PAGE REPLACEMENT GUIDE FOR

AMENDMENT 73

CLINCH RIVER BREEDER REACTOR PLANT

PRELIMINARY SAFETY ANALYSIS REPORT

(DOCKET NO. 50-537)

Transmitted herein is Amendment 73 to Clinch River Breeder Reactor Plant Preliminary Safety Analysis Report, Docket 50-537. Amendment 73 consists of new and replacement pages for the PSAR text and Responses to NRC Questions.

Vertical margin lines on the right hand side of the page are used to identify changes resulting from NRC Questions and margin lines on the left hand side are used to identify new or changed design information.

The following attached sheets list Amendment 73 pages and instructions for their incorporation into the Preliminary Safety Analysis Report.

AMENDMENT 73

PAGE REPLACEMENT GUIDE

REMOVE THESE PAGES	INSERT THESE PAGES
Chapter 1	
1.5-46, 47	1.5-46, 46a, 47
Chapter 2	
2-xiii, xiv	2-xiii, xiv
2-xix thru xxii	2-xix thru xxii
2.4-3, 4	2.4-3, 4
2.4-7, 8	2.4-7, 7a, 8
2.4-9 thru 20	2.4-9 thru 13, 13a, 14, 15, 15a, 16 thru 20
2.4-20a, 21 thru 29	2.4-20a, 21 thru 29
2.4-30, 31, 31a, 32	2.4-30, 30a, 31, 31a, 32
2.4-39, 40	2.4-39, 40
2.4-75, 75a, 76 thru 82	2.4-75, 75a, 76 thru 82
2.4-117, 118	2.4-117, 118
2.4-121 thru 124	2.4-121 thru 124
2.4-125, 126, 127, 127a, 127b, 128	2.4-125, 125a, 126, 127, 127a, 127b, 128
2.4-130a, 131 thru 135, 135a, 136	1.4-130a, 131 thru 135, 135a, 136
2.4-153 thru 156	2.4-153, 154, 155, 155a, 156
2.4-159, 160, 161	2.4-159, 160, 161
2.4-165	2.4-165
Chapter 3	
3.7-7, 8	3.7-7, 8
3.7-14, 14a	3.7-14, 14a
3.8-C.1, 2	3.8-C.1, 1a, 2
3A.1-5a	3A.1-5a
3A.8-8, 9, 9a, 9b	3A.8-8, 9, 9a, 9b
Chapter 4	
4.2-162b, 163, 164, 165	4.2-162b, 163, 163a, 164, 165
4.4-89, 90	4.4-89, 90

REMOVE THESE PAGES	INSERT THESE PAGES
Chapter 5	
5.5-8, 9	5.5-8, 9
5.5-11, 11a	5.5-11, 11a
5.5-23, 23a	5.5-23, 23a
5.5-44, 45	5.5-44, 45
5.6-8, 8a	5.6-8, 8a
5.6-11, 11a	5.6-11, 11a
5.6-30 thru 33	5.6-30 thru 33
Chapter 7	
7.1-9, 10	7.1-9, 10
7.2-1, 1a, 2, 2a	7.2-1, 1a, 2, 2a
7.2-11 thru 15, 15a, 16 thru 19	7.2-11 thru 14, 14a, 15, 15a, 16 thru 19
7.2-26, 27	7.2-26, 27
7.4-7, 8	7.4-7, 8
7.5-52	7.5-52
7.7-5 thru 8	7.7-5, 6, 7, 7a, 8
7.7-17, 18	7.7-17, 18
Chapter 9	
9-xi, xii	9-xi, xii, xiia
9-xv, xvi	9-xv, xvi, xvia
9-xix, xx	9-xix, xx
9.6-39 thru 42	9.6-39 thru 42
9.6-94	9.6-94
9.7-17, 18	9.7-17, 18
9.9-1 thru 4	9.9-1 thru 4
9.9-7, 8	9.9-7, 8
-	9.9-12a, 12b, 12c
-	9.9-18a, 18b
9.13-13 thru 17, 17a thru 17d	9.13-13 thru 17, 17a thru 17d
9.15-1, 2	9.15-1, 2, 3
9.16-9, 9a	9.16-9, 9a
-	INSERT NEW 9.17 TAB AND PAGE
-	9.17-1
Chapter 12	
12A-5, 6	12A-5, 6
Chapter 15	
15.6-1, 2	15.6-1, 2, 2a
15.6-32, 33	15.6-32, 33, 33a

REMOVE THESE PAGES		INSERT THESE PAGES
	Chapter 17	
REMOVE ENTIRE APPENDIX J		INSERT NEW APPENDIX J (Last page is 17J-70)
	Appendix A	
A-113, 114		A-113, 114, 114a
	Appendix B	
B-25, 26		B-25, 26
	Appendix J	
-		INSERT NEW APPENDIX J WITH TAB (Last page is J-27)

AMENDMENT 73

QUESTION/RESPONSE SUPPLEMENT

This Question/Response Supplement contains an Amendment 73 tab sheet to be inserted following Qi page Amendment 72, October 1982. Page Qi Amendment 73 is to be inserted following the Amendment 73 tab sheet.

This Amendment 73 provides a revised Question/Response page* for NRC Question Received Before The Fall of 1981 plus New and Replacement Pages for NRC Questions Received Since the Fall of 1981.

The following Question/Response pages are to be inserted in numerical order behind the appropriate numbered tabs in the PSAR Question/Response Volumes.

REMOVE THESE PAGES	INSERT THESE PAGES
*Q001.245-1 thru 6	Q001.245-1
QCS760.60-1	QCS760.60-1, 2
-	QCS760.77-3, 4, 5, 6
QCS760.106-1, 2	QCS760.106-1

With the issue of this PSAR Amendment 73, an additional PSAR Binder (Volume 27) is being provided. In addition, new PSAR Volume 26 and 27 Identification Pages are provided. These I.D. pages should be inserted and retained as the first page in PSAR Volume 26 and Volume 27 respectively.

In order to accommodate the existing volume of New Question/Response pages plus the anticipated issue of additional New Question/Response pages in future PSAR Amendments, the shifting of Question/Response pages and their associated numbered tabs currently in Volumes 25 and 26 into Volumes 25, 26, and 27 is recommended. This page shift should be accomplished so that PSAR Volumes 25, 26 and 27 will contain Question/Response Series pages and tabs as shown below:

VOLUME 25 -	SHOULD CONTAIN	-	Q/R Series 210 thru 410
VOLUME 26 -	SHOULD CONTAIN	-	Q/R Series 421 thru 721
VOLUME 27 -	SHOULD CONTAIN	-	Q/R Series 760 thru 810

*Old NRC Question/Response Series

1.5.2.8 Sodium Fires Test Program

1.5.2.8.1 Purpose

The purpose of the sodium fires test program is to verify that plant design features for accommodation of sodium/NaK spills in air-filled cells will result in acceptable cell pressures and structural concrete temperatures. In addition, this test program will be used to demonstrate that the codes used in sodium fire analyses conservatively predict cell accident conditions.

1.5.2.8.2 Programs

The sodium fire experiments have been or will be performed at the Atomics International test facilities in Santa Susana, California. The following small scale tests have been completed:

1) A fast spill (approximately 15 gal/min) of 1000°F sodium onto the fire suppression deck surface

2) A slow spill (approximately 1.5 gal/min) of 1000°F sodium onto the fire suppression deck surface

3) A spray (approximately 15 gal/min) of 1000°F sodium onto the surface of the fire suppression deck

4) A fast spill (approximately 15 gal/min) of 1000°F sodium directly into the catch pan beneath the fire suppression deck

5) A spray (approximately 15 gal/min) of 1000°F sodium, onto the surface of the fire suppression deck, through a walk grating above the deck

6) A spray (approximately 15 gal/min) of 600°F sodium onto the surface of the fire suppression deck, through a walk grating above the deck

The results of the above small scale tests will be documented as the test reports become available. In addition to small tests, a large scale test will be performed using a large-scale model of the CRBRP catch-pan fire suppression deck system to collect spilled sodium under simulated spill conditions. The test facility is designed to accommodate a volume gas as large as 6600 gallons of 1000°F sodium with a sodium discharge flowrate of approximately 70 GPM.

1.5.2.8.3 Schedule

The small scale tests have been completed. The large scale test is planned to be performed in the last quarter of 1982.

1.5.2.8.4 Success Criteria

The small scale tests successfully demonstrated fire suppression deck design features to ensure drainage capability and fire-suppression effectiveness:

- o No blockage of drain pipes during spill.
- o Post-spill suppression of sodium burning by control of oxygen ingress to sodium pool via oxide plugging of drain pipes and closure of vent lids on vent pipes.
- o No leakage of sodium from catch pan.

The success criteria for the large scale test are that the catch pan shall contain the spilled sodium precluding sodium concrete interactions and that resulting test consequences are enveloped by those calculated with the Project's methodology.

1.5.2.8.5 Fallback Position

If the effectiveness of the fire-suppression deck/catch pan system is not demonstrated, alternative techniques to accommodate design basis liquid metal spill events will be considered and/or prediction of plant design basis accident consequences will be made with alternative methods.

1.5.3 References

1. HEDL-SA-771, "Fuel Pin Transient Behavior Technology Applied to Safety Analysis," Presentation to AEC Regulatory Staff, 4th Regulatory Briefing on Safety Technology, November 19-20, 1974.

2. Haugen, E. G., "Probabilistic Approaches to Design," Wiley Book Co., New York (1968).

3. Chang, [illegible] C., and C. B. Brown, "Functional Reliability of Structures," Journal of the Franklin Institute, September, 1973.

4. Fontana, M. H., et al, "Effect of Partial Blockages in Simulated LMFBR Fuel Assemblies," Proc. Fast Reactor Safety Meeting CONF-740401-P3, 1139 (1974).

5. Bell, C. R. "TRANSWRAP - A Code for Analyzing the System Effects of Large-Leak Sodium-Water Reactions in LMFBR Steam Generators," Proc. Fast Reactor Safety Meeting, CONF-740401-P1, 124 (1974).

6. Division of Reactor Research and Development, USAEC, RDT Standard M3-7T, "Austenitic Stainless Steel Welded Pipe (ASME SA-358 with Additional Requirements)" November, 1974.

7. Marr, W. W., et al, "Subassembly-to-Subassembly Failure Propagation: Thermal Loading of Adjacent Subassembly," Proc. Fast Reactor Safety Meeting, CONF-740401-P2, 598 (1974).

8. Van Erp, J. B., et al, "An Evaluation of Pin-to-Pin Failure Propagation in LMFBR Fuel Subassemblies," ibid, 615 (1974).

9. Erdman, C. A., et al., "Improvements in Modeling Fuel-Coolant Interactions and Interpretation of the S-11 TREAT Test," ibid, 955 (1974).

60 34 10. Deleted.

41 11. Letter from R. P. Denise (NRC) to L. W. Caffey (ERDA) May 6, 1976.

12. GEFR-00424, UC-79B, "A Physicochemical Model for Predicting Sodium Reaction Swelling in Breached LMFBR Fuel and Breeder elements", R. W. Caputi. M. G. 57 Adamson, and S. K. Evans, March, 1979.

LIST OF TABLES (Continued)

LIST OF TABLES (Continued)

LIST OF FIGURES (Continued)

LIST OF FIGURES (Continued)

LIST OF FIGURES (Continued)

Three minor tributaries which enter the Clinch River between Norris Dam and Melton Hill Dam are Beaver Creek, Bullrun Creek and Hinds Creek. These three streams enter from the south at CRM 39.6, 46.7 and 65.8, respectively. (Ref. 1) Annual average flows and peak flood data for these creeks are not applicable to the Site because they enter the Clinch River above Melton Hill Dam. Poplar Creek, a minor tributary below Melton Hill Dam, enters the Clinch River from the north at CRM 12.0. The average annual flow of Poplar Creek is 260 cfs and drainage area at the mouth is 136 square miles.

Several other small streams and sloughs enter the Clinch River near the Site; however, they are not considered to be significant tributaries from the standpoint of water flow contribution to the Clinch River. Caney Creek which enters from the south at CRM 17 has a drainage area at the mouth of 8.27 square miles and an average flow of 14 cfs. Poplar Springs Creek at CRM 16.2 has a drainage area of 3.01 square miles at the mouth and an average flow of 5 cfs. Grassy Creek entering from the north at CRM 14.5 has a drainage area of 1.95 square miles and an average flow of 3 cfs. The combined average flows of these creeks total 22 cfs which is only 0.5 percent of the Clinch River flow at the Site.

2.4.1.2.3 Reservoir Water Levels

The Site is located on an arm of the Watts Bar Reservoir which extends up the Clinch River. Thus, the water elevation at the Site is influenced by the operation of Watts Bar Dam. Elevation at the bottom of the Clinch River channel at the Site ranges between 719 and 720 feet above mean sea level (MSL). Water depth at the Site is equal to or greater than the difference between the pool elevation at Watts Bar Dam minus this bottom elevation as can be seen in the downstream profile of the Clinch River, Figure 2.4-6.

Watts Bar Reservoir is a multiple-purpose reservoir providing power generation, navigation aid and flood control. TVA generally maintains a pool elevation between 740 and 741 MSL during the spring and summer months (mid-April through September) and a winter pool elevation of 735 to 737 MSL for the remainder of the year.

During the 32 years of record since the initial filling of Watts Bar Reservoir, TVA has been able to follow closely the above plan of normal operation. Sufficient inflow has been available each year to raise the reservoir from winter level to summer level on schedule. The water surface elevation at the Site is normally one to two feet higher than the level measured at Watts Bar Bam as a result of a backwater. Since 1942, the minimum elevation of Watts Bar Reservoir was 733.44 MSL and occurred on March 20, 1945, (Ref. 8). A maximum elevation of 745.40 MSL occurred on March 17, 1973. (Ref. 7) Figure 2.4-26a shows the normal operating level for Watts Bar Reservoir. Table 2.4-3 shows the monthly maximum, minimum and average Watts Bar Reservoir elevations for the period 1964-1973.

Releases from Norris and Melton Hill Reservoirs, both upstream of the Site on the Clinch River, can be used to regulate flows at the Site. Although Norris Dam is the prime regulator of flow, Melton Hill Dam can influence low flows at the Site. Normal minimum pool stage at Melton Hill Reservoir is 790 MSL. (Ref. 8)

Norris Reservoir is a multiple-purpose reservoir providing power generation, flood control and low flow argumentation. The normal minimum pool elevation is 960 MSL with storage of approximately 260,000 day-second-feet between elevations 960 and 900 MSL. Although not a primary purpose, stored water below minimum pool elevation 960 is available for low flow augmentation in periods of drought. Release below elevation 960 requires specific approval of the TVA Board of Directors. Power generation at Norris can be maintained to about elevation 900 MSL. Of all the annual maximum elevations recorded, the lowest annual maximum elevation of Norris Reservoir was 993.8 MSL and occurred in June 1954. (Ref. 8)

Releases from Fort Loudoun Reservoir, located on the Tennessee River 72.4 miles upstream from Watts Bar, can be used to control the Watts Bar pool elevation. Normal minimum pool elevation of Fort Loudoun Reservoir is 807 MSL. (Ref. 8) Inflows into Watts Bar Reservoir from the Tennessee River are more than capable of maintaining the minimum pool elevation of Watts Bar Reservoir even under extreme conditions.

Tellico Dam, closed in 1979, is located on the Little Tennessee River at mile 0.3. Tellico Reservoir is connected to Fort Loudoun Reservoir by an uncontrolled canal. Except during large floods, inflows to Tellico Reservoir are discharged through Fort Loudoun Reservoir.

2.4.1.2.4 Water Flow

Stream gages had been maintained by the U.S. Geological Survey on the Clinch River at the three locations listed in Table 2.4-1. Gages were maintained at these locations for various time periods from 1936 through 1968. (Ref. 3,4,5,6). At the present time, no stream gages are being operated in the vicinity of the Site.

Based upon these stream gage records from the three locations, the average flow of the Clinch River was 4,561 cfs (Ref. 3,4,5,6). The maximum discharge during the period was 42,900 cfs and occurred on February 9, 1937, (Ref. 5) before the closing of Melton Hill Dam. Based on discharge records from Melton Hill Dam since the closing in 1963, (see table 2.4-2) the average annual flow is about 4,600 cfs at the Site. (Ref. 8) The maximum hourly average release was 43,400 cfs and the maximum daily average release was 26,900 cfs; both occurred on March 16, 1973 at Melton Hill Dam. (Ref. 8).

2.4.2.2 Flood Design Considerations

Table 2.4-8 compares the maximum flood level determined for the rain flood and seismic events specified in Regulatory Guide 1.59, more completely described below. The alternatives evaluated under each category are described in 2.4.3 and 2.4.4.

The computed Probable Maximum Flood (PMF) level at the plant site from an occurrence of the most severe sequence of storms, as defined by the National Weather Service, is elevation 778.8 at mile 18 and 777.2 at mile 16 excluding the effect of wind waves.

This compares with elevation 777.5 at mile 18 and elevation 776.0 at mile 16 previously given in the PSAR. The differences result from a reevaluation of and refinements in the Tennessee River watershed model and includes Tellico Dam, which was closed in 1979.

A conservatively high velocity of 40 MPH wind over land from the most adverse direction, was adopted to associate with the PMF Crest. The probability that this high velocity wind occurs on the same specific day that the PMF would crest is extremely remote. It has been estimated that the probability of the flood and wind occurring on the same day in a given year is on the order of 1×10^{-10} to 1×10^{-13} (Ref. 11).

Waves and runup are applicable to the plant only at MILE 16. At Mile 18, ground levels adequately shield the plant from coincident winds. For the 40 MPH wind from the most critical direction 99.6% of the wind waves were computed to be less than 2.4 feet high, crest to trough, resulting in a maximum water surface elevation of 778.80 in the reservoir approaching the plant site. Runup would be about 3.8 feet to elevation 781.0 on a vertical wall and 2.8 feet to elevation 780.0 on a smooth slope of 3:1. The Probable Maximum Precipitation (PMP) and Flood Flow are discussed in Sections 2.4.3.1 and 2.4.3.4.

The plant site and upstream reservoirs are located in the Southern Appalachian Tectonic Province and, therefore, subject to potential moderate earthquake forces with possible attendant dam failure. All upstream dams, including those on the Tennessee River, whose failure in a seismic event has the potential to cause flood problems at the plantsite were investigated as described in 2.4.4. Studies to determine the potential failure of upstream dams from PMF conditions, are also described in the same section.

The condition producing the maximum flood level at the plant site is the postulated failure of Norris Dam under the force of an operational basis earthquake (OBE) coincident with one-half of the PMF with the postulated attendant failure of Melton Hill Dam. This would produce a maximum flood level of 804.3 feet at Mile 18 and 798.2 at Mile 16 with a peak discharge of 921,000 cfs. The situations considered are consistent with Regulatory Guide 1.59.

For the analysis of the failure of Norris Dam, a debris level was postulated at elevation 970 feet which is considered the result of a logical mode of failure. The failure mode is discussed in detail in Section 2.4.4.

When the effects of wind wave and runup are added to still water elevations 804.3 and 798.2, the maximum design water levels will be established to be at elevation 809.2 and 803.1 on a vertical wall and elevation 807.9 and 801.8 on a smooth 3:1 slope, at mile 18 and 16 respectively.

All Seismic Category I structures housing safety-related facilities, systems and equipment are designed for or are protected from the highest flood elevation. The plant grade in the Reactor Containment Building area is established at elevation 815.0 which is well above the maximum flood runup level.

Hydrostatic pressure, buoyancy and dynamic wave effects will be considered in the design of all Category I structures either completely or partially submerged under the maximum design flood condition. Accesses and penetrations located below the flood level will be reduced to the minimum requirement, and will be designed and constructed as watertight elements.

Specific analysis of Clinch River flood levels resulting from oceanfront surges and tsunamis is not required because of the inland location of the plant. Snow melt and ice jam considerations are also not required because of the temperate zone location of the plant. Flood waves from landslides into upstream reservoirs required no specific study, in part because of the absence of major elevation relief in nearby upstream reservoirs and because the prevailing thin soils offer small slide volume potential compared to the available retention space in reservoirs.

2.4.2.3 Effects of Local Intense Precipitation

The overall site drainage facilities will be designed for 3.5 inches rainfall in one year. This rainfall corresponds to the maximum rainfall expected during a period of 100 years (Table 2.3-1).

The drainage facilities for safety-related structures will be investigated for local flooding resulting from Probable Maximum Precipitation (PMP) as specified by the Hydrometeorological Branch of the National Weather Services. (Ref. 13) The eight (8) hour PMP depth is 29.5 inches with a maximum one (1) hour depth of 14 inches (Table 2.4-8a). PMP intensities beyond 8 hours are less than 1 inch per hour and, therefore, not critical for defining site maximum flood conditions. Time distribution of the 8-hour PMP storm is based upon consideration of the time distribution of maximum observed storms and the time distribution of design storms adopted by the Corps of Engineers and the Soil Conservation Service (Ref. 47). The adopted sequence conforms closely to that used by the Corps of Engineers. No precipitation loss is applied to the 14-inch maximum hourly rainfall. 7

e) The following drainage system will be used in the Access Road and Railroad Area. Pipe culverts will be provided where the drainage channels are interrupted by access roads and railroads. Drainage ditches will be provided along the sides of the road and the railroad. In high cuts, drainage ditches will be provided at the top or along the slope to intercept surface flow and to prevent excessive erosion of the cut face. These ditches will be led into natural water courses or pipe culverts.

Since the maximum calculated overtopping resulting from PMP is not expected to exceed six inches, there will be no danger of water ponding against safety-related structures.

Natural drainage will be affected by the plant construction in approximately 100 acres of the 1364 acre Clinch River Site. On high fills, berms will be built along the edge of the fill to control surface flow on the top of the embankment except at points where paved channels will be provided to carry the flow down the embankment. Drainage ditches will be lined when the velocity of flow is abnormally high and at sharp turns, if any.

Settling basins of sufficient capacity will be provided to receive the runoff discharge from the plant drainage systems before discharge into the Clinch River. The purpose of providing the settling basins is to eliminate most of the suspended solids in the effluent before discharge, in accordance with local, state and federal regulations for effluent discharge. 7

2.4.3 Probable Maximum Flood (PMF) on Streams and Rivers

The probable maximum flood (PMF) would result from an occurrence of the probable maximum storm as defined by the National Weather Service. The flood flows and elevations from this storm define an upper limit of potential flooding at the plant site from meteorological conditions.

Occurrence of the PMF as determined and applied in this study is extremely unlikely. The postulated combination of events results in a probability of occurrence which approaches zero. The events combined include a main storm with rainfall volumes which are the physical upper limit that the present climate can produce, an assumed antecedent storm amounting to 40 percent of the main storm volume, which exceeds the maximum recorded on the water shed to date, and assumption of an exact centering of the storm to cause that combination of Clinch and Tennessee River flows which produces maximum flood levels at the plant. In applying PMF elevations, further conservatism is introduced by adding the runup due to a 40-mile-per-hour overland wind from the most critical direction.

Evaluation of seasonal and areal variations of probable maximum storms described in 2.4.3.1, and 2.4.3.4, showed that the PMF level at the Clinch River Breeder Reactor Plant (CRBRP) site would be caused by a sequence of two storms occurring in March and centered in the water shed above Watts Bar Dam. The flood crest at the plant site would be augmented by the failure of Fort Loudoun and Tellico Dams, upstream on the Tennessee River, and the nonoverflow section at Melton Hill Dam, upstream on the Clinch River. The estimated maximum discharge at the plant site would be 258,000 cfs. The PMF elevation at the plant site would be 778.8 at Mile 18 and 777.2 at Mile 16, including the three upstream dam failures and failure of the earth embankment at Watts Bar Dam, downstream on the Tennessee River, but excluding any wind wave effects.

2.4.3.1 Probable Maximum Precipitation

Probable maximum precipitation (PMP) for storms creating maximum flood conditions at the CRBR plant site has been defined for TVA by the Hydrometelorological Branch of the National Weather Service in Hydrometeorological Reports Nos. 41 and 45 (Ref. 12, 13). In addition, the Clinch River water shed PMP information contained in Report No. 45 was extended by the Hydrometeorological Branch to cover the total water shed above Watts Bar Dam and to provide PMP for the 4458-square mile Clinch River watershed (Reference 13a). These define depth-area-duration characteristics of rainfall and their seasonal variations and antecedent storm potentials. Because the water shed lies in the temperate zone, snowmelt is not a factor in generating maximum floods at the plant site. (See page 97 of Report No. 41.) 7

Four basic storms with five possible isohyetal patterns described in Reports Nos. 41 and 45 and Reference 13a were examined to determine which would produce maximum flood levels at the plant site. 7

One basic storm would produce PMP depths on the 21,400-square-mile water shed above Chattanooga. Two potential isohyetal patterns are presented in Report No. 41 for this storm. Computations for earlier TVA program studies determined that the downstream centering would be most severe for the CRBRP.

A second basic storm, described in Report No. 41, would produce PMP depths on a 7,980-square mile water shed centered in the Valley below the major tributary dams. The isohyetal pattern for the 7,980-square-mile storm is shown in Figure 2.4-7. The pattern is not orographically fixed and can be moved parallel to the long axis northeast and southwest along the Valley. Critical position centers this storm at Bulls Cap, Tennessee (50 miles northeast of Knoxville).

The third basic storm would produce PMP depths on the 4,458-square-mile Clinch River water shed and is described in Reference 13a. The isohyetal pattern for this storm is shown in Figure 2.4-8. This pattern is not orographically fixed and can be moved parallel to the long axis northeast and southwest along the Valley. Centerings both upstream and downstream of Norris Dam were tested.

The fourth basic storm would produce PMP depths on the 2912-square-mile watershed above Norris Dam and is described in Report No. 45. The isohyetal pattern of the storm is shown in figure ?-23 of that report. The pattern does not cover the full 2912-square-mile watershed. Full coverage was obtained by extending the lowest isohyet uniformly to the watershed boundary. The storm was centered 28 miles northeast of Tazewell, Tennessee, to obtain the maximum watershed rainfall. 7

A 3-day antecedent storm separated by a 3-day dry period from a 3-day main storm is recommended in Reports Nos. 41 and 45. For the 21,400- and 7,980-square-mile storms the antecedent storm is 40 percent of the main storm with uniform areal distribution as recommended in Report No. 41. In the 4,458- and 2912-square-mile Clinch River storms, the antecedent storm is 30 percent of the main storm with uniform areal distribution as recommended in Report No. 45.

A time distribution pattern was adopted for all antecedent and main storms based upon major observed storms transposable to the Tennessee Valley and distributions used by Federal agencies (Ref. 23). The adopted distribution is shown on Figure 2.4-9.

The effects of seasonal variations in storm amounts and storm centerings on plant site flood levels were examined in sufficient detail to assure that the situation producing the maximum flood level was found. July prevailed for the 4,458 and 2,912 square-mile Clinch River Basin storm and March prevailed for the others although a May, 7,980-square-mile storm was examined in this process.

The controlling probable maximum storm is the one for 7,980 square miles centered at Bulls Gap, Tennessee, which would follow an antecedent storm commencing on March 15. Over the Watts Bar water shed this results in (1) an antecedent storm producing an average precipitation of 6.9 inches in 3 days, (2) a 3-day dry period, and (3) a main storm producing an average precipitation of 17.2 inches in 3 days. Figure 2.4-10 is an isohyetal map of the maximum 3-day PMP. Basin rainfall depths by subwater sheds are given in Table 2.4-9.

2.4.3.2 PRECIPITATION LOSSES

A multivariable relationship, used in the day-to-day operation of the TVA system, has been applied to determine precipitation excess (P_e) directly. The relationships were developed from observed data. They relate precipitation excess to the rainfall, week of the year, geographic location, and antecedent precipitation index (API). In their application P_e becomes an increasing fraction of rainfall as the storm progresses in time and becomes equal to rainfall when from 7 to 16 inches have fallen.

In the CRBRP application, median API conditions were used at the start of the antecedent storm. This storm is so large, however, that the P_e in the main storm is not sensitive to this earlier condition.

For review purposes, precipitation losses have been determined by subtracting P_e from rainfall. In the controlling probable maximum storm the loss is 33 percent of rainfall in the 3-day antecedent storm and 10 percent of rainfall in the 3-day main storm. Table 2.4-9 displays the API, rain, and P_e for each of the subwater sheds used in CRBRP water shed model.

2.4.3.3 RUNOFF MODEL

The runoff model used to determine Clinch River flood hydrographs at the plant site is divided into 41 subareas shown on Figure 2.4-11. The model comprises the entire 17,310-square-mile Tennessee River water shed above Watts Bar Dam. This boundary, downstream from the CRBRP site, is appropriate because flood-induced headwater level at Watts Bar Dam may exert backwater influence upstream to the site.

The runoff model used in this amendment to the PSAR differs from that used previously because of refinements made in some elements of the model during PMF studies for other nuclear plants and those made from information gained from the 1973 flood, the largest that has occurred during present reservoir conditions. Changes are identified when appropriate in the text. They include both additional and revised unit hydrographs and additional and revised unsteady flow stream course models.

Unit hydrographs were developed for each unit area from maximum flood hydrographs either recorded at stream gaging stations or estimated from reservoir headwater elevation, inflow, and discharge data. The number of unit areas has been increased from 39 used previously to 41. The differences include:

1. Use of the model developed for the Phipps Bend study which combined the two unit areas for Watauga River (Sugar Grove and Watauga local) into one unit area and divided the Cherokee to Gate City unit area into two unit areas (Surgoinsville local and Cherokee local below Surgoinsville).

2. Changes to add an unsteady flow model for the Fort Loudoun-Tellico Dam complex which included dividing the lower Little Tennessee River unit area into two unit areas (Fontana to Chilhowee and Chilhowee to Telsico) and dividing the French Broad River local into two unit areas (Little Pigeon River at Sevierville and French Broad River local).

In addition, 7 of the unit graphs have been revised. Figure 2.4-12, which contains 10 sheets, shows the unit hydrographs. Table 2.4-11 contains essential dimension data for each unit hydrograph and identification of those hydrographs which are new or revised.

The 12,177-square-mile water shed above the Fort Loudoun-Tellico complex comprises 70 percent of the area above Watts Bar Dam. A detailed model is needed for this area, especially to assess the potential for and likely consequence of failure of several high tributary dams and of the Fort Loudoun-Tellico complex itself.

Because of the large, assured detention capacity of Norris Reservoir--7 inches, controlled, in March on the 2,912-square-mile water shed plus 4.5 inches, surcharge capacity in the PMF--flood outflows are largely a matter of inflow volume and are not significantly sensitive to inflow peaks and their timing. For this reason the entire upstream water shed may be represented by a single subarea (No. 1). Dual-peak performance is a consistent characteristic of the subarea as adequately represented by its unit hydrograph, Figure 2.4-12, Sheet 1.

In contrast, the 431 square miles of water shed, from Norris Dam downstream to Melton Hill Dam was divided specifically for this study into quite small subareas (Nos. 2-11) as shown in the inset on Figure 2.4-11. This was largely to provide accuracy of local inflow location points for the unsteady flow model of Melton Hill Reservoir considered potentially necessary because of the shape variations of contributing subarea units. In retrospect, because of the early timing of noncontrolling local inflow peaks, less detail would have been suitable.

Unit hydrographs are used to compute flows from the subareas. The subarea flows are combined with appropriate time sequencing or channel routing to compute inflows into the most upstream reservoir. Floods are routed through the reservoirs using standard techniques. Resulting outflows are combined with additional local inflows and carried downstream using appropriate time sequencing or routing procedures.

Unit hydrographs derived from observed records were developed from data for the largest floods available using procedures described by Newton and Vinyard (Ref. 14). For subareas 2,3,5-12, and 15 where records were not available, synthetic unit hydrographs were developed using the procedures described by the Corps of Engineers (Ref. 15). Subwater sheds 4 and 13 were gaged upstream from the mouth, and unit hydrographs developed from these records were modified for application at the river mouth. Figure 2.4-12, which contains 10 sheets, shows the unit hydrographs graphically. Table 2.4-11 contains essential dimension data for each unit hydrograph.

Tributary reservoir routings except for Tellico and Melton Hill Reservoirs used the Goodrich semigraphical method and flat pool storage. This differs from the previous submission in that an unsteady flow model has been added for the Fort Loudoun-Tellico complex.

Unsteady flow techniques (Ref. 16) were used in Fort Loudoun-Tellico, Watts Bar and Melton Hill Reservoirs. Prescribed boundary conditions are inflow hydrographs at the upstream boundary, local inflows, and headwater discharge relationships at the downstream boundary based upon standard operating rules, or on rating curves when geometry controlled.

The unsteady flow mathematical model for the 49.9-mile long Fort Loudoun Reservoir was divided into 24, 2.08-mile reaches. The model was verified at 3 gaged points within Fort Loudoun Reservoir using 1963 and 1973 flood data. The unsteady flow model was extended upstream on the French Broad and Holston Rivers to Douglas and Cherokee Dams, respectively. The French Broad and Holston River unsteady flow models were verified at one gaged point each at mile 7.4 and 5.5, respectively, using 1963 and 1973 flood data.

The Little Tennessee River was modeled from Tellico Dam, mile 0.3, through Tellico Reservoir to Chilhowee Dam at mile 33.6 and upstream to Fontana Dam at mile 61.0. The model for Tellico Reservoir to Chilhowee Dam was tested for adequacy by comparing its results with steady-state profiles at 1,000,000 and 2,000,000 cfs computed by the standard-step method. Minor decreases in conveyance in the unsteady flow model yielded good agreement. The average conveyance correction found necessary in the reach below Chilhowee Dam to make the unsteady flow model agree with the standard-step method was also used in the river reach from Chilhowee to Fontana Dam.

The Fort Loudoun and Tellico unsteady flow models were joined by a canal unsteady flow model. The canal was modeled with five equally-spaced cross-sections at 525-feet intervals for the 2100-foot long canal.

The unsteady flow mathematical model for Watts Bar Reservoir consists of two units combined in a junction model. These are (1) the Tennessee River from Watts Bar Dam, Mile 529.9, to Fort Loudoun Dam, Mile 602.3, and (2) the Clinch River embayment from its mouth to Melton Hill Dam, Mile 23.1. The model for the 72.4-mile Tennessee River unit was divided into thirty-four 2.13-mile reaches. The model for the 23.1-mile-long Clinch River embayment was divided into twenty-two 1.05-mile reaches.

The unsteady flow Melton Hill Reservoir model extending to Clinton, about Mile 59, and upstream on the Clinch River to Norris Dam (Mile 79.8) was divided into twenty-six 2.18-mile reaches. The model was verified by reproducing the floods of 1967 and 1969-70 at gages at Clinton, below Norris Dam, and Norris Dam tailwater. These verifications are not exhibited because the reservoir model is a part of the total water shed model above Melton Hill Dam which was verified using the 1969-70 flood and is a part of the total watershed model above Watts Bar Dam which was verified using the 1963 and 1969-70 floods. These verifications are described in later pages.

The Watts Bar Reservoir unsteady flow model was verified at four points along the Tennessee River and at Melton Hill Dam on the Clinch River embayment. Figure 2.4-15 shows that these locations span the reservoir in a practical manner for verification purposes. Floods of March 1967 and December-January 1969-70 were selected for this verification because they are large and because of the completeness of observed data for them. Watts Bar outflows were specified. Figures 2.4-16 and 2.4-17 for 1967 and 1969-70 respectively show good agreement between computed and observed elevation hydrographs at the five verification points.

It is impossible to verify unsteady flow models with actual data approaching the magnitude of the PMF; however, a series of uniform flows computed by both the unsteady flow model and the standard steady flow method were compared. This was done for both Watts Bar and Melton Hill Reservoirs with good agreement. A comparison at Mile 17.0 near the plant site in rating curve form, Figure 2.4-18, shows agreement within a maximum 1-foot difference. The unsteady flow model produces the higher levels.

The total water shed runoff model was verified at five locations critical to the study: the Tennessee River at Fort Loudoun and Watts Bar Dams, the Clinch River at Norris and Melton Hill Dams, and the Emory River at Oakdale. The Emory River drainage area of 865 square miles enters the Clinch River at Mile 4.4 and can influence plant flood levels in some flood situations. Emory River flows are not regulated.

Model verification at Fort Loudoun Dam used the large floods of March 1973 and March 1963. This differs from the previous submission in that the 1973 flood was added for verification replacing the 1957 flood. Observed volumes of precipitation excess were inputs, and reservoir operations were simulated by specifying observed headwater levels. Comparison between observed and computed outflows is shown in Figure 2.4-19.

The model predicts about 9 percent high in the 1973 flood and about 10 percent high in the 1963 flood. The model is considered to be fully adequate.

Norris Dam and Reservoir inflow was modeled with a 6-hour unit hydrograph derived from observed data in which time variant flow is estimated from observed changes in reservoir volume and observed project outflows. A best unit hydrograph was determined by the Newton-Vinyard procedure (Ref. 14) using floods of 1957 and 1963. Verification using the 1963 flood and a 1967 flood, shown on Figure 2.4-20, is good.

Norris Reservoir was modeled by the Goodrich steady flow method of flood routing using 3-hour routing intervals. Its verification in the 1963 and 1967 floods, shown on Figure 2.4-20, specified observed headwater levels. This is an extreme test because minute changes in headwater elevation create large changes in volume of water in the reservoir. Headwater elevations cannot be observed with total precision. Thus, small plus-and-minus errors in prescribed headwater create magnified plus-and-minus discrepancy in routed outflow to maintain volume continuity in the model. This results in "bouncy" computed outflows that are obvious on Figure 2.4-20. Under these circumstances only a general agreement can be expected, and this has been achieved. The verification of Norris outflows used inflows computed from precipitation excess.

Water shed model verification was carried on down the Clinch River to Melton Hill using the 1969-70 and 1973 floods. The 1973 flood is the largest that has occurred since the project was completed. Comparison of observed and computed discharges for the 1973 flood is shown on Figure 2.4-13 and for the 1969-70 flood on Figure 2.4-21. "Bounce" in the computed outflows is apparent and stems from the same cause as explained for Norris Dam but is less severe because of the small reservoir. Negative flows are attributable to the same cause. Except for "bounce" the verification is good and predicted a somewhat high peak.

The Emory River runoff model is a 4-hour unit hydrograph. It was prepared from the observed records for floods in 1948, 1957, and 1963 at Oakdale using the mathematical procedure described by Newton and Vinyard. The Oakdale drainage area, 764 square miles, is nearly 90 percent of the total Emory River water shed. The Emory River runoff model verification at Oakdale is shown in Figure 2.4-22, using the 1948 and December 1969 floods. These were the largest floods with adequate records at the time of this analysis. The model predicts the 1948 hydrograph closely except at the sharp peak, the duration of which is less than one-half day. Predicted peak is 20 percent high. The predicted hydrograph is good also in the 1969-70 flood, but is 14.5 percent low in a peak approaching a 1-day duration. Emory River enters the Clinch River about 12 miles downstream from the CRBRP site. Its flow contributions are of short duration and are timed ahead of much broader Clinch River peaks with the only effect on plant site flood levels through backwater influence downstream from Mile 4.4. Hence, Emory River floods have minimal effect on plant site flood levels. The water shed model is fully adequate in this circumstance.

Model verification was continued downstream on the Tennessee to Watts Bar Dam using the 1963, 1969-70 and 1973 floods. Figure 2.4-21 compares observed and computed discharges at Watts Bar for the 1963 and 1969-70 floods. Figure 2.4-14 compares observed and computed discharges for the 1973 flood. A unique Melton Hill situation existed during the 1963 flood. The partially completed dam modified flows in a way not typical of present, completed dam conditions. Consequently, observed flows at Melton Hill were used as inflow in the Watts Bar verification.

Figures 2.4-14 and 2.4-21 show that the Watts Bar model predicts flood peaks somewhat in excess of observed values in all three cases. It is considered to be conservative as an instrument to estimate larger floods. The negative computed flows in the 1969-70 flood occurred when actual project outflows were zero or minimal and resulted from specifying observed headwater level as the boundary. It is virtually impossible to model a reservoir perfectly enough to verify these severe conditions. Moreover, modification toward doing so would have no influence on model performance during flood peaks.

Studies by others (Ref. 17,18,19) and unpublished work of TVA indicate linearity of unit hydrographs (capability to predict floods of largely varying magnitude) if they are derived from large, out-of-bank floods produced by major, basinwide storms. Total capability of the runoff model has been verified at critical locations (Norris, Melton Hill, Fort Loudoun, and Watts Bar Dams) against the largest available floods. Comparisons revealed that the model predicts conservatively high at all four locations. Large volume in upstream reservoirs, particularly in nearby Norris Reservoir, has a strong stabilizing influence on the models. Unsteady flow techniques, the most advanced state of the art, have been used in the segments of the model having principal effect on flood elevations at the CRBRP site.

Results from unsteady flow techniques have been verified by steady flow methods to the extent possible. From these factors it is concluded that the water shed modeling used in this analysis predicts probable maximum flood elevations adequately and safely.

2.4.3.4 Probable Maximum Flood Flow

The maximum PMF discharge at the plant site would be a sharp, narrow peak of 258,000cfs resulting from the failure of Melton Hill. The discharge hydrograph is shown in Figure 2.4-23. It was computed with the unsteady flow model.

The flood would result from the 7,980-square-mile storm with center at Bulls Gap, Tennessee, shown in Figure 2.4-10, which also produces near PMP depths on the 17,310-square-mile water shed above Watts Bar Dam. The storm is more completely described in 2.4.3.1.

The flood would overtop and breach the earth embankments at Fort Loudoun and Tellico Dams upstream and Watts Bar Dam downstream. The concrete nonoverflow section of Melton Hill Dam would also fail. These are the only dams that would fail. The Melton Hill failure and Fort Loudoun-Tellico breach increases while the Watts Bar breach reduces the level of this flood at the plant site. The analysis of dam failures is described in Section 2.4.4.

The influence of the TVA reservoir system on the PMF was computed using operating procedures prescribed for floods.

In addition to spillway flow, these permit turbine and sluice discharge in tributary reservoirs in the antecedent storm. Turbine discharges are not used in the mainstream reservoirs after large flows develop because head differentials become too small. Normal operating procedures were used in the principal storm except that turbine discharge was not used in either the tributary or main river dams. The previous analysis did include turbine discharge in tributary reservoirs. All gates were determined to be operable during the flood. Prescribed operating procedures actually have little influence on maximum flood discharges, however, because spillway capacities and hence uncontrolled conditions are reached early in the main storm flood.

Historic, observed, mid-March reservoir levels were used at the start of the flood from the antecedent storm. As a result of the antecedent storm and flood, 51 percent of the reserved system flood detention capacity was occupied at the start of the flood from the main storm.

Norris Dam was examined for potential failure during the PMF. The PMF would result from a 3-day, July PMP of 18.7 inches with P_e of 16.5 inches, preceded by a 3-day dry period and antecedent storm equal to 30 percent of the PMP.

The maximum headwater reached would be 1055.5, 5.5 feet below dam top. Structural analysis confirmed that the dam would not fail under this condition. Inflow, outflow, and headwater hydrographs for the Norris PMF are shown in figure 2.4-23a.

Flows and elevations for other candidate storms were not computed at the plantsite because it can be judged from the flood-producing components that they would produce lower flood levels. Norris Dam outflow and backwater rise in the Watts Bar Reservoir system caused by high flow and Watts Bar headwater elevation are the dominant influences on CRBRP site flood levels. Local inflow from precipitation on the area below Norris Dam peaks early with only the recession of the hydrograph adding to peak dam outflows and hence has a less dominant effect. Precipitation on this area was used to judge flow rates when they were not computed. Emory River inflows at mile 4.4 on the Clinch River contribute somewhat to backwater effect.

Backwater elevation at the mouth of the Clinch River is a major influence on plantsite flood levels (see Figure 2.4-18), reaching elevation 773.2 in the controlling flood. This flood produces the highest Watts Bar Reservoir flow and headwater level and, except for the Norris PMF, essentially the highest Norris outflow. The Norris PMF peak outflow of 285,000 cfs would reduce to 230,000 cfs at the plantsite. A site elevation of not more than 772 was estimated for this flood based upon a conservative postulation of elevation 765 at the mouth of the Clinch River.

It is concluded that the March storm on 7,980 square miles produces the probable maximum flood. Any more detailed and definitive proof is not prudent because the controlling flood level at the CRBRP site, resulting from combined rainstorm flood and seismic failure of Norris Dam as discussed in 2.4.4, overrides the PMF by some 20 feet.

2.4.3.5 Water Level Determinations

The PMF would produce elevation 778.8 at Mile 18 and elevation 777.2 at Mile 16. Elevation hydrographs for these locations are given in Figure 2.4-24. Elevations were computed concurrently with the discharges for the site using the unsteady flow model. The influence of Melton Hill Dam failure is apparent. The influences of Fort Loudon-Tellico and Watts Bar Dam failures are not conspicuous but were an integral part of the analysis.

2.4.3.6 Coincident Wind Wave Activity

Winds are commonly associated with rainstorms. They usually subside, however, when rainfall ends. Flood crests, on the other hand, often occur some time after the end of rainfall. At the CRBRP site this lag from total basin runoff is at least 1 day. See Figures 2.4-23 and 2.4-24. Hence, winds integral with a given storm usually have ceased by the time of the flood crest. Yet meteorological conditions conducive to flood-producing storms can repeat themselves. Just such a repetition has been postulated in the PMF analysis which used an antecedent and a larger, main storm. To assign a wind and its wave runup effect during the flood crest of the second storm postulates yet a third, repetitive wind-producing event. The probability of such a sequence is extremely remote.

Nevertheless, a conservatively high wind velocity of 40 miles per hour over land from the most adverse direction has been applied at the time of the second, main storm flood peak to conform with Regulatory Guide 1.59. This is conservatively high compared to the requirements specified in Revision 2 of Regulatory Guide 1.59 (August 1977).

2.4.3.5 Water Level Determinations

The PMF would produce elevation 777.5 at Mile 18 and elevation 776.0 at Mile 16. Elevation hydrographs for these locations are given in Figure 2.4-24. Elevations were computed concurrently with the discharges for the site using the unsteady flow model. The influence of Melton Hill Dam failure prior to the main storm peak is apparent. The influences of Fort Loudoun and Watts Bar Dam failures are not conspicuous but were an integral part of the analysis.

2.4.3.6 Coincident Wind Wave Activity

Winds are commonly associated with rainstorms. They usually subside, however, when rainfall ends. Flood crests, on the other hand, often occur some time after the end of rainfall. At the CRBRP site this lag from total basin runoff is at least 1 day. See Figures 2.4-23 and 2.4-24. Hence, winds integral with a given storm usually have ceased by the time of the flood crest. Yet meteorological conditions conducive to flood-producing storms can repeat themselves. Just such a repetition has been postulated in the PMF analysis which used an antecedent and a larger, main storm. To assign a wind and its wave runup effect during the flood crest of the second storm postulates yet a third, repetitive wind-producing event. The probability of such a sequence is extremely remote.

Nevertheless, a conservatively high wind velocity of 40 miles per hour over land from the most adverse direction has been applied at the time of the second, main storm flood peak to conform with Regulatory Guide 1.59.

A 40-mile-per-hour wind of sufficient duration to produce maximum wave runup at the plant is, in itself, a rare event for March, the month of the PMF. As judged from 30 years of record at Chattanooga, Tennessee, recorded winds on 930 March days show a probability in the order of 1×10^{-3} for a 40-mile-per-hour wind on a specific March day. It is further postulated that, as a third, sequential meteorological event, it is independent of the PMF from two prior meteorological events. A 1×10^{-7} probability for a PMP storm and resulting PMF from a single meteorological event coincident with a high velocity wind from a second meteorological event has been receiving professional acceptance. Combining a 40-mile-per-hour wind from yet a third, independent event extends the probability of the combination to the 1×10^{-10} probability range. Newton and Cripe (Ref. 11) in alternative approaches applying to the Tennessee Valley estimate in the 1×10^{-13} range.

Wind waves were computed using procedures of the Corps of Engineers (Ref. 20). Waves and runup are applicable to the plant only at Mile 16. At Mile 18 ground levels adequately shield the plant in the PMF with coincident wind. (See Figure 2.4-44 which applies specifically to higher flood levels from combined hydrologic and seismic causes.) At Mile 16 the critical direction is from the southeast with an effective fetch of 0.5 mile. For a 40-mile-per-hour overland wind, 99.6 percent of the waves would be less than 2.4 feet high from crest to trough, resulting in maximum water elevation 778.8. Runup above still reservoir levels would be 2.8 feet to elevation 780.0 on a smooth 3:1 slope and 3.8 feet to elevation 781.0 on a vertical wall.

2.4.4 Potential Dam Failures (Seismically and Otherwise Induced)

The plant site and upstream reservoirs are located in the Southern Appalachian Tectonic Province and, therefore, subject to moderate earthquake forces. All upstream dams, including those on the Tennessee River, whose failure in a seismic event has the potential to cause problems at the plant when combined with appropriate floods were investigated as described in 2.4.4.2.1. Studies to determine the potential failure of upstream dams from hydrologic conditions are described in 2.4.4.2.2.

An operational basis earthquake (OBE), imposed concurrently with the one-half PMF resulting in postulated Norris failure, would be the controlling failure situation. Maximum water surface elevation would be 804.3 and 798.2 at Mile 18.0 and Mile 16.0 respectively, excluding any wind wave effects. As shown in Table 2.4-8 this condition produced the maximum plant flood level from any of the PMF or seismic conditions stipulated by Regulatory Guide 1.59.

This information is presented solely to confirm that the CRBRP can withstand postulated floods caused from probable maximum rainfall, from seismic dam failures, and from combinations of rainfall and seismic dam failure. TVA is of the strong opinion that the likelihood of events occurring concurrently which produce controlling flood levels for plant design is extremely remote.

By furnishing this information TVA does not imply or concede that its dams are inadequate to withstand great floods and/or earthquakes that may be reasonably expected to occur in the TVA region under consideration. TVA has a program of inspection and maintenance carried out on a regular schedule to keep its dams safe. Instrumentation of the dams to help keep check on their behavior was installed in many of the dams during original construction. Other instrumentation has been added since and is still being added as the need may appear or as new techniques become available. In short, TVA has confidence that its dams are safe against catastrophic destruction by any natural forces that could be expected to occur.

2.4.4.1 <u>Dam and Reservoir Description</u>

Characteristics of TVA dams and reservoirs are contained in Table 2.4-13. Their location with respect to the plant site is shown in Figure 2.4-25. There are nine dams upstream in the Tennessee River System which influence flood levels at the plant site and Norris and Melton Hill Dams upstream on the Clinch River. Elevation-storage relationships and seasonally varying storage allocation in the major projects are shown on the nine sheets of Figure 2.4-26. No guide is provided for Melton Hill because the reservoir is held at full pool elevation 795 throughout the year with only minor fluctuations. An area-volume curve for Norris Reservoir is given in Figure 2.4-27.

There is essentially no likelihood that future dams and reservoirs could adversely affect flood levels at the CRBRP. The Clinch River already is fully developed essentially to Norris Dam, and additions upstream of Norris Reservoir are not needed. There is small chance of future dams on other Tennessee River Tributaries upstream from the mouth of the Clinch River and on the Emory River. Even if these forecasts are incorrect, any new dams would be designed and built to withstand floods and seismic forces that otherwise could endanger by flooding not only the CRBRP but other nuclear power generating plants as well. Hence, the net influence of future dams, however unlikely, would be favorable rather than adverse.

Most of the dams upstream from the plant and Watts Bar Dam were designed before the hydrometeorological approach to spillway design gained its current level of acceptance, and spillway capacity is probably less than would be provided today. Arbitrary freeboard provided at these dams, however, permits many of them to meet today's criteria. Those dams whose failure in the PMF have a potential to influence plant flood levels were examined, as discussed in 2.4.4.2.2.

2.4.4.2 <u>Dam Failure Permutations</u>

The discussion of dam failure permutations has been separated into two sections--Seismic Failure Analysis (2.4.4.2.1) and Hydrologic Failure Analysis (2.4.4.2.2).

2.4.4.2.1 <u>Seismic Failure Analysis</u>

There are 11 major dams that can influence plant site flood levels--two on the Clinch River and nine on the Tennessee River System upstream of Watts Bar Dam. All 11 were examined individually and in groups to determine if postulated seismic failure combined with appropriate flood conditions would produce a controlling flood condition at the plant site. Two basic conditions were examined, a safe shutdown earthquake (SSE) during a 25-year flood with full reservoirs, and an operational basis earthquake (OBE) during the one-half PMF with full reservoirs. The latter combination produced controlling flood levels.

The FSAR for Sequoyah Nuclear Plant (Reference 20a) describes the investigation of potential single and multiple failures of Watts Bar and all 11 dams upstream during the two postulated seismic-flood combinations. All events referred to in that report were reexamined using flood conditions specifically applicable to the CRBRP. In the OBE the seismic dam failure combinations with a potential to create maximum plantsite flood levels are Norris Dam singly and Cherokee and Douglas Dams concurrently. In the SSE the candidate situations include failure of Norris Dam singly and concurrent failure of Norris-Cherokee-Douglas and Norris-Douglas-Fort Loudon-Tellico. In the situations involving Norris Dam failure, Melton Hill Dam was postulated to fail when the flood wave reached headwater elevation 804. Watts Bar Dam would be overtopped and the embankment would be breached from postulated Norris Dam failure in the OBE. However, failure would occur after the Clinch River flood peak had passed the plantsite and hence have no lowering effect. Because of this, plantsite flood levels were computed as though Watts Bar embankment did not fail.

Flows and elevations for the potentially critical situations are summarized in Table 2.4-12. The single, Norris Dam OBE failure combined with the one-half PMF was controlling.

Regulatory Grade 1.59 recommends use of Appendix A to 10 CFR 100 for estimates of seismically induced flood levels. As described above, both a safe shutdown earthquake with a 25 year flood and a 1/2 safe shutdown earthquake together with 1/2 PMF are considered in accordance with this guide. For this site the 1/2 SSE corresponds to a horizontal acceleration of 0.125 g at rock foundation.

The basic procedures and the specific analysis to determine Norris Dam stability are described below.

A standard method of computing stability is used. The maximum base compressive stress, average base shear stress, the factor of safety against overturning, and the shear strength required for a shear-friction factor of safety of one are determined. To find the shear strength required to provide a safety factor of one, a coefficient of friction of 0.65 is assigned at the elevation of the base under consideration.

The analyses of earthquakes are based on the static analysis method as given by Hinds (Ref. 21) with increased hydrodynamic pressures determined by the method developed by Bustamante and Flores (Ref. 23). These analyses include applying masonry inertia forces and increased water pressure to the structure resulting from the acceleration of the structure Horizontally in the upstream direction and simultaneously in a downward direction. The masonry inertia forces are determined by a dynamic analysis of the structure which takes into account amplification of the accelerations above the foundation route.

No reduction of hydrostatic or hydrodynamic forces due to the decrease of the unit weight of water from the downward acceleration of the reservoir bottom is included in this analysis.

Waves created at the free surface of the reservoir by an earthquake are considered of no importance. Based upon studies by Chopra (Ref. 24) and Zienkiewicz (Ref. 25), it is TVA's judgment that before waves of any significant height have time to develop, the earthquake will be over. The duration of earthquakes used in this analysis is in the range of 20 to 30 seconds.

Although accumulated silt on the reservoir bottom would dampen vertically traveling waves, the effect of silt on structures is not considered. There is only a small amount of silt now present and the accumulation rate is slow, as measured by TVA for many years (Ref. 26).

