor to actuated equipment.

7.6.5.8 Diversity

Diversity of components and equipment between the redundant trains is not required to protect against systematic failures, such as multiple failures resulting from a credible single event. The associated components are environmentally and seismically qualified in accordance with the procedures described in sections 3.10 and 3.11. Function diversity is provided in that manual operation is available as a backup to the semiautomatic mode.

7.6.5.9 Actuated Devices

The actuated devices are the two motor control center starters, one for each of the motor-operated sump valves, HV8811A and HV8811B. These valves are the only equipment actuated by the semiautomatic switchover from injection to recirculation following a LOCA. The remaining sequence of switchover operations is manual and includes alignment of the appropriate miniflow valves. For the sequence of these manual operations, refer to table 6.3.2-7.

7.6.6 INTERLOCKS ISOLATING SAFETY SYSTEMS FROM NONSAFETY SYSTEMS

7.6.6.1 <u>This paragraph has been deleted.</u>

7.6.6.2 <u>Refueling Water Storage Tank Isolation</u>

7.6.6.2.1 Description

As described in detail in section 6.3, the refueling water storage tank (RWST) provides a source of water for the emergency core cooling operations. The RWST is a nuclear safety class, Seismic Category 1 structure. However, the sludge mixing pump and the electric circulation heater connected to the tank do not meet these qualification requirements; therefore, an isolation capability is provided to prevent a loss of the RWST water volume. Two train-oriented, air-operated, seismically qualified valves mounted in series on the suction line to the sludge mixing pump provide this capability. When closed, they isolate the safety-related portion of the line (connecting to the RWST) from its nonsafety-related, nonseismic portion connected to the sludge mixing pump. Both valves fail closed upon the loss of instrument air and/or control power. Each valve is automatically actuated to close upon a RWST low-level signal from a redundant level switch in its respective safety train. The isolation valves will remain closed until individually opened by the operator's manual action. Such action will result in the opening of the valve only if the RWST low-level signal is no longer present.

The capability for remote-manual isolation from the control room is also provided. The status of each isolation valve is displayed by the indicating lights in the control room.

The closure of either isolation valve will cause an automatic trip of the sludge mixing pump and the electric circulation heater due to low flow.

7.6.6.2.2 Initiating Circuits

Automatic initiation of the RWST isolation takes place when a low-level signal is received from the redundant level switches. For manual isolation, each isolation valve has a corresponding handswitch on the miscellaneous equipment panel in the control room.

7.6.6.2.3 Logic

The isolation logic is shown in drawing 1X5DN114-4.

7.6.6.2.4 Bypass

Neither bypass indication nor manual override of the automatic actuation are provided.

7.6.6.2.5 Interlocks

The isolation interlocks are shown in drawing 1X5DN114-4.

7.6.6.2.6 Sequencing

The solenoid valves controlling the RWST isolation valves are powered from a safety-related, 125-V dc, battery-backed power supply and are not sequenced. (See section 8.3.)

7.6.6.2.7 Redundancy

The RWST isolation equipment is fully redundant; two completely independent trains (A and B) are provided.

7.6.6.2.8 Diversity

Functional diversity is provided in that manual operation is available as a backup to the automatic mode.

7.6.6.2.9 Actuated Devices

The actuated devices are two solenoid valves (HY-10957 and HY-10958) controlling the air supply to the pneumatic actuators of the gate-type isolation valves (HV-10957 and HV-10958, respectively).

7.6.6.2.10 Supporting Systems

The following systems support the RWST isolation equipment:

- Class 1E, 125-V dc power supply.
- Instrument air systems.

Failure of either or both systems will cause immediate closure of the isolation valves and will not degrade the isolation function.

7.6.6.2.11 Analysis

Analysis is provided in paragraph 7.6.6.9.

7.6.6.2.12 Periodic Testing

Provisions for the periodic go testing of the actuation system at full power are discussed in the Technical Specifications.