Figure 2.4-28 is a general plan of Norris Dam showing elevations and sections. Results of Norris Dam stability analysis in the OBE for a typical spillway block and a typical nonoverflow section of maximum height are shown in Figure 2.4-29. Because only a small percentage of the spillway base is in compression, this structure is judged to fail. The high nonoverflow section with a small percentage of the base in compression and with high compressive and shearing stresses is also judged to fail. Based on stability analysis the lower nonoverflow blocks remaining in place are judged able to withstand the OBE.

Blocks 34-33 (665 feet of length) are judged to fail by overturning at the base foundation because the resultant of all forces falls very near the downstream toe which results in high compressive and shearing stresses. Supporting this judgment is a statement by Hinds, Creager, and Justin (Ref. 21): "As the resultant approaches the face the compression stress increases rapidly, hence overturning would be preceded and accelerated by a compression failure." Stability analyses indicate failure by overturning at a plane in the concrete above the foundation of the structure is less likely, principally because the height of the dam above such a plane is decreased and because a drainage system for uplift relief is provided in the structure above the inspection and drainage gallery.

The dam is located on the dolomite series of rock which belongs to the lower part of the Copper Ridge formation and is in turn the lowest part of the Knox group. The structures are well entrenched into rock which dips slightly downstream. Tests made during the original design of Norris Dam indicate the rock has high shear strength and, therefore, is judged able to resist sliding of the dam due to the additional earthquake forces.

Figure 2.4-30 shows the 665-foot-long part of the dam judged to fail under OBE conditions and the judged location and height (elevation 970) of the debris of the failed portion. The location of the debris is not based on any calculated procedure of failure because it is believed that this is not possible. It is TVA's judgment, however, that the failure mode shown is one logical assumption and although there may be many other logical assumptions the amount of channel obstruction would probably be about the same.

Under SSE conditions, blocks 31 through 45 (833 feet of length) are judged to fail. The resulting debris downstream would occupy a greater span of the valley cross section than would the debris from OBE failure but with the same top level, elevation 970. Figure 2.4-31 shows the part of the dam judged to fail and the location and height of the resulting debris.

2.4.4.2.2 Hydrologic Failure Analysis

All upstream and downstream dams which are close enough to have a significant influence on flood levels at the CRBRP were examined for potential failure during the PMF. Concrete sections were examined for overturning and for horizontal shear failure with a resultant sliding of the structures. Spillway and lock gates were examined for stability at potentially critical water levels, and against failure from being struck by waterborne objects. Concrete lock structures were examined for stability, and earth embankments were examined for erosion due to overtopping.

It was concluded that the only potential failures during the PMF would be of the earth embankments at Fort Loudon-Tellico and Watts Bar Dams due to erosion from overtopping and all the concrete nonoverflow portion of Melton Hill Dam to the left (looking downstream) of station 19+54 and above elevation 774.5.

Concrete Section Analysis

For concrete dam sections, comparisons were made between the original design headwater and tailwater levels and those that would prevail in the PMF. If the overturning moments and horizontal forces were not increased by more than

20 percent, the structures were considered safe against failure. All upstream dams passed this test except Melton Hill, Douglas, and Fort Loudon. Original design showed that the spillway sections of Fort Loudon and Douglas Dams to be most vulnerable. These were examined in further detail and judged to be stable. The nonoverflow portion of Melton Hill Dam left of station 19+54 and above elevation 774.5 was judged to fail by overturning if headwaters reached elevation 804. Figure 2.4-32 is a general plan of Melton Hill Dam showing elevations and sections.

Spillway Gate Failures

Consideration was given to the potential effect at the CRBRP of the failure of spillway gates at Watts Bar and upstream dams in the PMF. The analysis for the Sequoyah FSAR show that at Fort Loudon and Watts Bar Dams the gates would remain intact except possibly when struck by waterborne objects. These dams would be overtopped by the PMF. Gate failure would only make relative small changes in the timing of such failure. Because of this it was concluded that gate failures are not important to this analysis and were dropped from further consideration. Gates were assumed operable and not to fail in all routings.

Lock Gates

The lock gates at Fort Loudon, Watts Bar, and Melton Hill Dams were examined with the conclusion that no potential for failure exists because the gates are designed for a differential hydrostatic head greater than that which would exist during the PMF.

Embankment Breaching

Earth embankments at Fort Loudon-Tellico and Watts Bar Dams would be overtopped and subsequently breached by the PMF. The Fort Loudon-Tellico breach would add to PMF elevations and the Watts Bar breach would reduce flood levels at the plants'te. These situations will be described in some detail.

The adopted relationship to compute the rate of erosion in an earth dam failure is that developed and used by the Bureau of Reclamation in connection with its safety of dams program (Ref. 27). The expression relates the volume of eroded fill material to the volume of water flowing through the breach. The equation is:

$$\frac{Q_{soil}}{Q_{water}} = K_e^{-X}$$

where:

Q_{soil} = Volume of soil eroded in each time period

Q_{water} = Volume of water discharged each time period

K = Constant of proportionality, 1 for the soil and discharge relationships in this study

e = Base of natural logarithm system

X $= \frac{b}{H} \tan \phi_d$

b = Base length of overflow channel at any given time

H = Hydraulic heat at any given time

ϕ_d = Developed angle of friction soil material

A conservative value of 13 degrees was adopted for materials in the dams investigated.

Solving the equation, which was computerized, involves a trial-and-error procedure over short depth and time increments. In the program, depth changes of 0.1 foot or less are used to keep time increments to less than one second during rapid failure and up to about 350 seconds prior to breaching.

The solution of an earth embankment breach begins by solving the erosion equation using a headwater elevation hydrograph assuming no failure. Erosion is postulated to occur across the entire earth section and to start at the downstream edge when headwater elevations reached a selected depth above the dam top elevation. Subsequently, when erosion reaches the upstream edge of the embankment, breaching commences. Thereafter, computations include headwater adjustments for increased reservoir outflow resulting from the breach. Breaching proceeds relatively slowly for a short period; then, typically, breaching proceeds rapidly and the embankment is washed away in minutes. For purposes of routing, complete failure was assumed to occur at the beginning of rapid failure.

During the hour of failure the peak discharge was determined based upon the headwater and tailwater depth at that time. Unsteady flow routing techniques were used to define the rest of the outflow hydrograph.

Some verification for the breaching computational procedures illustrated above was obtained by comparison with actual failures reported in the literature and in informal discussion with hydrologic engineers. These reports show that overtopped earth embankments do not necessarily fail. Earth embankments have sustained overtopping of several feet for several hours before failure occurred. An extreme example is Oros earth dam in Brazil (Ref. 28) which was overtopped to a depth of approximately 2.6 feet along a 2,000-foot length for 12 hours before breaching began. Once an earth embankment is breached, failure tends to progress rapidly, however. How rapidly depends upon the material and headwater depth during failure. Complete failure computed in this and other studies has varied from about one-half to 6 hours after initial breaching. This is consistent with actual failures.

Fort Loudoun-Tellico Embankment Failure

Figure 2.4-33 is a general plan of Fort Loudoun Dam showing elevations and sections. Figure 2.4-34 is a general plan of Tellico Dam showing elevations and sections. Failure calculations were made for the earth embankments at Tellico and Fort Loudoun. Tellico would fail about 1-1/2 hours earlier than Fort Loudoun but the relief afforded would not prevent failure of Fort Loudoun. To conservatively determine a maximum plant site flood level and to facilitate computations, complete, instantaneous disappearance of the Fort Loudoun-Tellico complex was assumed at the earlier of the two calculated failure times. Figure 2.4-35 shows the headwater and tailwater discharge relationships for Fort Loudoun. Figure 2.4-35a shows the headwater and tailwater rating curves for Tellico. Figure 2.4-36 shows the computed outflow hydrograph for the CRBRP PMF immediately below the failed Fort Loudoun-Tellico complex.

Watts Bar Embankment Failure

Figure 2.4-37 is a general plan of Watts Bar Dam showing elevations and sections. Figure 2.4-38 is a general plan and section of the west saddle dike. Failure calculations were made for the 750 feet of earth embankment shown on Figure 2.4-37 which was assumed to erode down to average ground elevation 700. The computed rate of failure of the embankment section is shown on Figure 2.4-39.

The west saddle dike was examined and also found subject to failure from overtopping. This failure would be a complete washout and would occur some 8-1/2 hours before that of the main embankment. The relief afforded would not prevent failure of the main embankment and, therefore, was ignored.

Figure 2.4-40 shows the headwater discharge relationships for Watts Bar Dam, one before failure and one after failure of the 750-foot earth embankment section. The tailwater rating curve is also shown for comparison. The tailwater curve differs from that originally provided and results from changes made in the Chickamauga Reservoir hydraulic model based upon March 1973 flood data. The headwater discharge relationships also differ as a result of the revised tailwater and improved definition of flow at high levels where the spillway acts as a submerged orifice. Figure 2.4-41 is the computed outflow hydrograph from Watts Bar Dam for the CRBRP PMF. Corresponding headwater levels are shown on Figure 2.4-39.

2.4.4.3 Unsteady Flow Analysis of Potential Dam Failures

An unsteady flow model of Norris Reservoir was developed in sufficient detail to define the manner in which the reservoir would supply and sustain outflow at postulated seismically failured Norris Dam. The 61-mile reach of reservoir upstream to Clinch River Mile 141 was divided into twenty-eight 2.2 mile reaches. The model was verified by comparing its routed headwater levels in the one-half PMF with those using simplified routing techniques. Headwater levels agreed within a foot, and the model was considered adequate for the purpose.

Discharge rating curves for Norris Dam for both the postulated OBE and SSE failure conditions are shown on Figure 2.4-42. These rating curves were developed from 1:150 scale hydraulic model studies at TVA's Engineering Laboratory and verified closely by hydraulic analysis. Outflow for failed conditions is controlled by the degree to which the valley cross section downstream from the dam is obstructed by debris. This debris, not the dam breach, forms the discharge control section. Debris resulting from the SSE failure is more extensive than from the OBE failure, as shown by figures 2.4-30 and 2.4-31. Thus, discharge under OBE conditions with the shorter failed section but less downstream debris is greater at a given headwater than for SSE conditions with wider dam breach but greater downstream debris, as shown by the rating curves, figure 2.4-42.

In addition to the postulated OBE failure condition for Norris Dam shown in Figure 2.4-30, four other failure conditions were arbitrarily assumed. There is no engineering basis for these conditions which were assumed solely for sensitivity analysis. These are (1) overturning of blocks 33-44 (665-foot width) with 945 debris level, (2) overturning of seven blocks, 37-43 (370-foot width) with 925 debris level, (3) vanishment of the three tallest middle blocks, 38-40 (168-foot width) to ground level, and (4) instant vanishment of entire dam. Discharge rating curves for the first two conditions were developed from 1:150 scale hydraulic model studies at TVA's Engineering Laboratory. The discharge rating for the assumed three-block failure condition was developed analytically using hydraulic relationships for contracted openings. The outflow for the instant vanishment of the dam was defined by the unsteady flow models of Norris Reservoir and Melton Hill Reservoir, which were coupled together for this condition.

Unsteady flow routing was used in Melton Hill and Watts Bar (including the Clinch River embayment) Reservoirs to provide the accuracy needed to account for rapid flow and elevation changes at the plant site resulting from both upstream and downstream dam failures during the various postulated flooding conditions.

For Melton Hill failure in the PMF, headwater and tailwater curves appropriate to the overturned nonoverflow section were used as boundaries for the models. In the Norris Dam seismic failure flood wave, Melton Hill Dam was conservatively assumed to fail completely and instantaneously with no debris interference at which time the unsteady flow models upstream and downstream were coupled together. This allowed computation of wave propogation both upstream and downstream in one continuous analysis.

Routings of seismic dam failure surges upstream of Watts Bar Reservoir were made using short interval storage routing procedures. These define Watts Bar lake inflows with sufficient accuracy to demonstrate that Norris Dam OBE failure is the controlling situation.

2.4.4.4 Water Level at Plant Site

The unsteady flow analyses discussed in the previous section yield flow and elevation hydrographs in one operation. Results for PMF conditions are given in 2.4.3. These hydrographs for floods from the controlling combined seismic dam failure and precipitation flood are shown on Figure 2.4-43.

Peak flow at the plant for the controlling, OBE-one-half PMF Norris failure situation would be 921,000 cfs. Crest still reservoir levels would be elevation 804.3 at Mile 18 and elevation 798.2 at Mile 16.

Plantsite flood elevations were also determined for the arbitrarily assumed Norris failure conditions discussed in the previous section. These failure situations were combined with the one-half PMF and were determined only for comparative purposes. The tabulation below provides computed elevations for these specified arbitrary conditions and for the adopted level.

Failure Mode	Location (Mile)	Still Reservoir Elevation
Adopted Condition		
Blocks 33-44 overturned (665-foot width) 970 debris level	18 16	804.3 798.2
Arbitrary Conditions		
Blocks 33-44 overturned (665-foot width 945 debris level	18 16	808.9 802.6
Blocks 37-43 overturned (370-foot width) 925 debris level	18 16	811.9 805.3
Vanishment of blocks 38-40 (168-foot width) to ground level	18 16	808.4 802.2
Instant vanishment of entire dam to ground level	18 16	818.0 811.0

The only failure condition that would create flood levels above plant grade elevation 815 is the instant vanishment of the entire dam, an unrealistic assumption. TVA concludes that failure of Norris Dam coincident with a large flood will not endanger the plant.

A coincidental 40-mile-per-hour overland wind was applied for the fetch radials and directions shown on Figure 2.4-44. Critical direction is from the northeast for Mile 18 and from the southwest for Mile 16, both with an effective fetch length of 0.8 mile. For these conditions 99.6 percent of the waves would be less than 3.0 feet from crest to trough. Runup would be 3.6 feet on a 3:1 smooth slope and 4.9 feet on a vertical wall. Resulting elevations for the adopted condition are as follows:

	Elevation			
	Still	Maximum	Runup	
Location	Reservoir	Water Surface	Smooth 3:1 Slope	Vertical Wall
Mile 18	804.3	806.3	807.9	809.2
Mile 16	798.2	800.2	801.8	803.1

Windwaves were not computed for the arbitrarily assumed failure conditions.

2.4.7 Ice Flooding

Because of the location in a temperate climate, significant amounts of ice do not form on the lakes or rivers in the area and ice jams seldom occur and are not a source of major flooding. There are no records of frazil or anchor ice on the Clinch River in the vicinity of the plantsite.

The potential for ice formation at the site is less today than in the past because (1) daily water level fluctuations from operating Watts Bar (closed 1942) and Melton Hill (closed 1963) Reservoirs would break up surface ice before significant thickness can be formed, (2) increased water depths due to Watts Bar Reservoir result in a greater mass needing to be cooled by radiation compared to prereservoir conditions, (3) Clinch River flows are warmed by release from near the bottom of Melton Hill Reservoir, and (4) Melton Hill Lake waters, in turn, are warmed by releases from near the bottom of Norris Reservoir (closed 1936).

Since Melton Hill was closed in May 1963, daily winter variation in tailwater level, mile 23.1, has ranged from 0.2 foot to 7.4 feet and from 0.02 foot to 4.1 feet at the USGS stream gage near Oak Ridge, mile 14.4. Fluctuation at the plantsite would be somewhere in-between.

Minimum average water depths encompassing the 2-mile plantsite reach have been increased from 7 feet to 19 feet due to Watts Bar Reservoir. The lowest observed temperature in Melton Hill Lake was 40.4° in January 1964 at

2.4.9 Channel Diversions

Channel diversion is not a potential problem for the plant. There are now no channel diversions upstream of the CRBR plant that would cause diverting or rerouting of the source of plant cooling water, and none are anticipated in the future. The floodplain is such that large floods do not produce major channel meanders or cutoffs. Carbon 14 dating of material at the high terrace levels shows that the Clinch River has essentially maintained its present alignment for over 2,000 years. The topography is such that only an unimaginable catastrophic event could result in any flow diversion above the plant.

2.4.10 Flooding Protection Requirements

All Category I Structures, housing safety-related facilities, systems and components, and on-site power supply, will be designed and constructed for protection against all possible flooding conditions. These Category I Structures, capable of surviving the design flood conditions, include the Reactor Containment Building, Reactor Service Building, Steam Generator Building, Intermediate Building, Diesel Generator Building and the Control Building. 33

With the maximum flood level established at elevation 809.2, structures which are either completely or partially located at elevations below this level will be analyzed for the effects of the following forces:

a. Hydrostatic pressures

b. Buoyancy

c. Wave action.

Hydrostatic pressures and dynamic wave effects (where applicable) will be combined with other loads in the design of the Category I structure or components.

Stability against floatation will also be provided. Protection against buoyant effects will be provided for Category I structures by resistance from dead loads or mechanical anchors to bedrock.

All safety-related systems and equipment will be either located on floors above the maximum flood level, or will be protected by the following measures:

dard conversion of units).

Releases from Norris Reservoir, located on the Clinch River 56.7 miles upstream of Melton Hill, flow into Melton Hill Reservoir and subsequently by the site. Norris Reservoir is a multiple-purpose reservoir providing power generation and flood control. The normal minimum pool elevation is 960 (See Figure 2.4-58). Power generation at Norris can be maintained to about elevation 900. Although not a primary purpose, stored water between elevations 960 and 900 is available for low flow augmentation in periods of drought. However, minimum levels will not be violated without specific TVA Board of Directors' action. The total volume of storage in Norris Reservoir between elevations 960 and 900 is 260,650 sfd. This volume of water represents an average discharge of 714 cps for a period of one year. It is possible to lower Norris Reservoir to about elevation 860 by the use of slide gates. The total storage volume in Norris Reservoir between elevations 900 and 860 is 46,940 sfd (see Figure 2.4-59).

Releases from Fort Loudoun Reservoir, located on the Tennessee River 72.4 miles upstream from Watts Bar, can be used to control the Watts Bar pool elevation. The normal minimum pool elevation for Fort Loudoun is 807 (See Figure 2.4-60
27 and Reference 37). The minimum pool elevation of record is 805.54, on January 18, 1954. It is possible to lower Fort Loudoun Reservoir to about elevation 783 by the use of the spillway. The total volume of storage in the reservoir between elevations 807 and 783 is 97,500 sfd (See Figure 2.4-61).

Inflows into Watts Bar Reservoir from the Tennessee River are large, even during periods of low flow. Observed low flows at Loudoun (gaging station Number 3-5200, 10 3/4 miles downstream from Fort Loudoun Dam and 9 3/4 miles downstream from the mouth of the Little Tennessee River) during the period from 1923 through 1954 are 1,820 cfs for one day and 2,790 cfs for 30 days. Observed low flows at this location since the filling of Fort Loudoun Reservoir are 1,820 cfs for one day and 9,020 cfs for 30 days. Thus, the 30-day low-flow volume for the period of record is equal to 83,700 sfd. The 30-day low-flow since the filling of Fort Loudoun Reservoir represents a volume of more than 270,000 sfd. An appraisal of the significance of these flows may be obtained by noting that the storage capacity of Watts Bar Reservoir at elevation 735 (minimum pool elevation) is about 15,000 sfd per foot (See Figure 2.4-62). Thus, the Tennessee River is more than capable of maintaining the minimum pool elevation of Watts Bar Reservoir even under extreme conditions.

2.4.11.4 Future Control

No plans for new structures on the Clinch River are known which might result in future low flows at the site significantly different from those observed in the past. The extended periods of no release from Melton Hill Reservoir in the past have been the result of special operations either upstream or downstream of Melton Hill Dam which are unrelated to either power generation or navigation. These extended periods of no release will be avoided in the future thru appropriate reservoir operations should plant requirements so dictate.

Flows at the site can be augmented from storage in Norris and Melton Hill Reservoirs. Inflow into Watts Bar Reservoir can also be augmented from storage in Fort Loudon and Tellico Reservoirs in the Tennessee River. Characteristics of these reservoirs are described in Section 2.4.11.3.

2.4.11.5 Plant Requirements

2.4.11.5.1 River Water Service System

This system incorporates a non-Seismic Class I intake structure designed to withstand a flood level of 750'0". The system supplies all plant make-up water from the Clinch River to the Emergency Cooling Tower Basin and the Main Cooling Tower Basin. This system also provides the Plant Water Treatment Facility with a source of water to meet all demands for potable and process water.

The River Water Pump House is designed such that make-up water supply will not be interrupted during periods when river level drops to minimum water elevation of 735 feet. Additional description of the river water system is provided in Section 9.9.5.

2.4.11.5.2 Circulating Water System

The circulating water system is a closed cycle utilizing mechanical draft cooling system. This system relies upon the river only for make-up supply. The River Water Service System is designed to provide this water for river stage levels down to minimum water level of 735 feet. River flow conditions will not effect the performance of the system as long as the river stage is at or above 735'. TVA operating procedures are such that Watts Bar Reservoir is maintained at or above the level at all times. The circulating water system is described in Section 10.4.5.

TABLE 2.4-8

FLOOD ELEVATION SUMMARY, CRBRP

Clinch River Mile	Flood Elevations		Wave Runup Elevations	
	Still Reservoir	Wave Top	3:1 Slope	Vertical Wall
	Norris Failure in OBE With One-half PMF			
16	798.2	800.2	801.8	803.1
18	804.3	806.3	807.9	809.2
	Probable Maximum Flood			
16	777.2	778.8	780.0	781.0
18	778.8	780.4	781.6	782.6

Amend. 73
Nov. 1982

TABLE 2.4-8a

PROBABLE MAXIMUM PRECIPITATION (PMP) DISTRIBUTION

Time Period (Hours)	Rainfall (Inches)	Rainfall Accumulation (Inches)
1	0.9	0.9
2	1.1	2.0
3	2.3	4.3
4	5.0	9.3
5	14.0	23.3
6	3.0	26.3
7	1.7	28.0
8	1.5	29.5

The above tabulated time distribution of the PMP is depicted in Figure 2.4-6a. 7

Amend. 7
Nov. 1975

TABLE 2.4-9

PROBABLE MAXIMUM STORM RAINFALL AND PRECIPITATION EXCESS

Subwatershed No.	Location	Antecedent Storm Rain Inches	Antecedent Storm Pe,* Inches	Main Storm Rain Inches	Main Storm Pe,** Inches
1	Norris	6.16	4.58	16.71	15.49
2	Coal Creek	6.16	4.25	16.00	14.59
3	Hinds Creek	6.16	4.25	17.70	16.29
4	Bullrun Creek	6.16	4.41	18.50	17.09
5	Beaver Creek	6.16	4.25	19.10	17.69
6	Clinch River local above M71.3	6.16	4.25	16.90	15.49
7	Clinch River local above M55.2	6.16	4.25	17.10	15.69
8	Clinch River local above M41.0	6.16	4.25	17.10	15.69
9	Clinch River local above M35.4	6.16	4.25	17.10	15.69
10	Clinch River local above M28.0	6.16	4.25	17.10	15.69
11	Clinch River local above M25.5	6.16	4.25	17.10	15.69
12	Clinch River local above M16	6.16	4.25	16.90	15.49
13	Poplar Creek	6.16	4.25	16.70	15.29
14	Emory River at mouth	6.16	4.25	14.60	13.19
15	Clinch River local at mouth	6.16	4.25	16.00	14.59
16	Watts Bar local below Clinch Rv.	6.16	4.25	13.30	11.89
17	Watts Bar local above Clinch Rv.	6.16	3.79	16.20	14.21
18	Little Tennessee River local, Fontana-Chilhowee	6.16	2.71	15.40	12.72
18a	Little Tennessee River local, Chilhowee-Tellico	6.16	3.79	16.10	14.11
19	Fontana local	6.16	2.71	14.40	11.72
20	Tuckasegee River at Bryson City	6.16	2.71	12.80	10.12
21	Nantahala	6.16	2.71	11.20	8.52
22	Little Tennessee River at Needmore	6.16	2.71	11.20	8.52
23	Fort Loudon local	7.48	4.99	19.90	17.91
24	Holston River local	7.48	5.52	21.90	20.30
25	French Broad River local	7.48	5.17	23.30	21.51
25a	Little Pigeon River at Sevierville	7.48	4.99	20.00	18.01
26	Little River at mouth	7.48	4.99	19.80	17.81
27	Douglas local	7.48	5.88	27.00	25.78
28	Pigeon River at Newport	7.48	4.99	15.80	13.81
29	French Broad River, Newport to Asheville	7.48	4.99	16.60	14.61
30	French Broad River at Asheville	7.48	4.03	10.80	8.12

TABLE 2.4-9 (Continued)

PROBABLE MAXIMUM STORM RAINFALL AND PRECIPITATION EXCESS

Subwatershed		Antecedent Storm		Main Storm	
No.	Location	Rain Inches	Pe,* Inches	Rain Inches	Pe,** Inches
31	Nolichucky local	7.48	4.99	21.50	19.51
32	Nolichucky River at Embreeville	7.48	4.99	16.30	14.31
33	Surgoinsville local	7.48	5.88	22.80	21.58
33A	Cherokee local below Surgoinsville	7.48	5.88	24.00	22.78
34	North Fork Holston River near Gate City	7.48	5.88	17.40	16.18
35	Fort Patrick Henry	7.48	5.88	23.80	22.58
36	Boone local	7.48	4.99	19.80	17.81
37	South Holston	7.48	5.52	17.00	15.40
38	Watauga	7.48	4.99	16.70	14.71
	Average above Watts Bar Dam	6.9	4.6	17.2	15.4

*Adopted API prior to antecedent storm, 1.0 inch, based on median observed conditions.

**Computed API prior to main storm, 3.65 inches.

Amend. 73
Nov. 1982

TABLE 2.4-10

INTENTIONALLY DELETED

TABLE 2.4-11

UNIT HYDROGRAPH DATA

Subwatershed No.	Subwatershed Location	Drainage Area, Sq. Miles	Q_p	C_p	T_p	W_{50}	W_{75}	T_B	Duration
1	Norris	2912	43,300	0.07	6	15	8	118	6
2	Coal Creek	36.6	2,150	0.64	8	9	5	40	2
3	Hinds Creek	66.4	3,620	0.68	9	7	5	54	2
4	Bullrun Creek	104	2,400	0.47	14	21	14	84	2
5	Beaver Creek	90.5	2,600	0.58	14	14	10	88	2
6-11	Clinch River local	22.25	1,350	0.10	2	8	5	34	2
12	Clinch River local above M16	37	4,490	0.95	6	4	3	46	2
13	Poplar Creek	136	2,800	0.61	20	25	13	88	2
14	Emory River @ mouth	865	34,000	0.37	9	13	8	8[illegible]	6
15	Clinch River local at mouth	32	3,870	0.95	6	3	2	46	2
16	Watts Bar local below Clinch Rv.	427	16,300	0.36	9	9	7	84	6
17	Watts Bar local above Clinch Rv.	293	11,300	0.30	8	9	7	84	6
18	Little Tenn. River local, Fontana-Chilhowee[b]	406	16,900	0.58	12	9	5	84	6
18a	Little Tenn. River local, Chilhowee-Tellico	650	17,000	0.61	18	21	11	72	6
19	Fontana local	389	16,350	0.46	10	9	5	94	6
20	Tuckasegee River at Bryson City	655	26,000	0.43	10	12	7	58	6
21	Nantahala	91	3,770	0.45	10	12	7	70	6
22	Little Tennessee River at Needmore	436	9,130	0.49	18	23	12	126	6
23	Fort Loudoun local[a]	323	20,000	0.29	6	10	6	36	6
24	Holston River local[a]	289	6,800	0.55	18	22	15	96	6
25	French Broad River local[a]	207	7,500	0.51	12	11	8	60	6
25a	Little Pigeon River at Sevierville	353	15,600	0.62	12	10	6	102	6

TABLE 2.4-11 (Continued)

UNIT HYDROGRAPH DATA

No.	Subwatershed Location	Drainage Area, Sq. Miles	Q_p	C_p	T_p	W_{50}	W_{75}	T_B	Duration
26	Little River at mouth[a]	379	11,730	0.68	16	14	8	96	4
27	Douglas Local[a]	832	47,930	0.27	6	8	6	60	6
28	Pigeon River at Newport	666	26,600	0.56	12	11	6	78	6
29	French Broad River, Newport to Asheville	913	35,000	0.53	12	12	7	108	6
30	French Broad River at Asheville	945	15,000	0.27	14	35	12	166	6
31	Nolichucky local	378	10,600	0.40	12	16	9	87	6
32	Nolichucky River at Embreeville	805	27,300	0.58	14	14	9	82	6
33	Surgoinsville local[b]	299	10,280	0.48	12	13	9	66	6
33a	Cherokee local below Surgoinsville[b]	554	18,750	0.48	12	14	7	66	6
34	North Fork Holston River near Gate City[a]	672	12,260	0.60	24	33	25	108	6
35	Fort Patrick Henry	63	3,200	0.40	8	8	6	64	6
36	Boone local[a]	669	22,890	0.16	6	13	8	90	6
37	South Holston	703	16,000	0.53	18	24	17	100	6
38	Watauga[b]	468	17,700	0.53	12	13	7	84	6

a. Revised
b. New

Definition of Symbols

Q_p = Peak discharge in cfs

C_p = Snyder coefficient

T_p = Time in hours from beginning of precipitation excess to peak of unit hydrograph

W_{50} = Width in hours at 50 percent of peak discharge

W_{75} = Width in hours at 75 percent of peak discharge

T_B = Base length in hours of unit hydrograph

Dur = Duration in hours of unit hydrograph

TABLE 2.4-12

FLOODS FROM POSTULATED SEISMIC FAILURE OF UPSTREAM DAMS

OBE Failures With One-half PMF	Headwater Watts Bar[a]	Headwater Norris	Peak Flow, CFS	CRBRP Elevation Mile 16	CRBRP Elevation Mile 18
Norris	765.8	1035	921,000	798.2	804.3
Cherokee-Douglas	765.0	-	35,000	765.4[c]	765.6[c]
SEE Failures With 25-Year Flood					
Norris	754.5	1027	744,000	790.5	796.3
Norris-Cherokee-Douglas[b]	754.5	1024.3[d]	770,000[d]	791.6	797.7
Norris-Douglas-Fort Loudoun-Tellico[b]	764.5	1024.3[d]	754,000[d]	791.6	797.7

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a. Lake level at mouth of Clinch River concurrent with peak CRBRP stage.
b. Taken from recent analyses for Sequoyah Nuclear Plant.
c. Estimated by steady flow backwater with starting elevation 765 at mouth of Clinch River from unsteady flow analysis.
d. Difference in Norris headwater elevations and peak site flows from that for Norris single failure results from use of the Sequoyah watershed 25-year flood.

FACTS ABOUT MAJOR T

MAIN RIVER PROJECTS	River	State	County	Nearby City	Type of Dam (g)	Concrete in dam, lock, & pwrhse (cu. yds.)	Earth and/or Rock Fill cu. yds.	Max. Height (Feet) (a)	Length (Feet)	Drainage area above dam (sq. mi.)	Length of Lake (miles)	Max. Width of Lake (miles)	Area of Lake at Full Pool (acres)
Kentucky	Tenn.	Ky.	Marshall (b) Livingston	Paducah	CGE	1,356,000	5,582,100	206	8,422	40,200	184.3	2.5	160,300
Pickwick Landing	Tenn.	Tenn.	Hardin	Savannah	"	679,100	3,081,000	113	7,715	32,820	52.7	1.5	43,100
Wilson (l)	Tenn.	Ala.	Lauderdale (b) Colbert	Sheffield Florence	CG	1,729,400	0	137	4,535	30,750	15.5	1.6	15,500
Wheeler	Tenn.	Ala.	Lauderdale (b) Lawrence	Town Creek	"	1,100,000	0	72	6,342	29,590	74.1	2.8	67,100
Guntersville	Tenn.	Ala.	Marshall	Guntersville	CGE	308,640	874,900	94	3,979	24,450	75.7	2.5	67,900
Nickajack (k)	Tenn.	Tenn.	Marion	So. Pittsburg	"	516,900	989,200	83	3,767	21,870	46.3	2.7	10,900
Chickamauga	Tenn.	Tenn.	Hamilton	Chattanooga	"	306,390	2,793,500	129	5,800	20,790	58.9	1.7	35,400
Watts Bar	Tenn.	Tenn.	Meigs (b) Rhea	Spring City	"	480,200	1,210,000	112	2,960	17,310	72.4	1.3	39,000
Fort Loudoun	Tenn.	Tenn.	Loudon	Lenoir City	"	586,700	3,591,000	122	4,190	9,550	55.0	0.7	14,600
TRIBUTARY PROJECTS													
Tims Ford	Elk	Tenn.	Franklin	Winchester	E & R	95,450	3,216,000	170	1,470	529	34	—	10,700
Apalachia	Hiwassee	N. C.	Cherokee (c)	Farner	CG	237,806	0	150	1,308	1,018	9.8	0.3	1,100
Hiwassee	Hiwassee	N. C.	Cherokee	Murphy	"	800,556	0	307	1,376	968	22	0.6	6,090
Chatuge	Hiwassee	N. C.	Clay	Hayesville	E	25,760	2,348,000	144	2,850	189	13	1.5	7,050
Ocoee No. 1 (l)	Ocoee	Tenn.	Polk	Benton	CG	160,000	0	135	840	595	7.5	—	1,890
Ocoee No. 2 (l)	Ocoee	Tenn.	Polk	Benton	RFT	0	0	30	450	516	—	—	—
Ocoee No. 3	Ocoee	Tenn.	Polk	Ducktown	CG	82,500	82,000	110	612	496	7	0.3	621
Blue Ridge (l)	Toccoa	Ga.	Fannin	Blue Ridge	E	—	1,500,000	167	1,000	232	10	—	3,290
Nottely	Nottely	Ga.	Union	Blairsville	E & R	21,790	1,552,300	184	2,300	214	20	1.1	4,180
Melton Hill	Clinch	Tenn.	Loudon (b) Roane	Oak Ridge	CG	246,800	0	103	1,020	3,343	44	0.8	5,690
Norris	Clinch	Tenn.	Anderson (b) Campbell	Knoxville	CGE	1,002,300	181,700	265	1,860	2,912	72	1.2	34,200
Tellico	Little T.	Tenn.	Loudon	Lenoir City	CGE	78,000	2,700,000	129	3,238	2,627	33.2	1.3	15,860
Fontana	Little Tenn.	N. C.	Graham (b) Swain	Robbinsville	CG	2,815,500	760,600	480	2,365	1,571	29	0.6	10,640
Douglas	French Broad	Tenn.	Sevier	Sevierville	CGE	556,390	127,900	202	1,705	4,541	43.1	1.5	30,400
Cherokee	Holston	Tenn.	Jefferson (b) Grainger	Jefferson City	"	694,200	3,304,100	175	6,760	3,428	59	1.5	30,300
Fort Patrick Henry	S. Fork Holston	Tenn.	Sullivan	Kingsport	CG	72,500	0	95	737	1,903	10.3	0.25	872
Boone	S. Fork Holston	Tenn.	Sullivan (b) Washington	Johnson City Kingsport	CGE	198,400	714,000	160	1,532	1,840	17.3	0.5	4,400
South Holston	S. Fork Holston	Tenn.	Sullivan	Bristol, Va.-Tenn.	E & R	97,500	5,897,400	285	1,600	703	24.3	1.3	7,580
Watauga	Watauga	Tenn.	Carter	Elizabethton	"	80,400	3,497,800	318	900	468	16.7	0.8	6,430
Great Falls (l) (in Cumberland Valley)	Caney Fork	Tenn.	Warren (b) White	Rock Island	CG	—	—	92	800	1,675	22	—	2,100
Totals													638,353
PUMPED STORAGE Raccoon Mountain (j)	Tenn.	Tenn.	Marion	Chattanooga	E & R	12[illegible],000	9,200,000	230	8,080	—	—	—	520

a. Foundation to operating deck.

b. River is county line.

c. Powerhouse is in Polk County, Tenn

d. Original construction or acquisitio subsequent additions, retirements, of projects under construction.

e. Construction discontinued early in 1

f. Initial construction started Februa serve critical materials during war.

g. Abbreviations: CG-Concrete gravi embankments. E-Earth fill. E&R-E

h. Unit 2 is a reversible pump-turbine.

TENNESSEE VALLEY AUTHORITY, KNOXVILLE, TENN. 37902

Revised September 1970

F71I14R

VA DAMS AND RESERVOIRS

Shore line at Full Pool (miles)	Lake Elevation (feet above sea level) Ordinary Minimum	Top of Gates	Full Pool (m)	Lake Volume (acre-feet) Ordinary Minimum Elevation	Top of Gates Elevation	Useful Controlled Storage (Ac.-Ft.)	Construction Started	Closure	Constr. Completed (1st unit on line)	Cost of Plant in Service 6-30-70 (d) (millions)	Ultimate Generating Capacity KW and No. of Units ( )	Lock Size (Feet)	Lock Max. Lift (Feet)	MAIN RIVER PROJECTS
2,380	354	375	359	2,121,000	6,129,000	4,008,000	7-1-38	8-30-44	9-14-44	$118.0	170,000(5)	110x600	75	Kentucky
496	408	418	414	685,000	1,105,000	417,000	3-8-35	2-8-38	6-29-38	45.7	216,000(6)	110x600	63	Pickwick Landing
154	504.5	507.88	507.5	582,000	611,000	59,000	4-14-18	4-14-24	9-12-25	107.6	629,840(21)	110x600 60x300 60x292	100 100	Wilson (l)
1,063	550	556.3	556	720,000	1,071,000	351,000	11-21-33	10-3-36	11-9-36	87.5	356,400(11)	60x400 110x600	52 52	Wheeler
949	593	595.44	595	879,700	1,052,000	172,300	12-4-35	1-16-39	8-1-39	51.2	97,200(4)	60x360 110x600	45	Guntersville
192	632	635	634	221,600	251,600	33,000	1-1-64	12-14-67	2-20-68	74.9	97,200(4)	110x800(n) 110x600	42(n) 42	Nickajack (k)
810	675	685.44	682.5	392,000	739,000	347,000	1-13-36	1-15-40	3-4-40	42.1	108,000(4)	60x360	53	Chickamauga
783	735	745	741	796,000	1,175,000	379,000	7-1-39	1-1-42	2-11-42	35.6	150,000(5)	60x360	70	Watts Bar
360	807	815	813	282,000	393,000	111,000	7-8-40	8-2-43	11-9-43	42.4	131,190(4)	60x360	80	Fort Loudoun
														TRIBUTARY PROJECTS
246	860	895	888	294,000	617,000	323,000	3-28-66	12- -70	11- -71	49.5	45,000(1)			Tims Ford
31	1,272	1,280	1,286	48,600	57,500	8,900	7-17-41	2-14-43	9-22-43	21.0	75,000(2)			Apalachia
180	1,415	1,526.5	1,524.5	71,800	434,000	362,200	7-15-36	2-8-40	5-21-40	24.4	117,100(2)(h)			Hiwassee
132	1,860	1,928	1,927	18,400	240,500	222,100	7-17-41	2-12-42	12-9-54	9.1	10,000(1)			Chatuge
18	816.9	837.65	837.65	53,500	87,300	33,800	8- -10	12-15-11	1-10-12	3.0	18,000(5)			Ocoee No. 1 (l)
—	—	1,115	1,115	—	—	—	5- -12	—	10- -13	3.0	21,000(2)			Ocoee No. 2 (l)
24	1,413	1,435	1,435	790	4,650	3,860	7-17-41	8-15-42	4-30-43	9.0	27,000(1)			Ocoee No. 3
60	1,590	1,691	1,690	12,500	196,500	184,000	11- -25(e)	12-6-30	7- -31	5.5	20,000(1)			Blue Ridge (l)
106	1,690	1,779	1,779	12,700	174,300	161,600	7-17-41	1-24-42	1-10-56	8.1	15,000(1)			Nottely
173	790	796	795	94,500	126,000	31,500	9-6-60	5-1-63	7-3-64	36.2	72,000(2)	75x400	60	Melton Hill
800	930	1,034	1,020	290,000	2,555,000	2,265,000	10-1-33	3-4-36	7-28-36	33.3	100,800(2)			Norris
373	807	815	813	320,800	447,300	126,000	3-15-67	11-29-79	(i)	136.9	(i)	(i)		Tellico
248	1,525	1,710	1,708	295,000	1,448,000	1,153,000	1-1-42	11-7-44	1-20-45	78.6	225,000(3)			Fontana
555	920	1,002	1,000	84,500	1,490,000	1,405,500	2-2-42	2-19-43	3-21-43	45.9	112,000(4)			Douglas
444	980	1,075	1,073	83,600	1,544,000	1,460,400	8-1-40	12-5-41	4-16-42	36.6	120,000(4)			Cherokee
37	1,258	1,263	1,263	22,700	26,900	4,200	5-14-51	10-27-53	12-5-53	12.3	36,000(2)			Fort Patrick Henry
130	1,330	1,385	1,385	45,000	193,400	148,400	8-29-50	12-16-52	3-16-53	27.8	75,000(3)			Boone
168	1,616	1,742	1,729	121,400	764,000	642,600	8-4-47(f)	11-20-50	2-13-51	31.4	35,000(1)			South Holston
106	1,815	1,975	1,959	52,300	677,000	624,700	7-22-46(f)	12-1-48	8-30-49	32.5	50,000(2)			Watauga
120	780	805.30	805.30	14,600	51,600	37,000	-15	12-8-16	-16	8.2	31,860(2)			Great Falls (l) (in Cumberland Valley)
11,070				8,621,490	23,732,350	15,110,860					3,138,090(105)			Totals
—	1,530	—	1,672	2,000	37,800	35,800	7-6-70	1- -74	1- -74	155.0	1,530,000(4)			PUMPED STORAGE Raccoon Mountain(j)

asee.

n cost, including switchyard, as adjusted by
and reclassifications. Includes estimated costs

26; resumed in March 1929.

y 16, 1942; temporarily discontinued to con-

y dams. CGE-Concrete gravity with earth
rth and rock fill. RFT-Rock-filled timber.

i. Tellico project has no lock or powerhouse. Streamflow through navigable channel to Fort Loudoun Reservoir will increase average annual energy through Fort Loudoun powerhouse by 200 million kwh.

j. Under construction; cost and quantity data estimated.

k. Nickajack Dam replaced the old Hales Bar Dam 6 miles upstream.

l. Acquired: Wilson by transfer from U. S. Corps of Engineers in 1933; Ocoee No. 1, Ocoee No. 2, Blue Ridge, and Great Falls by purchase from TEP Co. in 1939. Subsequent to acquisition, TVA heightened and installed additional units at Wilson.

m. Full Pool Elevation is the normal upper level to which the reservoirs may be filled. Where storage space is available above this level, additional filling may be made as needed for flood control.

n. Construction of Nickajack main lock limited to underwater portion; for completion later.

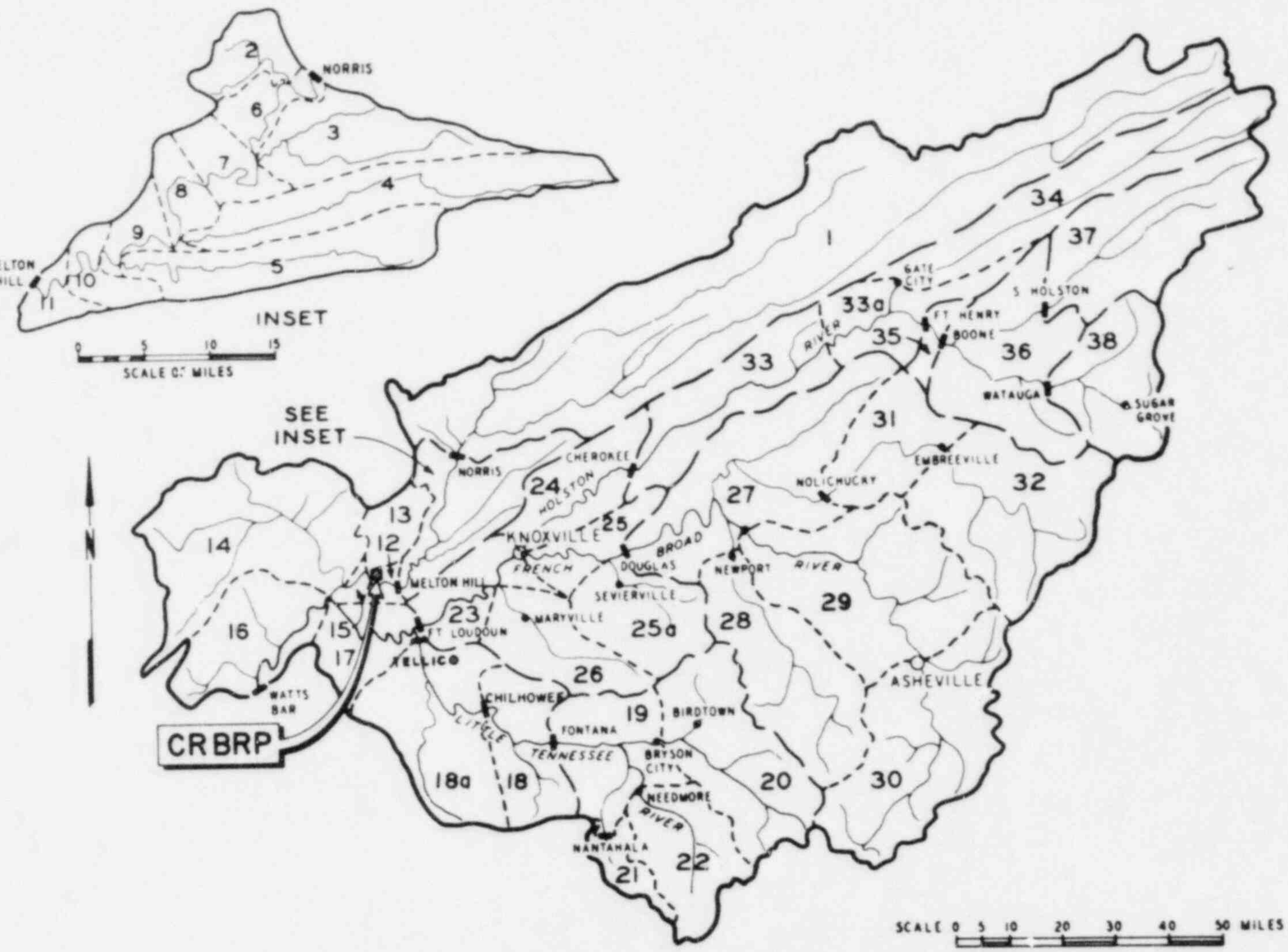
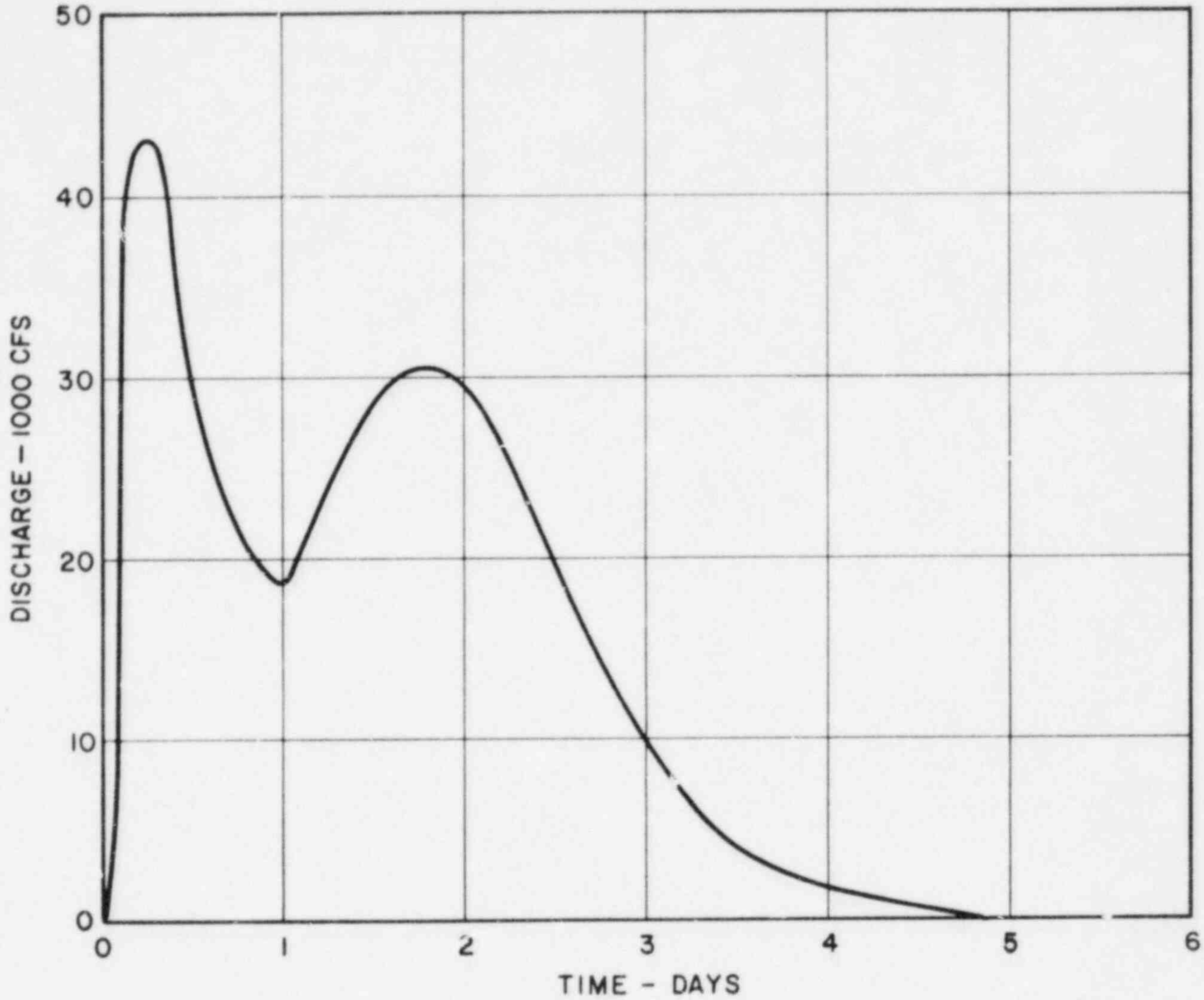


Figure 2.4-11 CRBRP Hydrologic Model Sub-Areas



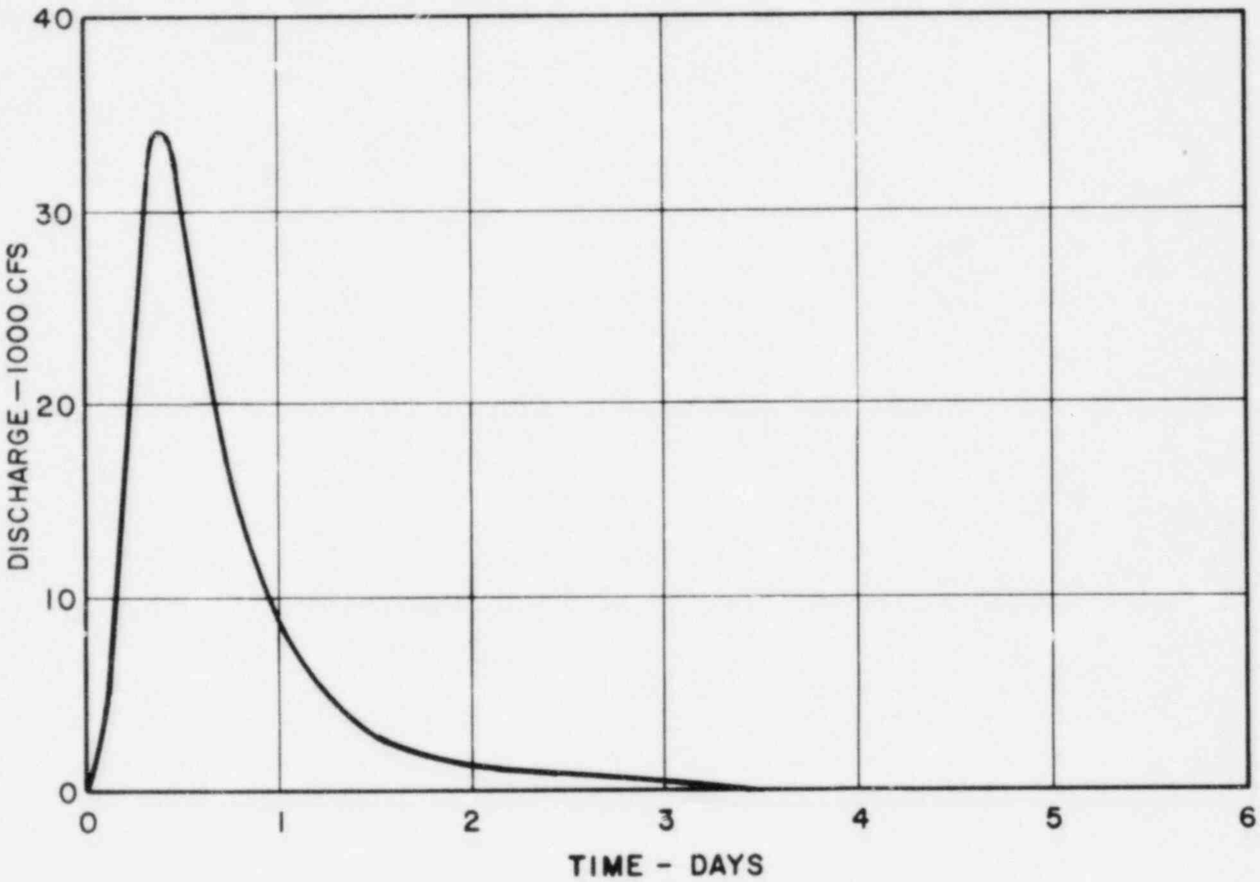
LEGEND:

AREA I, NORRIS DAM, 2912 SQ. MI.

Note: Two peaks result from different contributing times for two principal tributaries making up this long, narrow watershed.

Figure 2.4-12a. 6-Hour Unit Hydrograph

6650-6



LEGEND:

——— AREA 14, EMORY RIVER AT MOUTH, 865 SQ. MI.

FIGURE 2.4-12d. 6-Hour Unit Hydrograph

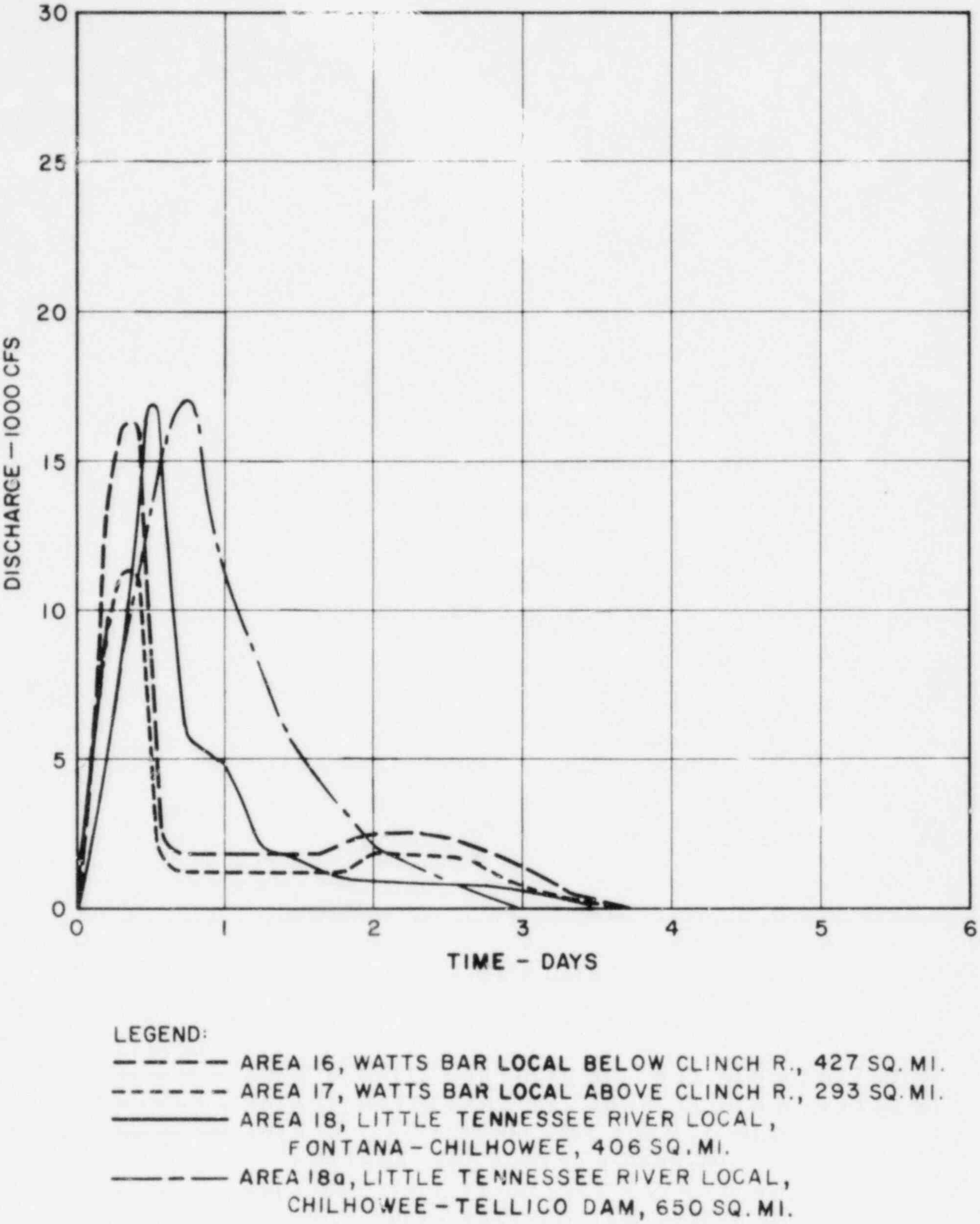


FIGURE 2.4-12e. 6-Hour Unit Hydrographs

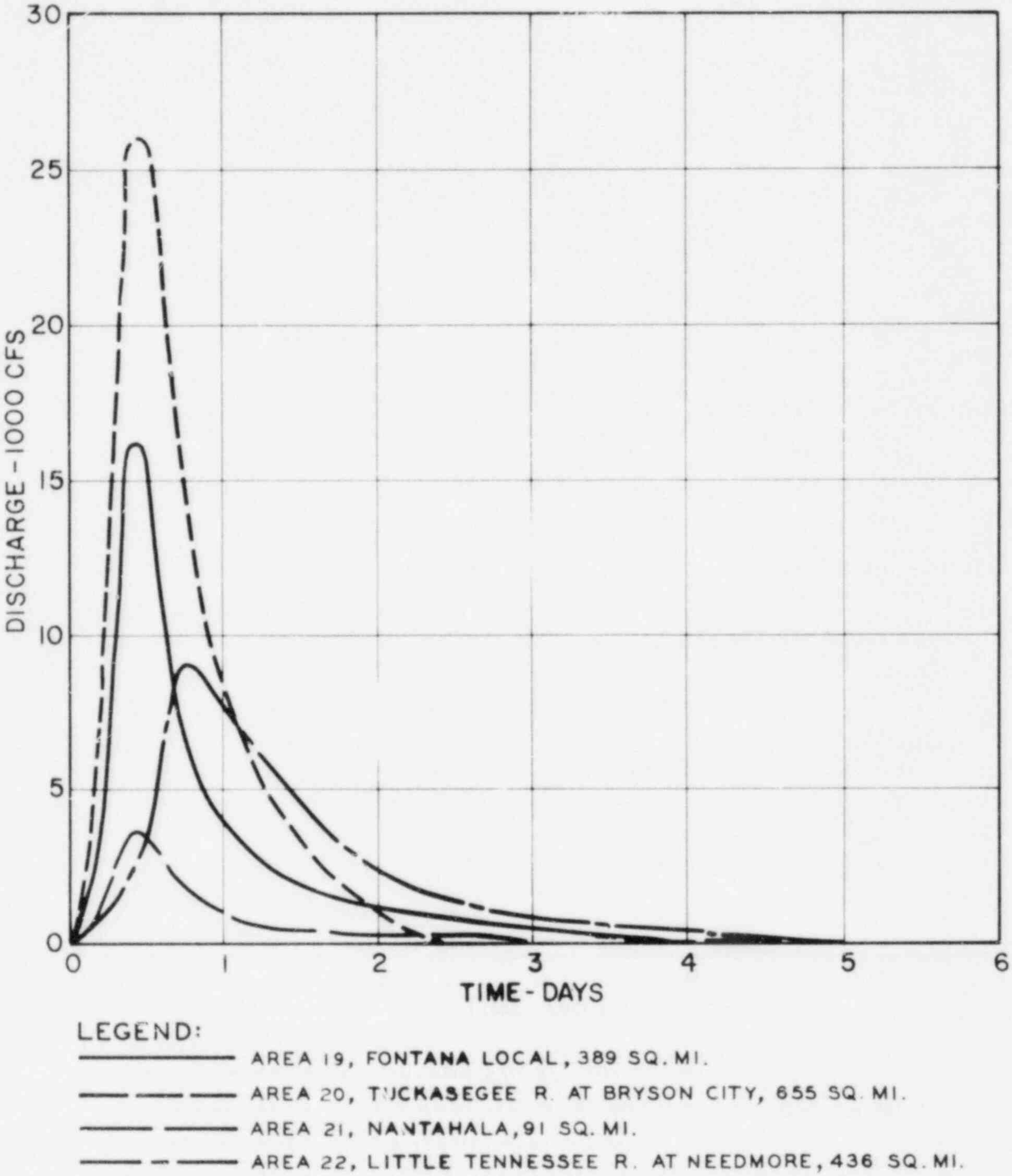
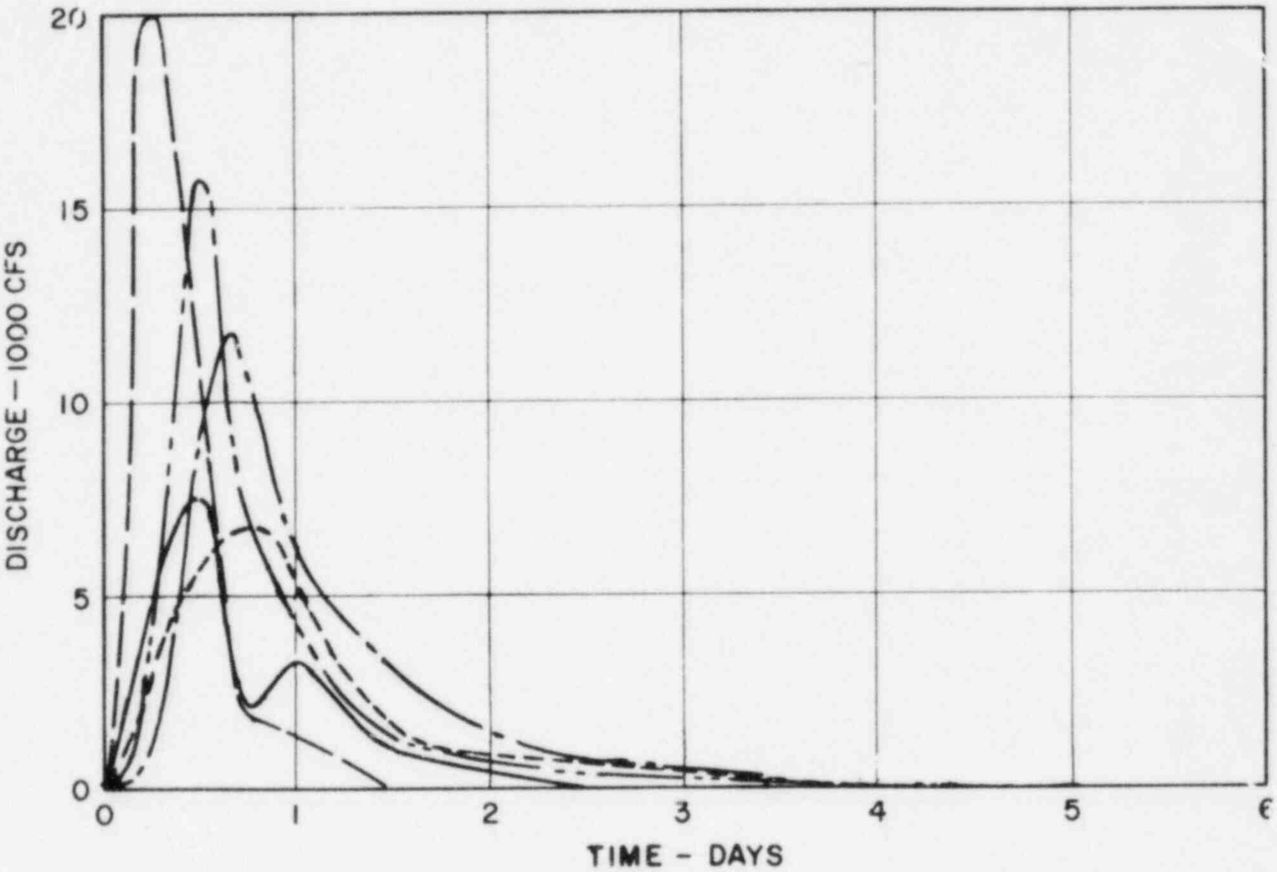


FIGURE 2.4-12f. 6-Hour Unit Hydrographs



LEGEND:

- — — AREA 23, FT. LOUDOUN LOCAL, 323 SQ. MI.
- - - - - - AREA 24, HOLSTON RIVER LOCAL, 289 SQ. MI.
- ——— AREA 25, FRENCH BROAD R. LOCAL, 207 SQ. MI.
- —·— AREA 26, LITTLE RIVER AT MOUTH, 379 SQ. MI.
- —··— AREA 25a, LITTLE PIGEON R. AT SEVIERVILLE, 353 SQ. MI.

FIGURE 2.4-12g. 6-Hour Unit Hydrographs

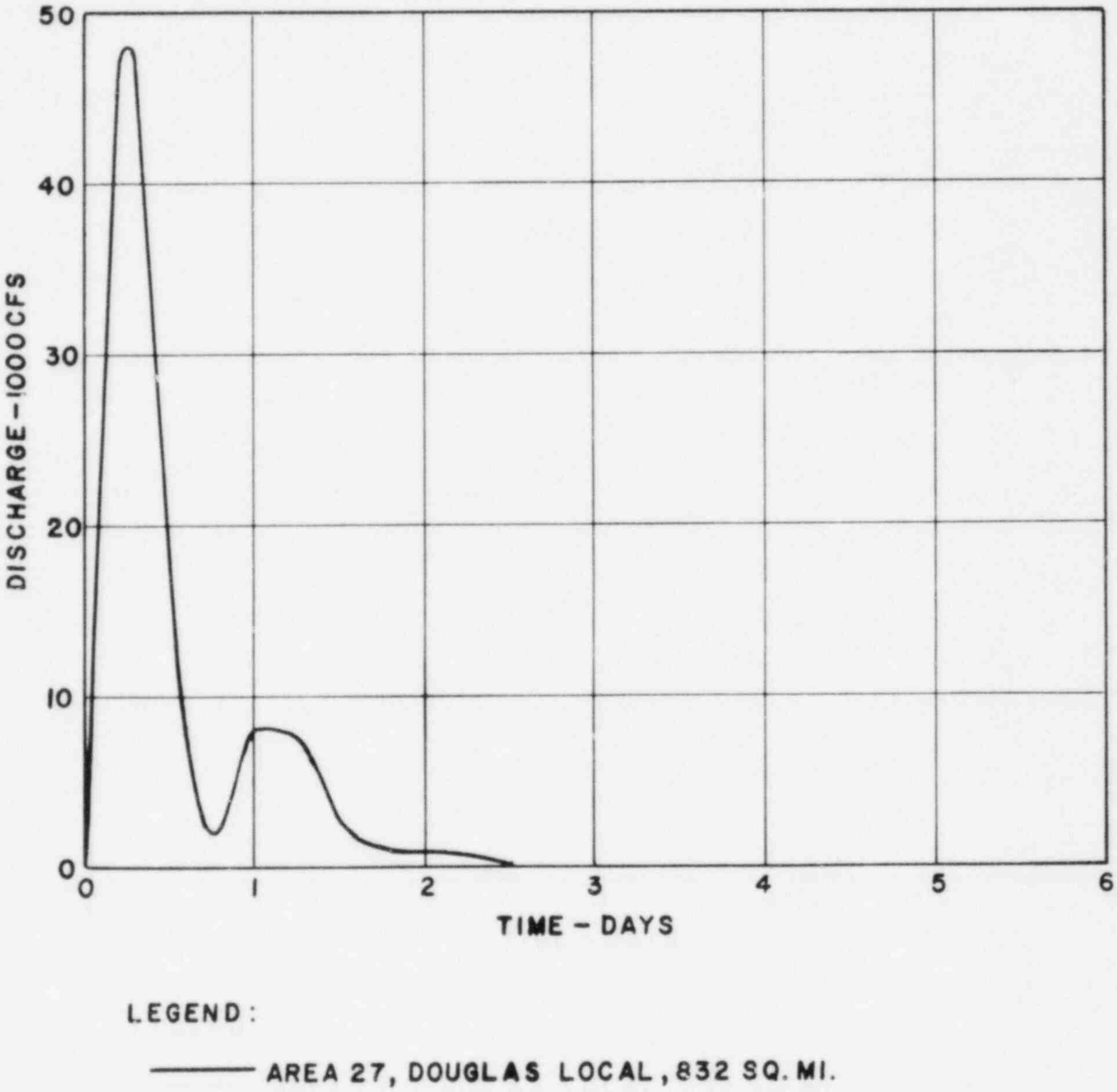
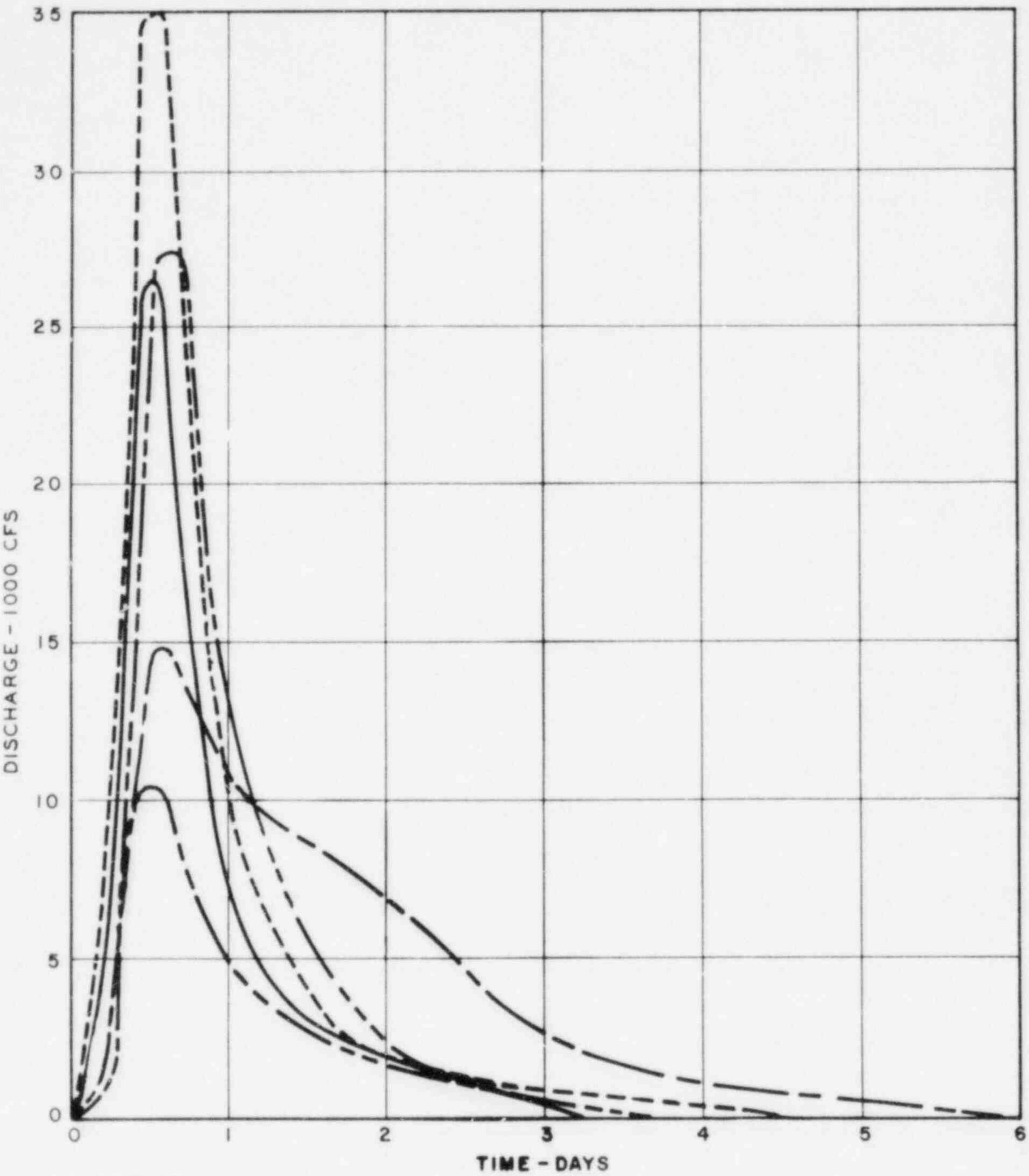


FIGURE 2.4-12b -Hour Unit Hydrograph

Amend. 73
Nov. 1982



LEGEND:

- AREA 28, PIGEON R. AT NEWPORT, 666 SQ. MI.
- AREA 29, FRENCH BROAD R. NEWPORT TO ASHEVILLE, 913 SQ. MI.
- AREA 30, FRENCH BROAD R. AT ASHEVILLE, 945 SQ. MI.
- AREA 31, NOLICHUCKY LOCAL, 378 SQ. MI.
- AREA 32, NOLICHUCKY R. AT EMBREVILLE, 805 SQ. MI.

FIGURE 2.4-12ha. 6-Hour Unit Hydrographs

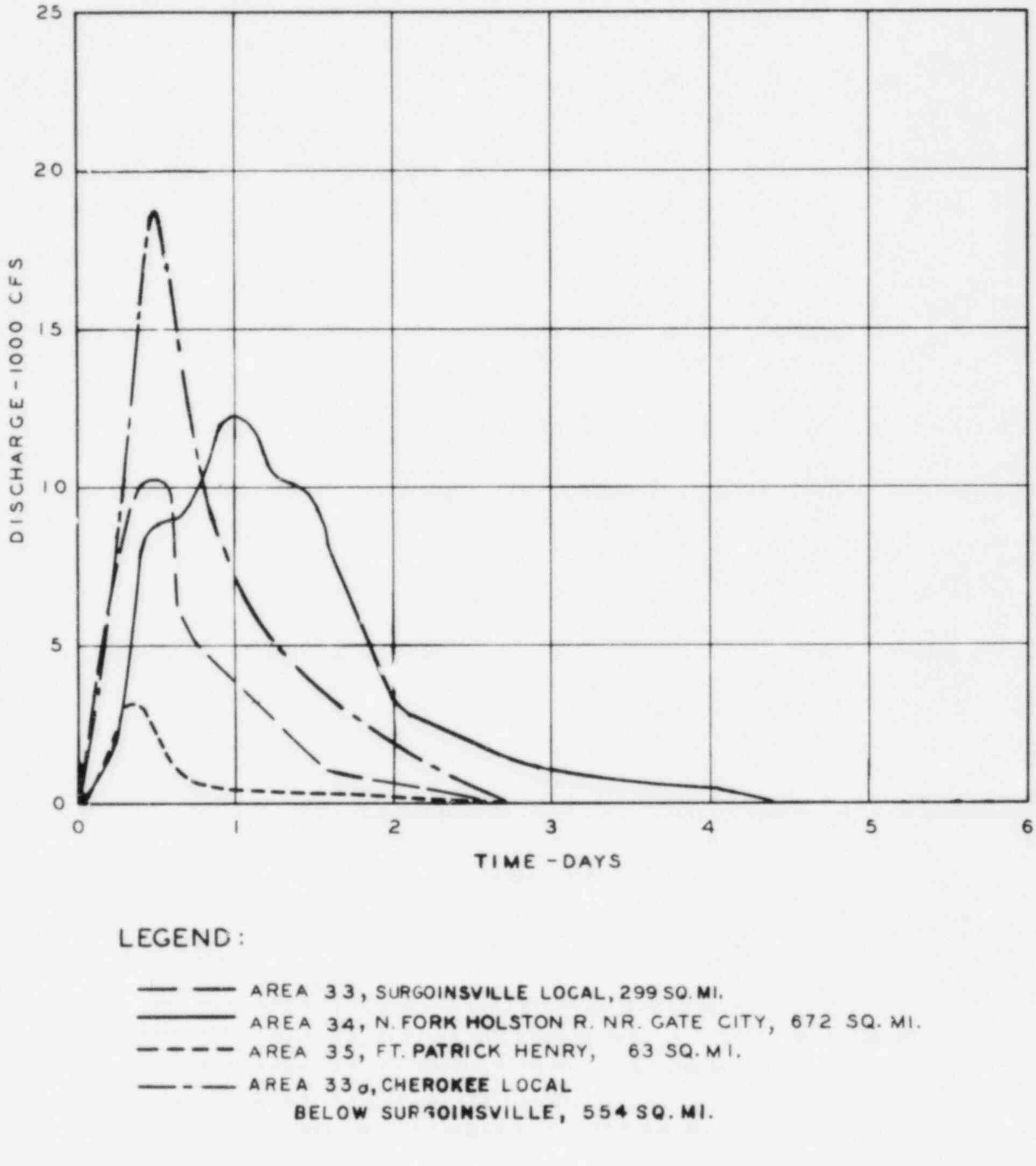
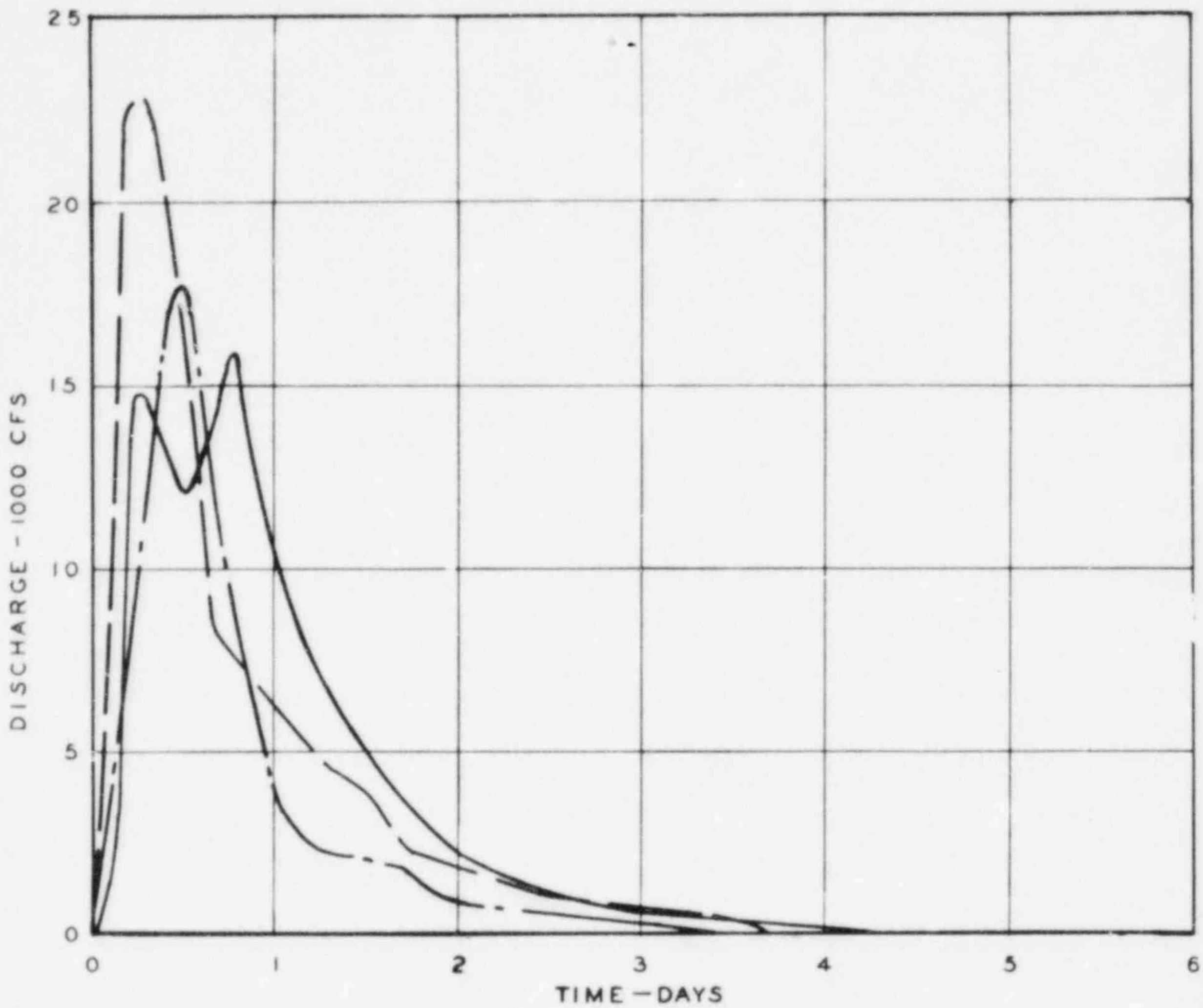


FIGURE 2.4-12i. 6-Hour Unit Hydrographs



LEGEND:

AREA 36, BOONE LOCAL, 669 SQ. MI.
AREA 37, SOUTH HOLSTON, 703 SQ. MI.
AREA 38, WATAUGA, 468 SQ. MI.

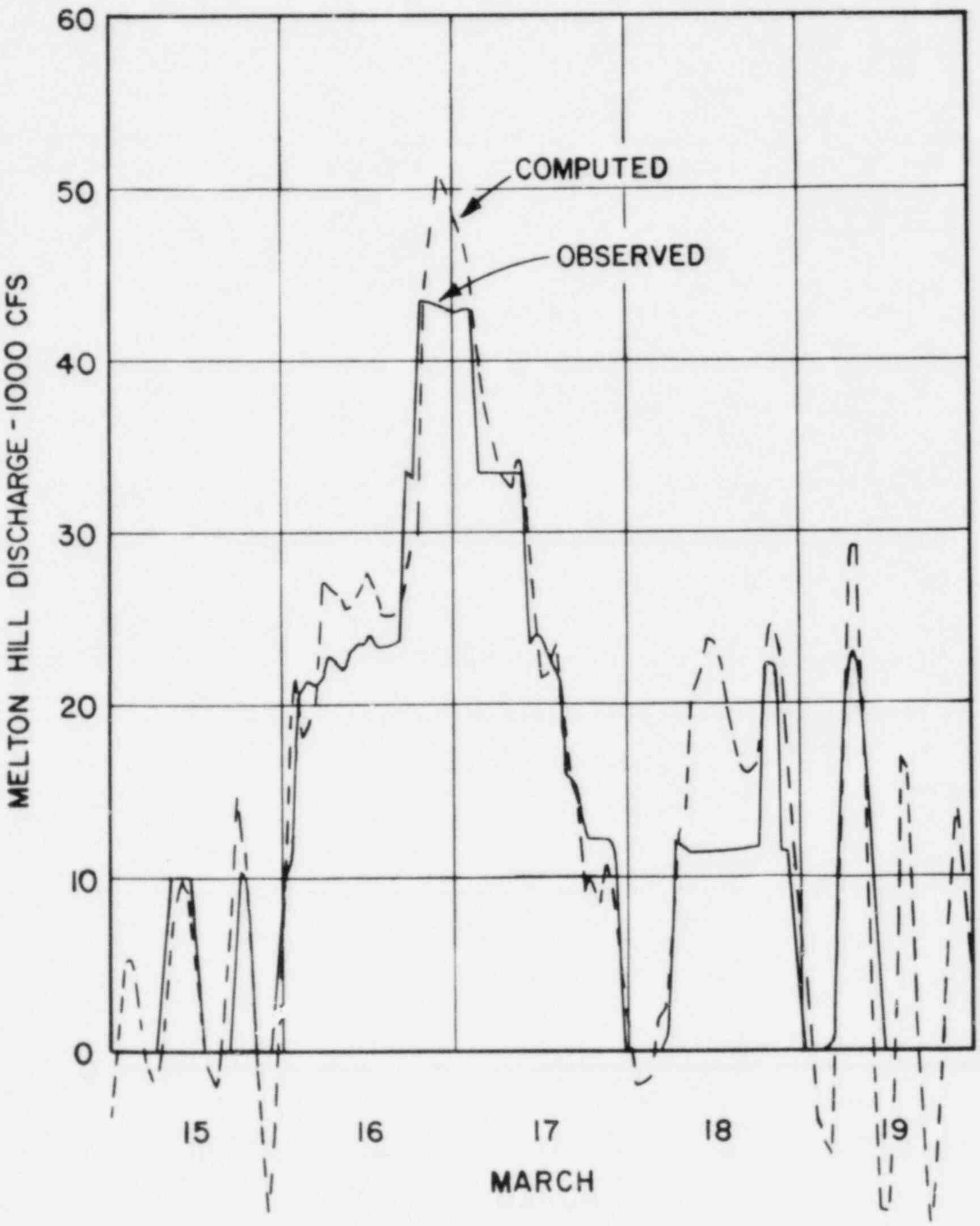
Note: Two peaks for area 37 result from different contributing times for the two large streams making up this long watershed.

FIGURE 2.4-12j. 6-Hour Unit Hydrographs

Amend. 73
Nov. 1982

FIGURE 2.4-13

HYDROLOGIC MODEL VERIFICATION - 1973 FLOOD



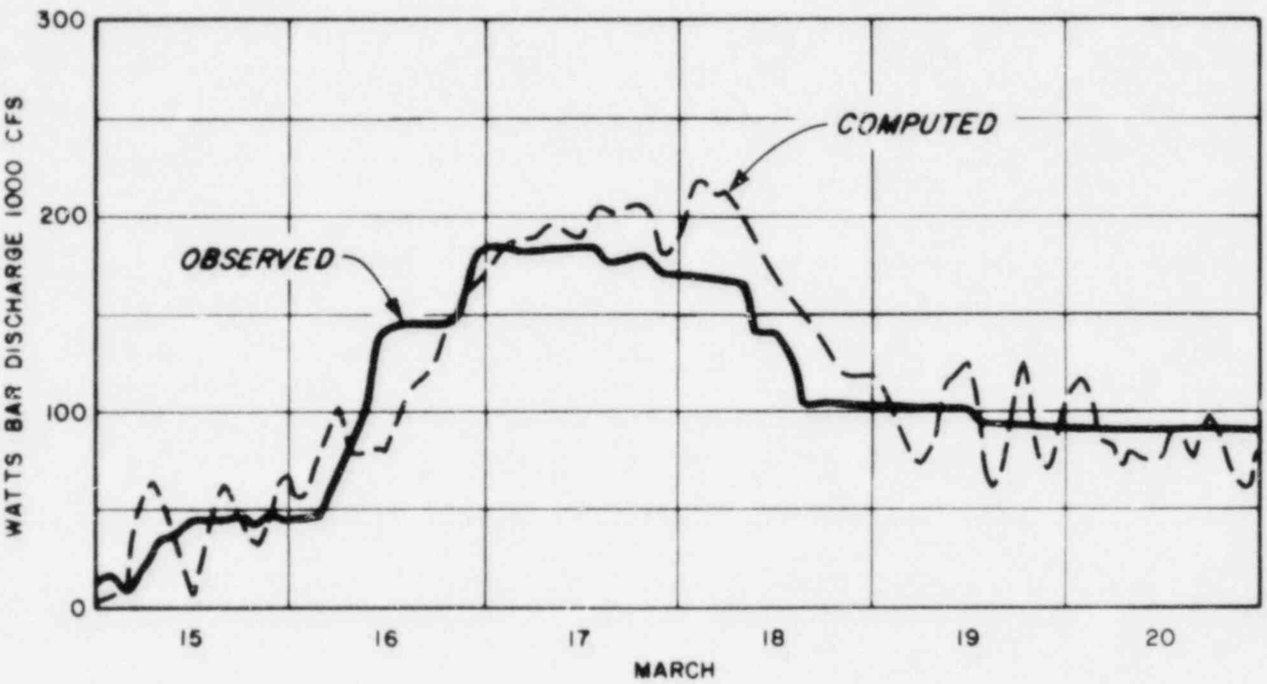


FIGURE 2.4-14

HYDROLOGIC MODEL VERIFICATION - 1973 FLOOD

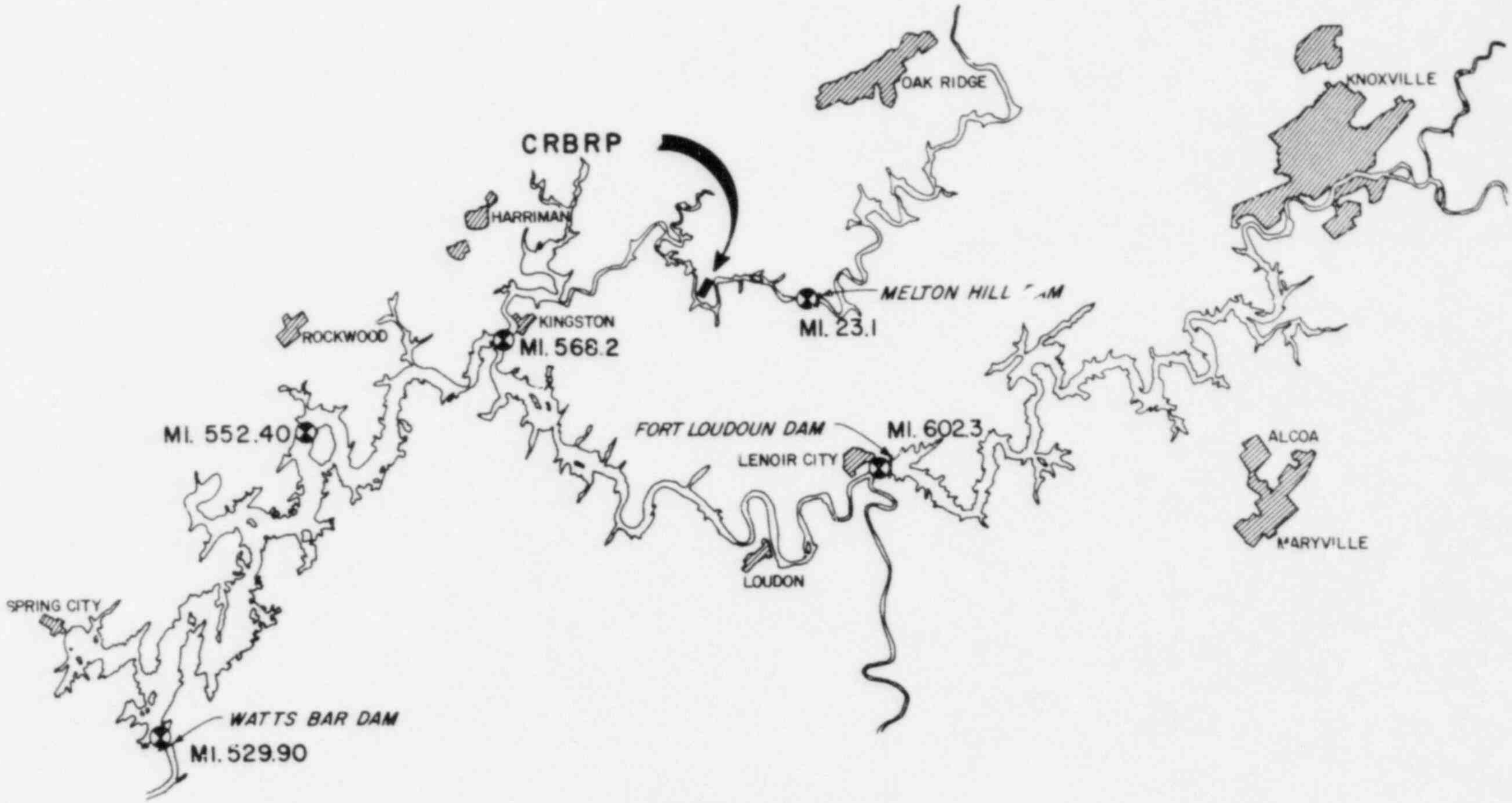


Figure 2.4-15. Stage Gages Used for Unsteady Flow Model Verification

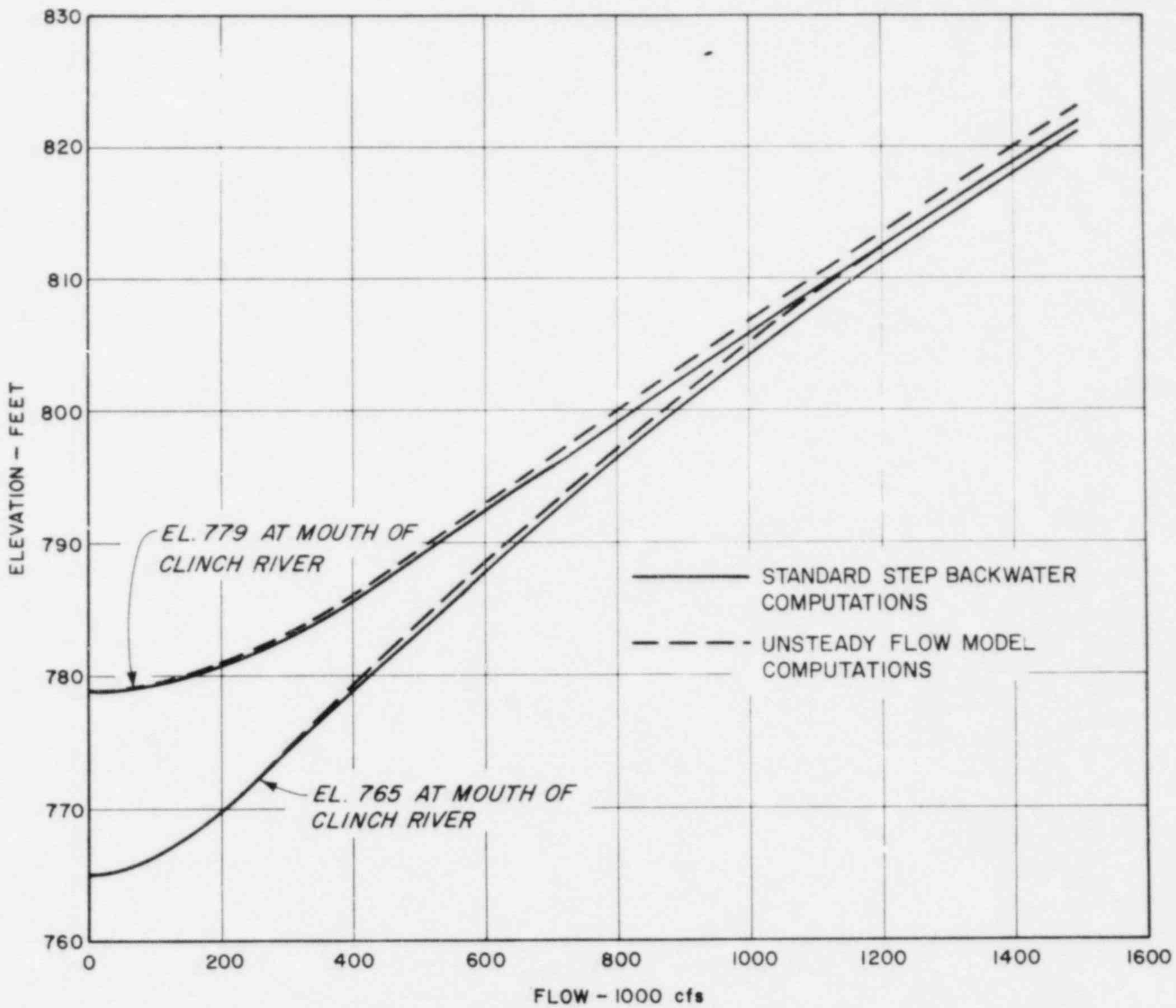


Figure 2.4-18. Steady State Model Verification - Clinch River Mile 17

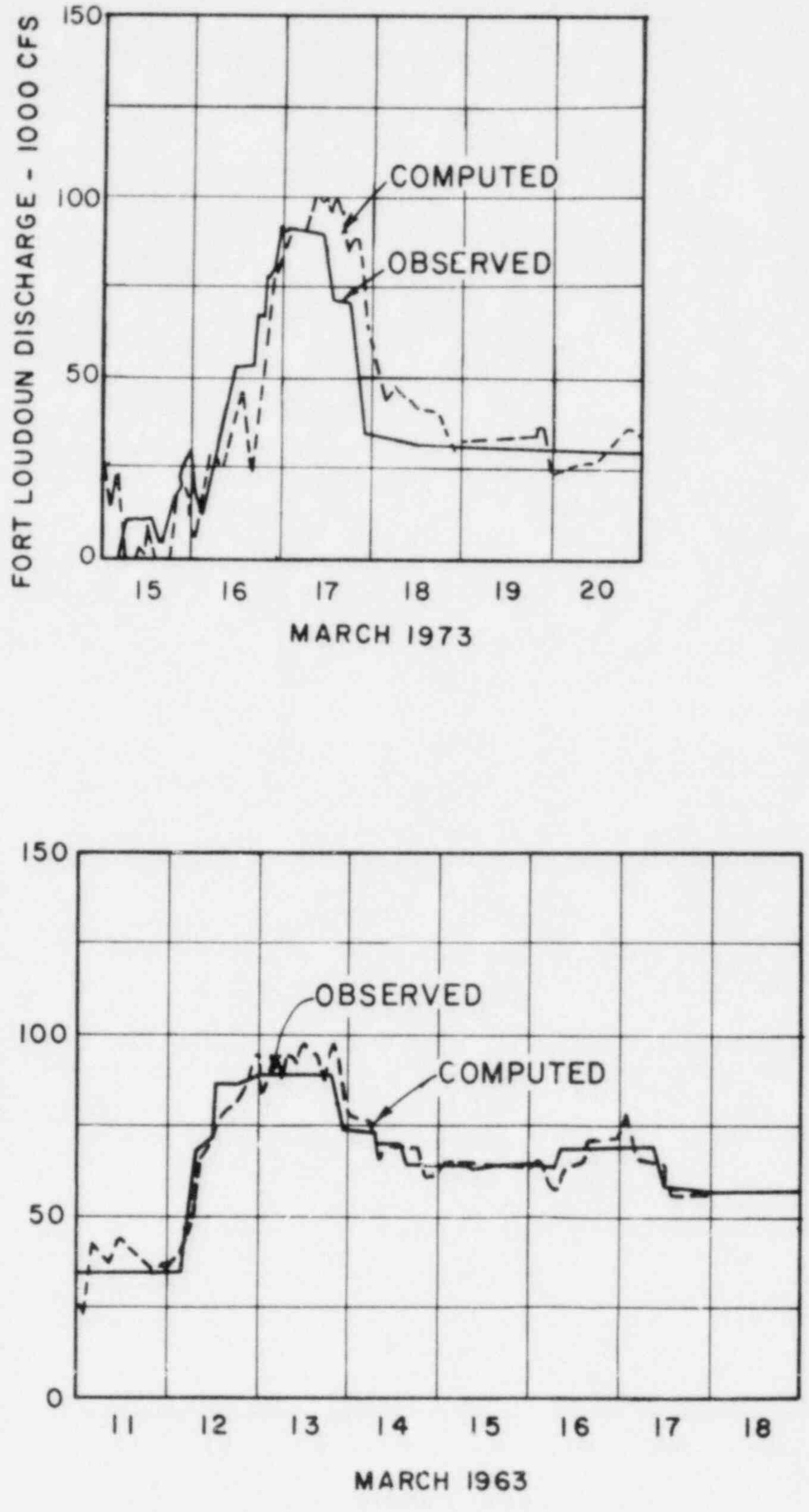


Figure 2.4-19 Hydrologic Model Verification - 1973 and 1963 Floods

Amend. 73
Nov. 1982

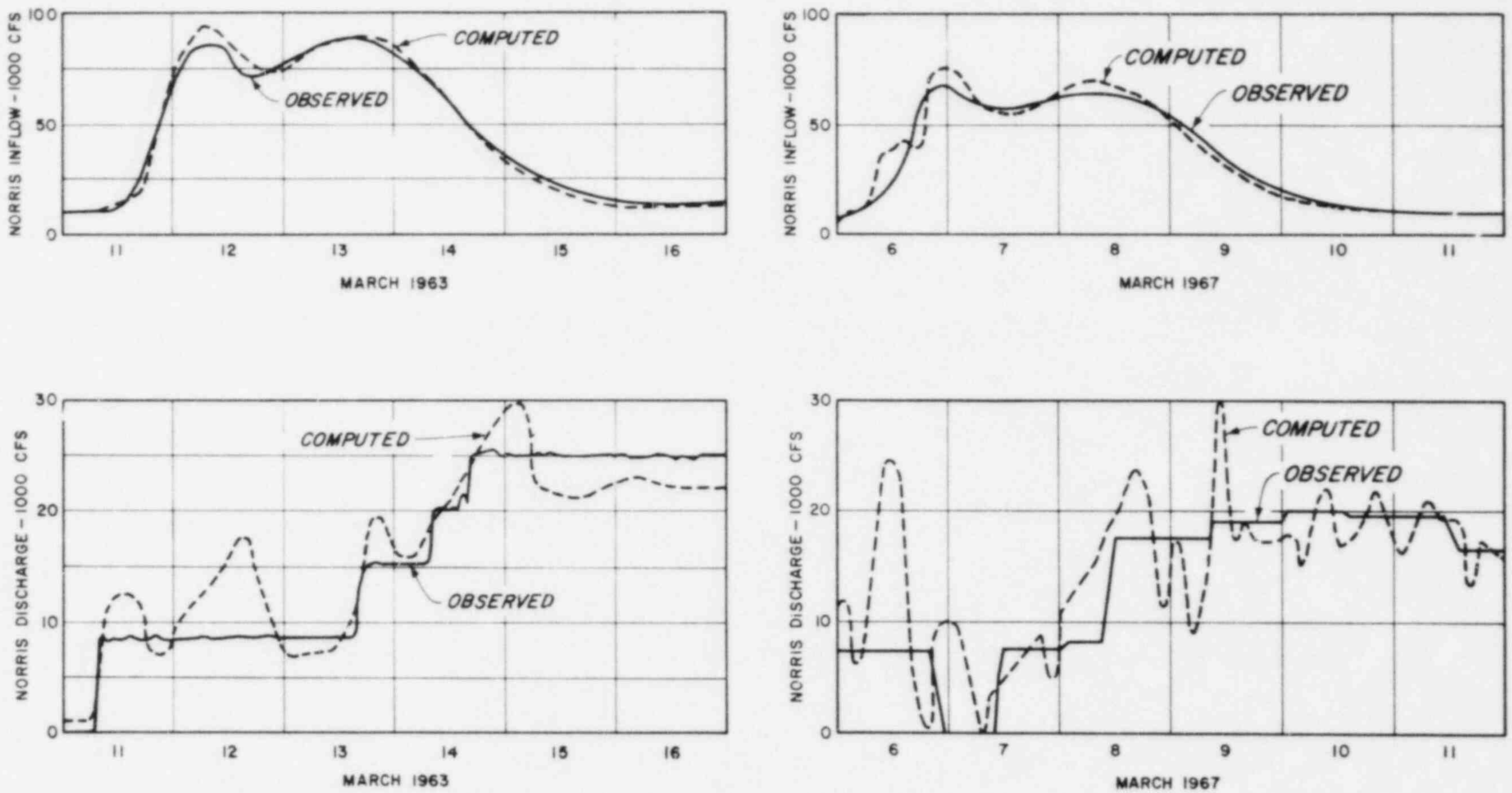
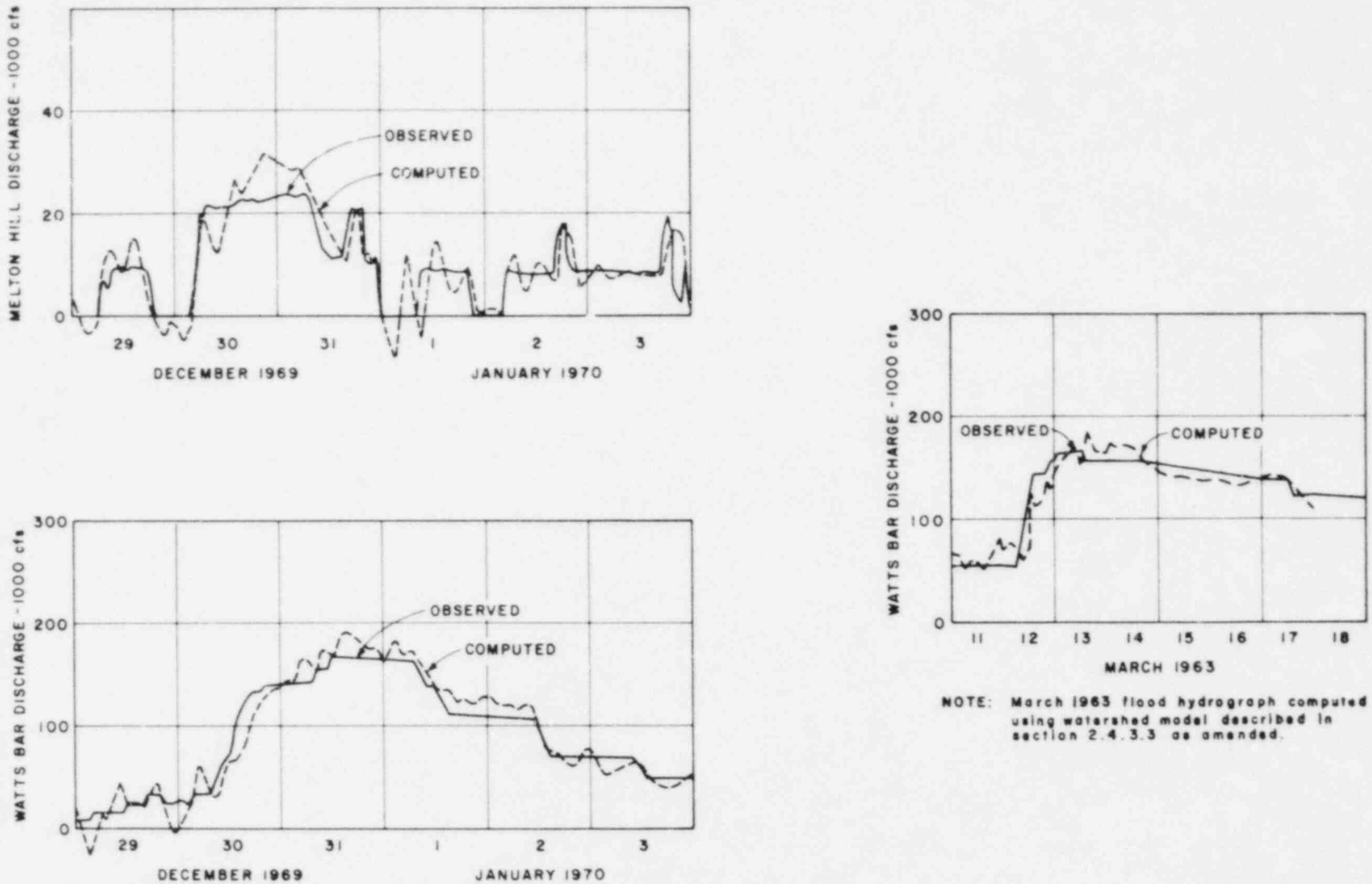
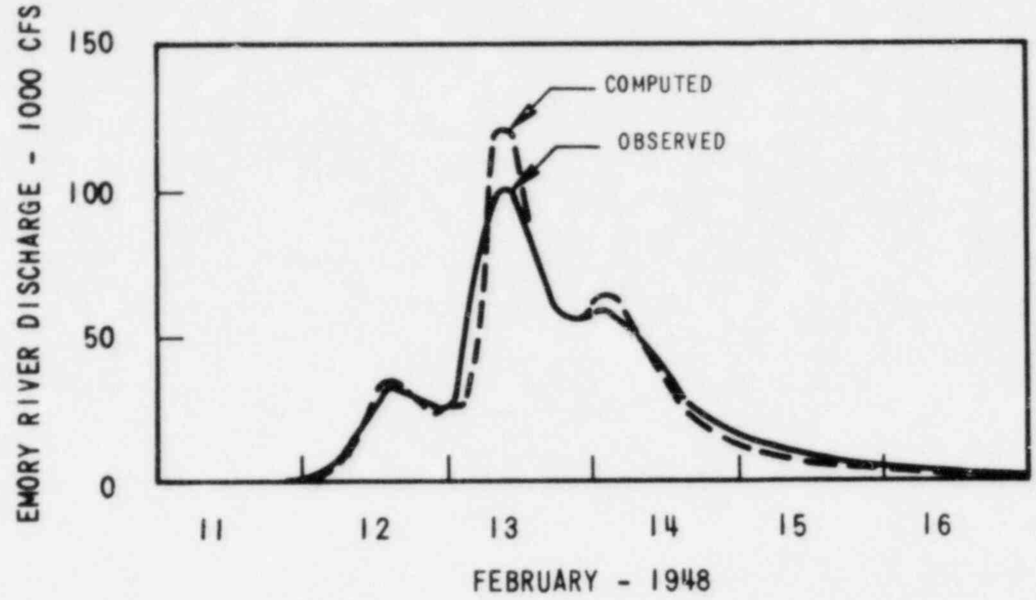


Figure 2.4-20. Hydrologic Model Verification - 1963 and 1967 Floods



NOTE: March 1963 flood hydrograph computed using watershed model described in section 2.4.3.3 as amended.