7.6.6.3 **<u>This paragraph had been deleted.</u>**

7.6.6.4 **<u>Isolation of Reactor Coolant Pump Thermal Barrier Cooling Water</u>**

7.6.6.4.1 Description

As described in detail in subsection 9.2.8, the auxiliary component cooling water (ACCW) system cools the thermal barriers of the reactor coolant pumps. The portion of the ACCW system related to this function is safety-related and Seismic Category 1; it interconnects with the nonsafety-related and nonseismic portion of the system. An isolation valve (HV-2041) is provided separating the safety from nonsafety class, nonseismic portions of the thermal barriers ACCW discharge line. The valve is a safety-related, motor-operated gate valve interlocked in a manner that prevents a spill of the reactor coolant from the postulated, breached thermal barrier should a break occur in the nonsafety-related piping downstream of that valve. The closure of the valve is either automatic or manual. The high-pressure and high-flow signals derived from safety-related transmitters cause the actuation, which enhances the reliability of the isolation. The high-pressure signal is indicative of a reactor coolant pump thermal barrier breach. The high-flow signal can result from the same cause or from a pipe break in the nonsafety-related portion of the piping, downstream of the isolation valve. The capability for remote-manual isolation from the control room is also provided. The isolation valve can be manually opened at any time, but it will automatically close when the handswitch handle is released, unless both actuating signals have cleared. The valve status is displayed in the control room by the indicating lights.

7.6.6.4.2 Initiating Circuits

The automatic closure of the reactor coolant pumps' thermal barrier ACCW isolation valve will occur upon high line pressure or high line flow signal. Each signal is derived from a safety-related transmitter. Both transmitters belong to instrumentation channel 2 and are powered from train B. The valve's control circuit and motor are powered from the same train. The handswitch for manual control is located on the main control board in the control room.

7.6.6.4.3 Logic

The isolation logic is shown in drawing 1X5DN094-3.

7.6.6.4.4 Bypass

Bypass of the isolation valve resulting from a loss of the control power is indicated in the control room. To manually override the automatic actuation, the handswitch handle is maintained in the open position, keeping the valve open. When released, the handle returns to the neutral position; and the valve closes if either of the actuating signals is still present.

7.6.6.4.5 Interlocks

The isolation interlocks are shown in drawing 1X5DN094-3.

7.6.6.4.6 Sequencing

The isolation valve motor is sequenced on the first (0.5-s) step of load sequencing.

7.6.6.4.7 Redundancy

Valve HV-2041 is not redundant; however, upstream from that valve, each of the ACCW discharge lines from the individual reactor coolant pumps have isolation valves powered and actuated by safety train A. Since valve HV-2041 is powered and actuated by train B, the functional redundance is maintained.

7.6.6.4.8 Diversity

The reactor coolant pumps' thermal barrier ACCW isolation valve closes automatically upon receiving either of the high-pressure or high-flow signals, providing actuation diversity. Functional diversity exists in the capability for manual actuation provided as a backup for the automatic mode.

7.6.6.4.9 Actuated Devices

The actuated device is the valve's 480-V motor starter.

7.6.6.4.10 Supporting Systems

The isolation function relies on the operability of the safety-related, 480-V ac power supply system, train B.

7.6.6.4.11 Analysis

Analysis is provided in paragraph 7.6.6.9.

7.6.6.4.12 Instrumentation

Annunciator windows are provided in the control room to alert the operator on a high flow or high pressure signal from the reactor coolant thermal barrier and auxiliary component cooling water interface system. Separate annunciator windows for high flow are provided to distinguish between which reactor coolant pump thermal barrier has failed. Isolation valve status is provided in the control room by indicating lights.

7.6.6.4.13 Periodic Testing

Provisions for the periodic go testing of the actuation system at full power are discussed in the Technical Requirements Manual.

7.6.6.5 Electric Steam Boiler Isolation

The electric steam boilers and all associated equipment located in the electric steam boiler building have been removed. All other equipment associated with the electric steam boiler that is located in areas other than the electric steam boiler building has been abandoned in place. The steam lines from the electric steam boiler going to the boric acid batching tank, which is the only safety-related interface with this system, have been cut and capped near the tank.

7.6.6.6 Steam Generator Blowdown Isolation

7.6.6.6.1 Description

As discussed in paragraph 10.4.8.1, the steam generator blowdown system (SGBS) is designed to maintain optimum secondary side water chemistry during normal operation and during anticipated operational occurrences of main condenser inleakage or primary to secondary leakage. Because portions of the SGBS are classifed as high energy lines, design features are provided to rapidly isolate the blowdown path should a rupture occur in the system piping outside of the containment.