Figure 2.4-21 Hydrologic Model Verification - 1963 and 1969-70 Floods



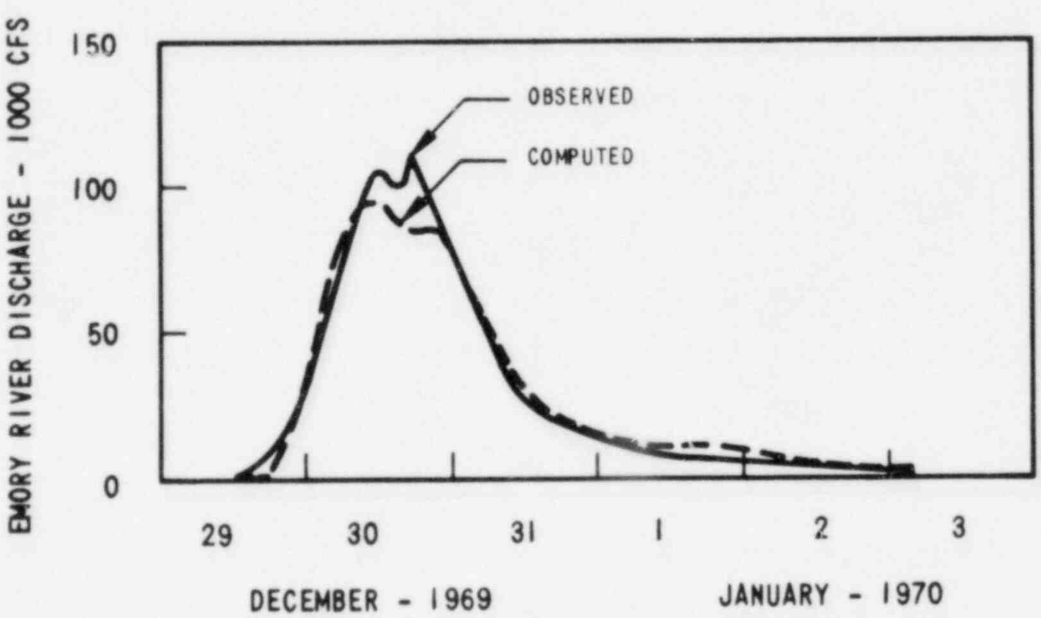
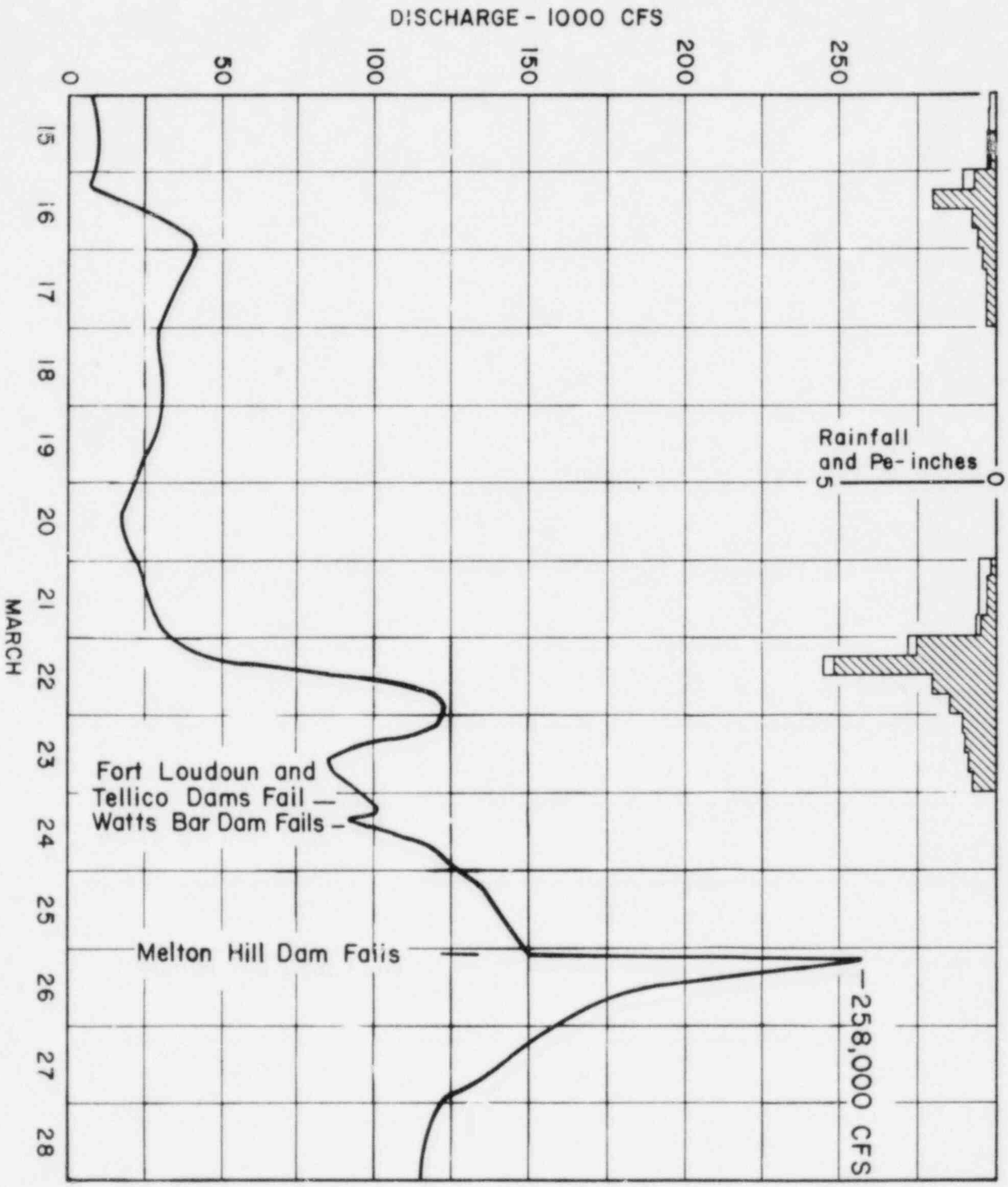


Figure 2.4-22 Hydrologic Model Verification - 1948 & 1969-70 Floods
Emory River at Oakdale

6650-25

FIGURE 2.4-23

CRBRP'S PROBABLE MAXIMUM FLOOD DISCHARGE



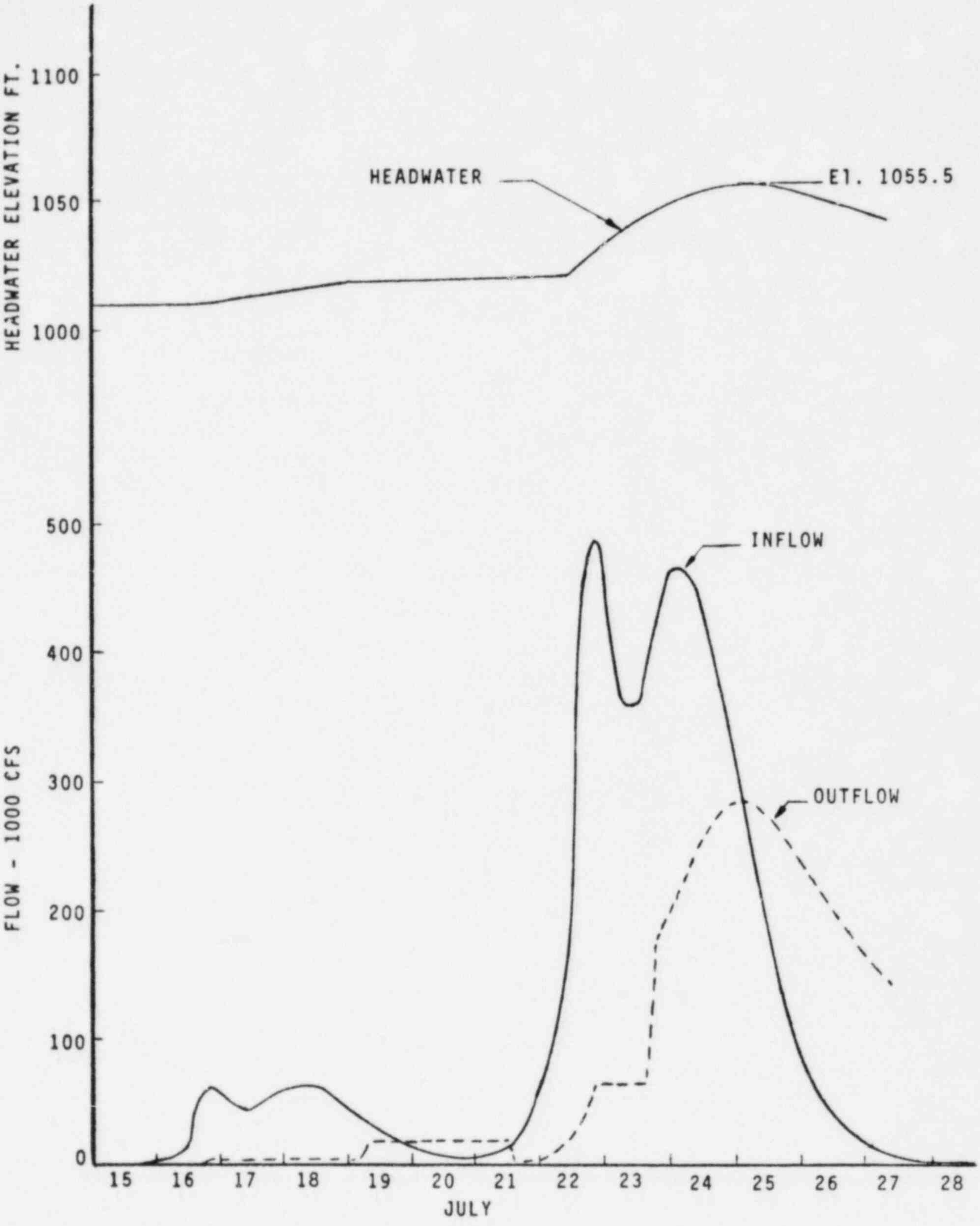


Figure 2.4-23A NORRIS PROBABLE MAXIMUM FLOOD
NORRIS HYDROGRAPHS AND HEADWATER ELEVATIONS

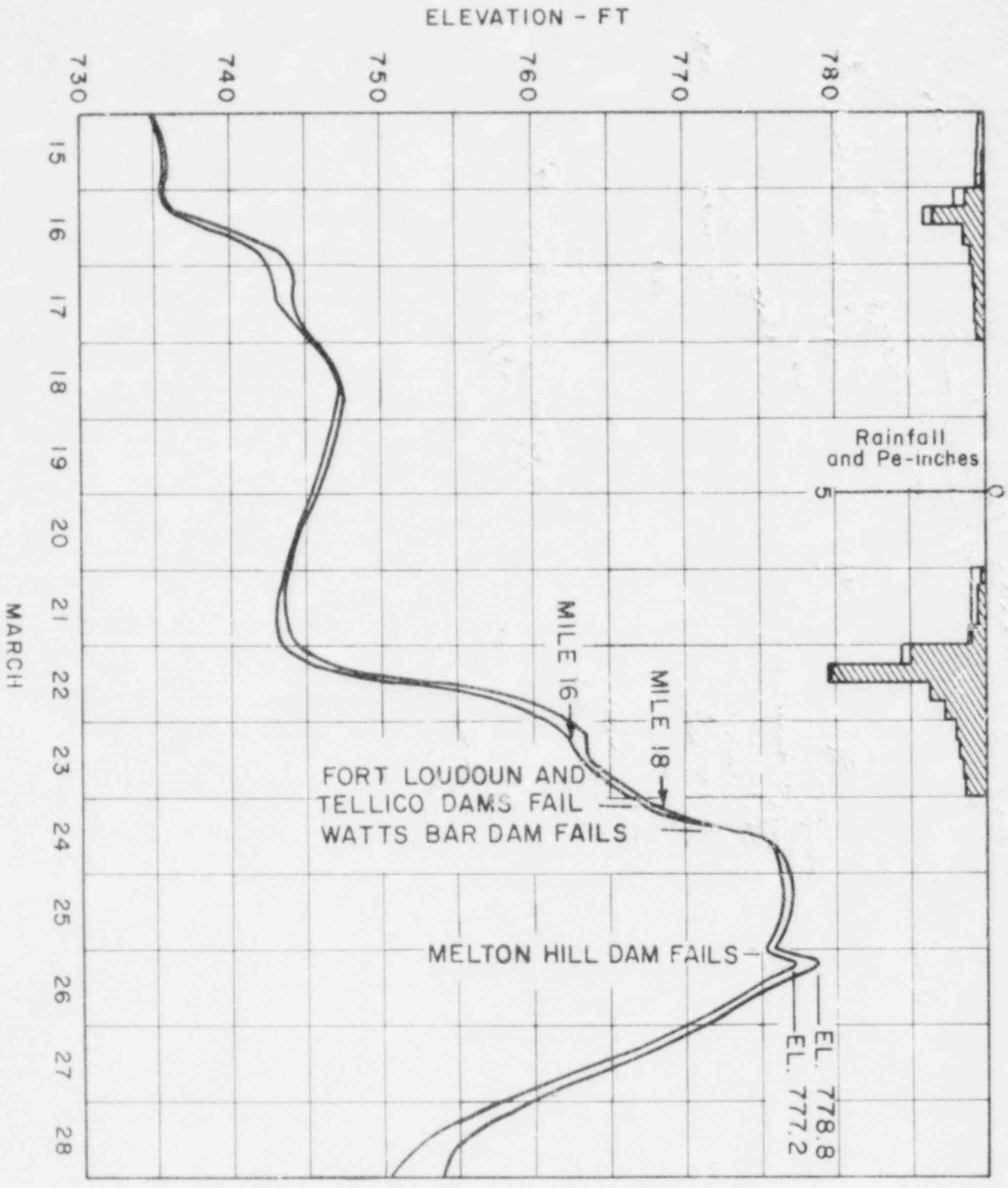
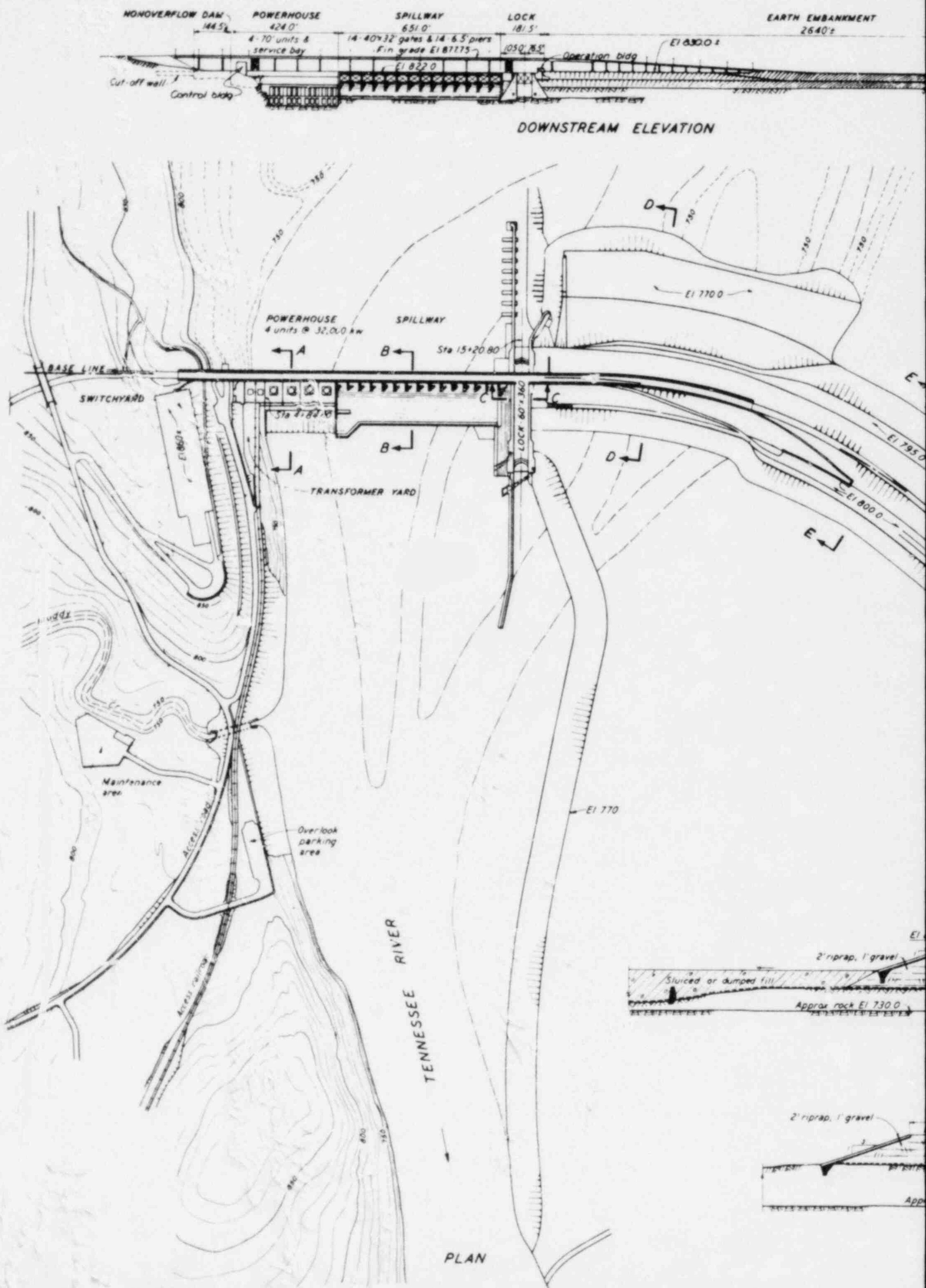


FIGURE 2.4-24

CRBRP'S PROBABLE MAXIMUM FLOOD ELEVATIONS


NONOVERFLOW DAM
144.5'
POWERHOUSE
424.0'
4-70' units & service bay
SPILLWAY
651.0'
14-40'x32' gates & 14-6.5' piers
Fin grade El 877.75
El 822.0
LOCK
181.5'
EARTH EMBANKMENT
2640'±
El 830.0±
Operation bldg
Cut-off wall
Control bldg
DOWNSTREAM ELEVATION
POWERHOUSE
4 units @ 32,000 kw
SPILLWAY
BASE LINE
SWITCHYARD
Sta 15+20.80
LOCK 60'x 360'
El 770.0
El 795.0
El 800.0
TRANSFORMER YARD
Maintenance area
Access road
Overlook parking area
Access railroad
El 770
TENNESSEE RIVER
2' riprap, 1' gravel
Sluiced or dumped fill
Approx rock El 730.0
PLAN

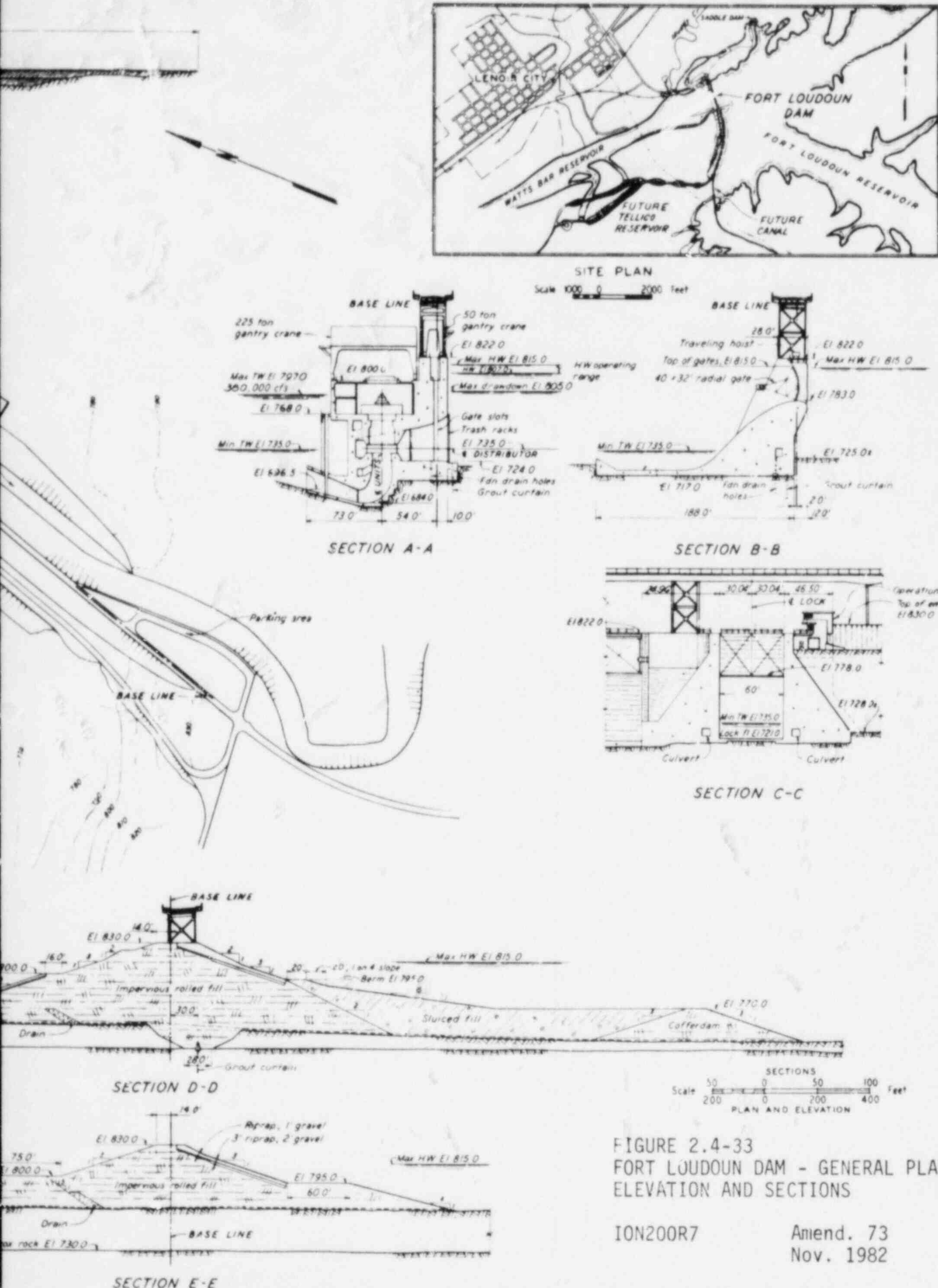
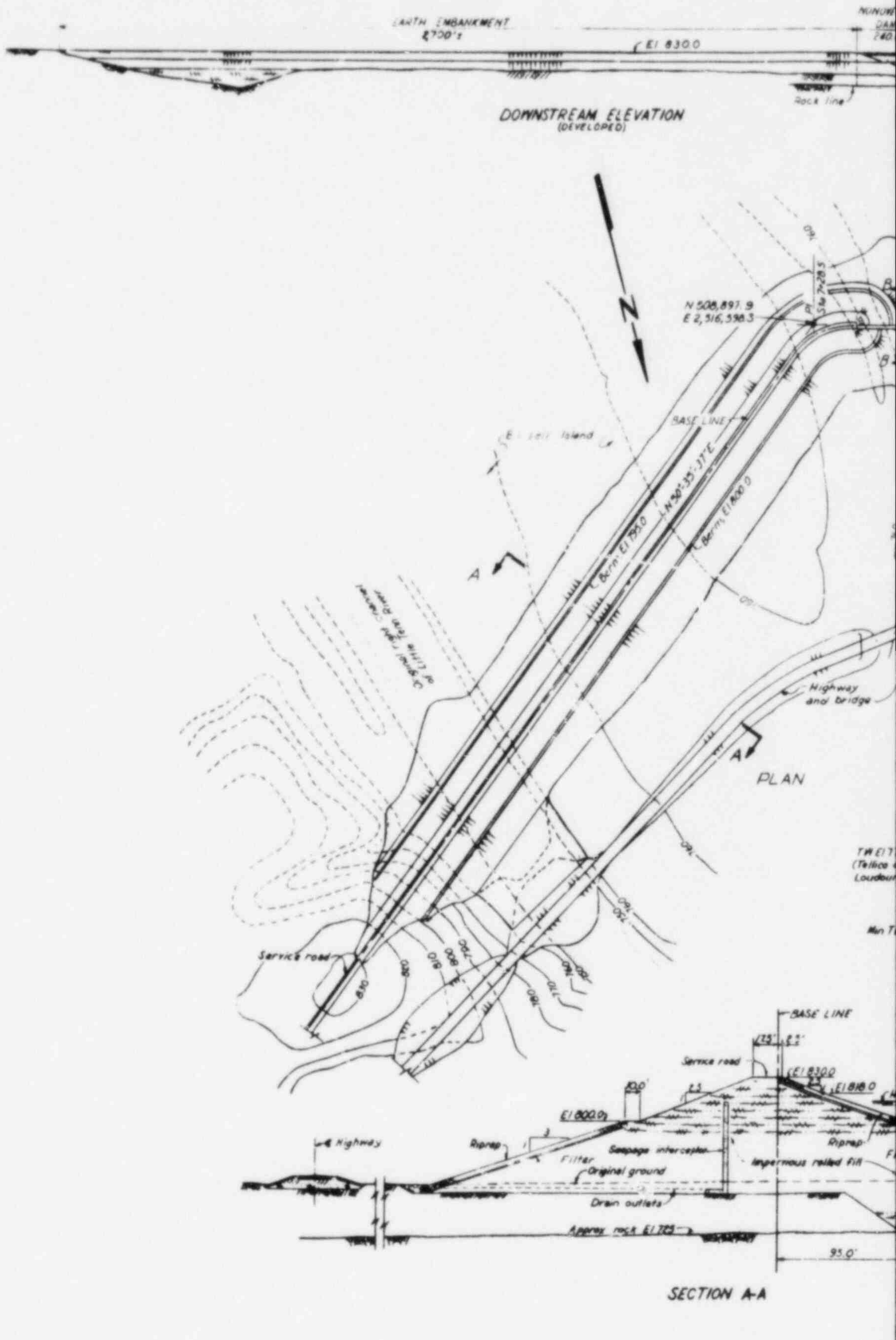


FIGURE 2.4-33
FORT LOUDOUN DAM - GENERAL PLAN, ELEVATION AND SECTIONS

ION200R7 Amend. 73
Nov. 1982

PROJECT MANAGER



EARTH EMBANKMENT
El 830.0
Rock line
DOWNSTREAM ELEVATION
(DEVELOPED)
N 508,897.9
E 2,516,598.3
BASE LINE
Berm El 800.0
Highway
and bridge
PLAN
Service road
BASE LINE
Service road
El 830.0
El 818.0
El 800.0
Highway
Riprap
Filter
Seepage interceptor
Original ground
Impervious rolled fill
Drain outlets
Approx rock El 725
95.0'
SECTION A-A

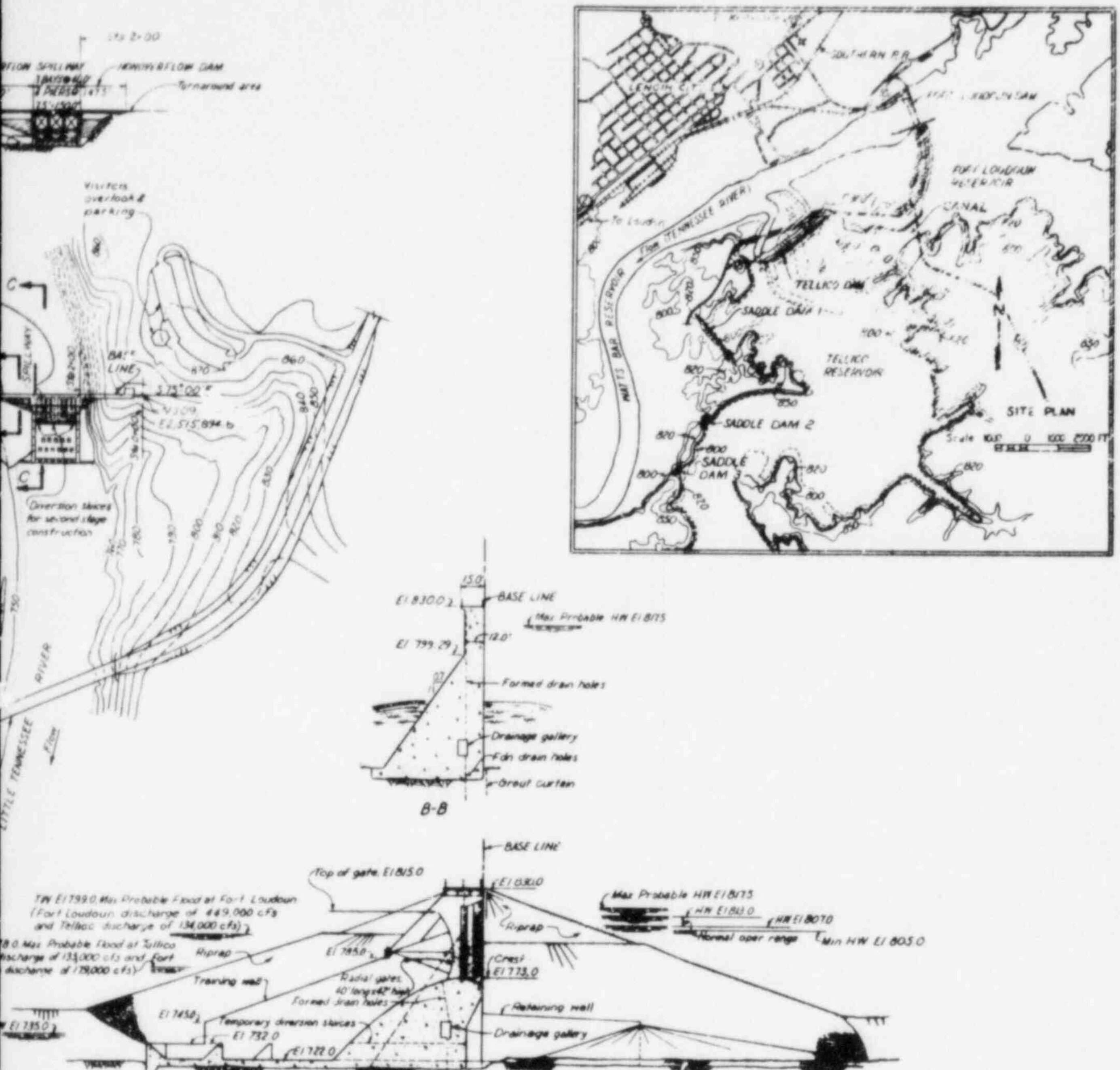
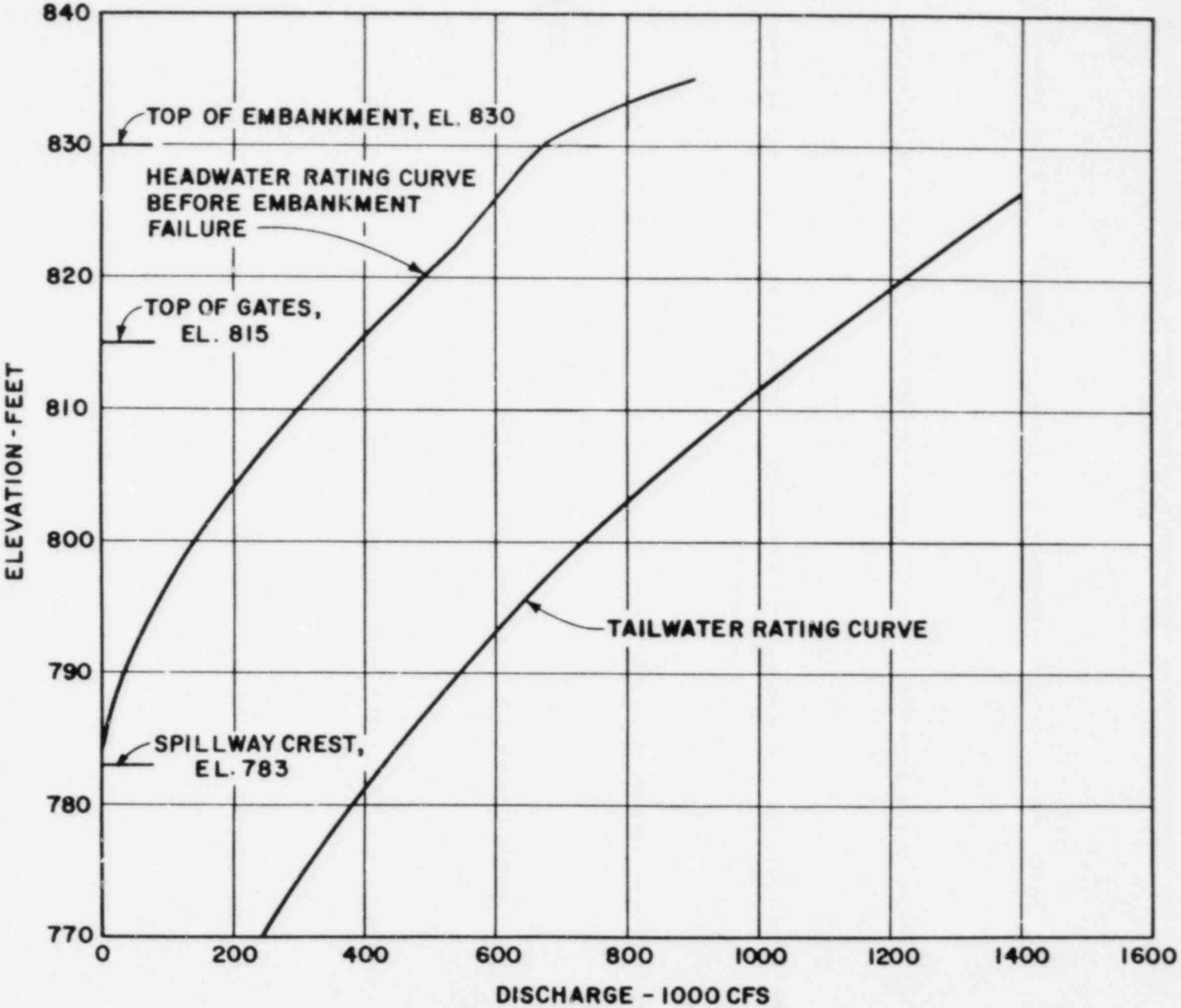


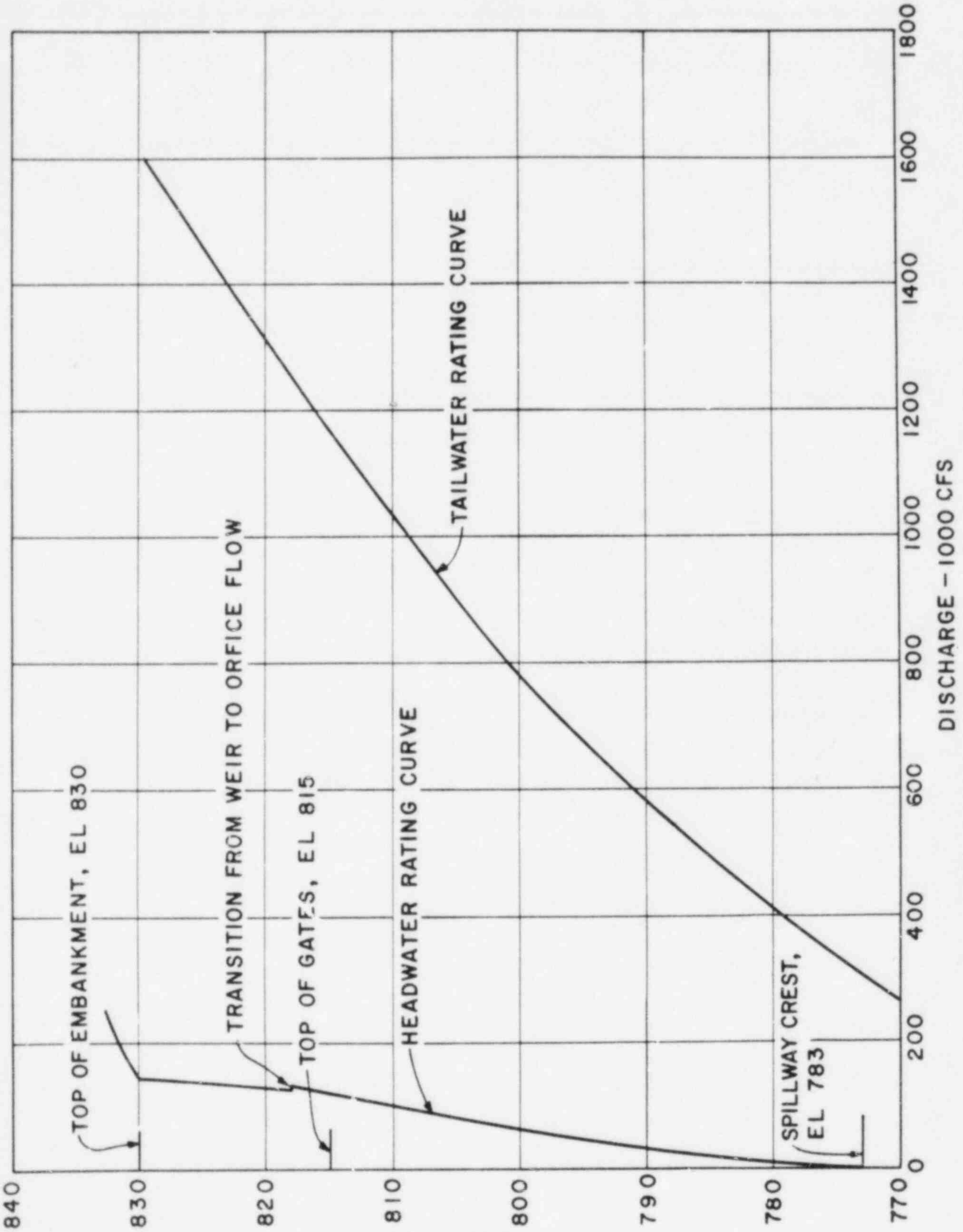
FIGURE 2.4-34
TELLICO DAM - GENERAL PLAN,
ELEVATION AND SECTIONS

ION200R3 Amend. 73
Nov. 1982



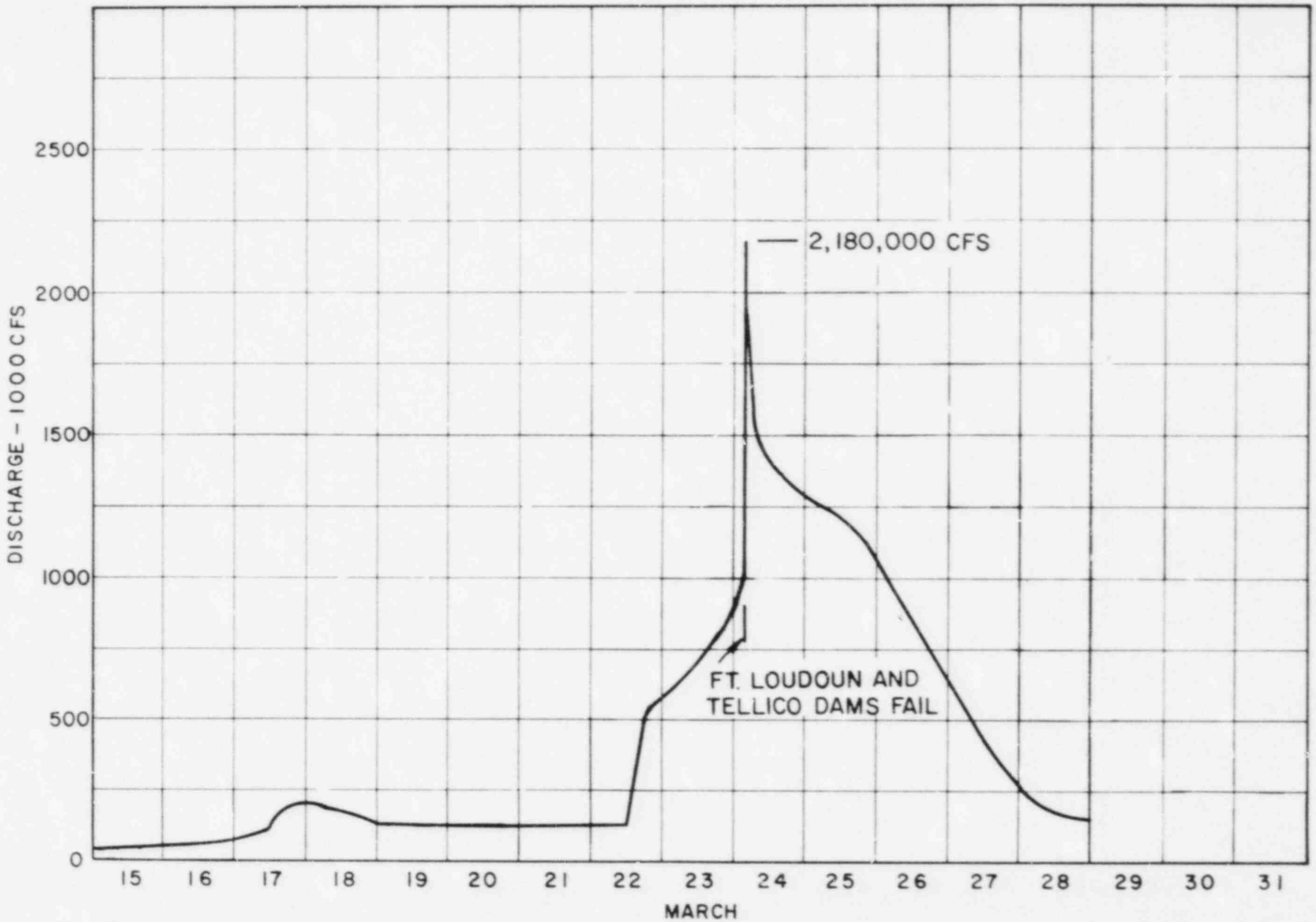
FORT LOUDOUN DAM RATING CURVES
FIGURE 2.4-35

Amend. 73
Nov. 1982



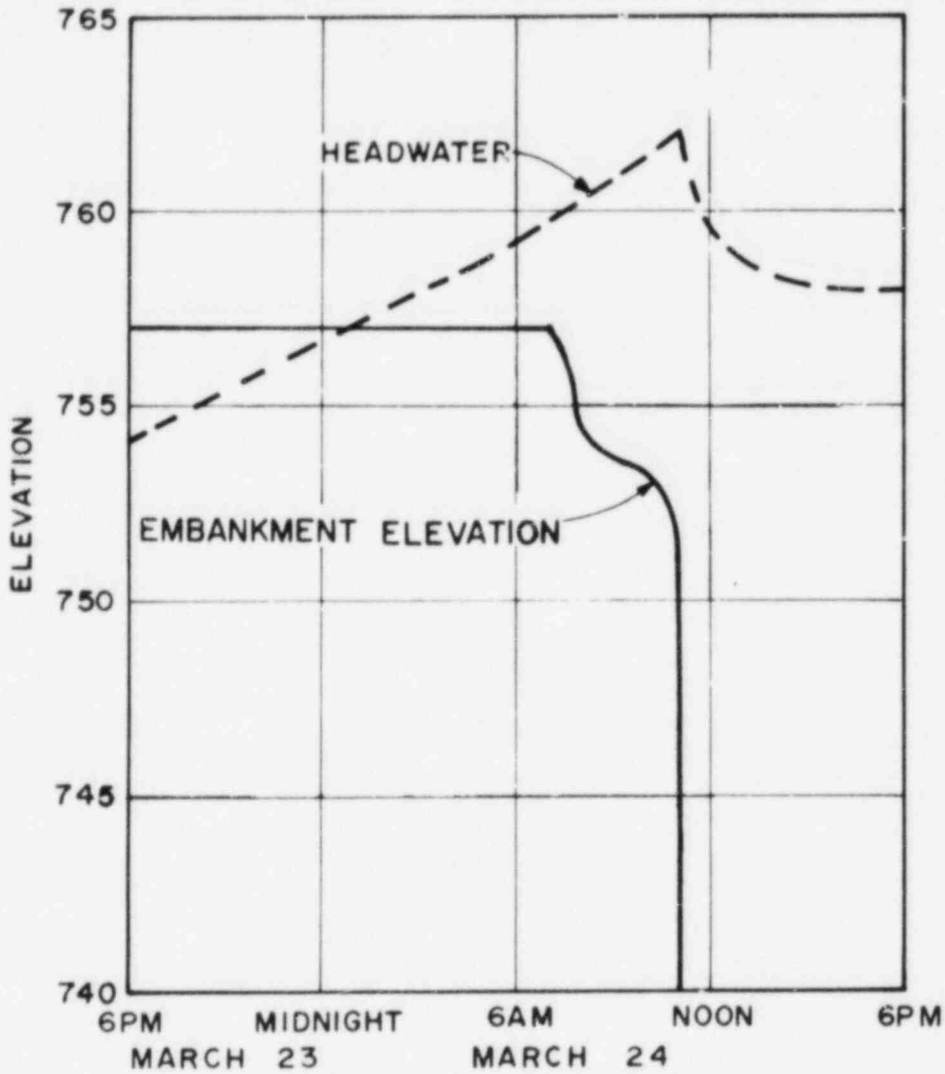
TELLICO DAM RATING CURVES

FIGURE 2.4-35a



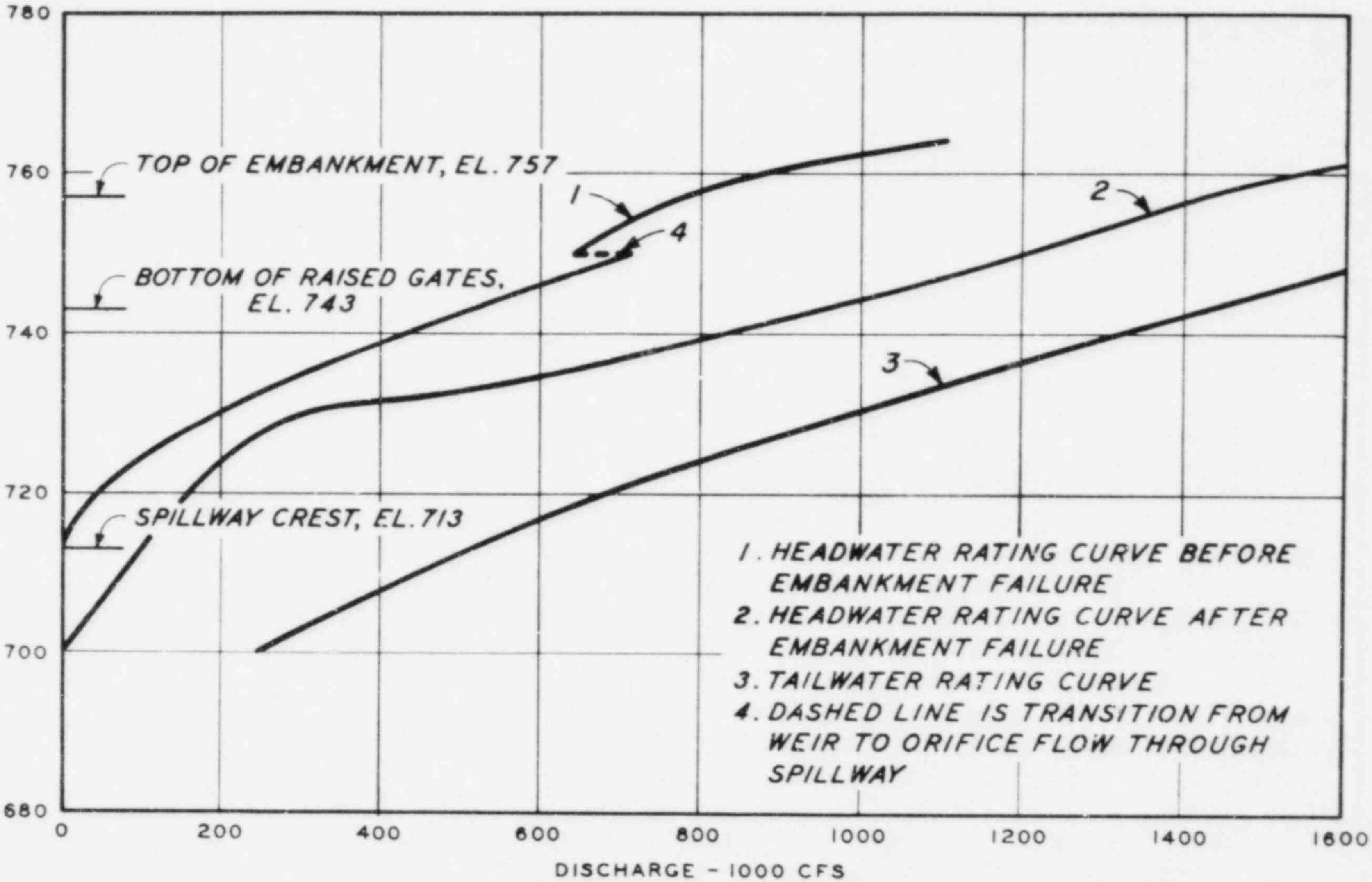
CRBRP PROBABLE MAXIMUM FLOOD
FORT LOUDOUN - TELLICO OUTFLOW
FIGURE 2.4-36

Amend. 73
Nov. 1982

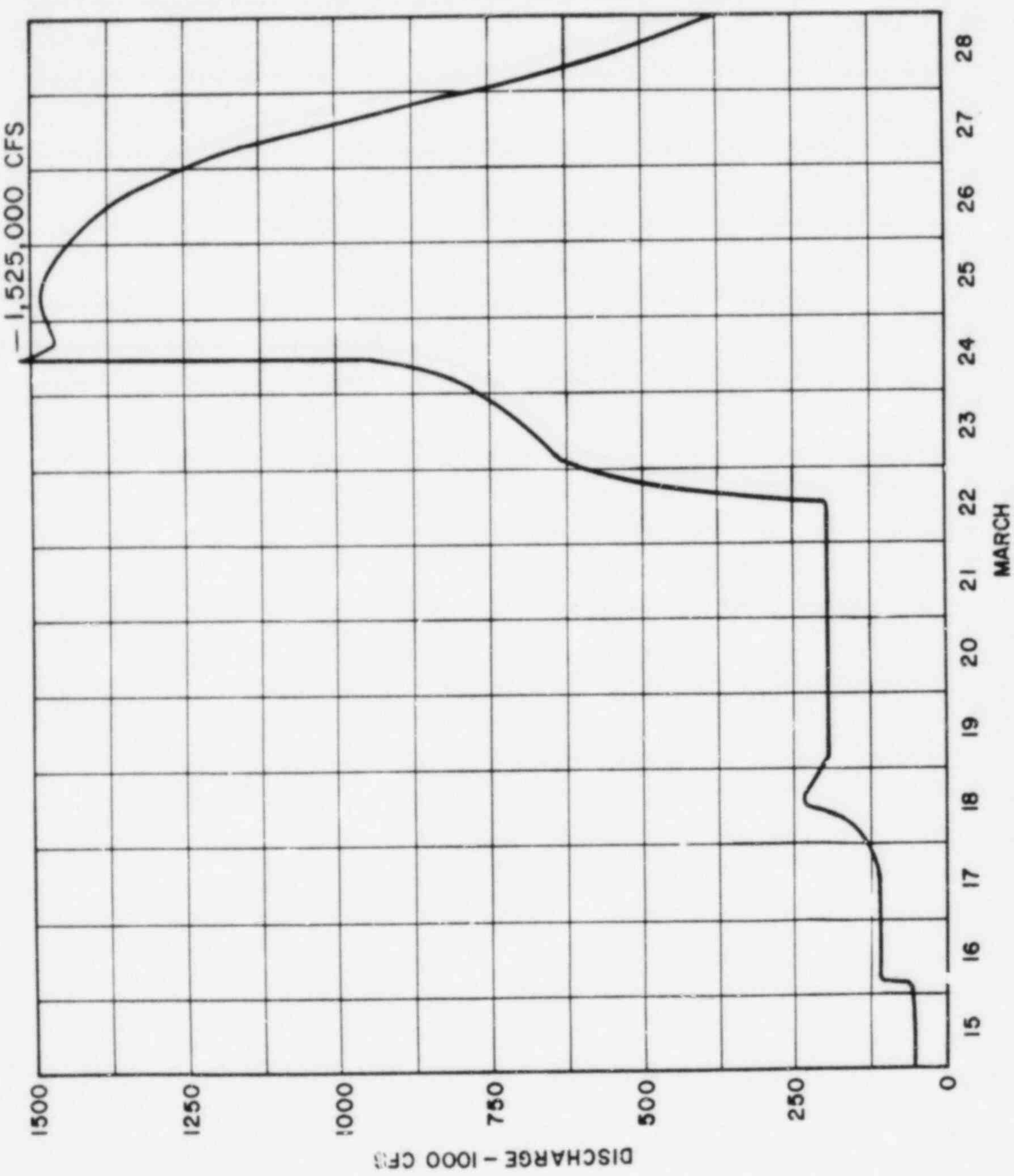


NOTE: FAILURE WOULD CONTINUE TO GROUND LEVEL, EL. 700

CRBRP PROBABLE MAXIMUM FLOOD
WATTS BAR EMBANKMENT FAILURE
FIGURE 2.4-39



WATTS BAR DAM RATING CURVES
FIGURE 2.4-40



CRBRP PROBABLE MAXIMUM FLOOD
WATTS BAR DAM OUTFLOW
FIGURE 2.4-41

FIGURE 2.4-45 WATTS BAR RESERVOIR

47

3.7.2.1.2 Seismic Category I Systems and Components

The analysis of Seismic Category I systems and components is determined by a detailed dynamic analysis using either the response spectrum method or the time history method. The analysis is performed on a multi-mass mathematical representation of the system or components. A sufficient number of masses with their appropriate degrees of freedom are used in the model to adequately describe the behavior of the structural system, and to insure an accurate determination of the dynamic response. Significant non-linearities, such as gaps or clearances between PCRS components, are included in the mathematical model. In this case, a nonlinear time history analysis is performed, which considers the impact forces generated at the gap locations. Non-symmetrical features of geometry, mass, and stiffness, are modeled to include their torsional effects in the analysis. Hydrodynamic effects of partially filled tanks will be evaluated wherever they are significant in magnitude. Descriptions of a preliminary reactor system linear model and a preliminary PCRS non-linear model are given in Section 3.7.3.15.

The methods of response spectra analysis and time history analysis are described in a number of publications. A description of these analyses techniques is provided in Appendix 3.7-A.

The system or component is analyzed with the seismic input (floor response spectra or time histories) derived at the particular points of support on the structure. All significant modes of the mathematical model are included in the analysis. The significant, dynamic response modes are those predominant modes which contribute to the total, combines modal response of the system. Other modes, whose inclusion in the square root of the sum of the squares modal summation have anegligible effect on the total response would not necessarily be used. With this procedure the number of modes included will be such that inclusion of additional modes will not result in more than a 10% increase in responses. Where the response spectrum method is used, the individual modal responses are combined by the square root of the sum of the squares, except for closely spaced modes (frequencies less than about 10% apart) where the modal responses are combined by the absolute sum. The analysis is performed independently in each of the two horizontal directions, and the vertical direction. Similar effects obtained for each of the three directions are combined by the square root of the sum of the squares. This is consistent with Regulatory Guide 1.92.

A simplified analysis based on a single mass model or an equivalent static load method may be used when it can be demonstrated that the simplified analysis provides adequate conservatism. For the simplified analysis, the equivalent static force, F_s, is distributed proportional to the mass of the component, and is calculated by the following equation:

$$F_s = 1.5 \; W \; A_s$$

where W is the total weight of the component, and A_s is the maximum peak acceleration of the response spectra, which apply at the points of support of the component. Components whose fundamental frequencies are greater than 33 Hz in any direction, are assumed to be rigid in that direction and may be designed for at least the maximum acceleration at their supports.

3.7.3.13 Interaction of Other Piping with Seismic Category I Piping

For Category 1 piping have non-Category 1 piping systems connected, the analysis of the Category 1 piping will include, as a minimum, the section of the piping system to the first anchor point beyond the classification boundary or sufficient non-Category 1 piping and seismic restraints to assure decoupling between the Category 1 piping and the remaining non-Category 1 piping. This will assure that the dynamic coupling effects at the interface between piping systems has been considered.

In any given fluid system, a valve will serve as the seismic Category I and non-Category I boundary. The valve capability to maintain a pressure boundary in the event of a seismic event is to be assured by designing piping on the non-Category I side through the first anchor beyond the valve for that same seismic event or through sufficient seismic restraints to capture the dynamic effects of the different seismic category piping systems at the interface.