The two isolation valves (in series) per blowdown line are located inside containment, powered from different safety trains and are automatically closed by the signals generated by separate instrumentation channels. The isolation valves (HV 15212A through D and 15216A through D) are air-operated, globe valves and fail closed upon loss of instrument air and/or control power. The capability for remote-manual isolation is provided in the control room as a backup for the automatic mode. Attempts to manually open either valve will not succeed, unless all actuating signals have cleared. The status of the isolation valves is displayed in the control room by the indicating lights.

7.6.6.6.2 Initiating Circuits

Each blowdown isolation valve in any given steam generator blowdown line will automatically close when a high-flow signal or any one of the high-temperature signals are received. The high temperature signals are generated by sensors located in four different safety-related equipment rooms within the auxiliary building. There are four temperature sensors and one flow transmitter associated with each valve. The automatic actuation signals are trained, channelized, and derived from safety-related flow transmitters and resistance temperature detectors. The signals generated are indicative of a steam generator blowdown line break outside of containment. Each valve can be manually actuated from the control room by the handswitch mounted on the miscellaneous system/equipment panel.

7.6.6.6.3 Logic

The isolation logic is shown in drawings 1X5DN152-1 and 1X5DN152-2.

7.6.6.6.4 Bypass

Neither bypass indication nor manual override of the automatic actuation are provided for the steam generator blowdown isolation valves.

7.6.6.6.5 Interlocks

The interlocks are shown in drawings 1X5DN152-1 and 1X5DN152-2.

7.6.6.6.6 Sequencing

The solenoid valves controlling the pneumatic isolation valves are powered from a safety-related, 125-V-dc, battery-backed power supply and are not sequenced. (See section 8.3).

7.6.6.6.7 Redundancy

All insulation valves, logic, instrumentation, controls, and power supplies are fully redundant and arranged in two completely independent trains, A and B. Each train is capable of providing 100-percent isolation of the appropriate steam generator blowdown line. The signals actuating train A and B isolation valves are generated by the redundant sensors and processed by redundant circuitry in two independent channels (3 and 4, respectively) in the balance of plant process instrumentation.

7.6.6.6.8 Diversity

Isolation can be initiated on either high line flow or high temperature, providing actuation diversity function. Manual isolation capability is provided as a backup for the automatic mode, which provides functional diversity.

7.6.6.6.9 Actuated Devices

The actuated devices are two solenoid valves per steam generator blowdown line (HY-15212A through D and HY-15216A through D) controlling the air supply to the pneumatic actuators of the globe-type isolation valves (HV-15212A through D and HV-15216A through D, respectively).

7.6.6.6.10 Supporting Systems

The following systems support the steam generator blowdown line isolation equipment:

- Class 1E, 125-V dc power supply.

- Instrument air system.

Failure of either or both of those systems will cause immediate closure of the isolation valves and will not degrade the isolation function.

7.6.6.6.11 Analysis

Analysis is provided in paragraph 7.6.6.9.

7.6.6.6.12 Instrumentation

A common annunciator window is provided in the control room to alert the operator of high temperature in any of four equipment rooms. The specific room may be identified by means of redundant temperature indicators with a selector switch in the control room. Isolation valve status is provided in the control room by indicating lights.

7.6.6.6.13 Periodic Testing

Provisions for the periodic go testing of the actuation system at full power are discussed in the Technical Requirements Manual.

7.6.6.7 CVCS Letdown Line Isolation

7.6.6.7.1 Description

As described in paragraph 9.3.4.1.2.1, the CVCS letdown line functions to maintain a programmed water level in the RCS pressurizer, thus maintaining proper reactor coolant inventory. Because the CVCS letdown line is classified as high energy, design features are provided to rapidly isolate the letdown path should a rupture occur in the system piping outside of the containment.