For the seismic restraints, the piping system analysis includes the structure or building interaction by considering the appropriate stiffness values in the analytical models. The structure/building mass is usually not considered since its dynamic response is negligible. For the anchors, the piping system is modeled to the anchor with the appropriate stiffnass values considered. The resultant anchor loads are summed to form the design loads for the anchor.

3.7.3.14 Field Location of Supports and Restraints

For the analysis of multiple supported subsystems, the effects of relative displacements between piping and support points at different elevations on the supporting system are considered as discussed in Section 3.7.2.7. The response spectra for the different elevations were superimposed to yield an envelope response spectrum to be used in the response spectrum analysis of multiple supported subsystems.

3.7.3.15 Seismic Analyses for Fuel Elements, Control Rod Assemblies and Control Rod Drives

The seismic analyses that will be used to establish the seismic design adequacy of the reactor internals, assemblies, control rod drives, etc., is discussed in Section 3.7.2.1.2. For components such as the assemblies and control rod drives where clearances exist between adjacent members, a non-linear time history analysis has been performed, see Section 4.2.3.3.1.4. The mathematical model consists of the whole reactor system. Preliminary models for linear analysis are discussed below.

3.7.3.15.1 Reactor System Structural Arrangement

Simplified sketches of the reactor configuration as modeled for seismic analysis are shown in Figures 3.7-17 A, B and C. Figure 3.7-17A shows the reactor and reactor enclosure system as idealized for normal operation. Figures 3.7-17B and 3.7-17C show the additional head mounted equipment during refueling and preparation for refueling respectively.

In Figure 3.7-17A the reactor vessel flange is attached to the support ledge in the reactor cavity through a bolt and support pad system. The outer plug riser is bolted directly to the vessel flange. Therefore, both the vessel and riser are assumed cantilevered from the flange which is attached (with an appropriate stiffness) to the support ledge.

The head is comprised of three separate plugs (large, intermediate and small). The rim of each plug is suspended within the penetration of the mating plug (or flange in the case of the large plug) by bearings mounted on concentric cylindrical risers. Both primary and secondary CRDM nozzles as well as the surrounding shield and seismic support structure are cantilevered from the intermediate plug. The upper internals columns are attached to the same plug through the jacking mechanisms. The upper internals structure is assumed laterally restrained by the core barrel in the operating and preparation for refueling cases. The core barrel is rigidly attached to the core support plate which is, in turn, attached to the vessel through the support cone. The lower end of the thermal liner is also directly attached to the vessel wall.

The fuel blanket, control and radial shield assemblies are all piloted into the inlet modules at their lower ends and laterally supported through adjacent assemblies to the core former rings attached to the core barrel at two elevations. Tolerances, twist, and bow of the assemblies as well as the sodium between assemblies tend to prevent relative lateral motion of the assemblies. Therefore, inter-assembly gaps and clearances within the core barrel are of relatively minor importance to the overall system. The assemblies and core barrel are assumed to be effectively coupled together in the lateral direction at the load pad-former ring elevations.

The primary and secondary control absorbers and drivelines are each effectively connected vertically to the CRDM on the head and laterally to the CRDM and core at several CRDM bushing and absorber wear pad elevations. The drivelines are free at other elevations where the clearances are larger. Section 3.7.3.15.3 gives a discussion of the nonlinear control rod and driveline model used to determine the scram retarding impact forces during a seismic event.

The reactor vessel is partially filled with sodium. The normal level of the sodium is about 36 inches above the suppressor plate, or
46 about 12 inches below the bottom reflector plate of the closure head. The

1. SCOPE

This appendix establishes the baseline requirements of the design and analysis of the steel catch pans and fire suppresion decks for the Clinch River Breeder Reactor Plant.

2. APPLICABLE DOCUMENTS

The edition and addenda of the following publications are part of this document and are applicable to the extent specified herein.

2.1 American Society of Mechanical Engineers (ASME)

2.1.1 Boiler and Pressure Vessel Code, 1977 Edition including Addenda through the summer 1977.

- (a) Section II, Material Specifications
- (b) Section III, Division 1, Nuclear Power Plant Components
- (c) Section V, Nondestructive Examination
- (d) Section IX, Welding and Brazing Qualifications

2.1.2 Boiler and Pressure Vessel Code, Section III, Division 2, Code for Concrete Reactor Vessels and Containments, 1977 Edition including Addenda through Summer 1977.

2.1.3 Boiler and Pressure Vessel Code, Section VIII Division 1, 1977 Edition including Addenda through Summer 1977.

2.2 American Institute of Steel Construction (AISC)

Specifications for the Design, Fabrication and Erection of Structural Steel for Buildings. (1969 including Supplements 1 (11/70), 2 (12/71), and 3, (10/75).)

2.3 Westinghouse Electric Corporation, Advanced Reactor Divison (WARD)

WARD Document No. WARD-D-0037, Seismic Design Criteria for Clinch River Breeder Reactor Plant (Rev 1, 1977), (PSAR Appendix 3.7-A).

3.0 TECHNICAL REQUIREMENTS

3.1 Design Requirements

Catch pans and fire suppression decks are located in non-radioactive Na and NaK cells in order to prevent a chemical reaction between Na or NaK and concrete following a accidental spill and to protect the structural integrity of cell structures for the preservation of the capital investment.

Catch pans, fire suppression deck and supports shall be designed as Seismic Category I components.

The design requirements and the associated criteria used to satisfy each of the requirements for catch pans, fire suppression decks, penetration assemblies, brackets and attachments, and seismic equipment and othe. structural supports, are described as follows:

3.1.1 Catch Pan Requirements

1. The catch pan plate shall be designed to contain a large sodium/NaK spill (faulted condition) with temperatures as per Attachment A "Design Parameters".

   Criterion

   There will be no catch pan failure under a Na/NaK spill such that Na/NaK penetrates the catch pan plate and interacts with the structural concrete. This is ensured by the strain limits under load combination C per Table 3.8-C-1 not being exceeded.

2. The catch pan plate shall be designed for maximum long term operating conditions of 120°F.

   Criterion

   Strain limits under Load Combinations A and B per Table 3.8-C-1 shall not be exceeded.

3. The equipment supports in the catch pan area shall be designed independently of catch pan plate.

   Criterion

   The equipment will not be supported on the plate but on local structural supports independent of catch pan plate. During maintenance, timber dunnage will be placed on the catch pan plate to facilitate equipment handling. Stresses under this condition shall not exceed those specified in Table 3.8-C-1.

4. The catch pan plate shall be designed to insure an essentially elastic response under normal operating conditions.

   Criterion

   Strain limits under Load Combination A shall not exceed 0.002 in/in. strain.

5. Catch pan plate surface shall be protected to facilitate decontamination after a sodium spill.

   Criterion

   The hot-rolled natural finish surface condition is considered adequate. A protective coating will be applied during construction to prevent corrosion.

6. The catch pan plate shall be designed for corrosion allowances commensurate with environmental conditions for a 30 year plant design life.

Cell Liners and Liner Support System	Carbon Steel
Piping	Carbon Steel & Stainless Steel
Pipe Insulation and Canning Material	Note 1
Pipe Supports and Auxiliary Steel	Carbon Steel
Conduit	Carbon Steel
Embedments	Carbon Steel
Penetration Seals	
Piping	Welded
Hatches and Doors	Silastic Rubber Compression Gaskets*
Electrical	TBD

*Some hatches, such as the piping cell hatches (Cells 101C, D, and E) may be seal-welded.

Note 1: Material requirements for piping insulation and piping are applicable to the components and piping in the inner cells. These are discussed in Chapter 9 for individual systems.

3A.8.4 TESTING AND INSPECTION

3A.8.4.1 Development Testing Programs

45 A series of development testing programs have been developed to support the cell liner design. These programs provide materials data to support the objective of designing the cell liners to accommodate large sodium spills without failure, demonstrate through qualification testing that integrity of the liner is maintained under sodium spill conditions, and provide test materials data on sodium-concrete reactions to assess the consequences of cell liner failure.

Five individual testing programs have been completed or are ongoing in support of the cell liner design. These development programs are:

(a) Comprehensive Testing Program for Concrete at Elevated Temperatures

(b) Sodium-Concrete Reaction Tests

(c) Sodium Spill Design Qualification Tests

(d) Cell Penetration Sealant Tests

(e) Base Material Tests for Liner Steels

The tests included in the development programs listed above are modeled to minimize the difference between small scale tests results and the actual mass concrete response at elevated temperatures. The development programs indicated above are directed toward the goal of designing and testing a cell liner system which will not fail, even
59 under the unlikely event of a large sodium spill.

Comprehensive Testing Program for Concrete at Elevated Temperatures

45 This ongoing experimental program will define the variation with temperature of various physical and thermal properties of prototypic CRBRP limestone aggregate concrete and lightweight insulating concrete. The properties include, but are not limited to, compressive strength, modulus of elasticity, shear strength, bond strength, thermal conductivity, specific heat, and coefficient of thermal expansion. The series of experiments will be carried out at various temperatures including those
37 representative of accident conditions.

The results of this testing program can be directly applied to the analysis of the building structures supporting the cell liners. The testing program is nearing completion and the results will be included in an ORNL/CRBRP report following completion.

Since the biaxial and triaxial testing of concrete at elevated temperatures will yield a greater compressive strength than uniaxial testing due to the influence of the lateral confining stress, the concrete tests performed on specimens in the uniaxial state of stress will yield a more conservative value of strength. Therefore the consequences of biaxxial and triaxial loading can be disregarded.

Sodium-Concrete Reaction Tests

The objective of this ongoing program is to determine the rate and extent of penetration due to sodium-concrete reaction. The effect of reaction product accumulation and gas release on the sodium-concrete reaction rates will be determined to allow upgrading of analytical capability. Additionally, intentionally defected liner tests will be performed to assess the response of the liner to a sodium-concrete reaction. Results of these tests will be documented as they become available.

The dimensions of the test articles have been selected to ensure that results representative of the actual mass concrete structure can be obtained.

Sodium Spill Design Qualification Tests

A large scale model of a CRBRP cell liner has been performance tested to demonstrate the ability of the cell liner system to maintain liner integrity, mitigate consequences of a large sodium spill, and prevent sodium-concrete reactions. A total of 3500 pounds of liquid sodium at 1100°F was spilled against a CRBRP cell liner wall forming a 50 inch deep sodium pool above the CRBRP liner floor in the test article. The sodium pool was then heated, using electric heaters, to temperatures ranging between 1460°F and 1580°F and maintained until six days after the spill. The 1100°F sodium spill simulated a Design Basis Accident sodium spill event and the subsequent heat up to approximately 1600°F simulated the fission decay heat of a sodium pool under TMBDB Accident conditions.

The test data and post test examination revealed no failures or liner defects and minimal deformation of the liner system under the DBA and TMBDB spill conditions. The results of this testing program are included in the HEDL final report (Reference 5).

Cell Penetration Sealant Tests

The objective of this program was to determine the effects of temperature, sodium and radiation on various candidate sealant materials for cell penetrations. This series of experiments enables selection of the most suitable sealant material for use in the CRBRP. Following selections of the prime sealant material, prototypic electrical cable penetration assembly performance testing were conducted. The results of this testing program were published in Reference (4).

Base Material Tests for Liner Steels

The objective of this completed testing program was to determine the response of the cell liner plate material (SA-516 Grade 55) and its associated weldment material to elevated temperatures up to 7100°F. The base liner steel will be tested for residual tensile strength (including stress-strain response), stress-rupture (Creep) and thermal expansion. The weldment material was tested for residual tensile strength (including stress-strain response) and stress-rupture (Creep). Both longitudinal and transverse welds were investigated. The results of the base liner steel and weldment material tests have been published in Reference 6.

The material properties information at elevated temperatures which was
59 obtained in this program has been used in the design and analysis of the cell
liner system.

References:

1. McAfee, W.J., Sartory, W.K., "Evaluation of the Structural Integrity of LMFBR cell liners - Results of Preliminary Investigations", ORNL-TM-5145, January, 1976.

2. Chapman, R.H., ORNL-TM-4714, "A State of the Art Review of Equipment Cell Liners for LMFBR's", February, 1975.

3. Sartory, W.K., McAfee, W.J., ORNL-TM-5145, "Evaluation of the Structural Integrity of LMFBR Equipment Cell Liner - Results of Preliminary investigation", February, 1976.

4. Humphrey, L.H., Horton, P.H., AI-DOE-13227 "Selection of a Sodium and Radiation Resistant Sealant for LMFBR Equipment Cell Penetrations", January 31, 1978.

5. Wireman, R., Simmons, L., Muhlestein, I., HEDL TME 79-35, "Large Scale Liner Sodium Spill Test (LT-1)", December, 1980.

6. Cowgill, M.G., WARD-D-0252, "Base Material Tests for Cell Liner Steels", February, 1980.

The core support structure is welded Type 304 stainless
steel structure which includes the core support plate and the core
barrel. The core support plate contains module liners which serve
as receptacles for the lower inlet modules. The core support structure
carries the weight of the other portions of the lower internals
structure, the reactor removable assemblies (fuel, blanket, control
and radial shield assemblies) and the core former structure. The
core support structure provides the upper boundary of the vessel inlet
58 plenum and distributes the coolant to the lower inlet and bypass flow modules.
The core support structure transmits the dead weight hydrostatic pressure
and seismic loads to the reactor vessel.

The core support structure concept is based upon the FFTF core
support structure, however, the FFTF manufacturing experience has been
utilized to reduce the complexity of the core basket. The FFTF core
basket was a core diameter size structure containing receptacles so that
each reactor assembly could be "plugged" into the core basket. This
single large core basket has been simplified by designing mini baskets
(lower inlet modules). Each inlet module receives seven reactor assemblies.
Each module in turn plugs into liners which are integral to the core
support plate. The concept of these liners is shown in Figures 4.2-38
and 4.2-39. Each liner is a Type 304 stainless steel tube inserted into
the support plate seated to the bottom of the plate by a flange and
clamped to the support plate by a cap at the top of the liner. The
cap complies with the ASME Code requirements for the use of the non-
51 integral joints. The liner is sealed near the lower surface of the

plate to permit hydraulic balance of the lower inlet modules. The liner has an alignment feature mating with the support plate and an alignment feature for the lower inlet modules. These two alignment features assure that the lower inlet modules are positioned correctly. The reactor assembly discrimination feature precludes placing an assembly in an improper location. Auxiliary flow ports and debris barriers, as shown in Figures 4.2-38 and 4.2-39 have been provided in each module liner to preclude the possibility of large debris of any type from blocking all flow to one or more of the inlet modules. The auxiliary flow ports are located immediately below the CSS plate in a secondary inlet plenum formed by the hexagonal debris barriers, which separate the auxiliary flow ports from the primary flow ports and the radial ribs on the peripheral liners. The primary flow ports are designed to prevent large debris from entering the module liner stem and blocking the auxiliary ports from the inside and the peripheral ribs prevents debris from working its way in from the side of the array. In the event that one or more of the primary flow ports become blocked, the affected liner would then draw cooling sodium via the auxiliary flow ports from the secondary plenum. Sodium feed to this secondary plenum is by (1) the auxiliary flow ports in the unblocked liners and (2) the array of 2 inch diameter holes in the hexagonal debris barrier array.

Lower inlet modules support and position the reactor assemblies on the core support plate. These modules, as shown in Figure 4.2-40, distribute the coolant to the various reactor components: fuel assemblies, blanket assemblies, removable shield assemblies and control rod assemblies. Each module fits into a liner integral to the support plate and receives seven reactor assemblies and provides orificing that is unique to specific reactor assembly locations as shown in Figure 4.2-41.

Each of the LIMs feature one alignment pin and two shorter discriminator pins. Proper alignment of each LIM is assured through the mating of the alignment pin to the module liner hole. Each LIM group has two uniquely machined discriminator pins that mate with two uniquely drilled holes on each of the module liners. During installation, the alignment pin will properly align the LIM. However, complete installation will be prevented if the two discriminator pins do not line up with module liner holes.

Sufficient clearance exists between the LIM and the module liner, as well as pin/hole dimensions, to allow thermal expansion. The module liner has an interference fit with the Core Support Plate and it maintains a fixed position with the plate. Both the liners and the Core Support Plate experience similar steady state temperatures and are made from the same material, therefore, thermal expansion variations between the two are minimum.

Mechanical discriminating features are designed into each module to assure placement of the reactor assemblies into the proper region (i.e., fuel, blanket, and control) so that assemblies cannot be undercooled. Furthermore, mechanical discrimination assures the proper core lattice positions for fuel assemblies. Angular alignment to the module for the correct lattice position is assured by an alignment pin between the liner and the core support plate. The modules are shielded by the lower shield within the reactor assemblies so that the loss of ductility limit is not exceeded during the plant life. The modules are a welded 304 stainless steel structure and all 61 modules have the same envelope dimensions. However, there are several distinct configurations due to the differing flow requirements of the reactor assemblies.

Loads from weight, hydraulic pressure drop and seismic acceleration are transmitted by the support plate to the reactor vessel. Sizing analysis for internal pressure, flow blockage, control rod drop, and seismic loads indicate that under normal operating loads with flow blockage the inlet module meets the ASME Section III criteria for primary stresses.

Six bypass flow modules, surrounding the lower inlet modules, distribute low pressure coolant received from the lower inlet modules to the removable radial shield assemblies. The bypass flow modules provide receptacles to accept the removable radial shield assemblies that are not positioned in the lower inlet modules.

51 The details of the FRS are provided in Section 4.2.2.2.1.4.

54

The general design rule of 5.0% minimum residual ductility insures that non-ductile fracture will not occur during short term loadings in reactor internal structures. This criterion is based upon the minimum residual total elongation of 10.0% and the established relationship between total and uniform residual elongation of $\varepsilon_t = \varepsilon_u + 5\%$ as noted in Table 4.2-53. This relationship is based upon the end-of-life tensile test data in Tables 4.2-54 through 4.2-57 and data from References 178, 179 and 180. It is conservatively based upon a data set showing the least uniform elongation for a total elongation of 10.0%. An evaluation of all current data indicates that when the degradation on ductility is greatest at a particular fluence level the uniform elongation tends to be a greater fraction of the total than this relationship indicates. Since this limit is based upon uniaxial test data a correction for the multiaxial state of stress for actual reactor component conditions is required. This correction can be performed using scientific paper 67-1DO-CODES-P1, "Applied Mechanics in the Nuclear Industry Applications of Stress Analysis". For a typical thermal stress conditions which causes an equibiaxial stress state the 5.0% would be reduced to 0.9%. The elongation available to insure ductile behavior can be determined by considering the factor of safety, consistent with the ASME Code Section III factor of safety protecting against ultimate failure. The use of the factor of safety of 3.0 would reduce the elongation for a equibiaxial state of stress to 0.30%.

The applied strain considered relevant to this elongation limit is the maximum value of the three principle strains and represents an accumulation of elastic plus plastic strain at the end of life. These limits would apply at a minimum to membrane plus bending strains regardless of whether the loading is primary or secondary. Thermal transient strains in reactor internal components are less than the 0.30% membrane plus bending. Therefore, from the tensile data base that is presently available, the ductility required at the end-of-life in reactor internal components is sufficient to insure their integrity when 10% residual total elongation is available and the criteria described is applied. In locations where significant fatigue damage occurs in the low cycle regime, which is also affected by the ductility of the material, corrections to the fatigue design curves are applied using accepted theories of fatigue design curve construction which are based upon reduction in area.

A test program is presently in place which will experimentally characterize the fracture toughness of reactor component materials when subjected to a fast-neutron irradiation environment. This program includes tests of smooth, notched and welded specimens. The establishment of the fracture toughness and fatigue crack propagation characteristics will provide a basis for confirmation of the described criteria or the substitution of a
57 more refined criteria.

4.2.2.2.1.2 Lower Inlet Module

Sixty-one inlet modules support and position the reactor assemblies on the core support plate. These modules distribute the coolant to the following reactor components: fuel assemblies,
51 blanket assemblies, removable shield assemblies, control rod

TABLE 4.4-3

<u>COOLANT LIMITING TEMPERATURES FOR TELT CALCULATIONS</u>
<u>(TEMPERATURES IN °F)</u>

TYPICAL WORST CASE FOR ASSEMBLY TYPE	HETEROGENEOUS CORE MAXIMUM TRANSIENT TEMP. (FØRE-2M CALCULATED)	STEADY STATE TEMP. CORRESPONDING TO HETEROGENEOUS CORE MAXIMUM TRANSIENT TEMP. (FØRE-2M)	STEADY STATE TEMP. CORRESPONDING TO 1550°F MAXIMUM TRANSIENT TEMP.	T_M
Fuel Assembly	1571	1331	1316	1252 First Core 1261 Second Core
Inner Blanket Assembly	1498	1247	1282	1198 First Core 1207 Second Core
Radial Blanket Assembly	1580	1331	1310	1232

Temperatures at THDV, 3σ, 750°F Inlet (heterogeneous core maximum transient temp., and both steady state temp. columns)

Temperatures for PEOV, 2σ (T_M)

TABLE 4.4-4

CORE ORIFICING ZONES FLOW ALLOCATION

ZONE	TYPE	NO. ASSYS/ ZONE	FLOW (lb/hr) CYCLES 1,3,5,..		CYCLE 2		CYCLES 4,6,8,..	
1	Fuel	39	169,990	(201,900)	188,520	(200,340)	187,050	(198,780)
2	Fuel	54	176,790	(187,870)	175,420	(186,420)	174,060	(184,970)
3	Fuel	21	166,900	(177,360)	165,610	(175,990)	164,320	(174,620)
4	Fuel	18	153,400	(163,020)	152,220	(161,760)	151,030	(160,500)
5	Fuel	24	149,480	(158,850)	148,330	(157,630)	147,170	(156,400)
6	Fuel	0,3 or 6			178,590	(189,780)	177,190	(188,300)
	Inner Blanket	6,3 or 0	68,790	(73,100)	69,330	(73,680)		
7	Inner Blanket	57	88,790	(94,360)	88,110	(93,630)	87,420	(92,900)
8	Inner Blanket	19	76,030	(82,920)	77,420	(82,270)	76,810	(81,620)
9	Radial Blanket	12	62,300	(66,210)	61,820	(65,700)	61,340	(65,190)
10	Radial Blanket	36	48,300	(51,330)	47,930	(50,930)	47,550	(50,530)
11	Radial Blanket	48	35,090	(37,290)	34,820	(37,000)	34,540	(36,710)
12	Radial Blanket	30	25,740	(27,350)	25,540	(27,140)	25,330	(26,920)

NOTE: Flows are for THDV (PEOC) conditions.

CORE REGION FLOW FRACTIONS

REGION	CYCLES 1,3,5...	CYCLE 2	CYCLES 4,6,8...
Fuel	0.65	0.66	0.66
Inner Blanket	0.17	0.16	0.16
Radial Blanket	0.12	0.12	0.12
Total	0.94	0.94	0.94

4. Piping shall be designed with suitable access to permit in-service testing and inspection.

5. All "horizontal" piping shall be sloped. Steam traps and drain valves shall be located at the low points to permit complete draining of the piping.

6. Piping sizes shall be chosen such that average fluid velocities at the 100% plant power condition will not exceed the following values:

   a. water 25 fps

   b. water-steam mixture 50 fps

   c. saturated steam 125 fps

   d. superheated steam 175 fps

System Description

All Steam Generation System piping is shown in Figure 5.1-4. The design characteristics and ASME Code classifications are presented in Table 5.5-7.

The only field run piping planned for the steam generator system is non-safety class piping. The internal diameter of the piping will be 2 inches or less and is used for drain lines from steam traps. The design pressure would not exceed 100 psia and the design temperature would be less than 300°F.

The Seismic Category I design requirements are placed on the Steam Generation System's steam-water piping. Superheater and evaporator modules and the steam drum are provided with quick acting isolation valves. Design pressures of all piping are nominally 110% of the operating pressure at rated power.

The use and location of rigid-type supports, variable or constant spring-type supports, and anchors or guides will be determined by flexibility and stress analysis. Piping support elements will be as recommended by the manufacturers and will meet applicable code requirements. Direct weldment to thin wall piping will be avoided where possible.

Attachment and penetrations shall be designed and fabricated according to the ASME Code requirements.

Design loading used for flexibility and seismic analysis for the determination of adequate piping supports will include all expected transient loading conditions. Spring-type supports will be provided for the initial dead weight loading during hydrostatic testing of steam systems to prevent damage to piping supports.

Test and Inspection

In-service inspection is considered in the design of the main steamwater and feedwater supply piping. This consideration assures adequate working space and access for the inspection of selected pipe segments.

After completion of the installation of a support system, all hanger elements will be visually examined to assure that they are correctly adjusted to their cold setting position. Upon hot start-up operations, thermal growth will be observed to confirm that spring-type hangers are functioning properly. Final adjustment capability will be provided for all hanger or support types.

5.5.2.3.4 Steam Generator Module

The steam generator module shown in Figure 5.5-2 is a shell and tube heat exchanger with fixed tubesheets. Flow is counter-current, with sodium on the shell side and water/steam on the tube side. The evaporator modules transfer heat from the sodium and generate 50 percent quality steam from the subcooled recirculation water. The steam-water mixture exiting from the evaporator is separated into saturated water and saturated steam in a steam drum. The superheater modules transfer heat from the sodium to superheat the saturated steam to the temperature required for admission to the turbine.

The Atomics International - Modular Steam Generator (MSG) was a 32.1 Mwt maximum power, hockey stick designed unit used as the basis for the CRBRP Steam Generator design. The salient features of the MSG unit are as follows:

- Maximum Power — 32.1 Mwt
- Temperature — 930^{o}F
- Pressure — 2550 psig
- Startup/Shutdown — 37 Cycles
- Tube Design — 158 Tubes 5/8 in. O.D. x 109 mil. wall
- Length — 66 ft
- Material — 100% Ferritic Steel - 2 1/4 Cr-1 Mo

For further details see Reference 4.

Evaporator and superheater modules are identical in all respects except for the inlet orifices that may be added to the evaporator tubes at the lower tubesheet to increase the evaporator water flow stability margin. Each module consists of a 53 1/2 inch O.D. shell containing a tube bundle with locations for 739 5/8 in. O.D. x 0.109-inch wall tubes. The design employs

An upper header thermal liner and an inlet nozzle thermal liner are provided to mitigate the effects of system sodium transients.

c. Shell Arrangement

(1) Major Components of Shell

The shell connects to an upper and lower tubesheet, and consists of two reducers, an elbow, an inlet header "tee" section, an outlet header "cross" section, a main support section and a main shell section. These components have been sized structurally to contain postulated maximum large leak SWR conditions as well as meet design operating conditions.

(2) Shell Penetrations

Each superheater and evaporator module is fitted with one inlet sodium nozzle and two outlet sodium nozzles. Present intermediate sodium loop arrangement drawings show both superheater outlet nozzles being used, while only one of the two outlet nozzles is used on each of the two evaporator units. The spare evaporator exit nozzles are capped. The inlet sodium nozzle is a 30-inch nozzle that attaches to the 4 1/4-inch thick inlet sodium header in the direction of the hockey stick. The 30-inch nozzle is reduced to a 26-inch, 1-inch thick wall pipe, which will be mated to the loop piping. The two outlet sodium nozzles are 22-inch nozzles that attach at 90° to the direction of the hockey stick to the 4 1/4-inch thick outlet sodium header. The 22-inch nozzles reduce to 18-inch, schedule-60 pipes, which will be mated to the loop piping. The purpose of the oversized nozzles in regard to the piping size is to provide space in the nozzles for thermal liners and to reduce flow velocities in the inlet/outlet regions.

Two 8-inch sweepolets are attached to the reducers located at both tubesheets. These serve as ports to inspect the final closure welds. Also, one of the ports on the lower reducer is attached to a 6-inch schedule-80 pipe by a transition section to provide for rapid drainage of the lower stagnant end of the modules, should it be required. Again, the purpose of the transition section is to provide for possible lining of the nozzles. A one-inch drain is also provided through the lower tubesheet to drain the lower thermal baffle region. A three-inch sodium bleed vent is provided in the hockey stick end of the module to provide for: 1) venting during initial filling of the shell side, and 2) a small sampling flow to a hydrogen detector to allow detection of any small leak in that region during operation.

(3) Steam/Water Heads

The steam/water heads are integrally welded to the tubesheets. The steam piping is in turn welded to the steam heads. An integral steam head provides an enhanced maintenance capability since 1) the heads are not removed for in-service inspections, 2) drainage of the module is not required since the integral steam head will serve as the tank to contain the water medium and 3) the air/water exposure of the steam tubes will be minimized. The welded steam head also significantly reduces potential steam water leakage by exchanging a large diameter steam head seal for a smaller diameter manway seal which is relatively insensitive to distortion and leakage during normal transients.

Steam Generator Inspection

Access to the heat transfer tubes of the steam generator is readily obtained by removal of the manway nuts and removal of the manway cover. The steamhead is basically a 32 inch radius sphere which provides larger stress margin than the alternate bolted design. The manway is a standard 16 inch diameter port. The 57 inch ID sperical head provides adequate space and headroom for inspections and maintenance and tube plugging as required. The upper steamhead also serves as the water tank for in-service inspection (ISI).

The inner diameter of the heat transfer tube is readily available for inspection by ultrasonics, eddy current and/or other suitable means which will be determined acceptable at the conclusion of a development program (now in progress). The outer surface of the heat transfer tubes cannot be readily inspected since the shell of the steam generator is a fully welded assembly. However, it is expected that the above tube inspection techniques will give sufficient information on the condition of the tubes to provide assurance of integrity of the sodium/water boundary.

5.5.2.3.5 Steam Drum

The steam drum, shown in Figure 5.5-4, is a horizontally mounted 82 inch O.D., 35 ft. long cylinder with hemispherical heads (42 ft. overall length). Most of the major nozzles are located in a vertical plane through the steam drum centerline. These consists of one 12 inch steam outlet nozzle located at vessel midpoint and directed vertically upward, two 16 inch riser nozzles (evaporator return) located at approximately cylinder quarter points and directed downward, four 10 inch downcomer nozzles (recirculation pump suction) spaced evenly along the cylinder and directed downward, one 6 inch continuous drain nozzle located in one head and directed downward normal to the head at a 45° angle to the vertical, and one 10 inch feedwater inlet nozzle located in the opposite head and directed downward normal to the head at a 45° angle to the vertical. The only nozzle that is not coplanar with the vessel centerline is the auxiliary feedwater nozzle. This is a 4 inch nozzle located on the same head as the main feedwater inlet nozzle in a vertical plane rotated 45° from the vessel centerline; the nozzle is directed downward normal to the head at a 45° angle to the vertical.

Safety/power relief valves are installed on the outlet line of the evaporator units, on the steam drum and on the outlet line from the superheater. These valves all meet the requirements of Section III of the ASME Boiler and Pressure Vessel Code for protection against overpressure. Table 5.5-8 indicated design pressures and valve settings for the steam generator safety/relief valves. Additional valve data is provided in Table 5.5-8A.

5.5.3.5 Steam Generator Module Characteristics

Each evaporator module will produce 1.11 x 10^6 lb/hr of 50% quality steam from subcooled water. Each superheater module will produce 1.11 x 10^6 lb/hr of superheated steam from saturated steam. The thermal hydraulic normal design operating conditions are given in Table 5.5-9.

The steam generator modules will supply the turbine with steam at design conditions over a 40% to 100% thermal power operating range for both clean and fouled conditions. The steam generator modules are also capable of removing reactor decay heat with the natural convection in both the intermediate sodium loop and the recirculaton water loop.

This hockey stick unit is of the same basic design as that of the Atomics International-Modular Steam Generator (AI-MSG) unit which was tested in a test program carried out at the Sodium Component Test Installation. The AI-MSG employed a 158-tube module with an overall length of 66 feet, as compared to the 739-tube CRBRP Steam Generator which has an overall length of 65 feet. The AI-MSG heat exchanger was operated for a total of 4,000 hours including operation both as an evaporator (slightly superheated steam out) and as a once through evaporator-superheater (from sub-cooled liquid to completely superheated steam).

The AI-MSG served as a proof test of the AI prototype hockey-stick steam generator design. The unit was operated for 4,000 hours under steaming conditions; all of these 4,000 hours, the unit was at the same temperature level at which the prototype will operate, with a steam pressure equal to or greater than prototype conditions. Table 5.5-9A compares various design operating conditions for the CRBRP Units to the AI-MSG, and lists the number of hours which the AI-MSG operated under respective conditions. The AI-MSG operated at steam pressures equal to or greater than the CRBRP Units for essentially the whole 4,000 hrs., and at CRBRP superheater inlet temperature for 750 hrs.

Since the AI-MSG unit was operated in the once-through mod, simultaneous simulation of both inlet and outlet CRBRP conditions for the separate CRBRP evaporator and superheater units was not achieved, but operation over the CRBRP temperature and pressure range was achieved on both the sodium and steam conditions for significant portions of the test.

Safety Evaluation

The steam generators are essential to remove reactor decay heat. However, since there are three independent loops with each loop containing two evaporator modules and one superheater module, the loss of one loop would not preclude removal of reactor decay power. The steam generators
41 are Safety Class 2, but shall be constructed to Class 1 rules.

Design transients for normal, upset, emergency and faulted conditions are discussed in Section 5.7.3 and Appendix B.

Methods for detecting internal leakage between sodium and the water or steam, the margin in tube walls for thinning and time dependence of tube wastage to effect adjacent tubes are discussed under Steam Generator System Leakage Detection System, Section 7.5.5.

The rationale for the selection of any given number of failed tubes to establish an overpressure design for the IHTS is discussed under Evaluation of Steam Generator Leaks, Section 5.5.3.6.

TABLE 5.5-5

SGS PUMP AND VALVE DESCRIPTION

PUMPS	ACTIVE	INACTIVE	ACTUATING SIGNAL
Recirculation Pump		X	N/A
VALVES			
Pump Suction Isolation		X	Manual (Remote)
Evaporator Inlet Isolation		X	SWRPRS
Evaporator Inlet Water Dump		X	SWRPRS
Evaporator Outlet Relief	X		SWRPRS**, High Pressure Evaporator (Steam)
Steam Drum Relief	X		High Pressure - Steam Drum
Superheater Inlet Isolation		X	SWRPRS
Superheater Relief	X		SWRPRS**, High Pressure Superheater (Steam)
Superheater Outlet Isolation	X		SWRPRS**, OSIS/SGAHRS or Low Super-heater Outlet Pressure
Superheater Bypass Valve	X		SWRPRS**, OSIS/SGAHRS, or Low Super-heater Outlet Pressure
Steam to SGAHRS HX		X	Manual (L.O.)*
Water from SGAHRS HX		X	Manual (L.O.)*
Steam to SGAHRS Auxiliary FW Pump		X	Manual
Feedwater from SGAHRS		X	Manual (L.O.)*
Main Feedwater SGB Isolation	X		SWRPRS**, High Steam Drum Level, Low Steam Drum
Pressure,			Cell Temp and Humidity
Main Feedwater Drum Isolation		X	High Steam Drum Level
Main Feedwater Check Valve		X	Simple Check
Main Feedwater Control	X		High Steam Drum Level, Cell Temp and Humidity
Startup Feedwater Control	X		High Steam Drum Level, Cell Temp and Humidity
Evaporator Outlet Check Valve		X	Check Valve
Superheater Outlet Check Valve		X	Check Valve
Steam Drum Drain Isolation	X		SWRPRS**, SGAHRS Initiation, Low Steam Drum Pressure

* L.O. - Locked open

** This function is not safety active

Amend. 73
Nov. 1982

TABLE 5.5-5 (Continued)

Valves	ACTIVE	INACTIVE	ACTUATING SIGNAL
SWRPRS Stack Check Valve		X	Check Valve
SWRPRS Atmospheric Seal Bypass		X	Manual
Sodium Dump Tank Pressure Relief		X	High Sodium Dump Tank Pressure
Evaporator Water Dump Tank Drain		X	Manual

41

59

42

The pump discharge lines contain check valves to prevent back flow through inoperable pumps. The motor driven pump discharge lines also contain a manually operated, locked open isolation valve downstream of the check valve. All three Class 3 discharge lines also have a 2 inch pump recirculation line containing an electrically-operated, normally closed isolation valve, branching off and running back to the PWST.

e. Auxiliary Feedwater Supply Lines

The six auxiliary feedwater supply lines from both the turbine and motor driven pump discharge headers are 4 inch diameter and contain (in order and in direction of flow) a manually operated, locked open isolation valve; a normally open electro-hydraulic control valve; a normally closed, electric operated isolation valve; and a manually operated, locked open isolation valve. After the final isolation valve, the turbine and motor driven pump supply lines are joined. The resulting 4 inch carbon steel line, which contains two check valves and a manual isolation valve, is then routed to the steam drum.

Routing of the auxiliary feedwater supply lines is such that high pressure lines (high pressuring during normal plant operation) are not located in cells containing the PWST, auxiliary feedwater pumps or other SGAHRS equipment whose failure could cause a loss of SGAHRS safety function.

f. AFW Pump Test Loop

Downstream of the tee where the motor-driven and turbine-driven pump supply lines join at the loop #1 valve station, an AFW pump test line returns flow to the protected water storage tank during periodic testing. This line contains redundant automatic valves for isolating the AFW supply from the PWST should SGAHRS be initiated during testing.

g. Steam Supply Line From Steam Drum to AFP Drive Turbine

There are three 4 inch steam supply lines, one from each steam drum. Each of these lines contains a locked open, manual isolation valve, an electrically operated, normally closed isolation valve, a check valve, and another locked open, manual isolation valve. Downstream of the final isolation valves, the three lines are headered together. The resulting 4 inch line then passes through a normally closed, electro-hydraulic operated pressure control valve before entering the drive turbine.

Routing of the turbine steam supply lines is such that they do not pass through the PWST cell. When the turbine lines pass through adjacent cells, protection is provided from missiles and jet impingement.

h. Steam Drum to Protected Air Cooled Condenser (PACC)

This is a high temperature, high pressure insulated 8 inch diameter carbon steel line. There are three parallel lines, one to each of the PACCs, which are separated by the Steam Generator Building Containment walls. Each line, which supplies steam from the steam drum to the PACC, has two locked open, manually operated isolation valves. Before entering the PACC, each 8 inch line tees into the 6 inch lines, each of which leads to one of the PACC's two half size tube bundles. During normal plant operation, these lines remain hot due to the PACC heat losses and natural circulation flow.

i. Protected Air Cooled Condenser to Steam Drum Recirculation Lines

Condensate from each of the half size PACC tube bundles will be piped in a separate 8-inch insulated line down to an elevation 3 feet below normal water level in the steam drum (See Figure 5.6-7). These separate lines assure that each half size PACC bundle is isolated from the other by a water seal. The isolation allows one half-size PACC bundle to be started and operated independently of the other. At an elevation 3 feet below the normal water level the 8-inch half PACC returns join to a single 6-inch line which continues down to the recirculation header 19 feet below the normal water level. This common condensate return line contains two locked open manual isolation valves and a venturi flowmeter. Above the water seal elevation, condensate flow will be a vertical annular or stratified two phase gravity flow pattern. A large line size (8-inches) is used to assure the two phase gravity flow remains stable and does not result in entrainment over the PACC operating range. (See Section 5.6.1.3.2.3) The lines from each PACC to its steam drum are separated from the lines for other PACCs by the Steam Generator Building walls.

j. Steam Drum and Superheater Steam Vent Lines

These two lines, one branching from the steam drum to superheater piping and the other branching from the superheater to main turbine line, contain a locked open, manual isolation valve and a normally closed electro-hydraulic operated pressure control valve. Both lines are used to vent steam from the system to release heat from the plant and maintain the steam drum at a pressure below the design head of the auxiliary feedwater pumps. The superheater vent valve and vent line are made of 1 1/4 CR - 1/2 Mo steel; the steam drum vent valve and vent line are carbon steel. Following the plant trip and the initial pressure reducing transient, these valves will normally be used as the only means for venting steam during SGAHRS operation. Power relief valves located at the superheater outlet will serve as a backup should both the SGAHRS superheater and steam drum vent valves be unavailable. These steam generator system valves will be set to open at a higher pressure. The advantage of separate SGAHRS vent valves is a controlled steam drum pressure by venting through valves designed for low erosion rather than the on/off operation of the safety valves.

5.6.1.3.1.5 Analytical Method for Component Supports (Vessels, Piping, Pumps, and Valves)

In accordance with the ASME Code, component supports will have the same code classification as the components they support. Design of each component support will comply with the ASME Section III design rules corresponding to the component support classification. In order to provide assurance that the component support stresses comply with limits specified in Section 5.6.1.1, analysis of each component support will be performed. The applicable analytical techniques and applicable computer codes discussed in Section 5.3.3.1.5 will also apply to detailed analysis of support components. The classification of components within the SGAHRS is included in Section 5.6.1.1.1.4. Allowable stress limits and pressure limits are specified in Tables 3.9-3 and 3.9-4.

5.6.1.3.2 Thermal Hydraulic Design Analysis

5.6.1.3.2.1 Natural Circulation

The SGAHRS auxiliary feedwater supply subsystem draws its driving force from the Auxiliary Feedwater Pumps. The Protected Air Cooled Condensers (PACC) operate on natural circulation on the steam and water side. The relative elevations are shown in Figure 5.1-6.

Since the relative densities of water and steam are 10:1, there will be no difficulty in ensuring steam supply to the PACC. The condenser design will permit adequate circulation within the condenser tubing. The PACC design will be verified by analyses and by proof testing after installation.

The PACC closed loop schematic is shown on Figure 5.6-7. The steam/water side natural circulation is comprised of two parts as follows:

(1) Steam flow from the steam drum superheater supply piping, through the steam inlet piping, into the tube bundle.

(2) Condensate flow from the tube bundle through the condensate return piping, to the recirculation pump header located below the steam drum.

The tube bundles during normal plant operation are filled with saturated steam at steam drum conditions and kept on hot standby (i.e., isolation from ambient by air side isolation louvers). Assuming 3% heat loss through the insulated isolation louvers (design goal) during standby, condensate is formed at the rate of 2974 lbm/hr. The condensate outflow from the tube bundle during its period is due to gravity.

Upon SGAHRS initiation signal, the isolation louvers are opened, the fan is turned on, and steam condensation increases. Condensation causes a volume collapse inside the finned tube bundle. This volume collapse causes the bundle pressure to drop below the steam drum pressure as makeup flow from the drum is established. The return piping connected to the recirculation pump header is supplied with water from the steam drum. Because this line contains relatively high density water (43.2 lbm/ft^3 for water as compared to 3.36 lbm/ft^3 for steam) the low pressure in the bundle causes the liquid level in the return piping to rise above the steam drum liquid level while steam flows into the tube bundle through the supply line. The units are designed to condense 89,000 lbm/hr of saturated steam from the steam drum. The combined pressure drops associated with flow of steam through the inlet piping, steam/water mixture through the tube bundle, and water through the return piping is calculated to be 4 psi. This causes the liquid level in the condensate return pipe to rise 16 ft. above the steam drum liquid level. This height is 11 ft. below the low point of the tube bundle (i.e., the tube bundle exit header nozzle). This 11 ft. margin is enough that the tube bundle pressure drop could be as high as 4.6 psi without drawing water into the tube bundle. The tube bundle pressure drop is not expected to be more than the 2 psi allowed by the PACC Equipment Specification.

The condensate outflow from the tube bundle is caused by two factors as follows:

(1) Shear forces resulting from flow of steam over the condensate formed in the tubes. These forces are directly proportional to the velocity differential between the steam and the condensate as predicted by the relation:

$$\tau = \mu\left(\frac{\partial u}{\partial y}\right) y = \delta$$

where:

τ = The shearing stress at steam/condensate interface
μ = Steam viscosity
u = Steam velocity
δ = Location of the steam/condensate interface

(2) Gravitational forces causing the condensate to flow to the low point of the tube bundle.

The tube bundle length may be divided in three parts. The condensate flow through the first region is primarily due to shear forces as described above. In the second region the steam velocity is greatly reduced and both gravitational and shear forces cause condensate to flow towards the tube bundle exit header. The governing forces in the third region are gravitational, shear, and pressure gradient induced. These forces cause the condensate to flow into the tube bundle exit header where it is returned to the recirculation header. The steam inlet nozzle location (high point of the tube bundle) with respect to the condensate return nozzle (low point of the tube bundle) also serves to insure flow of all condensate steam towards the condensate return pipe.

TABLE 5.6-2

CLASSIFICATION OF SGAHRS COMPONENTS

COMPONENT	SAFETY CLASS	NATIONAL CODES	QUALITY STANDARDS*	QUALITY ASSURANCE ASME
Protected Water Storage Tank (PWST)	SC-2	ASME III/2	Group B	NA-4000
PWST Piping	SC-2	ASME III/2	Group B	NA-4000
PWST Valves	SC-2	ASME III/2	Group B	NA-4000
Protected Air Cooled Condenser (PACC)	SC-3	ASME III/3	Group C	NA-4000
PACC Piping	SC-3	ASME III/3	Group C	NA-4000
Auxiliary Feedwater System (AFS) Piping	SC-3	ASME III/3	Group C	NA-4000
AFS Pumps	SC-3	ASME III/3	Group C	NA-4000
AFS Valves	SC-3	ASME III/3	Group C	NA-4000

17 * NRC Regulatory Guide 1.26 "Quality Group Classifications and Standards," March 23, 1973.

TABLE 5.6-3

SGAHRS EQUIPMENT LIST AND MATERIAL SPECIFICATIONS

SGAHRS COMPONENT	ASME SECTION III CODE CLASS	MATERIAL*	DESIGN TEMP (°F)	DESIGN PRESSURE (PSIG)
Air Cooled Condenser Bundle	3	CS	650	2200
Air Cooled Condenser Fan, Motor, Louvers	-	--	100	----
Auxiliary Feedwater Pump	3	CS	200	2200
Pump Motor Drive	-	--	104	----
Pump Turbine Drive				
Downstream of Admission Values	-	CS	600	1250
Upstream of Admission Values	-	CS	650	2200
Water Storage Tank	2	CS	200	15
SGAHRS Piping:				
PWST to First Isolation Valve	2	CS	200	15
First Isolation Valve to AFW Pumps	3	CS	200	100
AFW Pumps to AFW Headers	3	CS	200	2200
AFW Headers	3	CS	200	2200
AFW Headers to Electrically Operated Isolation Valve	3	CS	200	2200
AFW Pump Test Loop to and between Isolation Valves	3	CS	650	2200
AFW Pump Test Loop From Isolation Valves to PWST Fill Line	3	CS	200	100
Isolation Valve to Main FW Line	3	CS	650	2200
Superheater Inlet Line to PACC	3	CS	650	2200
PACC to Evaporator Recirc Line	3	CS	650	2200
AFW Pump Recirc to Orifice	3	CS	200	2200
Orifice to PWST-Recirc	3	CS	200	250
Superheater Vent Line (Upstream of Valve)	3	1 1/4 Cr-1/2 Mo	935	1900
Steam Drum Vent Line (Upstream of Valve)	3	CS	650	2200
Superheater Vent Line (Downstream of Valve)	3	1 1/4 Cr-1/2 Mo	850	250
Steam Drum Vent Line (Downstream of Valve)	3	CS	400	250
Steam Supply Line to Drive Turbine	3	CS	650	2200
PACC Vent Line Upstream of Vent Orifices)	3	CS	650	2200

*CS - Carbon Steel

Amend. 73
Nov. 1982

TABLE 5.6-3 (Cont'd)

SGAHRS COMPONENT	ASME SECTION III CODE CLASS	MATERIAL*	DESIGN TEMP (^{o}F)	DESIGN PRESSURE (PSIG)
PACC V[illegible] Line (Downstream of Vent Orifices)	3	CS	400	250
PWST Fill Line	3	CS	200	100
AFW Pump Alternate Supply Line	3	CS	200	100
Drive Turbine Exhaust	3	CS	340	100
SGAHRS Valves:				
Alternate AFW Supply	3	CS	200	100
PWST Fill	3	CS	200	100
PWST Drain	2	CS	200	15
PWST Level Indicator	2	CS	200	15
AFW Pump Inlet (Manual)	2	CS	200	15
AFW Pump Inlet (Electrical)	2	CS	200	100
Alternate AFW Pump Inlet	3	CS	200	100
Pump Recirculation	3	CS	200	2200
Pump Recirculation c/v	3	CS	200	2200
Pump Discharge C/V	3	CS	200	2200
Pump Discharge Isolation	3	CS	200	2200
AFW Supply Isolation (Manual)	3	CS	200	2200
AFW Supply Control	3	CS	200	2200
AFW Supply Isolation (Electrical)	3	CS	650	2200
AFW Supply C/V	3	CS	650	2200
AFW Supply Isolation (Manual)	3	CS	650	2200
AFW Supply C/V	3	CS	650	2200
AFW Pump Test Loop Isolation	3	CS	650	2200
Superheater Vent Control	3	2 1/4CR-1 Mo	935	1900
Steam Drum Vent Control	3	CS	650	2200
Drive Turbine Steam Supply Isolation (Elect.)	3	CS	650	2200
Drive Turbine Steam Supply C/V	3	CS	650	2200
Drive Turbine Steam Supply Isolation (Manual)	3	CS	650	2200
Drive Turbine Steam Supply Pressure Control	3	CS	650	2200
PACC Steam Supply	3	CS	650	2200
PACC Steam Supply Bypass	3	CS	650	2200
PACC Condensate Return	3	CS	650	2200
PACC Noncondensible Vent	3	CS	650	2200
PACC Noncondensible Vent Isolation	3	CS	650	2200
Pressure Instrument (Pump Inlet)	3	CS	200	100
Pressure Instrument (Pump Discharge)	3	CS	200	2200
Pressure Instrument (Turbine Inlet)	3	CS	650	2200
Chilled Water Isolation	3	CS	200	100

*CS - Carbon Steel

TABLE 5.6-4

SGAHRS WELD FILLER METAL SPECIFICATIONS

	BASE MATERIAL	ASME SECTION II	SPECIFICATION
	Carbon Steel	SFA-5.1	Specification for Mild Steel Covered ARC--Welding Electrodes
26	1 1/2 Cr-1/2 Mo	SFA-5.5	Specification for low-alloy steel covered arc-welding electrodes.

TABLE 7.1-3

LIST OF IEEE STANDARDS APPLICABLE TO
SAFETY RELATED INSTRUMENTATION AND CONTROL SYSTEMS

IEEE-279-1971	IEEE Standard: Criteria for Protection Systems for Nuclear Power Generating Stations
IEEE-308-1974	Criteria for Class 1E Power Systems for Nuclear Power Generating Stations
IEEE-317-1976	Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations
IEEE-323-1974	Qualifying Class IE Electric Equipment for Nuclear Power Generating Stations
IEEE-323-A-1975	Supplement to the Foreword of IEEE 323-1974
IEEE-336-1971	IEEE Standard: Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During Construction of Nuclear Power Generating Stations
IEEE-338-1977	Criteria for the Periodic Testing of Nuclear Power Generating Station Safety Systems
IEEE-344-1975	IEEE Std. 344-1975, IEEE Recommended Practices for Seismic Qualification of Class 1 Equipment for Nuclear Power Generating Stations
IEEE-352-1975	General Principles for Reliability Analysis of Nuclear Power Generating Station Protection Systems
IEEE-379-1972	IEEE Trial-Use Guide for the Application of the Single-Failure Criterion to Nuclear Power Generating Station Protection Systems
IEEE-383-1974	Standard for Type Test of Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generating Station.
IEEE-384-1974	IEEE Trial Use Standard Criteria for Separation of Class IE Equipment and Circuits
IEEE-420-1973	Trial-Use Guide for Class IE Control Switchboards for Nuclear Power Generating Stations
IEEE-494-1974	IEEE Standard Method for Identification of Documents Related to Class 1E Equipment and Systems for Nuclear Power Generating Station

TABLE 7.1-4

RSS DIVERSITY

	Primary	Secondary
Logic:	Local Coincidence	General Coincidence
Sensors:	Inlet Plenum Pressure	Primary Loop Flow
	Primary Pump Speed	Primary Loop Flow
	Intermediate Pump Speed	Intermediate Loop Flow
	HTS Bus Frequency	HTS Bus Voltage
	Steam Flow	Steam Drum Level
	Feedwater Flow	Reaction Products Flow
	IHX Primary Outlet Temperature	Evaporator Outlet Sodium Temperature
Logic Isolation:	Photo Coupling	Direct Coupled
Equipment:		
o Circuitry	Integrated Circuits	Discrete Components
o Power Supplies	Separate vendors utilized	
o Potentimeters	Separate vendors utilized	
o Buffers	Light Coupling	Magnetic Coupling
o Control Rod Release	Circuit Breakers in 2/3 Logic Arrangement	Solenoid Operated Pneumatic Valve in a 2/3 Logic Arrangment

7.2 REACTOR SHUTDOWN SYSTEM

7.2.1 Description

7.2.1.1 Reactor Shutdown System Description

The Reactor Shutdown System (RSS) consists of two independent and diverse systems, the Primary and Secondary Reactor Shutdown Systems, either of which is capable of Reactor and Heat Transport System shutdown. All anticipated and unlikely events can be terminated without exceeding the specified limits by either system even if the most reactive control rod in the system cannot be inserted. In addition, the Primary RSS acting alone can terminate all extremely unlikely events without exceeding specified limits even if the most reactive control rod in the system cannot be inserted. To assure adequate independence of the shutdown systems, mechanical and electrical isolation of redundant components is provided. Functional or equipment diversity is included in the design of instrumentation and electronic equipment. The Primary RSS uses a local coincidence logic configuration while the Secondary RSS uses a general coincidence. Sufficient redundancy is included in each system to prevent single random failure degradation of either the Primary or Secondary RSS.

As shown in the block diagram of the Reactor Shutdown System, Figure 7.2-1, the Primary RSS is composed of 24 subsystems and the Secondary RSS is composed of 16 subsystems. Figure 7.2-2A is a typical Primary RSS instrument channel logic diagram. Each protective subsystem has 3 redundant sensors to monitor a physical parameter. The output signal from each sensor is amplified and converted for transmission to the trip comparator in the control room. Three physically separate redundant instrument channels are used. When necessary, calculational units derive additional variables from the sensed parameters with the calculational units inserted in front of the comparators as needed. The comparator in each instrument channel determines if that instrument channel signal exceeds a specified limit and outputs 3 redundant signals corresponding to either the reset or trip state. The 3 outputs of each comparator are isolated and recombined with the isolated outputs of the redundant instrument channels as inputs to three redundant logic trains. The recombination of outputs is in a 2 out of 3 local coincidence logic arrangement. 1

Operating bypasses are necessary to allow RSS functions to be bypassed during main sodium coolant pump startup, ascent to power, and two loop operation. Operating bypasses are accomplished in the instrument channels. For bypasses associated with normal three loop operation, the bypass cannot be instated unless certain permissive conditions exist which assure that adequate protection will be maintained while these protective functions are bypassed. Permissive comparators are used to determine when bypass conditions are satisfied. When permissive conditions are within the
57 allowable range, the operator may manually instate the bypass. If the

out of the allowable range, the protective function is automatically reinstated. The trip function will remain reinstated until the permissive conditions are again satisfied and the operator again manually initiates the bypass. Operator manual bypass control is not effective unless the bypass comparator indicates that permissive conditions are satisfied. A functional diagram of the Primary and Secondary bypass permissive logic is shown in Figure 7.2-2AA.

Two loop bypasses are established under administrative control by changing the hardware configuration within the locked comparator cabinets. These bypasses are also under permissive control such that the plant must be shutdown to establish two loop operation and if the shutdown loop if activated the bypass is automatically removed.

Bypass features included within the Primary and Secondary RSS hardware for two loop operation will be deactivated during all three loop operating modes so that the three loop operating configuration can not be affected by these bypass features either by operator action or by two loop hardware failure.

Bypass permissives are part of the Reactor Shutdown System (RSS), and are designed according to the RSS requirements detailed elsewhere in this section of the PSAR.

Continuous local and remote indication of bypassed instrument channels will be provided in conformance with Regulatory Guide 1.47, "Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems".

Figure 7.2-2B is a logic diagram of the Primary RSS logic trains. The outputs from the comparators and 2/3 functions are inputs to a 1 out of 24 general coincidence arrangement. The output of the 1/24 is an input to a 1 out of 2 with the manual trip function to actuate the scram breakers. The scram breakers are arranged in a 2 of 3. When . or more logic trains actuate the associated scram breakers, power to the control rods is open circuited and the control rods are released for insertion to shutdown position with spring assisted scram force. Open circuiting the control rod power initiates Heat Transport System shutdown.

In the Secondary RSS, the sensed variables are signal conditioned and compared to specified limits by equipment which is different from the Primary RSS equipment. The secondary logic is configured in general rather than local coincidence to provide additional protection against common mode failure. Each instrument channel comparator outputs its trip or reset signal to a 1 of 16 logic module. The 3 redundant secondary instrument channels from each subsystem feed 3 redundant logic trains, which are coupled to the secondary scram actuators. Figure 7.2-2D is a logic diagram for the Secondary RSS logic.

The Secondary RSS consists of 16 protective subsystems and monitors a set of parameters diverse from the Primary RSS as shown in Table 7.2-1. However, since a measure of nuclear flux is necessary in both the Primary and Secondary RSS, nuclear flux is sensed with compensated ionization chambers in the primary while fission chambers are used in the secondary. The Primary RSS monitors primary and intermediate pump speed while the Secondary RSS monitors primary and intermediate coolant flow. Similarly, the steam flow to feedwater flow ratio is used in the Primary RSS while the steam drum level is sensed for the Secondary RSS.

Figure 7.2-2C is a typical Secondary RSS instrument channel logic diagram. Each protective subsystem has 3 redundant sensors to monitor a physical parameter. The output signal from each sensor is conditioned for transmission to the trip comparator located in the control room. Redundant instrument channels are used. When necessary, calculational units are placed in front of the comparators to derive additional variables. The output of the comparators are input to redundant logic trains in a general coincidence arrangement.

Bypass of secondary comparators is implemented in the same fashion as in the primary system except that different equipment is used to provide the permissive comparator function.

57 Figure 7.2-2D is a logic diagram of the Secondary RSS logic trains. The outputs from the instrument channels are input to a 1/16 general coincidence arrangement. The 1/16 output controls the solenoid power sources through isolated outputs. Isolated outputs are also provided to initiate Heat Transport System shutdown. A trip latch-in function is provided to assure that once initiated, the scram will go to completion. The remaining
43 redundant logic trains provide the other two signals for the 2/3 function.

Figure 7.2-2 shows the RSS interface with the Heat Transport System (HTS) pump breaker control. Two HTS pump breakers are connected in series for each HTS pump. Each HTS breakers receives input from the Primary RSS and Secondary RSS pump trip logic. Upon receipt of a reactor trip signal from either Primary or Secondary RSS, the HTS pump breakers open to remove power from the primary and intermediate pumps.

Provisions are made to allow testing of the HTS breaker actuation function during reactor operation. A test breaker is used to bypass the main HTS breaker during a test condition. Test signals are then inserted through the Primary or Secondary RSS pump trip logic to open the main HTS breaker. Mechanical interlocks are provided on the bypass breakers to prevent more than one main HTS breaker in any loop from being bypassed at a time. Control interlocks are provided which make the breaker test inputs ineffective unless the bypass breakers are properly installed. Main HTS breaker and test breaker position status is supplied as part of the RSS status display or the main control panel.

The RSS subsystems do not directly require the reactor operator or control system to implement a protective action. However, manual control devices to manually initiate each protective function are included in the design of the Plant Protection System.

Where signals are extracted from the Reactor Shutdown System, buffers are provided. These buffers are designed to meet the requirements of IEEE-279-1971. The buffers prevent the effects of failures on the non-IE output side from affecting the performance of the RSS equipment. The buffers are considered part of the RSS and meet all RSS criteria.

<u>System Testability</u>

Both Reactor Shutdown Systems are designed to provide on-line testing capability. For the Primary RSS, overlapping testing is used. The sensors are checked by comparison with redundant sensor outputs and related measurements. Each instrument channel includes provisions for insertion of a signal on the sensor side of the signal conditioning electronics and test points to measure the performance at the comparator (or calculational unit) input. Where disconnection of the sensor is unavoidable for test purposes, the comparator is tripped when disconnected. The instrument channel electronics including trip comparators and bypass permissive comparators are tested for ability to change value to beyond the trip point and provide a trip input to the logic. The comparators and logic are tested by the PPS Monitor. A set of pulsed signals are inserted from the monitor into the comparators associated with one subsystem and the logic output is checked by the Monitor to assure that logic trip occurs for the correct combinations of comparator trips. The logic and scram breakers are tested by manually tripping one logic train and observing that the corresponding breakers trip. HTS breakers are tested by maintaining power to the pump through a bypass circuit breaker and manually inserting a test signal to the pump trip logic.

Evaporator Outlet Sodium Temperature

The Evaporator Outlet Sodium Temperature Subsystems (Figure 7.2-10) compare the sodium temperature at the outlet of the evaporator in each HTS loop to a fixed set point. If this temperature exceeds the set point, a reactor trip is initiated. There are three of these subsystems, one per loop. These subsystems detect a large class of events which impair the heat removal capability of the steam generators. These subsystems are never bypassed.

Sodium Water Reaction

The Sodium Water Reaction Subsystems (Figure 7.2-10) detect the occurrence of a sodium water reaction within a superheater or evaporator module. There are three of these subsystems, one per loop. Each subsystem receives nine signals from the sensors in the reaction products vent lines of a steam generator. These subsystems are never bypassed.

7.2.1.2.3 Essential Performance Requirements

In order to implement the required protective functions within the appropriate limits, RSS equipment must meet several essential performance requirements. These essential performance requirements and the RSS equipment to which they apply are summarized below.

The RSS instrumentation will meet the essential performance requirements of Table 7.2-3. This table defines the minimum accuracy and time constants which will result in acceptable performance of the RSS.

Analysis of worst case RSS functional performance is based on the values given in Table 7.2-3.

The maximum delay between the time a protective subsystem indicates the need for a trip and the time the rods are released is 0.200 second. This time includes the delays due to the calculational units, comparators, logic, scram breakers, and control rod release.

The maximum delay between the time a protective subsystem indicates the need for a trip and the time the HTS sodium pumps are tripped is 0.500 second. This time also includes the delays due to the logic and HTS scram breakers.

The RSS is designed to meet these essential performance requirements over a wide range of environmental conditions and credible single events to assure that environmental effects do not degrade the performance of the PPS. The environmental extremes are documented in Reference 13 of PSAR Section 1.6. Provisions are incorporated within the PPS which provide a defense against the following incidents:

o Environmental Changes

All electrical equipment is subject to performance degradation due to major changes in the operating environment. Where practical, PPS equipment is designed to minimize the effects of environmental changes; if not, the performance at the environmental extremes is used in the analysis.

Measures have been taken to assure that the RSS electronics are capable of performing according to their essential performance requirements under variations of temperature. The range of temperature environment specified for all the electronic equipment considered here is greater than is expected to occur during normal or abnormal conditions. Electronics do not fail catastrophically when these limits are exceeded even though this is the assumed failure mode. The detailed design of the circuit boards, board mounting and racks includes free ventilation to minimize hot spots. Ventilation is a result of natural convection air flow.

The RSS is designed to operate under or be protected from a wider range of relative humidity than that produced by normal or postulated accident conditions.

Vibration and shock are potential causes of failure in electronic components. Design measures, including the prudent location of equipment, minimize the vibration and shock experienced by RSS electronics. The equipment is qualified to shock and vibration specifications which exceed all normal and off-normal occurrences.

The RSS comparators and protective logic are designed to operate over a power source voltage range of 108 to 132 VAC and a power source frequency range of 57 to 63 HZ. The maximum variation of the source voltage is expected to be ±10%. More extreme variations in the power source may result in the affected channel comparator or logic train outputting a trip signal. In addition, testing and monitoring of RSS equipment is used, where appropriate, to warn of impending equipment degradation. Therefore, it is not expected that changes in the environment will cause total failure of an instrument channel or logic train, much less the simultaneous failure of all instrument channels or logic trains.

The majority of the RSS electronics is located in the control building, and is not subjected to a radioactive environment. Any PPS equipment located in the radioactive areas (such as the head access area) will be designed to withstand the level of activity to which it will be subjected, if its function is required.

o Tornado

The RSS is protected from the effects of the design basis tornado by locating the equipment within tornado hardened structures.

o Local Fires

All RSS equipment, including sensors, actuators, signal conditioning equipment, wiring, scram breakers, and cabinets housing this equipment is redundant and separated. These characteristics make any credible fire of no consequence to the safety of the plant. The separation of the redundant components increases the time required for fire to cause extensive damage and also allows time for the fire to be brought to the attention of the operator such that corrective action may be initiated. Fire protection systems are also provided as discussed in Section 9.13.

o Local Explosions and Missiles

All RSS equipment essential for reactor trip is redundant. Physical separation (distance or mechanical barriers) and electrical isolation exists between redundant components. This physical separation of redundant components minimized the possibility of a local explosion or missile damaging more than one redundant component. The remaining redundant components are still capable of performing the required protective functions.

o Earthquakes

All RSS equipment, including sensors, actuators, signal conditioning equipment, wiring, scram breakers and structures (e.g., cabinets) housing such equipment, is classed as Seismic Category I. As such, all RSS equipment is designed to remain functional under OBE and SSE conditions. The characteristics of the OBE and SSE used for the evaluation of the RSS are found in Section 3.7.

7.2.2 Analysis

The Reactor Shutdown System meets the safety related channel performance and reliability requirements of the NRC General Design Criteria, IEEE Standard 279-1971, applicable NRC Regulatory Guides and other appropriate criteria and standards.

The RSS Logic is designed to conform to the IEEE Standards listed in Table 7.2-4.

General Functional Requirement

The Plant Protection System is designed to automatically initiate appropriate protective action to prevent unacceptable plant or component damage or the release or spread of radioactive materials.

Single Failure

No single failure within the Reactor Shutdown System nor removal from service of any component or channel will prevent protective action when required.

Two independent, diverse reactor shutdown systems are provided, either of which is capable of terminating all excursions without allowing plant parameters to exceed specified limits. Each system uses three redundant instrument channels and logic trains. The Primary RSS is configured using local coincidence logic while the Secondary RSS uses general coincidence logic. To provide further assurance against potential degradation of protection due to credible single events, functional and/or equipment diversity are included in the hardware design.

Bypasses

Bypasses for normal operation require manual instating. Bypasses will be automatically removed whenever the subsystem is needed to provide protection. The equipment used to provide this action is part of the RSS. Administrative procedures are used to assure correct use of bypasses for infrequent operations such as two loop operation. If the protective action of some part of the system has been bypassed or deliberately rendered inoperative, this fact will be continuously indicated in the control room.

Multiple Setpoints

Where it is necessary to change to a more restrictive setpoint to provide adequate protection for a particular normal mode of operation or set of operating conditions, the RSS design will provide automatic means of assuring that the more restrictive setpoint is used. Administrative procedures assure proper setpoints in infrequent operations.

For CRBRP, power operation on two-loops will be an infrequent occurrence, and will only be initiated from a shutdown condition. While the reactor is shutdown, the RSS equipment will be aligned for two-loop operation which will include set down of the appropriate trip points. Sufficient trip point set down is being designed into the RSS equipment to adequately cover the possible range (conceptually from 2% to 100%) of trip point adjustment required. In addition, administrative procedures (specifically the pre-critical checkoff) will be invoked during startup to ensure that the proper RSS trip points have been set.

The analysis of plant performance during two-loop operation has not been completed to date. Therefore, the exact trip point settings for two-loop operation cannot be specified at this time. However, the range of trip point settings indicated above is adequate to ensure that trip points appropriate for the anticipated lowest two-loop operating power can be achieved.

In summary, the design of the RSS equipment trip point adjustments and other features for two-loop operation coupled with the anticipated two-loop operating power level and administrative procedures assure full compliance with Branch Technical Position EICSB 12 and satisfy Section 4.15 of IEEE std 279-1971.

Completion of Protective Action

The Reactor Shutdown Systems are designed so that, once initiated, a protective action at the system level must go to completion. Return to normal operation requires manual reset by the operator because the Primary RSS scram breakers or Secondary scram latch circuitry must be manually closed following trip. Trip signals must be cleared prior to closure of scram breakers.

Manual Initiation

The Reactor Shutdown System includes means for manual initiation of each protective action at the system level with no single failure preventing initiation of the protective action. Manual initiation depends upon the operation of a minimum of equipment because the manual trip directly operates the scram breakers of the solenoid scram valve power supply.

Access

Administrative control of access to all setpoint adjustments, module calibration adjustments, test points and the means for establishing a bypass permissive condition is provided by locking cabinets and other access design features of the control room and the equipment racks.

Information Read-Out

Indicators and alarms are provided as an operating aid and to keep the plant operator informed of the status of the RSS. Except for the IHX primary outlet temperature analog indicators which are part of the accident monitoring system, all indicators and alarms are not safety-related. The following items are located on the Main Control Panel for operator information.

Analog Indication

A. Secondary Wide Range Log MSV Power Level
B. Secondary Wide Range Linear Power Level
C. Primary Power Range Power Level
D. Reactor Vessel Level
E. HTS Pump Speeds
F. HTS Loop Flows
G. Reactor Inlet Pressure
H. IHX Primary Outlet Temperature
I. Evaporator Outlet Temperature
J. Steam Flows
K. Feedwater Flows
L. Steam Drum Level

Indicating Lights

A. Instrument Channel Bypass Permissive Status
B. Instrument Channel Bypass Status
C. Logic Train Trip/Reset Status
D. HTS Loop Trip/Reset Status
E. HTS Loop Test Status

Annunciators

A. Instrument Channel Trip/Reset information is provided for each function listed in Table 7.2-1
B. Logic Train Power Supply Failure
C. Two Loop Bypasses Instated

Most information is also available to the operator via the Plant Data Handling and Display System.

Annunciator for RSS Channel Trips

A visual and audible indication of all channel trip conditions within the RSS will be provided in the control room. These alarm conditions include any tripped RSS comparators in the Primary RSS or Secondary RSS. The Plant Data

Handling and Display system alerts the operator to significant deviations between redundant RSS analog instrumentation used to monitor a reactor or plant parameter for the RSS.

Control and Protection System Interaction

The Reactor Shutdown System and the Plant Control System have been designed to assure stable reactor plant operation and to protect the reactor plant in the event of worst case postulated Plant Control System failures. The RSS is designed to protect the plant regardless of control system action or lack of action. Isolation devices will be used between protection and control functions. Where this is done, all equipment common to both the protection and control function is classified as part of the RSS. Equipment sharing between protection and control is minimized. Where practical, separate equipment (sensors, signal conditioning, cabling penetrations, raceways, cabinets, monitoring etc.) is provided. The sharing of components does not lead to a situation where a single event both initiates an incident through Plant Control System malfunction and prevents the appropriate RSS acton.

Periodic Testing

The Reactor Shutdown System is designed to permit periodic testing of its functioning including actuation devices during reactor operation. In the Primary RSS, a single instrument channel is tested by inserting a test signal at the sensor transmitter and verifying it at the comparator output. A logic train is tested by inserting a very short test signal in 2 comparator inputs and verifying that the voltage on the scram breaker trip coils decrease. Because of the time response of the undervoltage relay coils of the scram breakers and very short duration of the test signal, the reactor does not trip. In the Secondary RSS, an instrument channel can be tested from sensor to scram actuator by inserting a single test signal because of the general coincidence configuration of the 3 redundant channels. The primary and secondary rod actuators cannot be tested during reactor operation since dropping a single control rod will initiate a reactor scram. Scram actuators and control rod drop will be tested and maintained when the plant is shutdown (See Section 7.1-2). Whenever the ability of a protective channel to respond to an accident signal is bypassed such as for testing or maintenance, the channel being tested is placed in the tripped state and its tripped condition is automatically indicated in the control room.

Failure Modes and Effects Analysis

A Failure Modes and Effects Analysis (FMEA) has been conducted to identify, analyze and document the possible failure modes within the Reactor Shutdown System and the effects of such failures on system performance (see Appendix C, Supplement 1). Components of the RSS analyzed are:

- Reactor Vessel Sodium Level Input
- RSS Sodium Flow Input
- Pump Electric Power Sensor
- Compensated Ion Chamber Nuclear Input
- Fission Chamber Nuclear Input
- Primary Loop Inlet Plenum Pressure Input
- Sodium Pump Speed (Primary and Intermediate)
- Steam Mass Flow Rate Input
- Feedwater Mass Flow Rate Input
- Steam Drum Level Input
- Primary Comparator
- Secondary Comparator
- Primary Logic Train
- Secondary Logic Train
- Primary Calculational Unit
- Secondary Calculational Unit

- Scram Actuator Logic

- Heat Transport System (HTS) Shutdown Logic

- Control Rod Drive Mechanism (CRDM) Power Train

- RSS Isolation Buffer

Figures 7.2-3 and 7.2-4 provide assistance in locating the above system level components within the overall RSS.

The probability of occurrence of each failure mode is listed in the tables of Appendix C, Supplement 1, in the Probability Column. The effects of each potential failure mode have also been categorized in the tables in the Criticality Column. Even though the failure of an individual element may result in the inability to initiate channel trip, the provision of redundant independent instrument channels and logic trains assures that single random failures cannot cause loss of either the Primary or Secondary RSS thereby meeting the design requirements of IEEE 279-1971. The high reliability of components, redundant configuration, provision for on-line monitoring and on-line periodic testing further assure that random failures will not accumulate to the point that trip initiation by either Primary or Secondary RSS is prevented. All failure effects are therefore categorized as not causing any degradation or failure of a system safety function. The majority of the identified failure modes can be eliminated from consideration based on their low probability of occurrence and the insignificance of their criticality. They are included in the FMEA, however, to document their consideration.

TABLE 7.2-1

REACTOR SHUTDOWN SYSTEM PROTECTIVE FUNCTIONS

Primary Reactor Shutdown System	Number of Inputs[1]
o Flux-Delayed Flux (Positive and Negative)	2
o Flux-Pressure	1
o High Flux	1
o Primary to Intermediate Speed Mismatch	3
o HTS Pump Frequency	1
o Pump Electrics	1
o Reactor Vessel Level	1
o Steam-Feedwater Flow Mismatch	3
o IHX Primary Outlet Temperature	3

Secondary Reactor Shutdown System	Number of Inputs
o Modified Nuclear Rate (Positive and Negative)	2
o Flux-Total Flow	1
o Startup Nuclear Flux	1
o Primary to Intermediate Flow Mismatcn	2
o Steam Drum Level	3
o Evaporator Outlet Sodium Temperature	3
o HTS Pump Voltage	1
o Sodium Water Reactio	3

[1] The Primary RSS can accept a total of 24 inputs and the Secondary RSS can accept 16 inputs. There are 9 spare Primary inputs.

TABLE 7.2-2

RSS DESIGN BASIS FAULT EVENTS

Fault Events	Primary Reactor Shutdown System	Secondary Reactor Shutdown System
I. Anticipated Faults		
A. Reactivity Disturbances[1]		
Positive Ramps ≤5¢/sec and Steps ≤10		
Startup	Flux-Delayed Flux or Flux- Pressure	Startup Nuclear
5-40% Power	Flux-Delayed Flux or Flux- Pressure	Modified Nuclear Rate or Flux-Total Flow
40-100% Power	Flux- Pressure	Flux-Total Flow
Full Power	High Flux	Flux-Total Flow
Negative Ramps and Steps	Flux-Delayed Flux	Modified Nuclear Rate
B. Sodium Flow Disturbances		
Coastdown of a Single Primary or Intermediate Pump	Primary-Intermediate Speed Mismatch	Primary-Intermediate Flow Ratio
Loss of 1 HTS Loop	Flux-Pressure	Primary-Intermediate Flow Ratio
Loss of 3 HTS Loops	HTS Pump Frequency	Flux-Total Flow

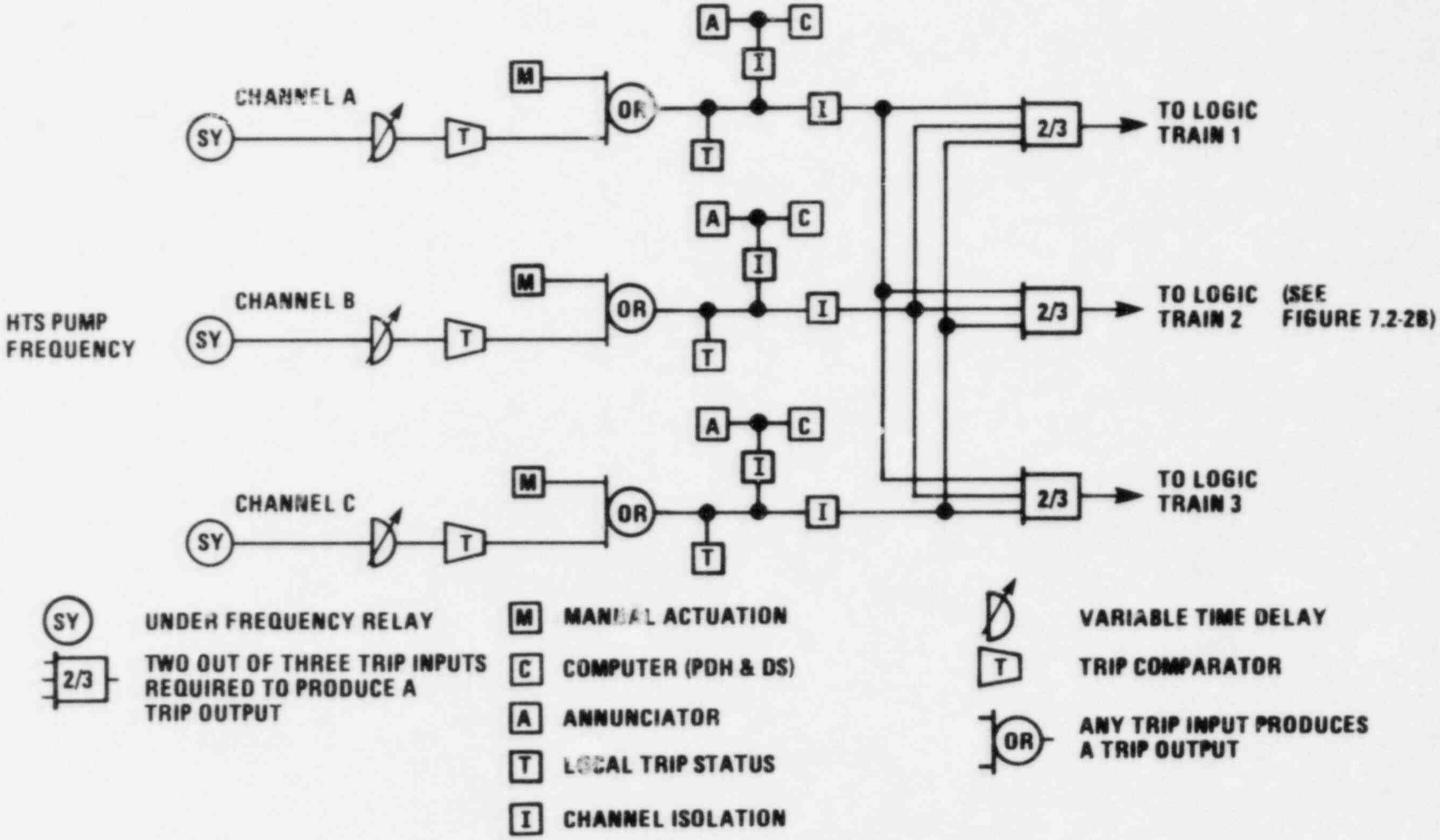


Figure 7.2-2A. Typical Primary RSS Instrument Channel Logic Diagram (HTS Pump Frequency Subsystem Shown)

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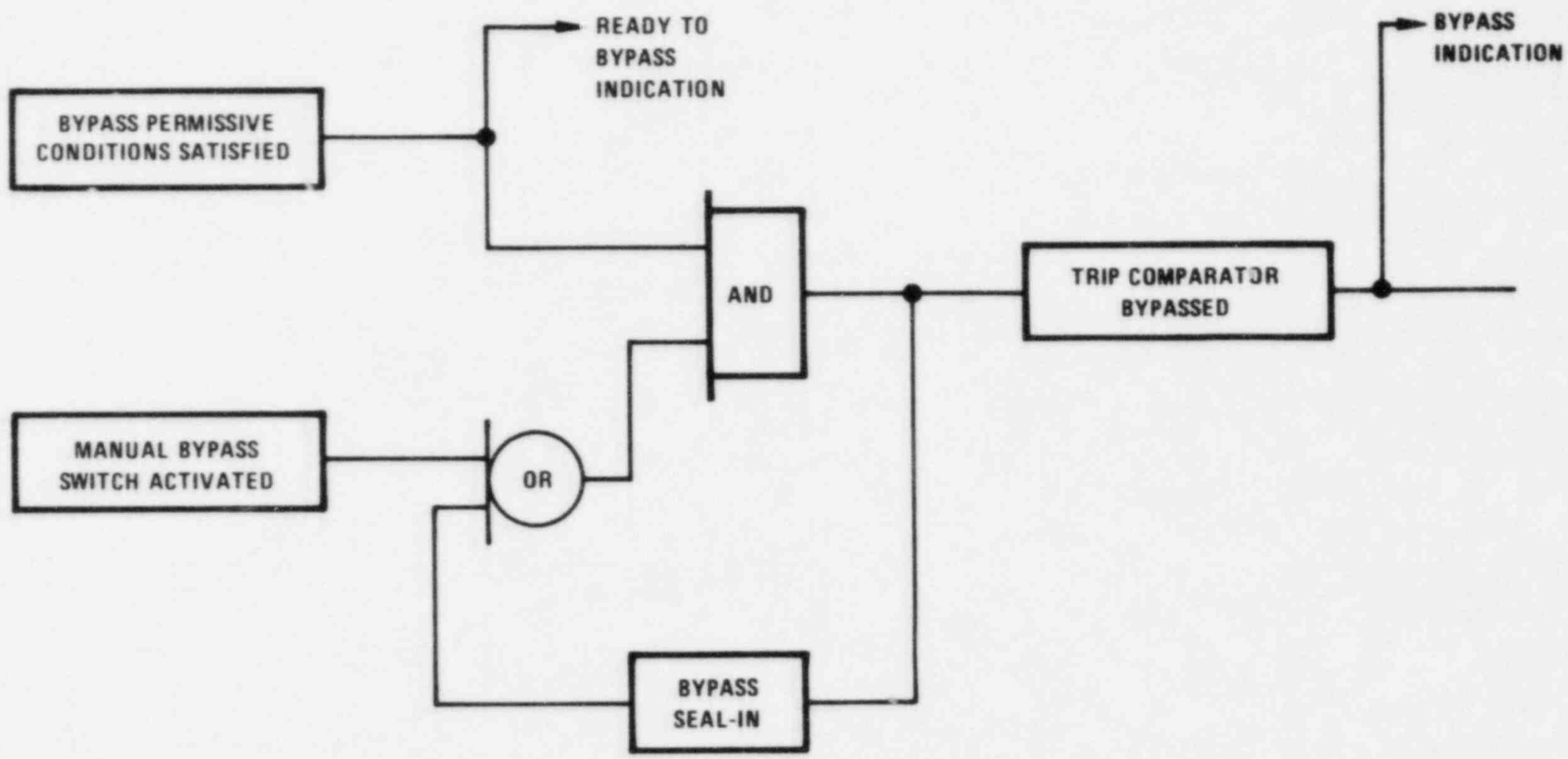

Figure 7.2-2AA. RSS Bypass Function Block Diagram

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Nov. 1980

7.4.2.1.2 Equipment Design

A high steam flow-to-feedwater flow ratio is indicative of a main steam supply leak downstream from the flow meter or insufficient feedwater flow. The superheater steam outlet valves and superheater bypass valves shall be closed with the appropriate signal supplied by the heat transport instrumentation system (Section ~ This action will assure the isolation of any steam system leak common to all three loops and also provide protection against a major steam condenser leak during a steam bypass heat removal operation.

7.4.2.1.3 Initiating Circuits

The OSIS is initiated by the SGAHRS initiation signal. The SGAHRS initiation signal is described in 7.4.1.1.3. This initiation signal closes the superheater outlet isolation valves in all 3 loops when a high steam-to-feedwater flow ratio or a low steam drum level occurs in any loop. In each Steam Generator System loop, the three trip signals for high steam-to-feedwater flow ratio and the low steam drum level are input to a two of three logic network. If two of three trip signals occur in any of the 3 loops, the OSIS is initiated, and all 3 loops are isolated from the main superheated steam system by closure of the superheater outlet isolation valves and superheater bypass valves.

7.4.2.1.4 Bypasses and Interlocks

Control interlocks and operator overrides associated with the operation of the superheater outlet isolation valves have not been completely defined.

Bypass of OSIS may be required to allow use of the main steam bypass and condenser for reactor heat removal. In case the OSIS is initiated by a leak in the feedwater supply system, the operator may decide to override the closure of certain superheater outlet isolation valves.

7.4.2.1.5 Redundancy and Diversity

Redundancy is provided within the initiating circuits of OSIS. The primary trip function takes place when a high steam-to-feedwater flow ratio is sensed by two of three redundant subsystems on any one SGS loop. The low steam drum level sensed by two of three redundant channels in any one loop provides a backup trip function. Additional redundance is provided by three independnt SGS steam supply loops serving one common turbine header. Any major break in the high pressure steam system external from the individual loop check valves will be sensed as a steam feedwater flow ratio trip signal in all three loops.

7.4.2.1.6 Actuated Device

The superheater outlet isolation and superheater bypass valves utilize a high reliability electro-hydraulic actuator. These valves are designed to fail closed upon loss of electrical supply to the control solenoid.

7.4.2.1.7 Separation

The OSIS Instrumentation and Control System, as part of the Decay Heat Removal System is designed to maintain required isolation and separation between redundant channels (see Section 7.1.2).

7.4.2.1.8 Operator Information

Indication of the superheater outlet isolation valve position is supplied to the control room. Indicator lamps are used for open-close position indication to the plant operator.

7.4.2.2 Design Analysis

To provide a high degree of assurance that the OSIS will operate when necessary, and in time to provide adequate isolation, the power for the system is taken from energy sources of high reliability which are readily available. As a safety related system, the instrumentation and controls critical to OSIS operation are subject to the safety criteria identified in Section 7.1.2.

Redundant monitoring and control equipment will be provided to ensure that a single failure will not impair the capability of the OSIS Instrumentation and Control System to perform its intended safety function. The system will be designed for fail safe operation and control equipment, where practical, will assure a failed position consistent with its intended safety function.

7.4.3 Pony Motors and Controls

There are six pony motors, one in each primary and intermediate heat transport loop to provide sodium flow for decay heat removal. These motors through the use of a gear box are capable of providing five to ten percent sodium flow in five discrete steps by gear changes. Section 5.6 describes the interaction of the primary and intermediate heat transport loops with the SGAHRS to provide decay heat removal.

7.4.3.1 Design Description

The pony motors are 75 horsepower, 480 VAC, 3 phase, 60 Hz, totally enclosed fan cooled Class 1E motors. These motors are mounted on top of the sodium pump vertical drive motor. They are 1800 rpm motors which deliver power to the sodium pump via a reducing gear, an overrunning clutch, and the vertical motor shaft.

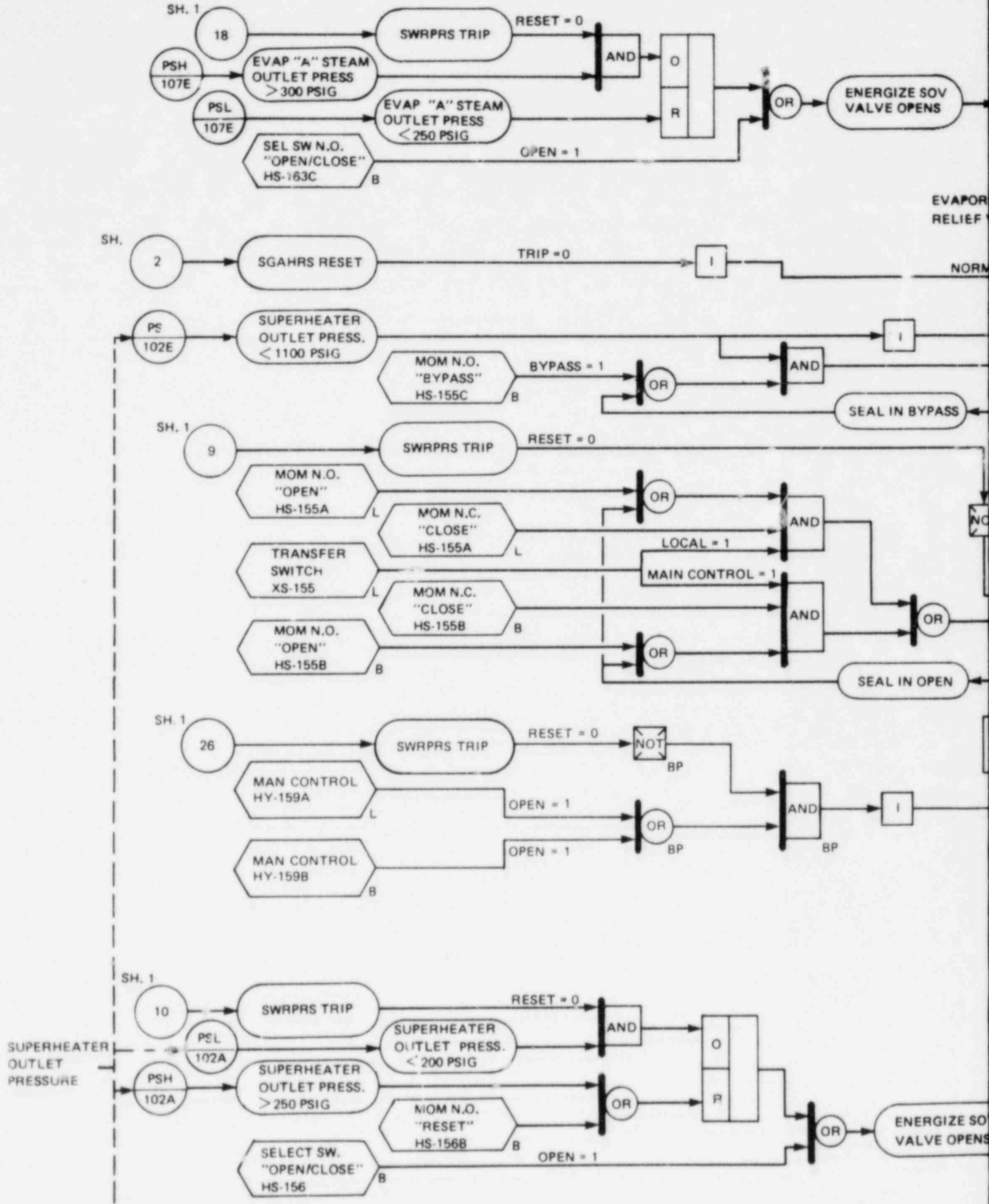
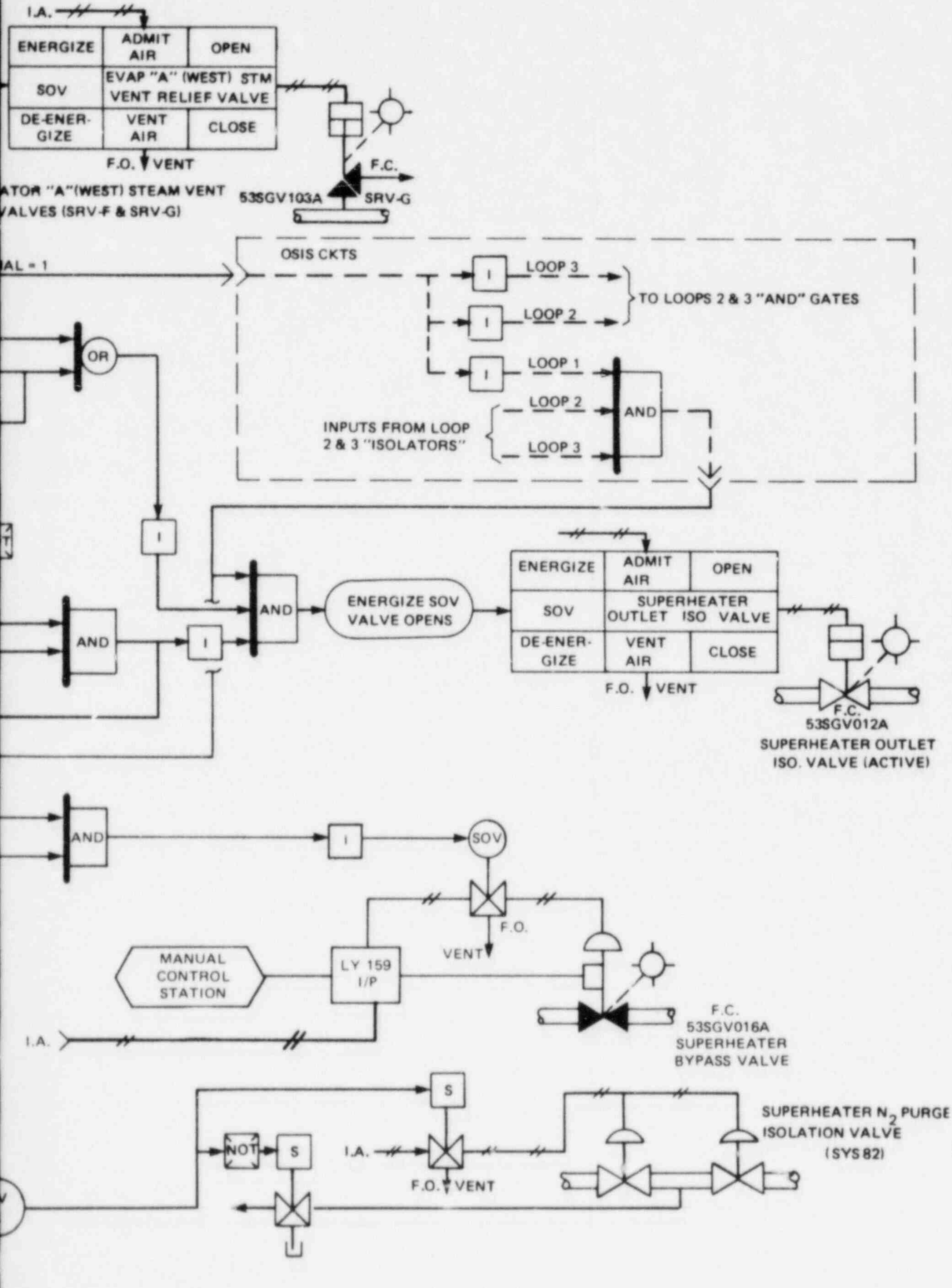


Figure 7.5 - 6 SWRPRS TRIP AND SWRPRS CONTROLLED IS



OLATION VALVES CONTROL LOGIC DIAGRAM

SHEET 5 of 6

82-135-02

Amend. 73
Nov. 1982

Each CRDM controller requires control power to operate the interface
circuitry, programmer, gate drives, internal interlocks and display
equipment. As shown on Figure 7.7-4, redundant AC power sources
57 energize redundant DC logic power supplies whose outputs are auctioneered.
This design prevents failure of a power supply from causing a rod to
drop.

The power supplies are sized to provide sufficient capacity for all
of the CRDM controllers in the primary group. Transformer isolation,
including grounded Faraday shields, is used to prevent failures from
propagating into the controller electronics.

<u>CRDM Motor Controller</u>

The CRDM Motor requires DC energization of coils in the pro-
per sequence to develop the required setpoint motion. The sequence
of coil energization for rod motion is in a two coil-three coil
57 sequence. Thus a forward step is produced each time
a leading coil is energized and also when a trailing coil is
de-energized. To reverse the motion, the sequence is reversed.

The CRDM Controller uses six SCR's for each stator coil to half wave
rectify the 6 phase AC input power and supply DC output to a stator
coil. All six SCR's for a stator coil are turned on by one gate
drive unit. The Controller incorporates the logic necessary to
correctly sequence the gate drive units on and off, thereby
sequencing the coils in appropriate order. Separate controllers are
provided for each individual mechanism. Holds are provided when
input or output logic errors are detected.

57 In Single Rod Control Mode, the input circuitry to each controller accepts
on-off inputs for IN, OUT, and HOLD commands and provides the sequencer with
an IN pulse train, OUT pulse train, or HOLD DC output. The IN command steps a
single rod down in the core at a predetermined rate. The OUT command
steps a single rod up out of the core at a predetermined rate (not
necessarily the same as the IN rate) and the HOLD command maintains
the rod in its present position (no motion). The input circuitry
also incorporates adjustable speed settings for the IN, OUT, and
LATCH modes of CRDM operation and assures that an IN command takes
precedence over an OUT command. In addition to the adjustable speed
settings, the controller provides an independent speed limitation
which has a separate clock and power supply from that used by the
input circuitry. If the input circuitry called for a speed greater
57 than 10% above 9 inches per minute due to a postulated failure, the
speed limiter circuit will place the rod in the Hold Mode.

In any automatic control mode, or in Group Manual mode, the mechanism controllers are operated in sequence one step at a time to keep the rod bank in required alignment. The sequence rate and direction are determined respectively by analog and digital signals from the reactor control system. If the selector sequence rate is higher than a predetermined trip point, an overspeed detector will alarm and place the controllers in HOLD. A functional block diagram of the control is shown in Figure 7.7-5.

Hold Bus

A Hold Bus Power Supply and transfer select circuitry are provided to allow any controller to be replaced without a plant shutdown. In the event of a controller failure, the mechanism controller in question can be switched out and transferred to a Hold Bus. Power to the Hold Bus Power Supply is provided downstream from the scram breakers. This ensures that if a scram is initiated, a rod on the Hold Bus will also scram.

7.7.1.3.2 Primary Rod Position Indication System

Two independent Rod Position Indicating Systems are provided for each primary control rod: An Absolute Position Indication System (ARPI) and a Relative Position Indication System (RRPI). These systems assure that the plant operators can continuously determine the position of the control rods.

The ARPI provides a direct measurement of rod position at any time and, unlike the RRPI, does not require re-zeroing after a scram or temporary loss of power. The system is solid state, utilizing ultrasonics and magnetics to provide a D.C. output indicative of rod position.

The sensor for this system consists of a tube extending down from the top of the motor tube and into the inside diameter of the PCRDM lead screw. A nickel-cadmium wire is stretched axially through the tube. As the lead screw translates, the flux from a torroidal magnet mounted on top of the lead screw intersects the wire at a point indicative of the rod position. Electrical pulses sent down the wire generate magnetic fields which, when they intersect the flux of the lead screw magnet, causes a torsional strain creating a sonic pulse which travels from the point of flux intersection upward. The sonic pulse is detected at the top of the wire, and the time of propogation is measured electronically. This propagation time is converted to a D.C. signal which is analagous to rod position.

This signal is read out on the main control panel by rod top and rod bottom indicator lights and a vertical bar graph indicator. It is also used to operate the rod out of alignment alarm, the rod misalignment rod block system and rod control interlocks.

The Relative Rod Position Indication System provides a digital rod position indication on a CRT at the Main Control Board. Two pairs of magnetic coil pick-ups are mounted within each stator jacket above the stator and on opposite sides. A 6 pole magnetic section is attached to the mechanism rotor and rotates in the plane of the pick-up coils. Voltage pulses caused by the movement of the poles in the proximity of the pick-up coils are sent to a digital to analog converter. The D/A converter produces an analog signal which is a measure of rod position. This analog signal is sent to the PDH&DS and the rod misalignment rod block system. The resolution of this signal is ±0.1 inch. Unlike the Absolute Position Indication System, this system must be reset after each scram and in the event of a power failure reset after power is restored. The pulses are also counted by an odometer type readout in the rod control equipment room.

7.7.1.3.3 Rod Misalignment Rod Block System

The rod misalignment rod block system ensures that a row 7 control rod cannot be withdrawn more than a set distance above the average position of the six row 7 control rods when the plant is operating. As shown in Figure 7.7-6, rod position signals from the Relative Rod Position Indication (RRPI) and Absolute Rod Position Indication (ARPI) systems are used by two redundant trains of rod blocking logic. Each logic train outputs a rod block signal when the position of one of the six row 7 control rods is more than a set distance above the average position of all the six row 7 rods comprising the operating bank. A rod block signal from either of the two redundant logic trains results in all controllers for the six rods of the operating bank switching to the HOLD mode. Signals are also provided to the unit load controller of the supervisory control system to ensure that a plant loading or unloading is stopped upon the occurrence of a rod block. This prevents a reactor trip due to power/flow mismatches which may occur if sodium flow is allowed to change without a corresponding change in reactor power. In addition to the redundant logic trains, the rod block system includes:

1) Circuitry necessary to convert the pulses of the RRPI signal conditioners to an analog signal.

2) Deviation alarms which continually compare the RRPI signal and ARPI signal from each rod and from the rod position overage circuit and provide a position fault alarm to the Plant Annunicator System when the two signals differ by a set amount.

3) A Low Power Bypass in each logic train which may be manually instated at low power to disable the rod block system. This bypass is provided to allow for control rod movement which is necessary to perform low power physics and startup testing. This bypass is automatically removed during the ascent to power.

4) A momentary manual override feature to allow the removal of the rod block so that the operating bank may be realigned if a misalignment occurs. When the manual override feature is engaged, the operator may manually insert control rods to realign the operating bank. Withdrawal of control rods while the manual override feature is engaged is automatically prohibited.

5) Testing and bypass features to allow for the testing and maintenance of the RRPI, ARPI or one train of the rod block system during plant operation.

6) System alarm outputs which provide signals to the Plant Annunciator System when either train is bypassed or upon the occurrence of a rod block.

7.7.1.4 Sodium Flow Control System

The Sodium Flow Control System consists of six controllers used to drive the three primary and three intermediate sodium pumps. Each controller consists of a cascade system with an inner loop using speed as the feedback signal and an outer loop based on a flow feedback signal. The flow control range is 30 to 100% of rated flow. The flow setpoints are generated either manually or by the Supervisory Control.

Figure 7.7-7 is a block diagram of the flow/speed control loop which is typical of the six controllers in the system. The Speed Control System is an inner loop and used pump speed, which is sensed via a pump shaft mounted tachometer, as the feedback variable. The Speed Control System is limited internally by the torque limit circuit which sets both the accelerating and decelerating torque of the variable speed pump drive.

The demand to the Speed Controller is set by the FLOW/SPEED Mode Select Switch. In the Speed Mode, pump speed is set by a manually adjusted potentiometer; in the Flow Mode, pump speed is set by the Flow Controller. The Flow Controller uses the filtered, median select signal of three available redundant flow meter buffered PPS outputs as the feedback signal. This signal, along with the flow demand, is used to generate the error signal which is compensated through the Control Compensation Network and then limited by the High Speed Limit Circuit prior to being used as the speed demand signal. The demand to the Flow Controller is set by the MAN/AUTO Select Switch. In the automatic mode, the demand comes from the supervisory control, while in the Manual Mode, the demand comes from a manually adjusted potentiometer on the control panel.

7.7.1.5 Steam Generator, Steam Drum Level Control System

The steam drum level control system regulates the feedwater flow to the steam drum to maintain a constant water level in the steam drum during plant operation.

The control system consists of a three element (steam flow, feedwater flow and steam drum water level) controller and a median select module. Each of the input elements have three redundant measurement channels. The median select module selects the median signal of the three channels as the input to the controller.

Independent Class 1E high steam drum level trip logic trains are provided at 8 inches and 12 inches above steam drum normal water level. Each logic train also uses three redundant inputs and a median select module.

The steam drum level control signal, the 8 inch high level signal and the 12 inch high level signal, have separate buffered signals provided from the PPS instrument channels for isolation and independence.

The control logic is shown in Figure 7.7-1.

7.7.1.5.1 Feedwater Flow Control Valve Control

The startup feedwater control valve conntrols flow in the range of 0 to 15% of rated flow. The control loop for this valve is a single element controller, using drum water level to control valve position. The main feedwater control valve is closed during this operation. When the flow rate increases to approximately 15%, the control system will automatically open the main feedwater control valve and close the startup control valve. A deadband is provided for this switchboard point to prevent cycling from one valve to the other.

The control loop for the main valve is a three element controller, using drum normal water level, steam flow, and feedwater flow, to control the valve position. Drum drain flow rate, which remains essentially constant at all power levels, is a manual input to the controller. The controller compares steam flow to feedwater flow, and the resulting net flow error signal is combined with the drum water level error signal, to control the valve position. Drum water level is controlled within ± 2 inches of the normal water level. Three redundant buffered signals are provided from the PPS for steam flow, feedwater flow and steam drum level. The median signal of each element is provided to the steam drum level controller. Manual control of the startup and main feedwater control valves is provided in the control room. Instrumentation required by this control system is obtained as follows:

- o Steam Drum Level - Water level is measured by a differential pressure transmitter which senses the difference between the pressure resulting from a constant reference column of water and the pressure resulting from the variable height of water in the steam drum. The measurement is density compensated.

initiates a transient requiring Protection System action and could concurrently degrade the performance of one shutdown system. The consequences of this potential failure will be mitigated by diverse instrumentation in the second Reactor Shutdown System which, being independent, is unaffected by the sensor failures.

Postulated failures for the Plant Control System, their actuators, and sensors and the features included to mitigate results of these failures are described below.

7.7.2.1 Supervisory Control System

The function of the Supervisory Control System shown in Figure 7.7.2, is to relate the plant load demand to the second level (subloop) control system demands and to provide trim of the subloop controls to achieve the desired temperature or pressure operating conditions. Failures of this control system could result in either a combination of misdirected subloop control system demands, or a consistent, but erroneous, set of subloop control system demands.

The first case may be caused by a failure of at least one section (e.g., one or more programmers, one or more sensors, etc.) of the supervisory control. This will result in some of the subloop controllers being directed away from their desired profiles, while others would be controlling normally. An obvious result of this failure mode is a mismatch of some key plant variables. For instance, if the intermediate flow of a single HTS loop is at its desired flow and the primary flow is directed otherwise, the intermediate flow to primary flow ratio would be incorrect. The Plant Protection System would then trip the plant based on this erroneous ratio. In general, failures of this type, would result in activation of those Plant Protection subsystems which are based upon a ratio or mismatch of plant variables.

In the second type of failure mode, it is assumed that all plant variables are maneuvered in such a way that no mismatch occurs but that the general direction or rate of the control demands are wrong. This would result from a misinterpretation of the plant load demand or a gross failure of the entire Supervisory Control System. In general, those Plant Protection subsystems based on single variables (i.e., high flux, flux-delayed flux) would be activated under these conditions.

The Supervisory Control design uses multiple sensors and average/reject, auctioneer, or medial select circuitry to minimize the possibility that single sensor failure will result in inappropriate control system action. Failures in the electronic controllers can only affect the plant at the rate of change of the actuators (pump drives, control rod drive mechanisms, etc.). As shown in Chapter 15, the Plant Protection System acceptably terminates the results of all incidents involving incorrect actuator response. Therefore, the Supervisory Control System is inherently incapable of initiating a transient which is more severe than the PPS design basis.

7.7.2.2 Reactor Control System

The Reactor Control System shown in Figure 7.7-3 contains an Outer Core Exit Temperature Controller with an inner loop based on flux feedback. Failure in this system could result in erroneous movement of the control rods. This could result from failure in the sensors or feedback signal conditioning (i.e., flux or temperature), failures in the controller electronics, or a failure in the CRDM controller. The Reactor Control System has redundant sensors and average/reject or median select circuitry to prevent single sensor failures from initiating reactivity transients. Even though it is highly improbable, simultaneous multiple failures in PPS compensated ionization chamber instrumentation could cause the loss of flux instrumentation channels in both the Plant Protection and Control Systems, the consequences of this potential failure will be mitigated by diverse fission chamber instrumentation in the secondary reactor shutdown system. Rod withdrawal block circuitry and a rod misalignment rod block system are provided which are independent of the normal control to prevent control electronic failures from causing reactor trip. Withdrawal blocks are initiated for both high power and power-to-flow ratio. These withdrawal blocks operate directly on the Control Rod Drive Mechanism Controllers to stop outward rod motion of all primary rods. Withdrawal and insertion blocks are initiated by the rod misalignment rod block system to prevent severe misalignment of the control rod bank. The Control Rod Drive Mechanism Controller and Rod Sequencer include overspeed detector and block circuitry to provide assured limitation of rod withdrawal speed even if reactor control failures and failures of the rod block or overspeed circuitry are postulated. The PPS acceptably terminates the results as shown in Chapter 15.

It is also considered that a failure of the Reactor Control System could result in improper banking of the control rods which is not severe enough to require action by the rod misalignment rod block system. Under these conditions the reactor operator would have to readjust the out of bank rods manually. To aid the operation, the main control board is equipped with rod position indications for each rod and also an alarm if the rods deviate from the proper banking requirements.

7.7.2.3 Sodium Flow Control System

A block diagram of the Sodium Flow Control System is given in Figure 7.7-7 which is typical of the six HTS flow loops. The controller contains an outer flow loop with an inner loop based on pump speed. A failure of any of the six flow controllers would result in improper pump speed and, consequently. undesired sodium flow. Power to flow or primary to intermediate flow mismatch would occur resulting in a plant trip. Even though it is highly improbable, multiple failures in PPS flow instrumentation could cause the loss of flow instrumentation channels such that the secondary RRS fails to trip; the consequences of this potential failure to initiate control system action which requires Protection System action will be mitigated by the primary reactor shutdown system. Pump speed instrumentation; this is independent of the flow instrumentation and is, therefore, not affected by these failures.

TABLE OF CONTENTS (cont'd.)

TABLE OF CONTENTS (cont'd.)

TABLE OF CONTENTS (cont'd.)

TABLE OF CONTENTS (cont'd.)

TABLE OF CONTENTS (cont'd.)

TABLE OF CONTENTS (cont'd.)

LIST OF TABLES (cont'd.)

LIST OF FIGURES

Main supply ducts leaving the air handling units run in the Operating Floor El. 862'-0" parallel to column lines TC and TF to serve the west and east zones respectively. Branches from the main ducts are routed to the lower elevations to distribute the supply air to the various areas of the building.

Eleven (11) roof exhaust fans are provided, with a total capacity equal to the total air supply, for the building. The three (3) exhaust fans serving the Chemical Storage Area, Lube Oil Storage Area and Operating Floor are sized to handle the minimum outside air and run continuously while the number of remaining exhaust fans that are operating is determined by the percentage of outside air in the total air supply for the building.

The Roof Exhaust Fans are located as follows:

2 Fans at Roof El. 861'-0"
2 Fan at Roof El. 878'-0"
5 Fans at Roof El. 910'-6"
2 Fans at Roof El. 921'-0"

A relief hood, located above the deaerator area, will relieve the air from the building and maintain the air balance during the various steps of exhaust fans operation.