The two isolation valves (in series) are located inside containment, powered from different safety trains and are automatically closed by the signals generated by separate instrumentation channels. The isolation valves (HV-15214 and HV-8160) are air-operated globe valves and fail closed upon loss of instrument air and/or control power. The capability for remote-manual isolation is provided in the control room as a backup for the automatic mode. Attempts to manually open either valve will not succeed, unless all actuating signals have cleared. The status of the isolation valves is displayed in the control room by the indicating lights.

7.6.6.7.2 Initiating Circuits

Each isolation valve in the CVCS letdown will automatically close when any one of the high temperature signals is received. Isolation valve HV-8160 will also automatically close upon receipt of a containment isolation signal (see FSAR Section 6.2.4). The high temperature signals are generated by sensors located in three different safety-related equipment rooms within the auxiliary building. There are three temperature sensors associated with each valve. The automatic actuation signals are trained, channelized, and derived from safety-related resistance temperature detectors. The signals generated are indicative of a CVCS letdown line break outside of containment. Each valve can be manually actuated from the control room by the handswitch mounted on the main control board.

7.6.6.7.3 Logic

The isolation logic is shown in drawings 1X5DN151-1 and 1X5DN151-2.

7.6.6.7.4 Bypass

Neither bypass indication nor manual override of the automatic actuation are provided for the CVCS letdown line isolation valves.

7.6.6.7.5 Interlocks

The interlocks are shown in drawings 1X5DN151-1 and 1X5DN151-2.

7.6.6.7.6 Sequencing

The solenoid valves controlling the pneumatic isolation valves are powered from a safety-related, 125-V dc, battery-backed power supply and are not sequenced. (See section 8.3.)

7.6.6.7.7 Redundancy

All isolation valves, logic, instrumentation, controls, and power supplies are fully redundant and arranged in two completely independent trains, A and B. Each train is capable of providing 100-percent isolation of the CVCS letdown line. The signals actuating train A and B isolation valves are generated by the redundant sensors and processed by redundant circuitry in two independent channels (3 and 4, respectively) in the balance of plant process instrumentation.

7.6.6.7.8 Diversity

Isolation is initiated on high temperature for valve HV-15214 and either high temperature or an LI signal for HV-8160. Manual isolation capability is provided as a backup for the automatic mode, which provides functional diversity.

7.6.6.7.9 Actuated Devices

The actuated device is solenoid valve HY-15214 controlling the air supply to the pneumatic actuators of the globe-type isolation valve HV-15214 and solenoid valves HY-8160 and HY-15215 for valve HV-8160.

7.6.6.7.10 Supporting Systems

The following systems support the CVCS letdown isolation equipment:

- Class 1E, 125-V dc power supply.
- Instrument air system.

Failure of either or both of those systems will cause immediate closure of the isolation valves and will not degrade the isolation function.

7.6.6.7.11 Analysis

Analysis is provided in paragraph 7.6.6.9.

7.6.6.7.12 Instrumentation

A common annunciator window is provided in the control room to alert the operator of high temperature in any of three equipment rooms. The specific room may be identified by means of redundant temperature indicators with a selector switch in the control room. Isolation valve status is provided in the control room by indicating lights.

7.6.6.7.13 Periodic Testing

Provisions for the periodic go testing of the actuation system at full power are discussed in the Technical Requirements Manual.

7.6.6.8 <u>Analysis</u>

A. Conformance to Nuclear Regulatory Commission Regulatory Guides

1. Regulatory Guide 1.22

   Isolation controls and interlocks can be tested periodically.

2. Regulatory Guide 1.29

   Isolation equipment, circuitry, and instrumentation are designed to withstand the effects of an earthquake without loss of function.

   All related components are classified as Seismic Category 1, in accordance with the guide.

3. Regulatory Guide 1.62

   Isolation controls discussed previously provide manual actuation capability, in accordance with the applicable portions of the guide.

4. Regulatory Guide 1.75 and Institute of Electrical and Electronics Engineers (IEEE) Standard 384

   Those isolation circuits discussed above that are classified safety-related conform to the requirements of both the guide and the standard.

B. Conformance to IEEE Standard 279-1971

Those isolation circuits and devices discussed above that are classified safety-related conform to the applicable portions of the standard.

C. Conformance to Other Criteria and Standards

Conformance to other criteria and standards is indicated in table 7.1.1-1.