Two (2) unit coolers are provided to serve the condensate pumps and L.P. Feedwater Heaters to supplement the main HVAC system and conserve energy during part load operation.

A separate Heating and Ventilating Unit at El. 816'-0" along with a roof exhaust fan at Roof El. 861'-0" serve the Ammonia Storage Room and operate continuously. The supply and exhaust air quantities are balanced to maintain slightly negative pressure inside the room.

The sampling room is served by a branch duct from one air handling unit. Constant temperature and humidity are maintained inside the room through a heating coil and a Steam Humidifier.

The caustic and acid storage room is served by a branch duct from the main air handling system with a reheat coil that maintains the required indoor design conditions.

The Radiation Monitoring System will provide the equipment necessary to sample and analyze tritium in the exhaust air released from the building to meet the requirements of 10CFR20.

9.6.4.3 Safety Evaluation

This section describes the design and operation of the TGB HVAC System during single failure of the TGB HVAC System Components.

The TGB HVAC System consists of active and passive components.

This system design has no provisions for failures of passive components. Active components in the TGB HVAC System which are susceptible to failure are as follows:

- Supply Fans
- Exhaust Fans
- Automatic Roll-Type Filters
- Outside Air Dampers
- Return Air Dampers
- Exhaust Air Dampers
- Unit Cooler Supply Fans

The TGB HVAC System is provided with five (5) supply fans and twelve (12) exhaust fans. Failure of any one supply or exhaust fan would not increase the average temperature in the affected area above 120°F.

The TGB Air Handling Units are provided with automatic roll-type filters with an automatic advance mechanism that advances the filter medium on the basis of sensed differential pressure across the filter. The failure of the advance mechanism results in increased pressure across the filters. A sensing device is provided for each filter with an alarm setpoint to indicate higher than normal differential pressure across the filter. The alarm setpoint is selected on the basis that after initiation of the alarm, 72 hours are available to correct the failure without significantly deviating from the system design parameters.

The steam generator feed pump area, the condensate pump area, the L.P. Feedwater Heater Area, are provided with two (2) unit coolers. Each unit cooler has one (1) 100% capacity centrifugal fan. Failure of any one unit cooler fan would not increase the space temperature in the immediate area above 120°F.

9.6.4.4 Testing and Inspection Requirements

All components are tested and inspected as separate components and as integrated systems. Velometer readings are taken to ensure that all systems are balanced to deliver and exhaust the required air quantities. All water coils are hydraulically tested for leakage prior to being placed in service. Capacity and performance of the fans are tested according to the Air Moving and Conditioning Association requirements prior to operation of the plant.

9.6.5 Diesel Generator Building HVAC System

9.6.5.1 Design Basis

9.6.5.1.1 Diesel Generator Rooms HVAC System

The Diesel Generator Rooms HVAC System is a safety related system designed to provide ventilation to the Diesel Generator Rooms under all conditions.

The system provides the required environment to permit personnel access during normal plant operation and to ensure operability of the equipment under all conditions. The HVAC system serving the Diesel Generator Rooms is designed to:

a) Limit maximum temperatures in the Diesel Generator Rooms to 120°F.

b) Operate from the Class IE AC power supply during loss of off-site power.

c) Provide air movement through the Diesel Generator Rooms to the final exhaust points during normal plant operation and when the Diesel Generators are in operation.

d) Provide heating during the winter months to the Diesel Generator Rooms during normal plant operation and when the Diesel Generators are in operation.

9.6.5.1.2 <u>Diesel Generator Building Class IE Switchgear Room HVAC System</u>

The design basis for the Diesel Generator Building Class IE Switchgear Rooms HVAC System is provided in Section 9.6.1.1.2.

9.6.5.1.3 <u>Diesel Generator Building Non-Class IE Switchgear Rooms and Motor Generator Set Rooms HVAC System</u>

The design basis for the Diesel Generator Building Non-Class IE Switchgear Rooms and Motor Generator Set Rooms HVAC System is provided in Section 9.6.1.1.3.

9.6.5.1.4 <u>Diesel Generator Building Motor Generator Sets Unit Cooler System</u>

The design basis for the Diesel Generator Building Motor Generator Sets Unit Cooler System is provided in Section 9.6.1.1.3.

9.6.5.2 <u>System Description</u>

9.6.5.2.1 <u>Diesel Generator Rooms HVAC System</u>

The Diesel Generator Rooms HVAC System P&ID is shown on Figure 9.6-11. The classification of the Diesel Generator Rooms HVAC System components and their primary parameters are indicated in Table 9.6-6.

One (1) 100% capacity Heating, Ventilating Unit is provided for each Diesel Generator Room to satisfy the Ventilation Requirements during normal operation. In addition, two (2) 50% capacity

Emergency Supply Fans are provided for each Diesel Generator Room. The operation of the supply fans are in conjunction with the operation of the Diesel Generator which they serve. The temperature in each cell is controlled by modulating the outside air and return air dampers. The air is relieved from the Diesel Generator Rooms through an exhaust damper connected to the DGB exhaust structure.

The day tank cell in each of the two (2) Diesel Generator Rooms at El. 816'-0" is ventilated by an Exhaust Fan using infiltrated air from the Diesel Generator Rooms in which they are located. These Exhaust Fans also exhaust the air from the fuel oil transfer pump cells.

One of the 100% capacity Heating, Ventilating Units is located at El. 829'-0" south of the missile protected air intake structure serving Cell No. 511. The other unit is located at El. 829'-0" south of the missile protected air intake structure serving Cell No. 512. The units are connected by a plenum to their respective air intake structures. The suction side of each unit is connected to the plenum by an automatic damper and a flexible connection. The discharge side of each fan is provided with a flexible connection and supply ductwork to distribute the air to the cell. The fans are V-belt driven centrifugal fans.

Two of the 50% capacity supply fans are located at El. 837'-0" south of the missile protected air intake structure serving Cell No. 511. The other two 50% capacity supply fans are located at El. 837'-0" south of the missile protected air intake structure serving Cell No. 512. Each pair of supply fans are connected by a plenum to their respective air intake structure. Two (2) return air openings with automatic dampers are provided in each plenum for each pair of supply fans. The suction side of each fan is connected to the plenum by a flexible connection and an inlet bell. The discharge side of each fan is provided with a flexible connection, duct transformation section, and an automatic damper. The fans are direct driven vaneaxial fans.

A missile protected exhaust structure is located on the roof at El. 847'-3". Gravity dampers are provided which connect the exhaust structure with each Diesel Generator Room.

An Exhaust Fan is provided for exhausting each day tank cell at El. 816'-0", and each fuel oil transfer pump cell at El. 808'-0". The fans are located at El. 816'-0" and are connected by ductwork to the DGB missile protected exhaust structure. The fans are direct driven vaneaxial fans with flexible connections at the inlet and outlet of each fan.

49

TABLE 9.7-1
COMPONENTS SERVED BY
THE NORMAL CHILLED WATER SYSTEM

EQUIPMENT TITLE	BLDG.	LOCATION CELL	ELEVATION
MG Sets A/H Unit	CB	412	847'-3"
Loop #1 A/H Unit	SGB	244	852'-6"
Loop #2 A/H Unit	SGB	245	852'-6"
Loop #3 A/H Unit	SGB	246	852'-6"
SGB-IB A/H Unit	SGB	262	816'-0"
Maintenance Bay A/C Unit	SGB	261	816'-0"
Primary Na Tank Unit Cooler	SGB	211	733'-0"
Below Operating Floor A/C Unit	RCB	105I	752'-8"
Below Operating Floor A/C Unit	RCB	105K	752'-8"
Operating Floor Unit Cooler	RCB	161A	857'-11"
Operating Floor Unit Cooler	RCB	161A	857'-11"
Operating Floor Unit Cooler	RCB	161A	857'-11"
LCCV Unit Cooler	RCB	125	733'-0"
RCB A/H Unit	SGB	271	836'-0"
RSB A/H Unit	RSB	305H	733'-0"
RWA A/H Unit	RSB	660	867'-0"
Communication Center A/C Unit	RSB	328	865'-0"
Air Handling Unit	TGB	-	892'-0"
Air Handling Unit	TGB	-	862'-0"
Unit Cooler	TGB	-	816'-0"
Unit Cooler	TGB	-	838'-0"
Air Conditioning Unit	PSB	105	816'-0"
Air Conditioning Unit	PSB	151	816'-0"
Air Conditioning Unit	PSB	151	816'-0"
Air Conditioning Unit	PSB	151	816'-0"
Air Conditioning Unit	WB	212	828'-0"
Air Conditioning Unit	WB	210	828'-0"
Air Conditioning Unit	WB	210	828'-0"
CRDM	RCB	152	794'-0"
CRDM	RCB	152	794'-0"
Cold Trap, NaK Cooling, etc.	RCB	105V	794'-0"
EVST Cavity	RSB	306B	755'-0"

59

47

44

TABLE 9.7-1 (continued)

EQUIPMENT TITLE	BLDG.	LOCATION CELL	ELEVATION
PHTS, #1	RCB	150I	752'-8"
PHTS, #2	RCB	105J	752'-8"
PHTS, #3	RCB	105K	752'-8"
Reactor Cavity	RCB	105E	733'-0"
Cooler	RCB	125	746'-0"
Intermediate System Cooler & Condenser	SGB	235	782'-0"
Vapor Condenser	RCB	125	746'-9"
Intermediate System Condenser	SGB	235	782'-0"
Autoclave Sparge Gas Condenser	RSB	640	816'-0"
Primary Cold Trap NaK Cooler	RCB	131	790'-4 7/8"
CAPS Compressor Cooler	RSB	365	755'-0"
CAPS Compressor Cooler	RSB	366	755'-0"
RAPS Compressor Cooler	RCB	105BD	733'-0"
RAPS Compressor Cooler	RCB	105BE	733'-0"
SGB/IB Air Handling Unit	SGB	271	836'-0"
Constant Temperature Bath	TGB		838'-0"
Third Loop	RSB	324	816'-0"
HAA Unit Cooler	RCB	152	800'-9"
RAPS & CAPS Unit Cooler	RSB	365	755'-0"

Amend. 73
Nov. 1982

9.9 SERVICE WATER SYSTEMS

9.9.1 Normal Plant Service Water System

9.9.1.1 Design Basis

The Normal Plant Service Water System is a non-safety related system designed to provide cooling water for the Normal Chilled Water System chiller condensers, the Secondary Service Closed Cooling Water System and other equipment listed in Table 9.9-1 during normal plant operation and planned outages. The system will be designed according to the ASME Section VIII/ANSI B31.1 requirements.

9.9.1.2 System Description

The Normal Plant Service Water System is shown in Figure 9.9-1. The system consists of two (approximately 26,600 GPM) 100 percent capacity electric motor driven vertical, wet-pit, circulating water pumps and the required piping, valves and instrumentation. The Normal Plant Service Water is pumped from the basin of the Circulating Water System cooling tower to the equipment to be cooled, and is returned to the cooling tower return header. The pumps are located in the Circulating Water Pumphouse. Normally, one pump is operating with the second pump in an auto-standby mode.

The components served by the Normal Plant Service Water System are listed in Table 9.9-1. Design data for the major system components are listed in Table 9.9-2.

9.9.1.3 Safety Evaluation

The Normal Plant Service Water System is a Seismic Category III and a nonsafety class system.

Pipe break analysis for this moderate energy fluid system will be provided in the FSAR.

9.9.1.4 Tests and Inspections

The Normal Plant Service Water pumps are tested at the manufacturer's facility and retested in the system prior to continuous plant operation. The operation of the pumps will be rotated to equalize wear.

9.9.1.5 Instrumentation Application

Indication of the Normal Plant Service Water header pressure is provided in the Control Room. Normal Plant Service Water low discharge header pressure is annunciated in the Control Room. A logic circuit is available to automatically start the standby pump when the operating pump motor trips or is inadvertently stopped.

9.9.2 Emergency Plant Service Water System

9.9.2.1 Design Basis

The Emergency Plant Service Water System is designed to provide sufficient cooling water to permit the safe shutdown and the maintenance of the safe shutdown condition of the plant in the event of an accident resulting in the loss of the Normal Plant Service Water System or the loss of the plant AC power supply and all offsite AC power supplies. The Emergency Plant Service Water System is not used during normal plant operation. The system provides the Emergency Chilled Water System chiller condensers and the Standby Diesel Generators with cooling water. Additionally, this system provides fire fighting water for the seismically qualified fire pumps of the nonsodium fire protection system. The Emergency Plant Service Water System includes the Emergency Cooling Towers and Emergency Cooling Tower Basin, as described in Section 9.9.4.

The Emergency Plant Service Water System is designed to Seismic Category I requirements as defined in Section 3.2. Pumps, valving and piping required for the safe shutdown of the plant are designed to ASME Section III, Class 3 requirements, as defined in Section 3.9.2. All electric motors serving the system are connected to the Class 1E onsite power supply. In case of loss of plant and offsite power, these motors are switched automatically to the Standby Diesel Generator. The piping and equipment for each redundant loop of the system is physically separated or protected with a barrier to conform to common mode failure criterion. System piping is below ground between the Seismic Category I Emergency Cooling Tower and Diesel Generator Building. The Emergency Cooling Tower structure is tornado missile hardened as described in Section 9.9.4.1.

9.9.2.2 System Description

The Emergency Plant Service Water System (EPSW) consists of two 100 percent capacity fully redundant cooling loops. Each cooling loop includes one circulating pump, one make-up pump, one emergency cooling tower and associated piping, valves, instrumentation and controls. Figure 9.9-2 shows the various equipments and represents the system component configuration and relationship.

The components served by the Emergency Plant Service Water System are listed in Table 9.9-3. Design data on the major system components is listed in Table 9.9-4.

Upon loss of Normal Chilled Water or upon start of the Standby Diesel Generators, the EPSW pumps, EPSW makeup pumps, and Cooling Tower Fans will automatically start and provide cooling water at 90^{O}F maximum to the

Emergency Chiller Condensers in the SGB and the Standby Diesel Generators in the DGB. The EPSW pumps take suction from the Emergency Cooling Tower operating basins which are located adjacent to the Emergency Cooling Tower. During system operation the EPSW makeup pumps will transfer water from the common storage basin to the redundant operating basins to compensate for evaporative and drift losses from the towers.

Cooled water from the Emergency Cooling Tower operating basins is pumped via underground supply mains to the emergency loads in the DGB and SGB. After cooling the emergency chillers and the standby diesel generators, warm water is returned, also through underground mains, to the Emergency Cooling Towers. To account for seasonal temperature variations, temperature control valves served by electro-hydraulic operators bypass a portion of the returning water back to the pump suction. A temperature indicator controller automatically adjusts the valves as required to maintain supply temperature above 55°F, the minimum required for chiller operation.

In addition to cooling the Emergency Chilled Water chillers and the standby Diesel Generators, each loop of the EPSW System provides a connection to supply water to the Non-Sodium Fire Protection System. The EPSW pumps and the Emergency Cooling Tower Basin are designed to allow fire protection operation while maintaining the capability for supplying 100 percent cooling to the emergency loads. The fire protection pumps are provided with instrumentation that will automatically terminate operation when a prescribed amount of water has been used (see Section 9.13). This ensures that the guaranteed 30 day supply of water for EPSW system operation will not be compromised. In addition, this system is connected to the EPSW loops in such a manner as to preclude a single failure from compromising the capability of the EPSW system to perform its required function.

9.9.2.3 Safety Evaluation

The EPSW system is a Seismic Category I, safety related system designed to have 100% redundancy in both active and passive components. The system is provided with AC power from the Class 1E power sources. EPSW Loop "A" is supplied from Class 1E Division 1 and Loop "B" is supplied from Class 1E Division 2. This arrangement assures that 100 percent cooling capability will be available even if one of the Standby Diesel Generators or one of the EPSW loops should fail.

The EPSW system is a fully automatic system, normally controlled from the Main Control Panel in the Control Room. Redundant controls have been provided that will allow full operation of the system from a control panel in the Diesel Generator Building.

Pipe break analysis for this moderate energy fluid system will be provided in the FSAR.

During the initial phase of recovery from an accident, one Emergency Plant Service Water loop satisfies the cooling of the Standby Diesel Generators and the Emergency Chilled Water Chiller Condensers.

The Emergency Plant Service Water System is capable of accommodating any single component failure without affecting the overall system capability of providing cooling water to achieve a safe shutdown condition. A single failure analysis of the Emergency Plant Service Water
59 System is given in Table 9.9-6.

15 9.9.2.4 Tests and Inspections

The system components will be tested at the manufacturer's facilities, and a complete system test will be accomplished prior to plant operation. The EPSW System does not operate during normal plant operations. However, the system, including all active components will be operated periodically during the year in conjunction with the Standby Diesel Generator testing program as outlined in USNRC Regulatory Guide 1.108. The system can be proven operable at any time by manual initiation. Inservice inspections will be conducted according to ASME Section XI, as described in Section 9.7.2.1.g. In addition, isolation valves and pressure test connections on the supply and return headers in the pumphouses and the DGB permit
50 inservice inspection of the buried piping by hydrostatic testing.

9.9.2.5 Instrumentation Application

Instrumentation will be provided for local and/or remote (Control Room) indication of the following parameters as indicated:

59 - pump discharge pressure (local/remote)
- diesel generator/emergency chilled water chillers supply temperature (local/remote)
50 - storage basin level (local/remote)
- diesel generator and emergency chiller flow rate (remote)
- diesel generator and emergency chiller supply temperature (local)
- diesel generator and emergency chiller return temperature (local/remote)
- diesel generator and emergency chiller supply and return pressure (local)
- operating basin level (local/remote)
- makeup water flow (local/remote - alarm on low)

A flow switch, located in the return line from each diesel generator and emergency chiller will detect an abnormal low flow condition
43 33 and energize an annunciator in the Control Room.

15 9.9.3 Secondary Service Closed Cooling Water System

The objective of the Secondary Service Closed Cooling Water (SSCCW) System is to provide cooling to auxiliary equipment located in the turbine building.

Amend. 59
Dec. 1980

The Emergency Cooling Towers pumphouses, operating basins and storage basin are designed to withstand the most severe natural phenomena (e.g., Safe Shutdown Earthquake, tornado, tornado missiles, wind, Probable Maximum Flood or drought). The design has the necessary redundancy of components.

Electrical power for the Emergency Cooling Tower fans, pumps, and control equipment is provided from the Class 1E AC power supply. One loop is provided with electrical power from System Class 1E Division 1 and the other from System Class 1E Division 2.

9.9.4.2 Design Description

The Emergency Cooling Tower Structure consists two of pumphouses (containing the pumps and piping of the EPSW System, Section 9.9.2) located directly above the operating water storage basin. The cooling towers, pumphouses and operating basins are 100% redundant Seismic Category I, Tornado protected structures. The common storage basin is a Seismic Category I, flood and tornado protected structure. The storage basin has sufficient storage capacity for 30 days of operation, including 30,000 gallons of water storage for the non-sodium Fire Protection System plus adequate allowance for drift and evaporation losses. Each cooling tower is designed to achieve the required heat dissipation rate at any time, approximately 2.36×10^7 BTU/HR at the maximum Emergency Plant Service Water Flow of approximately 3600 gpm.

The change in water chemistry due to the absence of blow-down from the cooling towers has minimal effect on operation of the Emergency Plant Service Water System. Proper selection of the Emergency Plant Service Water components, applied biocide additives, and maintainence of proper water chemistry will provide compensation for the increased tube fouling. The maximum makeup water required after 30 days of operation is approximately 100,000 gallons per day. In case the make-up water is not available after 30 days, make-up water can be supplied by either truck, rail or temporary piping from the Clinch River or purchased under agreements with the Department of Energy, Oak Ridge Operations.

The top elevation of the Emergency Cooling Tower Basin is 818 ft. which is 9 ft. above the probable maximum flood level. The entire basin and the cooling tower supports are founded on siltstone. The basin is a below grade reinforced concrete structure. For further details on the basin, ref to Section 3.8.4.1.5.

Each Emergency Cooling Tower consists of a single cell, provided with an induced draft fan system. Each cooling tower is enclosed in a Seismic Category I, tornado missile protected structure. The water intake and discharge piping are located within the tower or safely below the ground for tornado missile protection. The water intake and discharge piping and the internal distribution piping are Seismic Category I, ASME Section III, Class 3 design. Each Emergency Cooling Tower has a design flow rate of 3600 GPM.

The Emergency Cooling Towers are of a counter-flow, wet-type, mechanically induced draft design. The internal distribution piping distributes the intake water evenly over the fill area so that sufficient water area is exposed to the counter air flow to provide evaporation for the required heat removal. The counter air flow is provided by the induced draft fans.

Drift eliminators are located above the internal water distribution piping and below the induced draft fans. The drift eliminators are a zigzag pattern of channels which prevent water carryover through the fan stack.

The Emergency Cooling Towers are supported by the reinforced concrete storage basin. The top of the cooling towers is approximately 44 ft. above the maximum water level of the storage basin.

The Emergency Cooling Tower Basin is filled with potable grade water which is treated for bacteria control. The quality of the stored water is analyzed at regular intervals and the required biocide additive is injected manually in quantities required to control seasonal variations of the bacteria growth.

The Emergency Cooling Towers and Emergency Cooling Tower Basin will be seismically analyzed as described in Section 3.7.

9.9.4.3 Safety Evaluation

The Emergency Cooling Tower structure consists of two 100 percent capacity cooling towers pumphouses, and operating basins and one 100 percent capacity below grade cooling water storage basin. The entire structure is Seismic Category I, tornado, and flood protected. Piping, associated with the Emergency Cooling Tower is designed to ASME Section III, Class 3 requirements. The structure can withstand the most severe natural phenomena expected, and other site related events, such that the Emergency Cooling Tower cooling capability is assured under required conditions. The method of analysis is similar to that used for other Seismic Category I structures. The entire structure is designed to withstand the Safe Shutdown Earthquake. The fill, drift eliminators, motors, mechanical drives, piping, electrical conduit, cables and supports will be seismically analyzed in accordance with the procedures discussed in Section 3.7.

9.9.6 Potable Water System

9.9.6.1 Design Basis

The non-safety related Potable Water System receives drinking quality water from the Bear Creek Road Filtration Plant and supplies it to the Fire Protection Storage Tank and to the Potable Water Storage Tank, which feeds the Potable Water Supply pumps and the Make-Up Water Treatment System. The supply pumps distribute water to the various plumbing fixtures and other services throughout the plant buidings. All piping and components shall be designed, fabricated, inspected and erected in accordance with the Standard Plumbing Code.

9.9.6.2 System Description

The Potable Water System consists of a transmission line, Potable Water Storage Tank, two (2) 100 percent Potable Water Supply Pumps, (one (1) acting as a spare), distribution piping, valves, instrumentation and controls. The Potable Water System provides potable water to the buildings and services listed in Table 9.9-7. The Potable Water Supply Pumps take suction from the Potable Water Storage Tank and deliver water to the distribution header. Demand includes; supply for sinks, toilets, showers, eyewashes, water fountains, service hose connections and other services in BOP and Reactor Support Buildings; Circulating Water Pump seal; and Hypochlorite Generating Plant supply. The storage tank is sized to maintain a one (1) day reserve for all normal services based on the maximum estimated short term demand, except for supplier to the Hypochlorite Generating Plant. A recirculation orifice is installed in a bypass line running from each pump discharge, back to the Potable Water Storage Tank through a common header. Backflow preventers are installed in the supply lines to the Hypochlorite Generating Plant, the Circulating Water Pump seals, the Fire Protection Storage Tanks and to the Makeup Water Treatment System Clearwell Pumps to prevent possible contamination of the Potable Water System.

9.9.6.3 Safety Evaluation

The Potable Water System is a Seismic Category III and non-safety class system.

9.9.6.4 Tests and Inspections

Potable Water Supply Pumps are tested at the manufacturer's facility and again prior to normal plant operation.

9.9.6.5 Instrumentation Applications

Each pump is provided with a storage tank low-low level interlock and alarm to stop the pumps. The spare pump is on standby and starts automatically upon failure of the operating pump. Inlet flow to the Potable Water Storage Tank is automatically controlled by a level control valve.

9.9.7 Make-Up Water Treatment System

9.9.7.1 Design Basis

The non-safety related Make-Up Water Treatment System receives potable water from the Potable Water Storage Tank and provides high purity demineralized water for the Demineralized Water and the Condensate Systems.

All piping and components are designed, fabricated, inspected and erected in accordance with ANSI B31.1, Power Piping.

9.9.7.2 System Description

The Make-Up Treatment System consists of clearwell pumps, granular activated carbon units, two (2) 100 percent capacity demineralizer trains, chemical injection equipment, instrumentation, pumps, valves and piping. During startup operation, both trains can be put into service while normal operation requires only one (1) train to be in operation producing 100 percent flow while the remaining train is in standby or regeneration mode. The demineralizer system portion of the Make-Up Water Treatment System employs two (2) parallel demineralizer trains each consisting of one (1) cation, one (1) anion and one (1) mixed bed ion exchanger, piping, valves, and controls. A resin trap is installed in the outlet of each demineralizer train to prevent resin from entering the Demineralized Water System on failure of a demineralizer underdrain screen. The regeneration system consists of bulk acid and caustic storage tanks with respective injection pumps, a hot water tank with temperature control and means of dilution for chemicals. Means of transferring regenerant wastes, rinses and backwash water from activated carbon filters and demineralizers to the Waste Water System is provided.

9.9.7.3 Safety Evaluation

The Make-Up Water Treatment System is a Seismic Category III and non-safety class system.

9.9.7.4 Tests and Inspections

Vessels are ASME Section VIII except for the Hot Water Tank which is designed to Section IV. They are tested in accordance with Code requirements.

9.9.7.5 Instrumentation Applications

Mixed bed demineralizer effluent is checked for pH, silica, and sodium with indicator/recorders tied to alarms. Conductivity of dilute acid and caustic is measured with a indicator/recorder coupled to high/low alarms. Anion and mixed bed demineralizer effluent is measured for conductivity on an indicator/recorder with high alarms. Flow to the cation and mixed bed demineralizer is measured utilizing an indicator/recorder/totalizer with total flow alarm. Carbon filters and resin trap strainers are fitted with high pressure differential alarms. Temperature is monitored on the hot water tank and the hot water mixing valve outlet with a high alarm.

9.9.8 Demineralized Water System

9.9.8.1 Design Basis

The non-safety related Demineralized Water System receives demineralized water from the Make-Up Water Treatment System and pumps the water as required to the various systems and services.

All piping and components shall be designed, fabricated, inspected and erected in accordance with ANSI B31.1, Power Piping.

9.9.8.2 System Description

The Demineralized Water System consists of a Demineralized Water Storage Tank, three Demineralized Water Pumps (which include a Demineralized Water Jockey Pump and two (2) 100 percent Demineralized Water Transfer Pumps, one acting as a spare), distribution piping, valves, instrumentation and controls. the demineralized water provided by the Make-Up Water Treatment System is pumped to the Demineralized Water Storage Tank by the clearwell pumps. The Demineralized Water Jockey Pump and Demineralized Water Transfer Pumps take suction from the Demineralized Water Storage Tank and deliver water to the distribution header. The Demineralized Water Jockey Pump operates continuously to maintain pressure in the system and to supply water demand rates up to approximately 40 GPM. One (1) of the two (2) 100 percent Demineralized Water Transfer Pumps is on standby and starts and stops automatically to maintain system pressure under varying system demands. A recirculation orifice is installed in a bypass line running from each pump discharge back to the Demineralized Water Storage Tank through a common header. The Demineralized Water System provides water for the systems and services listed in Table 9.9-8.

9.9.8.3 Safety Evaluation

The Demineralized Water System is a Seismic Category III and non-safety class system.

9.9.8.4 Tests and Inspections

Demineralized Water Transfer Pumps and Jockey Pump are tested at the manufacturer's facility and again prior to normal plant operation.

9.9.8.5 Instrumentation Applications

One (1) of the Demineralized Water Transfer Pumps is on standby and will start and stop automatically under the control of a low pressure switch. Each pump is provided with a storage tank low-low level interlock and alarm to stop the pumps. The level in the storage tank is controlled automatically by a level control valve.

TABLE 9.9-7

BUILDING AND SERVICES SUPPLIED BY POTABLE WATER SYSTEM

a. Turbine Generator Building

b. Steam Generator Building

c. Maintenance Shop and Warehouse Building

d. Control Building

e. Plant Service Building

f. Reactor Service Building (Radwaste Area)

g. Gate House

h. Circulating Water Pump seal water during pump start-up

i. Hypochlorite Generating Plant

j. Fire Protection Storage Tanks

k. Make-up Water Treatment System

Amend. 73
Nov. 1982

TABLE 9.9-8

SYSTEMS AND SERVICES SUPPLIED BY THE DEMINERALIZED WATER SYSTEM

a. Backwash and regeneration for the condensate polishers in the Feedwater and Condensate System.

b. Demineralized water for initial fill and make-up water for Diesel-Generator water jacket coolers.

c. Demineralized water for initial fill and make-up water for the Secondary Services Closed Cooling Water System with provision for chemical conditioning.

d. Demineralized Water for initial fill and make-up water for the Hot Water Heating System

e. Demineralized Water for initial fill and make-up for Normal and Emergency Chilled Water Systems.

f. Demineralized Water for initial fill and make-up water supply for the stator cooling system.

g. Demineralized service water for decontamination facilities in the Radwaste area of the RSB and in the BOP Regulated shop complex for equipment and personnel, and rinse water to the Intermediate Component Cleaning System.

h. Backwash and regeneration of the demineralizer trains of the Make-Up Water Treatment System and source of make-up water for the Feedwater and Condensate System.

i. Equipment washdown and decontamination hose connections in Radwaste area.

j. Chemical dilution water for chemical feed units for miscellaneous closed water cooling systems.

k. Personnel decontamination facilities in the Plant Service Building and Combined Laboratory services.

l. Emergency Cooling Tower fill and make-up.

9.13.2 Sodium Fire Protection System (SFPS)

The SFPS provides the means of detecting, locating, alarming, containing and extinguishing sodium and/or NaK fires. The system consists of fire detection and alarm instrumentation, aerosol release limiting instrumentation, a catch pan system, portable fire extinguishers, and personnel protective clothing and equipment.

The steel catch pans, insulation between the catch pan and the structural concrete, and steel fire suppression decks, herein referred to as the catch pan system, and the aerosol release limiting instrumentation comprise the Engineered Safety Features of the SFPS. This equipment is installed in the air-filled cells of the plant in which sodium-NaK piping and other equipment containing sodium-NaK are located. In the event of a liquid metal spill, the catch pan system functions to: (1) limit burning and the production and spread of combustion product aerosols, and (2) limit the temperature imposed on the structural concrete. The aerosol release limiting instrumentation provides an initiating signal to interfacing systems for actions to limit the release of aerosols to the outside atmosphere. Other equipment that must perform a safety function to limit the release of aerosols in the event of a design basis leak in the Intermediate Heat Transport sodium piping include:

1) fire dampers in the HVAC outside openings in the SGB loop cells;
2) closure devices in the SGB vent stack
3) smoke detectors at the PACC's airside inlets.

The operation of this equipment is described in Section 6.2.7. Cells containing primary and EVST sodium systems and piping are equipped with steel liners and inert (nitrogen) atmospheres. These features are described in Sections 3, 8 and 9.5.

9.13.2.1 Design Bases

The catch pan system which is an Engineered Safety Feature is designed to mitigate the consequences of a design basis sodium or NaK spill in an airfilled cell. The design basis spill is based on leakage from a sharp edged circular orifice whose area is equal to one quarter of the pipe wall thickness multiplied by the pipe inside diameter. These spills are classified as Extremely Unlikely Events and are analyzed as faulted events.

The functional design and evaluation of the catch pan system is based on the sodium-NaK leak rates and spill volumes listed in Table 9.13-9. The relevant Engineered Safety Features for these accidents is the catch pan system. In all cases, with the exception of cell 211A (which contains the ex-containment storage tanks), the spill volumes are predicated on the assumption that no action is taken to terminate the leak. In cell 211A, action is required to limit the spill volume to 3400 gal. This is ensured through the operating procedures governing the transfer of sodium to the ex-containment storage tanks.

The specific functional requirements imposed on the catch pan system as an Engineered Safety Feature are:

1. The system shall be designed to contain the entire spillable volume from a full-flow piping leak in a leak-tight manner to preclude chemical reaction between the liquid pool and the structural concrete.

2. The system shall be designed to limit the temperature imposed on the structural concrete, in the event of a design basis leak, to a level sufficient to ensure the structural integrity of the building.

The functional requirement imposed on the aerosol release limiting instrumentation, as an Engineered Safety Feature, is to provide an initiating signal to the HVAC system within 10 seconds of the time the combustion product aerosol concentration in the SGB exhaust air reaches 10^{-7} gm/cc.

The fire detection and alarm instrumentation, the portable fire extinguishers, and the personnel protective clothing and equipment portions of the SFPS are designed to the requirements of applicable National Fire Protection Association (NFPA) codes. These features of the SFPS are not safety related.

9.13.2.2 System Description

9.13.2.2.1 Catch Pan System

Catch pan system features are provided in all air-filled cells of the Steam Generator Building (SGB) and the Reactor Service Building (RSB) which contain nonradioactive liquid metal systems and piping. These cells contain the nonradioactive sodium piping and components of the Intermediate Heat Transport System, the Auxiliary Liquid Metal System, the Impurity Monitoring and Analysis System, and portions of the non-radioactive NaK piping and components of the Auxiliary Liquid Metal System.

Catch pan system features are also provided in SGB Cells 211 and 211A. These cells contain the ex-containment primary sodium storage tanks and associated piping of the Auxiliary Liquid Metal System, and are inerted when radioactive sodium is infrequently present in the storage tanks.

The catch pan system consists of four basic features: (1) catch pans, which contain spilled liquid metal; (2) insulation between the catch pan plate and the surrounding structural concrete; (3) fire suppression decks that cover the catch pan open area; and (4) interconnections between adjacent catch pan cells that allow drainage of liquid metal from one cell to another. A steel grating above the fire suppression deck will be provided, where required, to serve as a walkway and to provide equipment and personnel access. The steel grating also acts to prevent damage to the fire suppression deck. A typical catch pan-fire suppression deck arrangement is shown in Figure 9.13-2. The plant arrangement of catch pan system features is summarized in Table 9.13-10.

Catch Pans

The catch pan consists of a carbon steel plate assembly which covers the entire floor surface of the cell and extends vertically up the wall to a minimum height of one foot above the maximum sodium level in the catch pan to prevent spilled liquid metal from flowing over the edge of the plate into the area between the plate and the wall.

A continuous lip plate is provided at the top of the catch pan side wall to prevent sodium or NaK from running down the structural concrete cell walls into the region behind the catch pan plate sidewalls. The catch pan is free floating and is supported above the concrete floor of the cell by a continuous layer of insulating material and by steel beams. In the event of a liquid metal spill, the catch pan contains the liquid metal and prevents contact between the liquid metal and the concrete structure. Open catch pans (without fire suppression decks) are used in those cells where the postulated spill volumes are small and open pool burning does not result in concrete temperatures that degrade structural concrete or release unacceptably high quantities of aerosols that affect safety-related equipment in adjacent loops.

Open catch pans cover the concrete floor surfaces of SGB Cells 244, 245, and 246, to prevent sodium concrete reactions during a spill event. The steel plates of the open catch pans are sloped toward the existing floor openings such that sodium will not be contained at this elevation. Sodium leaked onto the plates will spill into Cells 224, 225, and 226, respectively, and drain from there into Cells 207, 208, and 209, respectively, where the sodium is contained within a catch pan equipped with a fire suppression deck.

Insulation

Insulation is provided between the catch pan plate and the concrete floor, and behind the wall sections of the catch pans.

The insulation behind the wall sections of the catch pans is provided in the form of aluminum silicate, blanket type, and is attached to the structural concrete walls. An air gap between the insulation and the vertical catch pan plate sidewall provides additional insulation, allows for relative movement between the insulation and the catch pan plate, and vents hot gases from behind the catch pan plate to the cell atmosphere to prevent pressure buildup behind the plate.

Insulation in the floor consists of M_gO aggregate and extends to the bottom of the catch pan.

In the event of a liquid metal spill, the insulation and air gap act as a thermal barrier between the hot liquid metal pool and the building structural concrete.

Fire Suppression Decks

In cells where liquid metal spills are contained and where open pool burning may pose a challenge to the structural integrity of the building and/or to safety-related equipment, the catch pans are provided with fire suppression decks. The deck is supported above the catch pan plate surface by a structural (steel) framework supported at the edges of the cell by embedments in the structural concrete, and in the interior of the cell by stub columns. The stub column base plates are anchored directly into the structural concrete floor. Around the stub columns, as well as around penetrations through the concrete floor, a vertical plate is provided to form an enclosure to allow for the catch-pan free-expansion and to prevent leakage of spilled sodium from the catch pan. The fire suppression deck is connected to the support framing, with all edges sealed to form an essentially airleak-tight cover.

Carbon steel drain pipes (downcomers) are welded to the deck and extend downward to a point 1/2 inch above the catch pan plate. The pipes are uniformly spaced to form a uniform array over the cell floor area. Vent pipes are welded to the fire suppression deck and extend slightly below and above the deck. The vent pipes are provided to vent hot gases from the region below the deck to the cell atmosphere to prevent pressure buildup underneath the deck.

In the event of a liquid metal spill, the liquid metal flows from the surface of the fire suppression deck through the drain pipes into the catch pan. As the liquid metal drains into the catch pans, the drain pipes become partially filled, and the effective burning surface of the resulting liquid metal pool is limited to the cross-sectional area of the vent and drain pipes. After the sodium has drained into the catch pan, burning is terminated when the pipes become plugged with combustion products and air is prevented from reaching the liquid metal surface.

Cell Interconnections

In certain cells, where the postulated spill volumes are large compared to the floor area of the cell such that consideration of cell penetrations and building structural loading make it impractical to contain the entire volume, open catch pans equipped with drains are provided. The catch pan plates are pitched toward the drains. The minimum slope toward drains is 1/8"-1/4"/ft, except for cells 244, 245 and 246 where the slope is approximately 1/10"/ft. The drains are sized to accommodate the maximum spill rates from postulated design basis accidents.

The drains are in the form of carbon steel pipes passing through the structural concrete of the cell. Horizontal pipes interconnect cells on the same level; vertical pipes interconnect cells on different levels.

In the event of a liquid metal spill, the catch pan prevents contact between the liquid metal pool and the structural concrete. The liquid metal is drained into a cell which has the capability for fire suppression (catch pan with fire suppression deck). This concept has been extended to include draining large upper level cells into lower elevation cells, i.e., Cells 224, 225, and 226 draining into cells 207, 208 and 209. Net volume of catch pans in cells 207, 208 and 209 are 5180 ft^3, 4207 ft^3, and 5763 ft^3, respectively.

System Configuration

The catch pan fire suppression deck arrangement for Loops 1 and 3 of the Intermediate Heat Transport System, in the Intermediate Bay (IB) of the SGB, is shown schematically in Figure 9.13-3.

The catch pan fire suppression deck arrangement for Loops 1 and 3 in the steam generator bay of the SGB is shown schematically in Figure 9.13-4. The catch pan fire suppression deck arrangement for Loop 2 in the IB and the SGB is similar to loops 1 and 3, with appropriate adjustments for the modified loop layout.

The catch pan arrangement for SGB Cells 211A and 211 is shown schematically in Figure 9.13-5.

Cells 352A, 353A, and 332 in the RSB are equipped with open catch pans.

Cells 354, 355, and 350 of the RSB are equipped with catch pans with fire suppression decks.

Aerosol Release Limiting Instrumentation

Sets of safety-related aerosol detectors are installed in the HVAC exhausts at each Steam Generator Cell (Cells 244, 245, 246). Each detector set consists of three detectors which are provided with power from the three 1E battery power sources. These detectors trip when the sodium combustion product aerosol concentration in the exhaust reaches 10^{-7} gm/cc. An initiating signal is generated when any two of the three detectors in a set trip.

9.13.2.2.2 Fire Extinguishers

Portable sodium carbonate (NaX) fire extinguishers, hand-held and wheeled-cart types, are provided and stored in locations convenient to spaces in which there is sodium and NaK equipment in the RSB, RCB, SGB, and the sodium and NaK receiving station. The extinguishers and their storage locations are compatible with building space allocations and passageways. Distribution and labeling of these commercially available extinguishers are in accordance with NFPA 10.

9.13.2.2.3 Instrumentation and Control

The SFPS instrumentation is designed to:

1. Detect the presence of and location of incipient and existing sodium and NaK fires, and provide this information to the plant operator.

2. Detect inoperative detectors, and provide inoperative detector information to the plant operator.

Sodium Fire Detection

The fire detection and alarm channel arrangements are as shown in Figure 9.13-6.

Fire detectors are used to detect the presence of an incipient or fully developed sodium fire. The detectors are permanently installed at the locations listed in Table 9.13-11.

Receptacles, connected to the appropriate area panels, are provided both inside and outside of the cells listed in Table 9.13-10 for which the normal atmosphere is inert (nitrogen or argon). The ex-cell receptacle is located in proximity to the cell exhaust connection to the Heating, Ventilating and Air Conditioning System deinerting apparatus. This deinerting apparatus includes a smoke detector in the exhaust line. This detector is temporarily connected to the receptacle during the deinerting procedure.

Detectors are plugged into the in-cell receptacles while the cells are air filled.

The output signal from each detector is transmitted to an area panel. Each panel is installed in a location (continguous to a sodium fire protection zone) which is, or can be, isolated from the smoke and heat of a sodium fire within the zone. The sodium fire protection zones are sections of the Nuclear Island where sodium-containing equipment is installed or may be transported.

These zones are listed in Table 9.13-12. Signals received at an area panel are group retransmitted from each area panel to the sodium fire protection zone indicating panel in the control room.

Two types of detectors are used: product of combustion and optical. Smoke detectors are actuated by the particulate products of combustion or sodium or NaK. This actuation may be a result of: 1) reduced ion diode current in an photoelectric type detector; or 3) reduced light received by the detector in a photoelectric emitter-detector type detector. Optical detectors are actuated by the infrared energy emitted by a fire.

Inoperative Detector and Area Panel Locations and Test

The method of detecting a failed detector is to test its performance periodically as recommended in NFPA Code 72E. Loss of power to an area panel (with subsequent loss of operation of the associated detectors) is signaled to the sodium fire protection zone indicating panel in the control room. This is accomplished by supervising the power circuits.

Miscellaneous Equipment

Personnel protection equipment, protective clothing, self-contained breathing apparatus, and other equipment essential to personnel safety in event of a sodium or NaK fire, are stored at locations selected on the basis of ready availability for rescue or repair operations.

9.13.2.3 Design Evaluation

Those cells of the plant that normally contain radioactive sodium piping and components are equipped with steel liners and inert atmospheres (2% oxygen). The limited amount of oxygen in the cell suppresses both spray and pool burning. The steel liner contains the spilled liquid to prevent contact with the structural concrete and also acts to limit the spread of combustion products. The liner is thermally insulated from the cell structure to limit the temperatures imposed on the concrete. The liners and the cell structure are designed to withstand the imposed thermal and pressure loadings associated with a design basis leak. In the event of a sodium/NaK leak, the liquid pool is allowed to cool to a temperature at which burning is unlikely even if exposed to an ambient air atmosphere. This technique is universally employed in LMFBR loop-type designs and is considered the most effective fire suppression technique available.

Those cells containing nonradioactive sodium/NaK piping and components are normally air-filled. In these cells, the basic fire suppression feature is a covered catch pan located in the floor of the cell. The use of a covered catch pan to suppress pool burning is a well established concept and has been developed to varying degrees in several countries. Covered catch pans have been tested under simulated sodium spill conditions at HEDL and at the Karlsruhe Nuclear Research Center and were shown to be effective in suppressing pool burning. In both cases, a perforated cover plate was used. In the HEDL test, there were two holes per square foot of surface corresponding to 1% open area and in the Karlsruhe tests there was one hole per square foot of surface corresponding to 0.5% open area. In the HEDL test, a nitrogen flood was added below the cover plate. In both cases, the sodium burning rate was reduced to approximately 1/10 that of an open pool. The rate at which heat was generated due to burning was less than the rate of heat loss from the pool, and the sodium temperature which was initially approximately 1000°F decreased rapidly (<10 hours) to the freezing point, and burning was terminated. Calculations for a typical SGB cell of CRBRP indicate that with a pool burning rate of approximately 1/250 of that of an open pool, approximately 1/20 of that of the tests, the sodium pool temperature is maintained well above the freezing temperature such that burning may continue until either the sodium is completely reacted or until it is terminated by means other than freezing. This prediction is characteristically different from the experimental observations where the sodium cooled rapidly to the freezing point, and burning was terminated. The difference is attributed to the fact that in CRBRP, the heat losses from the pool are minimal. In CRBRP, the pool covers an area up to 5,000 ft^2, whereas the largest pool area of the experiments was approximately 36 ft^2. The large heat transfer area-to-volume ratio of the experiments gives rise to enhanced lateral heat transfer effects. Also, the large ratio of cell wall area to burning area increases radiation heat losses. Thus, in the experiments, heat losses from the pool were larger than the heat generated by burning, and the sodium temperature decreased to the freezing point. In CRBRP, the heat losses from the pool are so small that a much lower burning rate is sufficient to maintain the pool temperature above freezing.

The catch pan fire suppression deck design for CRBRP incorporates features to reduce the burning rate to approximately 1/250 of that of an open pool and to terminate burning with the sodium pool at an elevated temperature. The fire suppression deck is equipped with drainpipes (in place of holes) that extend downward to a point just above the catch pan plate. With these pipes and the catch pan filled with sodium, the effective pool burning surface is reduced to the surface of the sodium exposed in the pipes (1/250 of the floor surface area). Burning is terminated when the pipes become plugged with combustion products (approximately 36 hours). These are the essential design features of the CRBRP catch pan fire suppression deck design and form the basis for testing its effectiveness.

The complete spectrum of design basis sodium-NaK spills (Table 9.13-9) for air filled cells has been analyzed to verify that: (1) the structural integrity of the building is maintained; (2) the performance of the plant safety-related equipment is unimpaired; and (3) the site boundary combustion product aerosol concentration is acceptably low.

In the event of a sodium spill in SGB cells, the combination of catch pans and fire suppression decks contains the spilled sodium, prevents a self-sustaining fire (oxygen depletion), and allows the sodium to cool to its freezing temperature where reignition will not occur even when exposed to an ambient air atmosphere.

In the RSB, catch pans will contain spilled NaK and prevent its contact with concrete. In cells equipped with open catch pans, the NaK is allowed to burn until the fire is either self-extinguished or the entire mass of NaK is consumed. In cells equipped with catch pans with fire suppression decks, the NaK will cool to a temperature at which reignition is unlikely even if exposed to an ambient air atmosphere.

Analysis of the design basis sodium - NaK leaks shows that peak concrete temperatures remain below 350°F (except for two cases) and the long duration (greater than 24 hrs.) concrete temperatures are below 200°F. For two cases, the Intermediate Heat Transfer Shield Cells Loops 1 and 3, the wall temperature peaks at approximately 600°F and is reduced below 200°F within approximately 11 hours. These temperatures are acceptable for building structural design. A detailed examination of sodium-NaK spills and their consequences is given in Chapter 15.

The peak aerosol release rate, to the outside atmosphere is 2 kg/sec. In the case of a design basis leak in the intermediate heat transport loop, the total aerosol release, to the atmosphere must be maintained below 630 lbm in order to assure the performance of plant safety-related equipment. This is accomplished by: 1) closing the HVAC outside openings in the SGB loop cells; 2) venting the hot gases through a controlled area vent stack; and 3) closing the vent stack after the initial pressure pulse is over. These actions are initiated by the signal from the aerosol release limiting instrumentation. A detailed examination of sodium or NaK spills and their consequences is given in Sections 6.2.7 and 15.6.1.5.

NaX, used in fire extinguishers, has been tested by Underwriters Laboratory and is UL listed for use on potassium, sodium, and sodium potassium fires for temperatures up to 1400°F. The UL listing includes NaX in 50-lb pails and NaX in hand held and wheel-type fire extinguishers of 30, 150, and 350-lb capacities. NaX has been widely accepted in the U.S. as the preferred fire extinguishing agent for sodium/NaK fires. The use of NaX does not have any adverse effects on materials utilized in the plant heat transport systems.

In assessing the suitability of NaX fire extinguishers for use in CRBRP, it should be emphasized that these fire extinguishers are intended primarily for use as an auxiliary precautionary measure during maintenance operations, during sodium/NaK loading and unloading operations, and during sodium/NaK fire recovery operations. Sodium/NaK fire protection, in the sense of plant safety, is provided by a system of steel catch pans with fire suppression decks in air-filled cells and steel liners and low oxygen concentrations in inerted cells. Thus, it is expected that NaK fire extinguishers will not play a significant role in fire extinguishing.

9.13.2.3.1 Catch Pan Structural Analysis

The open catch pan system and the catch pan with fire suppression deck system with its support framing are designed to contain a large sodium/NaK spill while maintaining structural integrity at accident temperatures and pressures resulting from a sodium fire. The catch pan design is based on a "floating" concept which allows free expansion to minimize the thermal expansion effects due to the accident conditions. In some local areas where restraint to free expansion exists because of anchorage of equipment, the thermal stresses or strains will be calculated and compared against specified allowable values. Load combination and stress-strain allowables for the different load combinations are given in Appendix C of Section 3.8. Where required, an elastic-plastic finite element analysis using the computer program ANSYS will be performed to verify that the specified stress-strain limit under the accident conditions are not exceeded.

9.13.2.4 Inspection and Testing Requirements

The SFPS is designed to permit inspection of all instrumentation, and portable fire extinguishers, in accordance with NFPA codes. Periodic inspection of the catch pans and fire-suppression decks will be performed, as appropriate.

9.15 EQUIPMENT AND FLOOR DRAINAGE SYSTEM

9.15.1 Design Bases

The plant Equipment and Floor Drainage System (EFDS) is designed to collect the drainage from all plant equipment such as pumps, tanks, coolers, etc., as well as the floor drainage.

Under normal operating conditions the floor drains in the plant serve for house keeping purposes. However, the EFDS is sized to accomodate the maximum postulated flooding event such as a pipe rupture, tank rupture, or sprinkler discharge and limits water accumulation on the floor to no more than 3 1/2 inches. All safety related equipment is mounted on pads at least 4 inches high which is above the maximum flood level. In locations where a postulated complete blockage of the drainage system can cause an accumulation of water above 4 inches, the safety related equipment is mounted on 6 or 8 inch high concrete pads as required; the height was determined in the EFDS flooding study to assure that safety related equipment cannot be innundated. In some cases, also determined by the flooding study, the gaps under doors have been increased to provide an alternative passive means for drainage to egress from a cell with safety related equipment. The flooding study has also determined that backflow between connected cells will not occur. The drainage system sizing has been based on the largest postulated drainage load in each cell; such as fire protection system discharge flows, tank ruptures and pipe breaks.

9.15.2 System Description

Separate EFDS sumps are provided for radioactive, potentially radioactive and non-radioactive areas of the plant. Each sump contains two vertical sump pumps with one pump serving as a full capacity spare.

Equipment and floor drains in the BOP buildings, i.e., where there is no potential of radioactivity, are collected and discharged to the waste water disposal system. Drainage from the fire protection system in the Control Building, Electrical Equipment Building and Diesel Generator Building, which have no potential radioactivity are also directed to the waste water treatment system.

Potentially radioactive drainage will emanate from the Reactor Containment Building (RCB), the Reactor Service Building (RSB) and Radwaste Area (RWA) in the RSB. The drainage from the respective sump in the RCB and RSB will be pumped to the main collection sump in the RWA. This sump has the storage capacity for the single largest design drainage load. The potentially radioactive waste in the RWA where radioactivity is expected area drained directly to the radwaste sump. The main collection sump is equipped with a radiation monitor and diversion valves so that following an accident, radioactive drainage is pumped to the liquid radwaste sump in the RWA for processing. Non-radioactive drainage is pumped to the equalization ponds of the Wastewater Treatment System. A power failure to the radiation monitor or diversion valves will cause recirculation back to the sump to prevent radioactive drainage from entering the non-radioactive wastewater treatment system.

Treated water and other process water treatment wastes which do not have the potential to be radioactively contaminated, are routed to seperate sumps for transport to the waste water treatment system.

Where there is a potential for oil spills, the drainage is routed to the oil separation system prior to discharge into the waste water disposal system. Oil spills are not allowed to drain in areas that contain radioactively contaminated equipment or fluids. In this case, the oil spill is contaminated with curbs and dikes and removed manually. Oil routed to the oil separation system is collected in a waste oil tank and removed from the site for subsequent disposal.

9.15.3 Safety Evaluation

The plant equipment and floor drainage system is designed so that it is not reasonably possible for any radioactive drainage in these systems to be discharged out of the plant without undergoing the required treatment or processing.

Evaluations of radiological considerations for normal operation and postulated spills and accidents are presented in Sections 11.2.5 and 15.0 respectively.

The plant Equipment and Floor Drainage Systems is not safety related except for the piping and valves required for containment isolation (Section 6.2.4).

EFDS piping within areas containing safety related equipment is supported with Seismic Category I supports.

There are no drains in cells where sodium piping or equipment containing sodium is located, accordingly sodium leaks cannot enter the equipment and floor drainage system.

A water pipe break or fire protection system drainage load cannot enter cells or compartments containing sodium from drain system backflow because these cells do not have any drains. The CRBRP design criteria requires that three passive barriers (or two passive and one active barrier) exist between all sodium and water boundaries. Accordingly, leak detectors located in the drainage system are not required.

Safety related systems containing water have instrumentation to detect leakage.

9.15.4 Tests and Inspections

EFDS pipes embedded in concrete are leak tested prior to the pouring of concrete. All EFDS piping is tested for leaks after installation. All leaking pipes or joints are repaired before the concrete is placed. The piping will be cleaned out to insure that construction debris will not cause a blockage or reduction in the flow. All pumps are tested to ensure that their performances meet the required design flows and pressures. A check source will be provided with the radiation monitor to ensure its operability. Periodic sampling of drainage from the RWA main collection sump will be performed and analyzed at the plant laboratory.

9.15.5 Instrumentation Application

Each sump is provided with automatic controls to start and stop the operation of the sump pumps. A switch is provided to alternate the lead with the lag pump. In case the lead pump fails to start, a high-high level switch automatically starts the standby lag pump. A high-high level switch is provided in each sump and alarms in the control room to indicate potential sump overflow. A radiation monitor is provided in the potentially radioactive RWA EFDS main collection sump. The RWA main collection sump pump will recirculate the drainage flow back to the sump until the radiation monitor has sufficient time to determine whether the drainage is radioactive.