7.6.7 INTERLOCKS FOR REACTOR COOLANT SYSTEM PRESSURE CONTROL DURING LOW-TEMPERATURE OPERATIONS

The basic function of the reactor coolant system (RCS) pressure control during low-temperature operation is discussed in paragraph 5.2.2.1. As noted in paragraph 5.2.2.10, this pressure control includes semiautomatic actuation logic for two pressurizer power-operated relief valves (PORVs). The function of this actuation logic is to continuously monitor RCS temperature and pressure conditions, with actuation logic armed by operator action by means of an arm/block main control board switch, which is placed in the block position when the plant is at operating pressure. The monitored system temperature signals are auctioneered low; this auctioneered signal, when below the setpoint, is annunciated to direct the operator to arm the circuit. The auctioneered temperature is processed to generate monitored RCS pressure. This comparison provides an actuation signal to an actuation device which, if manually armed, causes the PORV to automatically open if necessary to prevent pressure conditions from exceeding allowable limits. (See drawings 1X6AA02-494 and 1X6AA02-495, for the logic diagram showing the basic elements used to process the generating station variables for this low-temperature RCS overpressurization preventive interlock. These two sheets present the logic diagram for the pressurizer pressure relief system for trains A and B that is part of the safety-grade cold shutdown system.)

The wide range temperature signals are used as input to generate the reference pressure limit program considering the plant's allowable pressure and temperature limits. This reference pressure is then compared to the actual RCS pressure monitored by the wide range pressure channel. The error signals derived from the difference between the reference pressure and the measured pressure first annunciates a main board alarm whenever the measured pressure approaches, within a predetermined amount, the reference pressure. On a further increase in measured pressure and after the operator has armed the circuit, the error signal generates an annunciated actuation signal channel; train independence between protection sets and between trains A and B is maintained from sensors to the PORVs.

Upon receipt of the actuation signal, the actuation device automatically causes the PORV to open. Upon sufficient RCS inventory letdown, the operating RCS pressure decreases, clearing the actuation signal. Removal of this signal from the actuation device causes the PORV to close.

7.6.7.1 Analysis of Interlock

The logic functions and actuation signals shown in drawings 1X6AA02-494 and 1X6AA02-495, are implemented in nuclear steam supply system protection equipment. For the criteria to which the protection system was designed and which apply equally well to the interlocks that are part of this protection system, see sections 7.2 and 7.3. The primary purpose of these interlocks is automatic transient mitigation. These interlocks do not perform a primary protective function but rather provide semiautomatic pressure control at low temperature as backup to the operator. However, to ensure a well-engineered design and improved operability, the instrumentation and control portions of the interlocks for RCS pressure control during low-temperature operation satisfy applicable sections of Nuclear Regulatory Commission (NRC) Branch Technical Position RSB 5-2 that addresses instrumentation and control. Institute of Electrical and Electronics Engineers (IEEE) Standard 279-1971 is applied with the following comments:

A. For the purpose of applying IEEE Standard 279-1971 to this circuit, the following definitions are used:

   1. Safety-Grade System

      The safety-grade system is the block valve and the PORV in series in each of the redundant lines and in all components of the interlocks for RCS pressure control during low-temperature operation. The instrumentation and control equipment for one redundant line is defined as the train A system; the instrumentation and control equipment for the other redundant line is defined as the train B system.

   2. Safety Function

      The safety function is defined as the automatic control of the RCS pressure during low-temperature operation to prevent the actual pressure from exceeding the calculated reference pressure limit. This safety function is satisfied by either train of the redundant system, the train A system or the train B system.

B. IEEE Standard 279-1971, Paragraph 4.2

   Any single random failure within the train A system or the train B system will not prevent protective action at the system level when required.

C. IEEE Standard 279-1971, Paragraph 4.10

   The above mentioned pressure interlock signals and logic is tested online while the system's manually operated main control board arm/block switches are in the block position. This online at power testing will be done to the maximum extent possible without adversely affecting safety. This test will include the analog signal through to the associated output bistables in the process equipment. There is no practical design which will permit an integrated online test through to the final simultaneous openings of the PORV and the PORV block valves. Furthermore, the valves themselves are testable when the reactor is shut down.

D. IEEE Standard 279-1971, Paragraph 4.12

   The safety function is manually blocked by operator action of the main control board arm/block switch which places it in the block position when the plant is at temperatures greater than the range of concern for RCS low-temperature operation. The annunciator initiated by the low-temperature auctioneered circuit will alarm to warn the operator that the arm/block switch should be placed in the arm position. Whether or not the system should be armed and actually is not armed will be indicated to the operator when this annunciator is initiated and the switch is positioned to the maintained block position. In addition, if the system is armed and the PORV block valve is not fully open, this condition is also annunciated.

7.6.7.2 Pressurizer Pressure Relief System

The interlocks described in paragraph 7.6.7.1, together with pressurizer pressure control and the pressurizer pressure control interlock shown in drawings 1X6AA02-235 and 1X6AA02-230, respectively, and the interlocks for the pressurizer block valves, 8000 A and B, shown on drawings 1X6AA02-494 and 1X6AA02-495, are referred to as the pressurizer pressure relief system.

The pressurizer pressure relief system provides the following:

A. Capability for RCS overpressure mitigation during cold shutdown, heatup, and cooldown operations to minimize the potential for impairing reactor vessel integrity when operating at or near the vessel ductility limits.

B. Capability for RCS depressurization following Condition II, III, and IV events.

C. Interlock that, with the pressurizer PORVs and PORV block valves in auto control, closes the PORV block valves and prevents signals from the pressurizer pressure control signal from opening the PORVs when the pressurizer pressure is low and the system is not manually armed.

Interlocks for the pressurizer pressure relief system control the valve positions of the pressurizer PORVs and the PORV block valves. The interlocks provide the following functions:

- Pressurizer pressure control.
- RCS pressure control during low-temperature operation.
- RCS pressure control to achieve and maintain a cold shutdown.

The interlock functions that provide pressurizer pressure control are derived from process parameters as shown in drawings 1X6AA02-230, 1X6AA02-235, 1X6AA02-494, and 1X6AA02-495. The functions shown in drawings 1X6AA02-494 and 1X6AA02-495 include those needed for the PORV block valves as well as the pressurizer PORVs to meet both interlock logic and manual operation requirements where manual operation can be either at the main control board or on the local shutdown panel.

TABLE 7.6.2-1

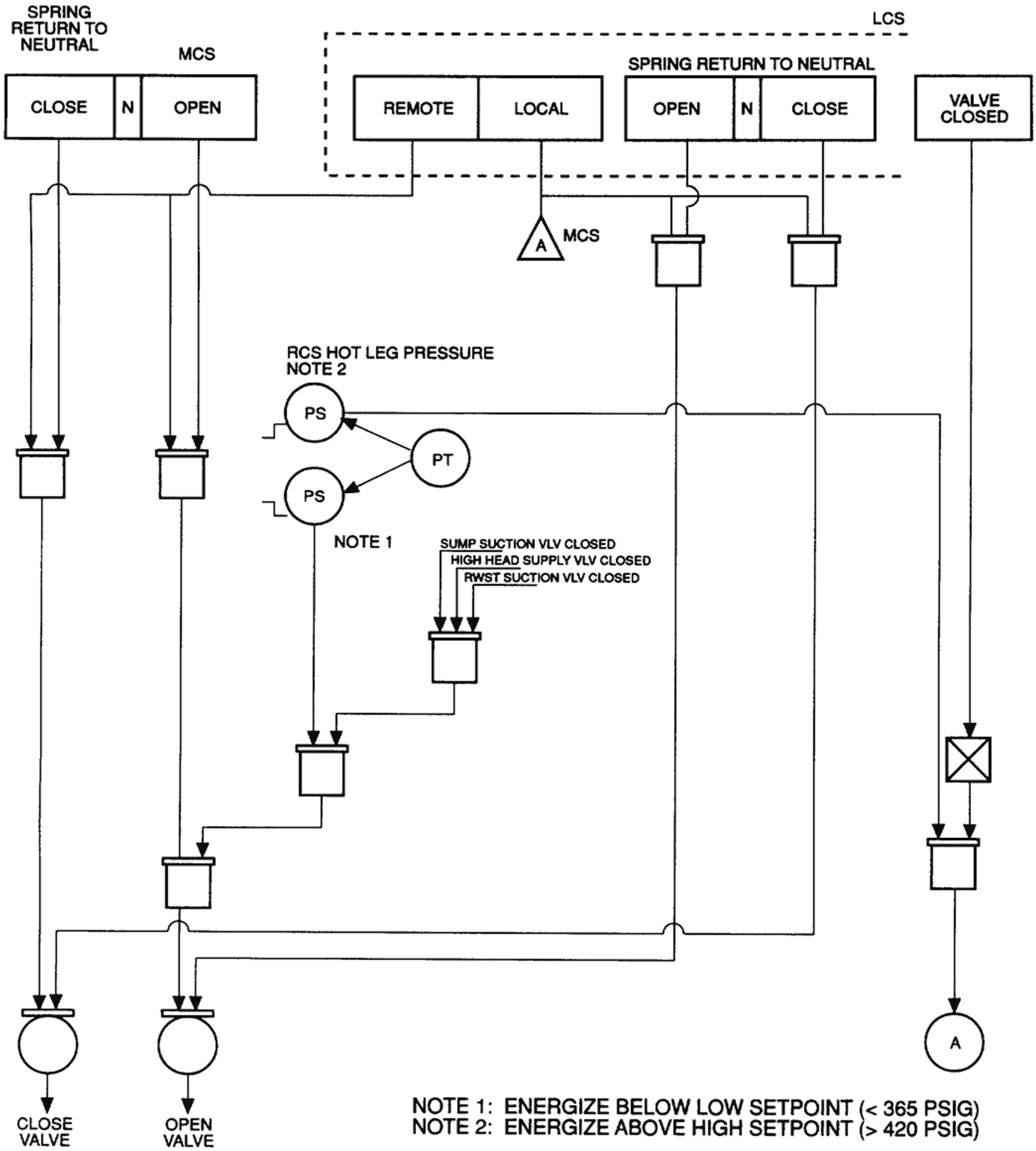
INTERLOCK TABLE FOR OUTER ISOLATION VALVES
(Refer to figure 7.6.2-1)

Outer Isolation Valve		HV8701A (Train A)	HV8702A (Train D)
Interlock ↓	Pressure transmitter →	PT 438	PT 418
Recirculation line valve	/ Limit switch[a]	HV8804A/No. 1[a]	HV8804B/No. 2[a]
Refueling water storage tank (RWST) isolation valve	/ Limit switch[a]	HV8812A/No. 1[a]	HV8812B/No. 2[a]
Sump line isolation valve	/ Limit switch[a]	HV8811A/No. 1[a]	HV8811B/No. 2[a]

INTERLOCK TABLE FOR INNER ISOLATION VALVES
(Refer to figure 7.6.2-1)

RCS-RHRS Inner Isolation Valve		HV8701B (Train C)	HV8702B (Train B)
Interlock ↓	Pressure transmitter →	PT 408	PT 428
Recirculation line valve	/ Limit switch[a]	HV8804A/No. 2[a]	HV8804B/No. 1[a]
RWST isolation valve	/ Limit switch[a]	HV8812A/No. 2[a]	HV8812B/No. 1[a]
Sump line isolation valve	/ Limit switch[a]	HV8811A/No. 2[a]	HV8811B/No. 1[a]

a. Limit switch No. 1 is a gear-driven limit switch supplied with a valve. Limit switch No. 2 is an added stem-mounted limit switch.



NOTE 1: ENERGIZE BELOW LOW SETPOINT (< 365 PSIG)
NOTE 2: ENERGIZE ABOVE HIGH SETPOINT (> 420 PSIG)

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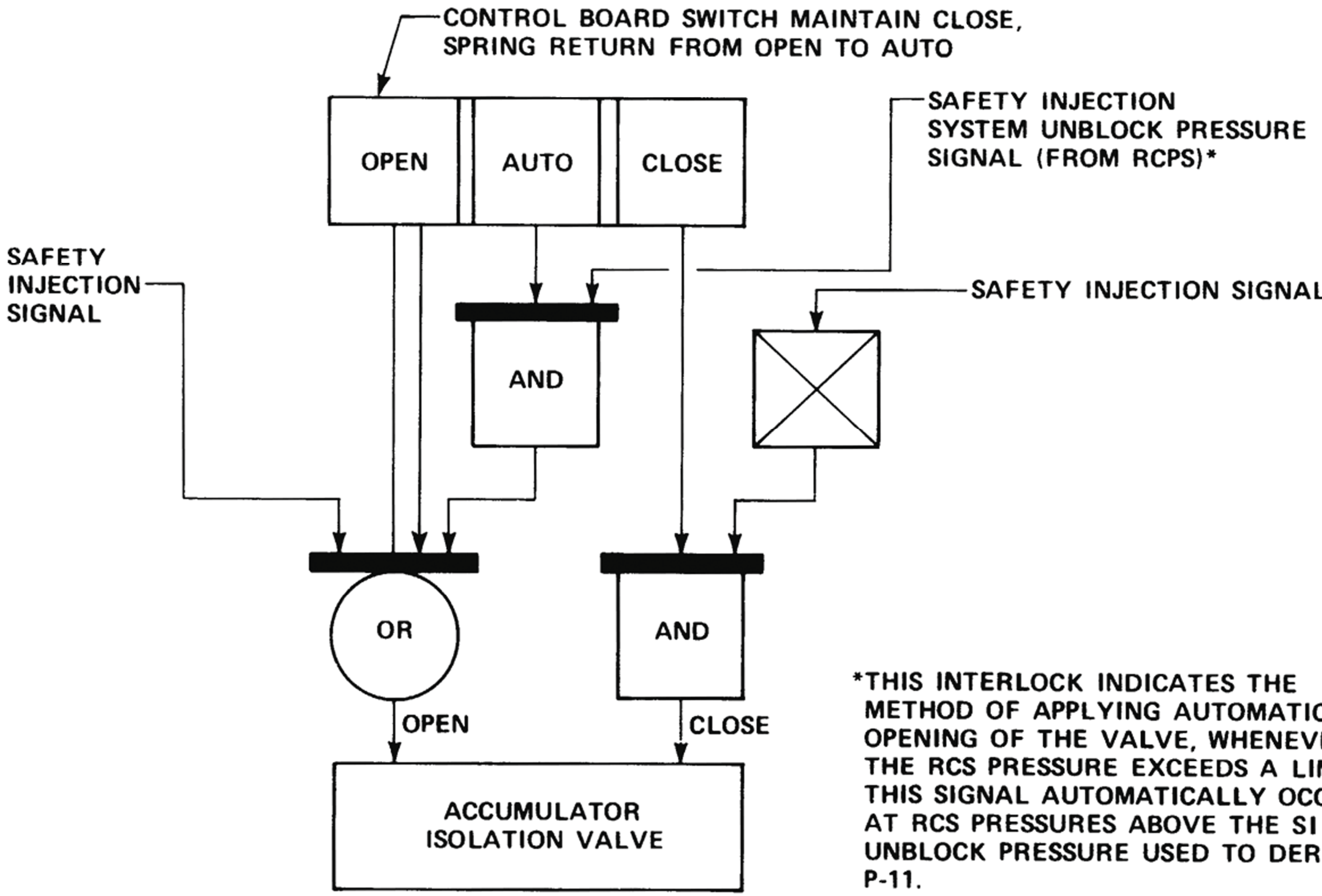
SOUTHERN COMPANY *Energy to Serve Your World®*	VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	LOGIC DIAGRAM FOR THE RHRS ISOLATION VALVES FIGURE 7.6.2–1



*THIS INTERLOCK INDICATES THE METHOD OF APPLYING AUTOMATIC OPENING OF THE VALVE, WHENEVER THE RCS PRESSURE EXCEEDS A LIMIT. THIS SIGNAL AUTOMATICALLY OCCURS AT RCS PRESSURES ABOVE THE SI UNBLOCK PRESSURE USED TO DERIVE P-11.

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SOUTHERN COMPANY Energy to Serve Your World®	VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2
FUNCTIONAL BLOCK DIAGRAM OF ACCUMULATOR ISOLATION VALVE	FIGURE 7.6.4–1