TABLE 9.16-2

SYSTEM PARAMETERS

Subsystem Designation	Title	Gas	Operating Cooling Capacity BTU/HR	Operating Gas Flow SCFM	Design Pressure PSIG
PA	PHTS Loop #1	N_2	1.17×10^6	16,300	35
PB	PHTS Loop #2	N_2	1.09×10^6	15,200	35
PC	PHTS Loop #3	N_2	1.17×10^6	16,400	35
CR	Control Rod Drive Mechanism	N_2	0.28×10^6	3,200	150
MA	Sodium Makeup Pump and Pipeways	N_2	1.24×10^6	18,300	15
MB	Sodium Makeup Pump and Vessels	N_2	0.60×10^6	9,400	15
CT	Cold Trap, NaK Cell	N_2	0.33×10^6	5,010	15
RC	Reactor Cavity	N_2	1.49×10^6	20,950	35
EA	EVS Loop #1	N_2	0.52×10^6	8,730	15
EB	EVS Loop #2	N_2	0.94×10^6	12,480	15
EC	EVS Loop #3	N_2	0.19×10^6	2,610	15
ET	Ex-Vessel Storage Tank Cavity	N_2	0.36×10^6	5,000	15
FH	Fuel Handling Cell	Ar	0.55×10^6	8,000	15

TABLE 9.16-3

LIST OF SAFETY-RELATED VALVES REQUIRING COMPRESSED AIR

TO PERFORM THEIR SAFETY-RELATED FUNCTION

Valve No.	Figure no.	Subsystem	Normal Position	Fail Position
28MANV001A	9.16-4	MA	Open	Closed
28MANV001B	9.16-4	MA	Open	Closed
28MBNV001A	9.16-4	MB	Open	Closed
28MBNV001B	9.16-4	MB	Open	Closed
28EANV001A	9.16-6	EA	Open	Closed
28EANV001B	9.16-6	EA	Open	Closed
28EBNV001A	9.16-6	EB	Open	Closed
59 28EBNV001B	9.16-6	EB	Open	Closed

9.17 Sewage Disposal System

9.17.1 Design Basis

The non-safety related Sewage Disposal System is required for sewage collection and treatment during plant construction and operating periods providing a level of treatment that satisfies effluent guidelines and performance standards defined in the National Pollutant Discharge Elimination system (NPDES). Permit is issued for the CRBRP by the Environmental Protection Agency (EPA).

9.17.2 System Description

The construction period (temporary) system and the operating period (permanent) system provide secondary treatment with chlorination of the effluent. Both the construction and permanent sewage treatment plants provide biological treatment by the extended aeration modification of the activated sludge process. Raw sewage first enters a surge tank which stores peak loads and provides downstream equipment with a constant flow. Each plant aerates the activated sludge-sewage mixture in the aeration tank and settles the aerated mixture in the clarifier. A portion of the settled activated sludge in the clarifier is continuously returned to the aeration tank by an air lift system. Excess activated sludge from the settling compartment is accumulated in the waste sludge holding tank. The overflow from the holding tank flows to the inlet of the aeration compartment. The effluent from the clarifier is continuously chlorinated by a hypochlorinating system and is post-aerated to maintain a desired dissolved oxygen level in the effluent to be discharged.

9.17.3 Safety Evaluation

The Sewage Disposal System is a Seismic Category III and non-safety class system.

9.17.4 Tests and Inspections

After each of the sewage treatment plants is connected for operation, acceptance tests are conducted in the field to determine the ability of the equipment to meet design and guaranteed conditions.

9.17.5 Instrumentation Applications

A calibrated V notch weir is provided to measure flow through the treatment plant. It is provided with float and cable flow indicator/recorder. A pressure switch is installed in the discharge piping to start the spare blower when the discharge pressure of the operating blower falls below the normal operating pressure of the air diffuser system.

12A.3.1.4 Health Physicists ALARA Reviews

The other level of review is performed by health physicists from TVA and Commonwealth Edison. There are three health physicists involved in these reviews, two from the TVA ALARA committee and one from Commonwealth Edison. The two TVA health physicists on the CRBRP ALARA committee satisfy the TVA commitments in PSAR Section 12A.3.2. The health physicist's ALARA review meetings are conducted twice a year. The health physicists review system/component design, maintenance outline procedures, and the radiation exposure data and provide recommendations to further reduce radiation exposure based on their ALARA experience at operating nuclear power plants. The specific personnel involved in these reviews by position title, including their health physics training and experience, are listed below:

Title	Training/Experience
Health Physics Supervisor, Technical Services, Nuclear, Commonwealth Edison Company	23 years experience in Power Reactor Health Physics
Chemical Engineer, Radiation Section, Emergency Preparedness and Protection Branch, Division of Nuclear Power, office of Power, Tennessee Valley Authority	7 years experience in power reactor chemistry programs. 1 1/2 years in radiation protection
Health Physicist Radiological Health Staff, Offices of Management Services Tennessee Valley Authority	23 years of experience in applied and technical aspects of health physics

12A.3.2 CRBRP Operations Stage ALARA Program

The purpose of TVA policies and procedures is to guide the official actions expected of TVA employees. A policy or a required procedure will not serve that purpose unless it is known to all those it affects and is understood, interpreted, and applied consistently. Continuing guides of this nature in TVA are published and distributed in such a way as to be available to all employees concerned. They are known as "administrative releases".

The TVA Administrative Release System is composed of Organization Bulletins, TVA Codes, TVA Instructions, and TVA Announcements.

With regard to information that occupational radiation exposures are low as is reasonably achievable, the following quotation is excerpted from TVA's Administrative Release Manual:

This instruction supplements the TVA Codes under VIII HAZARD CONTROL and VIII HEALTH SERVICES. It describes general responsibilities and administrative arrangements of ionizing radiation arising in connection with TVA's work. The detailed administrative arrangements in the instruction apply to all activities involving ionizing radiation.

TVA management is committed to maintaining radiation exposures to its employees and the general public, and the release of radioactive materials to unrestricted areas as low as is reasonably achievable (ALARA), as defined in 10 CFR Part 20. For the protection of its employees, TVA also subscribes to the ALARA philosophy set forth in the Nuclear Regulatory Commission Regulatory Guides 8.8 and 8.10 in the design and operation of all facilities utilizing radioactive materials or radiation sources.

ALARA Program - In view of the commitment in the TVA Administrative Release Manual, TVA has established a formal program to ensure that occupational radiation exposures to employees are kept as low as reasonably achievable (ALARA) and will apply this program to the CRBRP. The program consists of: (1) full management commitment to the overall objectives of ALARA; (2) issuance of specific administrative documents and procedures to the TVA design and operating groups that emphasize the importance of ALARA throughout the design, testing, startup, operation, and maintenance phases of TVA nuclear plants; (3) continued appraisal of inplant radiation and contamination conditions by the onsite radiation protection staff; and (4) a 4-member corporate ALARA committee consisting of management representatives from the TVA design, operations and radiation protection groups, whose purpose is to review and appraise the effectiveness of the ALARA program on a plant-by-plant basis, including the CRBRP. In developing its ALARA program, TVA has closely followed the recommendations of NRC Regulatory Guides 8.8 and 8.10.

The responsibility for implementing the ALARA philosophy in the operation of TVA nuclear power plants is assigned to two divisions. The Division of Power Production has the responsibility of implementing the operational procedures described in Section C.4 of Regulatory Guide 8.8. Further in the implementation of Section C.4, the Division of Environmental Planning provides the radiation protection staff for TVA nuclear facilities and has the ultimate responsibility for determining that TVA
52 maintains radiation exposures as low as reasonably achievable (ALARA) as defined in 10CFR Part 20. The radiation protection program management and staff in the Division of Environmental Planning will, as a minimum, meet the qualification and training guidelines set forth in Regulatory
49 Guides 8.8 and 8.10.

15.6 SODIUM SPILLS - INTRODUCTION

Postulated sodium fires could possibly result in the dispersion of some radioactive material to the atmosphere. Fires involving primary sodium coolant are of most concern since this sodium circulates through the reactor core and accumulates radioactivity due to neutron activation and entrainment of fission products leaking from defective fuel. Postulated fires involving sodium used in the Ex-Vessel Storage Tank (EVST) cooling system could also result in radiological releases. The EVST sodium is essentially non-radioactive at the beginning of plant life. However, during refueling a small quantity of primary sodium is tranferred to the EVST along with each irradiated assembly, resulting in a slow buildup of radioactivity in the EVST sodium.

Besides the potential radiological impact of postulated sodium fires, these fires can result in pressure/temperature transients. Therefore, for each fire the consequences are evaluated in terms of: 1) the potential individual whole body and organ doses at the site boundary and low population zone and 2) the pressure/temperature transient in the affected cell/building. The possibility of occurrence of any of the fires considered in this section is extremely unlikely. As such, it will be shown: 1) that the potential off-site doses are well within the guideline limits of 10CFR100, and 2) that the pressure/temperature transient does not exceed the design capability of the affected cell/building.

The computer codes utilized in the analysis of sodium spills and fires are SPRAY-3B, GESOFIRE, SOFIRE-II, SPCA, and HAA-3B. These codes are described in Appendix A with identification of supporting references.

Sodium spills at potential locations other than those discussed in this section have been examined. However the results of these spills were considered to be less severe in terms of radiological consequences and cell temperature/pressure transients and for this reason are not presented.

Since cells containing either primary or EVST sodium are normally closed and inerted, the potential for large postulated radioactive sodium fires exists only during maintenance, when these cells are opened and deinerted, and sufficient oxygen is available to sustain combustion. A spectrum of fires, both in inerted and de-inerted atmospheres, is investigated in this section.

The consistent application of conservative assumptions throughout the analyses presented in this section provides confidence that the consequences of the fires are within the predicted results. A number of these assumptions are generic to all the fires evaluated in this section, and are summarized below:

1. The radioactive content of the sodium is based on continuous plant operation for 30 years. The design basis radioisotope concentrations were assumed present in the sodium for the

accident analyses. Included in the basis and discussed in PSAR Section 11.1.5 is a design limit of 100 ppb (parts per billion) for plutonium content of the primary coolant.

2. Retention, fallout, plateout, and agglomeration of sodium aerosol in cells or buildings, whose design does not include specific safety features to accomplish that function are not accounted for in the analysis. Neglecting these factors (an assumption that all of the aerosol is available for release to the atmosphere) leads to over-prediction of potential off-site exposure.

3. No credit for non-safety related fire protection systems is taken.

4. Dispersion of aerosol released to the atmosphere was calculated utilizing the conservative atmosphere dilution factors (X/Q) applicable to discrete time intervals provided in Table 2.3-38 (the 95th Percentile Values). Guidance provided in NRC Regulatory Guide 1.145 was followed in calculating the X/Q values. Detailed descriptions of the atmospheric dilution factors estimates are provided in Section 2.3.4.

5. Fallout of the aerosol during transit downwind was neglected.

6. The cells will be structurally designed to maintain their integrity under the accident temperatures and pressures and the weight of the spilled sodium. For radiological calculations, no credit is taken for cell atmosphere leak tightness.

7. The cell liners, catch pans, and catch pan fire suppression decks are designated as Engineered Safety Features and will have design temperatures equal to or greater than the sodium spill temperature, thus confining the sodium spill.

8. The design basis liquid metal spill for either inerted or air filled cells is defined as that spill resulting from a leak in a sodium or NaK pipe/component in the cell producing the worst case spill/temperature condition. The leak is based on a Moderate Energy Fluid System break (1/4 x pipe diameter x pipe thickness) as defined in branch technical position MEB3-1 with the sodium or NaK system operating at its maximum normal operating temperature and pressure.

9. The only credit for operator action in mitigation of postulated sodium spills is shutdown of the Na overflow system makeup pumps 30 minutes after plant scram for a postulated leak in the Primary Heat Transport System (See Section 15.6.1.4).

10. The analysis of postulated liquid metal fires in air-filled cells does not include reaction of the liquid metal with postulated water released from concrete. The validity of this approach is presently being verified in conjunction with the large scale sodium fires test program discussed in Section 1.5.2.8 of the PSAR. If the test program does not support the present analysis approach, the appropriate effects of water release from concrete will be included in subsequent analyses.

Table 15.6-1 provides a summary of the initial conditions for each fire considered and the maximum off-site dose as a percentage of the 10CFR100 guideline limits. As the table indicates, a large margin exists between the potential off-site doses and 10CFR100. A discussion of the pressure/temperature transient for each event is provided in the following sections; in no case do the fires result in conditions beyond the design capability of the cell/building.

The Project is assessing the impacts of a design basis NaK spill in the Reactor Service Building and will provide the results in the PSAR when the assessments are completed.

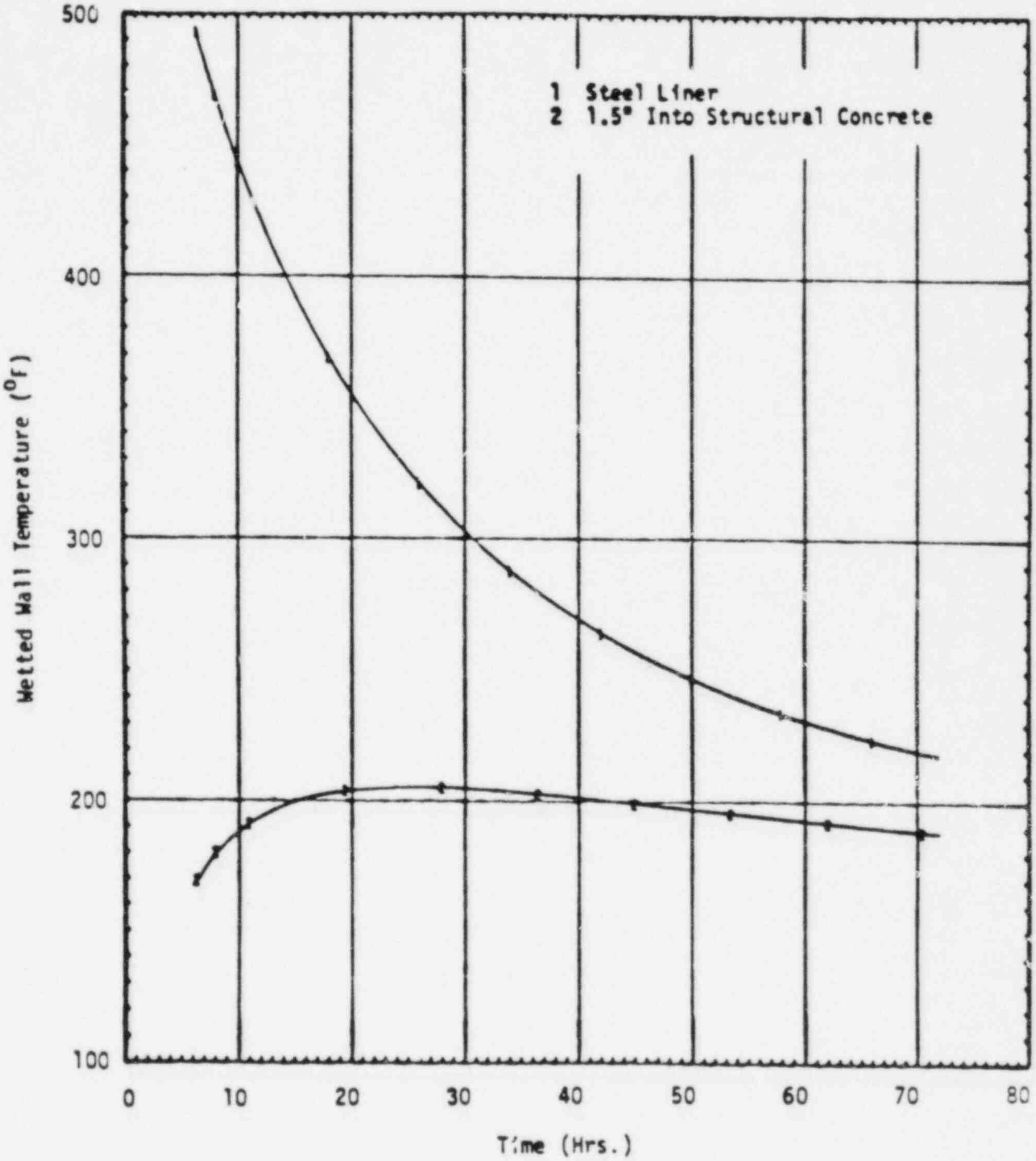


Figure 15.6.1.4-12. Reactor Cavity - Wall Temperature

Amend. 64
Jan. 1982

15.6.1.5 Intermediate Heat Transport System Pipe Leak

15.6.1.5.1 Identification of Causes and Accident Description

It is expected that results of inservice inspection, pipe fabrication and installation quality assurance measures, fracture mechanics analyses and tests, and leak detection provisions will lead to the conclusion that a sudden large failure approaching the complete severence of an IHTS pipe is not credible. In particular, data from tests of leak detectability indicate that the selected methods of leak detection ensure early detection of small IHTS leaks. The Design Basis IHTS leak selected on the basis of the existing information is that equivalent to the flow from a sharp edged circular orifice whose area is equal to one-half the pipe diameter times one-half the pipe wall thickness. (For the 24 inch IHTS piping the orifice area is 2.85 square inches.) This pipe break is consistent with the Moderate Energy Fluid System (MEFS) leak for piping with low stored energy identified in NRC Branch Technical Position MEB 3-1, "Postulated Break and Leakage Locations in Fluid System Piping Outside Containment."

Thermal and Aerosol Consequence Assessment

A sodium leak in the 24-in.-OD main loop hot leg piping in Cell 226 was selected as the limiting case for the design of the SGB; leaks in branch lines or thermowells would fall within the magnitude of this limiting analysis. Leaks in the main loop piping in other cells have been evaluated; however, the leak in Cell 226 represents the limiting case for design since the potential cell pressure and the potential combustion product aerosol release to the outside atmosphere are maximized. The leak is assumed to occur while the IHTS is operating at maximum normal operating temperature and pressure. The pipe break location was chosen to be at the low point of the main loop hot leg piping. This location maximizes the spill volume. The spill parameters were generated by considering the system hydraulic behavior during the pipe break. A conservative assumption is made that no operator action is taken to trip the pump in the leaking loop or to drain the loop to the dump tank. This assumption disregards the probable alarm of any leak by the extensive detection provisions of the Sodium-to-Gas Leak Detection System which are discussed in Section 7.5.5. A reactor trip is caused by a Plant Protection System signal from a Primary-Secondary flow mismatch. Loop flow is assumed to continue under pump head until the pump tank is emptied through the leak. The leak continues at a decreasing rate determined by the cover gas pressure and gravity head. The initial sodium discharge flow rate is 129 lb/sec, and the total spill quantity is approximately 300,000 lb of sodium. The spill duration is approximately 5.5 hours. The leak rate time history is depicted in Figure 15.6.1.5-1. The temperature of the initial sodium discharge is 936°F, and the average bulk temperature of the sodium is 800°F. The reactor decay heat is removed through the two remaining loops via the condenser by-pass or via steam venting and the protected air-cooled condensers. This accident is classified extremely unlikely.

This assessment has not included potential sodium jet impingement on SGB concrete walls. The Project is investigating techniques to mitigate the effects of sodium jet impingement on SGB concrete walls and will incorporate discussions of mitigation features into the PSAR as they are developed.

Radiological Consequence Assessment

An even more conservative assessment was made to demonstrate the potential radiological consequences of an IHTS pipe leak do not pose an undue hazard to public health and safety. The IHTS Design Basis Leak was combined with the

THE CLINCH RIVER BREEDER REACTOR PLANT

PRELIMINARY SAFETY ANALYSIS REPORT

CHAPTER 17.0 - QUALITY ASSURANCE

APPENDIX J

A DESCRIPTION OF THE ESG - RM

QUALITY ASSURANCE PROGRAM

ENERGY SYSTEMS GROUP

A DIVISION OF ROCKWELL INTERNATIONAL CORPORATION

CLINCH RIVER BREEDER REACTOR PLANT

A DESCRIPTION OF THE ENERGY SYSTEMS GROUP

MANUFACTURER QUALITY ASSURANCE PROGRAM

CONTENTS

CONTENTS
(continued)

Amend. 73
Nov. 1982

0.0 INTRODUCTION

0.1 SCOPE

This appendix provides a description of the Quality Assurance Program conducted by Rockwell International Energy Systems Group (ESG) as a Reactor Manufacturer (RM) for portions of the Nuclear Steam Supply System. Through the practices described herein, ESG discharges its responsibilities to assure the quality of systems, components, and structures provided by ESG and ESG's subcontractors.

ESG provides an annual review of the Quality Assurance Program description contained in this appendix, and modification as necessary to keep it current. Changes in the Quality Assurance organization are provided to the Lead Reactor Manufacturer within 30 days of issuance of the approved organization chart.

0.2 BASIS

The program defined herein is based on ESG having been assigned execution responsibility for the Quality Assurance Program applied to design, procurement, and manufacturer of systems, components, and structures as shown by Figure 17J-1. ESG is not assigned responsibilities for site construction and installation.

0.3 APPLICATION

The practices described herein will be applied to the planning, design, procurement, and manufacture of those systems, components, and structures defined in Sections 3.2, 7.1, and 9.13 of the PSAR that are assigned to the ESG scope of work.

1.0 ORGANIZATION

Energy Systems Group, a division of Rockwell International, has been assigned RM responsibilities for the systems, components, and structures defined in Section 0.3 of this appendix. The organization of individuals and groups performing quality-related activities is shown and defined in Section 1.4 of the PSAR. Figure 17J-2 depicts the organizational structure of the ESG Quality Assurance Department. This organization chart shows only lines of administrative control (salary review, hire-fire, position assignments). The separation of the organizational elements of Engineering, Procurement, Manufacturing, and Quality Assurance (which includes all inspection functions), with separate lines of administrative control from the Energy Systems Group President, provides the authority, independence, and freedom for each effectively to perform quality-related activities.

Quality Assurance responsibilities for CRBRP are assigned and executed by the following first line organizations of ESG:

Atomics International Division
Engineering and Test
Operations
Quality Assurance

The Atomics International Division contains the CRBRP Program Office and associated financial and program planning and control functions. The Operations organization contains the Purchasing and Manufacturing Departments which are responsible for CRBRP procurement and internal fabrication activities. Engineering and Test contains the ESG design as well as development and design verification testing functions. Quality Assurance has the responsibility for developing a quality assurance program meeting CRBRP project requirements and assuring its effective execution. Quality Assurance also provides resources for inspection, examination, and test of supplier and ESG fabricated items.

1.1 The responsibility and authority of key managers involved in quality-related activities is as follows:

1.1.1 Atomics International Division Vice President and General Manager

The Atomics International Division Vice President and General Manager has overall responsibility for the management of the LMFBR programs and the Nuclear Products Facilities and Services. LMFBR programs include the CRBRP RM activities as well as Large Breeder Reactor, Sodium Technology, LMFBR Component Development, and Safety programs. Therefore, the responsibility for ESG's overall performance on the CRBRP is vested in the General Manager.

1.1.2 LMFBR Programs Director

The LMFBR Programs Director has overall responsibility for the LMFBR business segment, including CRBRP Program activities, large plant design projects, and LMFBR Base Technology.

1.1.3 CRBRP Program Manager

The CRBRP Program Manager is responsible for the management of the CRBRP Program at ESG. In this capacity, he is responsible for managing the CRBRP Program work in accordance with the contract requirements and providing direction to the functional organizations within ESG for CRBRP development, design, and procurement.

1.1.4 Engineering and Test Vice President

The Engineering and Test Vice President is responsible for the management of ESG's centralized engineering activities. On the CRBRP program, engineering work in support of conceptual design, preliminary design, and final design is assigned to the Engineering Department. Engineering and design work conducted by the Engineering Department includes: Mechanical Design, Drafting and Checking, Electrical and Control Engineering, Materials and Process, Piping and Structural Design, Thermal and Process Systems Pressure Components Stress Analysis, Structural Systems Stress Analysis, Specifications and Manuals, Engineering Assurance and Data Management, and the verification of design through developmental and acceptance testing

1.1.5 Operations Director

The Director of Operations is responsible for the product manufacturing, material purchasing and warehousing in support of the CRBRP in accordance with the controlling programatic documents. The material purchasing function is responsible for selecting sources, procurement, subcontract administration, assuring adherence to work statements, prices and delivery schedules, receiving, inspection, storage, issuance, payment of invoices, and observing the performance quality of the articles purchased. The manufacturing manager is responsible for reviewing engineering and design work performed by ESG to assure manufacturability. On the CRBRP program, as with other programs, the Manager of Manufacturing Engineering is responsible for conducting on-the-board reviews, participating in design reviews, reviewing vendor design information, and assuring component designs can be fabricated and assembled expeditiously and at minimum cost.

1.1.6 Finance and Administration Vice President and Controller

The CRBRP administration is under the cognizance of the Finance and Administration Vice President. The Finance Controller reports administratively to the Finance and Administration Vice President and organizationally to the AI Division Vice President and General Manager. Within the Finance and Administration Organization, the Program Business Management function is responsible to the individual projects for assistance in the budgeting and planning of manpower and dollar expenditure rate; for maintaining and reporting project costs and remaining balances; for monitoring and satisfying contractual requirements; for maintaining contract data control systems; and for providing assistance in preparation of project schedules. On the CRBRP program, Program Administration provides the CRBRP project management with detailed weekly summaries of manpower expenditures, monthly cost information, projection of figure costs at various subaccount levels, commitment control system reports, and various other reports required by the project and the customer.

1.1.7 Quality Assurance Director

The Quality Assurance Director is responsible for the Quality Assurance activities within ESG, which include the Quality Assurance functions for the CRBRP project. He is responsible for establishing and maintaining a quality system that meets the requirements of all contracts received by ESG, including meeting the requirements of RDT F2-2 for the CRBRP project. The authority for achieving these responsibilities is through the issuance of Standard Operating Policies and Procedures from the President of ESG.

The Quality Assurance Director has the authority to prevent issuance of drawings and specifications, and to terminate work where quality requirements are not being met. He interfaces directly with the Atomics International Division Vice President and General Manager to assure that quality program requirements are being met by ESG personnel working on the CRBRP project.

The Quality Assurance Director manages a number of organizations and functions within the Quality Assurance Department to provide assurance that the ESG and CRBRP Quality programs are effectively implemented. A description of the responsibilities of the managers of these organizations and functions is given in the following sections.

The Quality Assurance Director reports directly to the President of ESG.

1.1.8 CRBRP Quality Assurance Program Manager

The CRBRP Quality Assurance Program Manager is responsible to the Quality Assurance Engineering LMFBR Programs Manager for defining and assuring that the Quality Assurance Program for CRBRP Reactor Manufacturer activities assigned to the Energy Systems Group is effectively executed within ESG. This responsibility also extends to assuring that subcontractors define and implement contractually applied quality assurance programs. He is also responsible for cost, schedule, and technical performance of the Quality Assurance cost accounts of the Energy Systems Group Performance Measurement System.

1.1.9 Quality Assurance Audits and Controls Manager

The Energy Systems Group Audit Program responsibilities of the Quality Assurance Director are implemented through the Manager, Quality Assurance Audits and Controls. The Manager, Quality Assurance Audits and Controls, is responsible for:

1) Maintaining and administering the Quality Program Audit System by preparing and maintaining audit schedules.

2) Arranging for checklists and conducting or arranging for audit teams to conduct audits.

3) Insuring preparation of audit reports.

4) Followup to verify corrective action implementation.

5) Maintenance of audit case history files.

6) Development, issuance, control, and revision of Quality Assurance Manuals and procedures.

7) Review of operating procedures, and revisions thereto, prepared by other quality-affecting organizations, to assure compatibility with overall ESG Quality Assurance Program requirements.

8) Performing supplier quality surveys of procurement sources for materials and fabrication services and maintenance of the approved list of such suppliers.

9) Administering a Material Review system for nonconforming items.

10) Administering a Corrective Action system to assure prompt and effective correction of conditions causing nonconformance to technical requirements/procedures.

11) Chemical, physical, and mechanical property testing services to support other Quality Assurance Department units.

12) Qualification programs for welders and welding procedures.

13) Performing surveillance of warehouse areas and manufacturing control stations to assure that only accepted items, properly identified and protected from damage and deterioration, remain in storage. Assure corrective action for any unsatisfactory conditions observed.

1.1.10 Quality Assurance Engineering LMFBR Programs Manager

The Quality Assurance Engineering LMFBR Programs Manager is responsible to the Quality Assurance Director and provides quality assurance engineers to support the CRBRP Quality Assurance Program Manager. Quality Assurance Engineering personnel perform the following activities:

1) Quality Assurance Program administration for specific portions of the CRBRP activities, to monitor and assure effective implementation of quality requirements from design through procurement and fabrication.

2) Quality Assurance engineering support for change control boards, design reviews, and design document review and approval.

3) Nonconforming item review board coordination.

4) Developing and implementing statistical test programs and analyses as required.

5) Evaluating inspection and test data and report quality trends.

6) Reviewing and evaluating bid invitations and returns for quality impact.

7) Participation on capability evaluation teams for prospective suppliers of major items.

8) Procurement document review and supplier quality surveys for materials and fabrication services and maintenance of the approved list of such suppliers.

9) Receiving inspection planning.

10) ESG fabrication inspection planning.

11) A quality data and records collection and storage system for procured and ESG-fabricated items.

12) Data packages for ESG-fabricated items.

13) Source inspection and surveillance of suppliers.

14) Qualification and certification programs for nondestructive examination (NDE) personnel and procedures.

15) Nondestructive examination technical support and consultation to ESG organizations and suppliers.

16) Quality Assurance instructions for complex inspection, tests, and process control operations.

17) Development of nondestructive examination methods for the Inspection and Test Unit.

1.1.11 Quality Assurance Engineering Utility and Energy Programs Manager

The Quality Assurance Engineering Utility and Energy Programs Manager is responsible to the Quality Assurance Director. This organization has no involvement in the CRBRP program.

1.1.12 Inspection and Test Unit Manager

The Inspection and Test Unit Manager is responsible to the Quality Assurance Director and, along with his assistant managers, is responsible for:

1) Performing receiving inspection of procured items and services, identifying and documenting nonconforming conditions of these items and services, and assuring conformance to the established nonconformance dispositions.

2) Performing inspections and tests of ESG fabrication and subassembly operations, final inspections, and performing or witnessing performance of acceptance and qualification tests of ESG-fabricated items.

3) Performing nondestructive examination and acceptance of ESG-fabricated items.

4) Making inspection acceptance and release acceptable ESG-fabricated items for delivery to the next operation. Reject and withhold nonconforming items. Document nonconforming conditions for Material Review evaluation and assure prompt conformance to Material Review disposition.

5) Performing inspection of purchased or ESG-manufactured tooling.

6) Performing inspection of packaging, preservation, and identification of items prior to shipment.

7) Maintaining a system for calibration of measurement instruments used for product inspection and test, including applicable procedures and records. Performing periodic calibration of measuring instruments, in accordance with established requirements.

1.2 Quality assurance policy originates with the President of Rockwell International, through the issuance of a Corporate Policy statement covering Product Integrity. The Quality Policy is issued to each division of Rockwell International in a Corporate Directive, prepared and authorized by the Senior Vice President, Corporate Staffs, which directs each division to take action to implement the Corporate Quality Policy. The President of the Energy Systems Group implements the Corporate Quality Policy Directive through Standard Operating Policies, which provide quality assurance direction consistent with Corporate Policy, as well as the Quality Assurance Program requirements applicable to ESG business objectives and contract requirements. The overall Quality Program is implemented in the operating manuals of the quality-affecting organizational units by the managers of these units. The Quality Assurance Director reports directly to the Energy Systems Group President and verifies compliance of the quality-affecting organizations to the Quality Program, under the authority granted in the Standard Operating Policies.

1.3 The Quality Assurance Director, by virtue of being at the same level of management as the highest level manager of other major Energy Systems Group functions, has the necessary unimpeded communication path to bring quality matters to the attention of the president and executive level management. Differences of opinion on quality matters that cannot be resolved at lower management levels are referred to the Energy Systems Group President by the Quality Assurance Director for final resolution. Quality Assurance Department Managers or Quality Engineers attend scheduled and ad hoc status meetings to assist in resolving problems, report quality results, interpret quality requirements, and provide a basis for providing adequate staffing.

1.4 Quality Assurance functions implemented within ESG are defined in Standard Operating Procedures. All functional organizations (Program Offices, Engineering, Purchasing, Quality Assurance and Manufacturing) are assigned responsibility for:

1) The preparation and issuance, in the operating manuals, of written instructions and procedures which establish the methods and responsibilities for performing quality-related activities, and for verifying satisfactory performance of such activities.

2) The indoctrination and training of their personnel in these procedures, as applicable to their work assignments.

1.5 In addition, the Quality Assurance Director is assigned the following specific quality assurance functions:

1) Identifying those procedures which cover the performance and verification of quality-related activities.

2) Conducting audits of the implementation of such procedures.

3) Identifying quality deficiencies and problems in the Program and reporting them, with any recommendations, to the responsible ESG executive, functional and program managers.

4) Verifying that solutions to reported quality problems or deficiencies are achieved.

5) Stopping nonconforming work and controlling further processing, fabrication, and delivery of nonconforming items.

6) Submit overall status reports on the ESG Quality Assurance Programs to the ESG President, as well as concerned program and functional managers.

1.6 Communications flow directly between the ESG Quality Assurance Department and the Quality Assurance organization of subcontractors, and are documented, as appropriate, by the Purchasing organization buyer assigned for each subcontractor. The lines of communication are defined in internal procedures, and in procurement and quality assurance administrative specifications contractually applied to each subcontractor. The ESG Contract Data Management organization tracks and provides management reports of all communications requiring action, on either the part of ESG or subcontractor, to provide a means of insuring timely resolution of problems.

1.7 Verification of conformance to established quality requirements is the responsibility of the Quality Assurance Department, through the actions of review and approval of design documents (specifications and drawings), procurement documents (purchase requisitions and purchase orders, along with their referenced documents and attachments), and manufacturing documents (travelers and processing procedures). Additionally, the Quality Assurance Department is responsible for verification of conformance to quality requirements of hardware items during source inspection/surveillance, receiving, in-process, and final inspections and process surveillance. As shown by the organizational structure and the functional descriptions of the ESG organization in Section 1.4 of the PSAR, the Quality Assurance Department is divorced from the quality-affecting organizational units performing the design, procurement, and manufacturing activities, with the Quality Assurance Department having a hierarchal position at the same or higher level than the performing organizations.

The authority and responsibility for stopping unsatisfactory work, or the control of further processing, delivery, or installation of nonconforming material, is an explicit function of the Quality Assurance Director in the Standard Operating Policy covering the ESG Quality Assurance Program and issued by the ESG President.

The ESG Quality Assurance Department reporting level, and the Standard Operating Policy covering the ESG Quality Assurance Program, are structured and explicitly provide for the Quality Assurance Director to:

1) Identify quality problems

2) Initiate, recommend, or provide solutions to quality problems

3) Verify implementation of solutions

1.8 The qualification requirements for the Quality Assurance Department management positions are as follows:

1) Minimum qualification requirements for the Quality Assurance Director are (a) a Bachelor of Science degree in Engineering, Science, or Technology from an accredited college or university, (b) 15 years experience in quality assurance or engineering in an advanced technology industry, of which at least 5 years will be in quality assurance; and, of this 5 years, at least 2 years will be in the nuclear area, (c) experienced in the direction of personnel, and the planning and management of resources needed to conduct a Quality Assurance Program, and (d) possess a knowledge of industry and government codes, standards, and regulations defining quality assurance requirements and practices; quality assurance administrative methods and technology and their application; and be experienced in planning, defining, and performing quality assurance practices and application of procedures.

2) Minimum qualification requirements for the Quality Assurance Engineering LMFBR Programs Manager, Quality Audits and Controls Manager, and Quality Assurance Engineering Utility and Energy Programs Manager are (a) a Bachelor of Science degree in Engineering, Science, or Technology from an accredited college or university, (b) 5 years experience in or related to the field of his educational major, of which at least 2 years will have been in quality engineering or technology; and (c) possesses a knowledge of at least two of the following areas of specialty: statistics/reliability, nondestructive examination, physical/mechanical properties measurement, metal fabrication, measurement technology, instrument and control fabrication and testing, chemical processing and analysis, failure analysis, and quality program development and implementation.

3) Minimum qualification requirements for the Inspection and Test Unit Manager are (a) 10 years experience in a manufacturing industry of which 5 years will have been in quality control/assurance; and (b) have a general knowledge of manufacturing and inspection methods and techniques including dimension and electrical measurements, nondestructive examination, quality planning, and fabrication and assembly methods.

4) Minimum qualification requirements for the CRBRP Quality Assurance Program Manager are (a) a Bachelor of Science degree in Engineering, Science, or Technology from an accredited college or university, (b) 5 years experience in quality assurance or engineering in an advanced technology industry, of which at least 3 years will be in quality assurance in the nuclear area, (c) experienced in the direction of personnel, and the planning and management of resources needed to conduct a Quality Assurance Program, and (d) possess a knowledge of industry and government codes, standards, and regulations defining quality assurance requirements and practices; quality assurance administrative methods and technology and their application; and be experienced in planning, defining, and performing quality assurances practices and application of procedures.

1.9 Adequate staffing of the QA Department is the responsibility of the QA Director and managers reporting to the Director. Basically, staff size is a function of business level. For each project or program, the QA Director provides an estimate of quality engineering, inspection, and supervision funding needs to the project or program manager. These estimates are prepared by members of the QA Department staff and negotiated when necessary by the QA Director with the project or program manager. Issuance of the funding to the QA Department is then through normal accounting channels to Quality Assurance Department Managers who then staff appropriately. Certain overhead functions, such as calibration, procedure development or audit are staffed to an adequate size based on negotiations between the QA Director and the Controller.

Quality Assurance personnel are involved in day-to-day plant activities to assure adequate QA coverage. For ESG fabrication, both the assigned Quality Engineer and Inspection Manager attend scheduled meetings with Manufacturing and Purchasing management on status of work in progress. These meetings are normally scheduled weekly and may be held daily during periods of intense activity. Floor level inspection and manufacturing managers also interact daily to ensure adequate inspector availability to meet current work schedules. Quality Engineers are assigned to specific portions of the CRBRP activities at ESG, e.g., systems and/or components, and these engineers interact daily with their counterparts in Program Office, Engineering and Purchasing. The quality engineers also attend scheduled and ad hoc meetings and are on distribution for appropriate correspondence, reports, drawings, and specifications.

2.0 <u>QUALITY ASSURANCE PROGRAM</u>

The Quality Assurance Program described herein complies with the requirements of Title 10, Code of Federal Regulations, Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants," for the ESG scope of work as a CRBRP Reactor Manufacturer. The elements of the CRBRP Quality Assurance Program to be executed by ESG are shown in Figure 17J-3. The Quality Assurance Program is applied to individual structures, systems, and components in a defined, graded approach, according to their importance to safety. This program is issued and made mandatory by direction of the President of Energy Systems Group by Standard Operating Policies that require the issuance of operating procedures, and provides for verification of their enforcement through a system of quality program audits. ESG delegates execution responsibility of appropriate Quality Assurance Program elements to suppliers of material, equipment, and services, but retains responsibility for their implementation by these suppliers. Such delegation is controlled as described in paragraphs 8.1, 9.1, 10.1, 11.1, 12.1, 13.1, 14.1, 15.1, 16.1, and 18.1 of this appendix.

2.1 Management assessment of the scope and effectiveness of the Quality Assurance Program is accomplished by two independent audits. One of these is performed at yearly intervals, and specifically addresses the 10 CFR 50, Appendix B, requirements as they are implemented through that portion of the Quality Assurance Program that addresses Section NCA-4000 of Section III of the ASME Boiler and Pressure Vessel Code. The second audit occurs at 18-month intervals and is conducted by senior officials from other divisions of Rockwell International. This latter audit is to assure compliance with contractual and statutory quality assurance requirements.

Continuing involvement of the ESG President in Quality Assurance matters is achieved by three routinely scheduled interactive associations with the Quality Assurance Director. These are: (1) periodic staff meetings, during which each member of the President's staff, which includes the Quality Assurance Director, must report on significant problems, accomplishments, and status of activities, (2) periodic Program Review Meetings, in which formal and in-depth reports are presented by Program Managers, and during which time the Quality Assurance Director addresses significant quality problems, with recommendations for corrective action, and (3) submission of a monthly quality status report to Executive Management that covers quality progress accomplishments, problems, and audit results, and to the customer as required by contract.

2.3 Quality policy originated at Rockwell International, with the issuance of a "Product Integrity" policy statement, in which the President of the Corporation states..."It is the policy of the Corporation that its product will meet or exceed applicable standards and requirements for quality, reliability, and safety," The Senior Vice President, Corporate Staffs, issues a directive applicable to all Division Presidents of the Corporation, which requires actions to be taken to implement this Corporate Policy, including:

1) Providing engineering activities for defining safe and reliable products.

2) Providing verification or qualification testing of new products and any subsequent significant design changes prior to introduction into the market.

3) Providing purchasing activities that are responsible for procuring materials, components, and end items that comply with specified requirements.

4) Providing manufacturing activities that are responsible for the manufacture of products that comply with specified requirements.

5) Providing quality assurance activities at each manufacturing location to ensure compliance with specified requirements.

6) Preparing and maintaining clear and correct descriptions of products to be used in advertising and sales literature, proposals, contracts, customer literature, service manuals, labeling, and other necessary documents.

7) Providing prompt feedback of field data regarding failures, complaints, and accidents to the appropriate functional organizations.

8) Developing procedures to ensure that appropriate government agencies and customers are promptly notified of product conditions that could be hazardous and timely resolutions of such conditions.

9) Notifying the Office of the Vice President - Communications, Corporate Offices, relative to all product conditions which could be hazardous.

10) Establishing measurement techniques to provide management visibility of the adequacy of product integrity activities.

11) Preparing and maintaining appropriate written operating procedures to implement the requirements of this Directive.

12) Maintaining a record retention program in compliance with the appropriate Corporate Finance Policy which will support the integrity of company products.

13) Conducting periodic audits throughout all activities having a direct impact on product integrity to measure compliance with established operating procedures.

2.4 The Corporate Quality Policy is implemented at Energy Systems Group through Standard Operating Policies issued by the President, Energy Systems Group. This Group Policy states: "The managers of Engineering, Material (Purchasing), Manufacturing, Quality Assurance, and Program Offices will be responsible for:

1) The preparation and issuance, in their operating manuals, of written instructions and procedures which establish the methods and responsibilities for performing quality-related activities and for verifying satisfactory performance of such activities;

2) The indoctrination and training of their personnel in these procedures, as applicable to their work assignments;

3) Assurance that the instructions and procedures covering quality-related activities meet the Quality Assurance Program requirements of the applicable government regulations and/or contract provisions;

4) Requiring that each individual be responsible for performing quality-related activities in accordance with the applicable instructions and procedures."

Based on the previously described quality policy, the department managers provide procedural coverage in their department manuals for quality-affecting activities.

2.5 The Quality Assurance Director has overall responsibility for assuring conformance to the procedures of the Quality Assurance Program Manual. He has the further responsibility, authority, and organizational freedom to stop nonconforming work, and control further processing, fabrication, and delivery of nonconforming items. If the differences of opinion occur that cannot be resolved, these are referred to the President of Energy Systems Group for final resolution. Changes to department manuals may be proposed by any individual or organization, but final review and approval rests with the department manager. Changes to ESG ASME Code Section III Manual and the basic Quality Assurance Department Manual receive final review and approval by the Quality Assurance Director. Additionally, Standard Operating Policies and Procedures, CRBRP Program Directives, Engineering Management Procedures are reviewed for concurrence by QA Department personnel. All procedures declared as quality-affecting are submitted to the lead reactor manufacturer and owner.

2.6 Provisions for controlling the distribution of Department and Quality Assurance Manuals are addressed in each manual. These provisions provide for serialization of each manual in use and maintenance of a record of the recipients of each manual. Revisions of procedures in the manuals are distributed to each manual holder of record, along with an updated table of contents.

2.7 The CRBRP Quality Assurance Project Manager identifies the procedures from Department and Quality Assurance Manuals that constitute the Quality Assurance Program for the ESG CRBRP Project Reactor Manufacturer scope of work. These procedures are documented in a Quality Assurance Program Index that is approved by the ESG Quality Assurance Director and CRBRP Program Manager. The Index is issued for use by managers and key personnel in organizations performing activities that affect quality. Changes to this Index must be approved by the ESG Quality Assurance Director and the CRBRP Program Manager. A brief synopsis of each procedure contained in the CRBRP Quality Assurance Program Manual is given in Attachment 17J-1 of this appendix.

The safety-related structures, systems, and components tasks controlled by the ESG Quality Program during engineering, design, and procurement are defined in Section 0.3 of this appendix.

2.8 Contractors of component designs and/or fabricated items are required to submit their quality assurance program descriptions for these items for review and approval. This review is made against contractually applied quality assurance program requirements. Additionally, audits of these program activities are conducted by ESG. The requirements for quality assurance program description submittal, and notification of the right of audit, are contained in administrative specifications, which are made part of each component contract.

2.9 Personnel performing quality-related activities for CRBRP receive a training and indoctrination course covering the CRBRP QA program including quality assurance for nuclear facility projects in the United States, the overall Clinch River Breeder Reactor Plant project, and the implementation of this QA program at ESG. This training includes quality concepts; CRBRP design familiarization, major participant responsibilities, and organization interrelationships; and procedure requirements for each ESG organization. Additionally, personnel involved in ASME Code Section III activities receive training courses as to the specific procedures applicable to their function, and their content, scope ard purpose. Contents of the courses, attendees, and dates of attendance are documented.

2.10 Specific categories of personnel responsible for verifying activities affecting quality require formal training in the principles, techniques, and requirements of the activity being performed. Certification as written testimony of qualification is provided in accordance with the appropriate code, standard or procedure, and course content, attendees and dates of attendance documented. Proficiency tests are given to obtain evidence of proper training and qualification. Certifications of qualification are issued that delineates the specific functions personnel are qualified to perform. The criteria for qualification are provided in applicable procedures, and results for each individual are maintained in Training Department files.

Proficiency of personnel is maintained by retraining, reexamination, or continued satisfactory performance in accordance with specified procedural requirements, and recertification is documented along with the basis for recertification. Quality verification personnel involved in the certification program are as follows:

Personnel performing nondestructive examinations, and establishing NDE techniques (SNT-TC-1A)

Personnel performing welding operations (ASME S-IX and AWS)

Personnel leading quality audit items (ANSI N45.2.23)

Personnel performing visual examination (ASME S-III, Subsection NF)

Personnel performing dimension inspection

Personnel certifying Design Specifications, Design Reports, Overpressure Protection Reports, and Load Capacity Data Sheets (ANSI/ASME N626.3)

2.11 Procedures that provide instructions for quality-related activities such as cleaning, welding, nondestructive examination, inspection, and test, specify equipment and facilities to be used as well as any appropriate environmental conditions to be maintained during these activities, e.g., temperature, humidity, and cleanliness. The sequence of events to be followed is specified in the work instruction documents (Test Procedures and Manufacturing Travelers), and verification of conformance to this sequence is performed to assure prerequisites have been met prior to successive operation.

2.12 The Quality Assurance Program described herein is reviewed and revised annually as appropriate. Changes in the QA Department organization are transmitted to the lead reactor manufacturer and owner within 30 days of issuance of the organization chart. The overall ESG organization given in Section 1.4 of the PSAR is reviewed and revised annually. Also, the lead reactor manufacturer is notified of key personnel changes before the changes are announced.

2.13 Development, control, and use of computer programs for design and design verification are covered by a procedure under the control of the Engineering Department and which is included as part of the CRBRP QA program. Adherence to this procedure is audited by Quality Assurance using knowledgeable and independent auditors.

2.14 The docket date of the CRBRP PSAR was April 11, 1975. Regulatory guides to be addressed prior to that date and other factors to be considered are as follows:

1) Regulatory Guides in Subsection V of Section 17.1 of NUREG 0800, as described in PSAR Sections 1.1, 17.0, and 17.1.2.1 and the answers to Questions 411.1 and 411.2.

2) 10 CFR Part 50, 50.55a, as described in PSAR Sections 17.1.2.1, 3.1, 3.2, and 7.1.

3) 10 CFR Part 50, 50.55(e) in accordance with the quality assurance program, as described in PSAR Section 17A.15.1.

4) 10 CFR Part 50, Appendix A, General Design Criteria 1, as described in PSAR Sections 17.0.5, 17.1.2.6, and 3.1.1.

5) ASME B&PV Code Section III, as described in PSAR Sections 17.1.2.6 and 3.2.2.

3.0 DESIGN CONTROL

3.1 ESG utilizes a Cognizant Engineer concept to assign engineering responsibility for the various systems and subsystems for which ESG is the Reactor Manufacturer. Each Cognizant Engineer, under the direction of his manager, has the responsibility for planning, directing, and controlling all effort in conformance with the contract work scope for the system, subsystem, or component under his jurisdiction. This responsibility includes the coordination and integration of all activities related to systems requirements definition, system engineering, component design, interface control, and change control. The Cognizant Engineer is supported in this effort by the functional engineering groups, such as the structural, electrical, and design groups. Written procedures describe the methods to be used in carrying out these activities.

3.2 Applicable regulatory requirements and design bases are defined in principal design documents. The top level design requirement document is the Overall Plant Design Description (OPDD-10). This document describes the overall CRBRP technical, functional, and quality parameters. OPDD-10 is written, released, and controlled by the Lead Reactor Manufacturer.

System Design Descriptions (SDDs) provide the principal means of design definition and control for each CRBRP system for which ESG has system responsibility. The SDDs reflect the OPDD-10 requirements and are used to define the various technical, operational, and safety considerations involved, identify interfaces, and serve as the basic technical document for the system.

Specifications and procedures are prepared to define the requirements for the design, fabrication, quality assurance, testing, handling, shipping, installation (where applicable), construction testing, and preoperational testing of components and structures in compliance with the SDD and all approved baseline documents.

Engineering drawings are developed to meet the requirements of the SDD, approved baseline documents, and component specifications, and further to define and establish engineering parameters, characteristics, and design functions.

Design drawings and specifications are reviewed prior to release by Quality Assurance engineers. This review is performed in accordance with a procedure that provides approval requirements established by senior management of the Engineering, Operations, Quality Assurance and Program Management organizations. The Quality Assurance engineering review is conducted to assure compliance to Engineering and program procedures which specify that drawings and specifications contain quality assurance requirements such as inspection and test requirements, acceptance requirements and inspection and test results documentation. Deviations or changes from these drawing and specification requirements are processed as specified in Sections 15.0 and 16.0 of this appendix.

1) Design characteristics can be controlled, inspected, and tested.

2) Inspection and test (including any design verification testing) criteria are identified.

3.4 Identification and control of design interfaces is accomplished by the Cognizant Engineer and documented by means of System Design Descriptions (SDDs), Component Specifications, and Interface Control Documents (ICDs). The fundamental control document for functional interface data is the SDD, which identifies the system interfaces including referencing supporting control documents (e.g., ICDs) and together with the ICDs, completely defines requirements for every interface within a system.

ICDs are drawings or documents that identify the physical interface characteristics necessary to ensure compatibility between mating pieces of equipment. ICDs are distributed to, and used by, project participants for assuring compatibility of system and/or components. Interface requirements are transmitted to interfacing organizations, and concurrence obtained prior to issue. Proposed changes are coordinated with interfacing organizations prior to implementation.

3.5 The preparation of design documents (SDDs, ICDs, specifications, and drawings) involves input from appropriate technical disciplines including system, safety, stress, thermal, fluid flow, mechanical, materials and process, electrical, control, manufacturing, and quality engineering. Qualified representatives of these disciplines review and approve design documents before issue. Additionally, drawings are checked for dimension accuracy by an independent checking function before issue.

SDD drawing and specification changes are reviewed and approved by the same disciplines as the original issue. A method is used by the releasing function to check the approvers and the functions they represent to assure all the same disciplines review and approve revisions.

3.6 Verification of designs is performed by formal and independent design reviews at various stages of the design to insure that all significant factors affecting performance, reliability, safety, operability, and maintainability of a component or system are properly considered. The Design Review Board is established on an ad hoc basis to provide an expert evaluation and is comprised of a Chairman and specialists in Design, Materials, Safety, Quality Assurance, and other disciplines. Members of the board are selected from any organization on the basis of their knowledge of the subject but are not responsible for the work. Action items are assigned during the meeting, and the followup is provided by the Design Review Board Administrator to assure that the action is taken and the action items closed out. Analyses and calculations having significant effect on the design are subject to verification. The completeness, adequacy, and appropriateness of assumptions, input data, and analytical or calculation method used are evaluated. Certain aspects of designs are verified by test to supplement independent design reviews. In those cases where the adequacy of a design is verified by a qualification test, testing is identified and documented. Testing is conducted using a prototype unit under the most adverse design conditions for which an item is required to perform its safety function. The results of design verification are clearly documented, with the verifier identified. Documentation of the results is auditable against the verification methods identified.

The design engineer, assisted by the materials process, and quality engineering, is responsible for determining the applicability of materials, parts, and equipment used in the design. This selection of hardware is reviewed during the design review.

One of the basic purposes of the design review system is to find and correct errors and deficiencies, prior to the release of the engineering document for procurements, manufacture, construction, or to another organization for use in other design activities. In all cases, the design verification is completed prior to relying upon the components system, or structure to perform its function. Documentation of the deficiency, and the resulting corrective action, are included in the records of the design review.

3.7 The methods for the collection, storage and maintenance of design documents, review records, and related engineering data are described in Section 17.0 of this appendix.

4.0 PROCUREMENT DOCUMENT CONTROL

4.1 ESG uses a system of procedures which describe the sequence of actions to be taken in preparing, reviewing, approving, and controlling procurement documents. The basis for all procurement actions is the Purchase Requisition, which is prepared by the organization requiring the material, service, or component being purchased. Each Purchase Requisition is reviewed and approved by qualified Quality Assurance Department personnel to assure that correct and complete quality requirements are stated or referenced. This review is documented. Drawings, specifications, design reports, and other documents which are referenced in the Purchase Requisition are reviewed and approved as described in Section 6.0 of this appendix. The requirements of the Purchase Requisition are transferred to a Purchase Order, which is offered to the supplier. Purchase Orders are reviewed by Quality Assurance Department personnel to assure no changes of requirements from the Purchase Requisition.

4.2 Purchase Orders for structures, systems, and components identify appropriate requirements, which must be addressed in the supplier's quality assurance program description. The supplier's program is reviewed against contract requirements and approved by qualified Quality Assurance Department personnel prior to start of activities affected by the Quality Assurance Program.

The Purchase Order and its referenced documentation contain all necessary design basis technical information. They additionally identify all documentation to be prepared, maintained, and submitted to ESG for review and approval. The Purchase Order also identifies those records which must be retained, controlled, maintained, or delivered to ESG. Provision is made in the Purchase Order to ensure ESG's right of access to the supplier's facilities and records for source surveillance and audits.

4.3 The Purchase Requisition - Purchase Order cycle described here is also used to process changes and revisions to the contract. The same review and approval is required of changes as is required of the original Purchase Requisition and Purchase Order. Procurement documents pertaining to spare or replacement parts are treated in the same manner as that used for initial production parts.

4.4 Applicable elements of 10 CFR 50, Appendix B, are applied to suppliers by invoking government or industry Quality Assurance standards in whole or in part, or by inserting specific quality requirements in the Procurement Specifications.

Procurement specifications contain the design basis technical requirements; identification requirements of components, subcomponents, and materials; applicable codes, standards and specifications; test and inspection requirements; and appropriate special process requirements covering critical processes such as welding, brazing, heat treatment, electroplating and thermal surface coating, cleaning, and nondestructive examinations. Applicable regulatory technical requirements are included in the procurement specifications rather than specifying these by reference to regulatory documents.

5.0 INSTRUCTIONS, PROCEDURES, AND DRAWINGS

5.1 Policy, procedures, and instruction documents are prepared to cover activities affecting quality. These quality-affecting activities include management, design and engineering, procurement, quality assurance, and manufacturing. Policies, procedures and instructions are collected and issued in operating department and quality assurance manuals. The manuals contain provisions for preparation, review, control, and revision of procedures and instructions comprising the manual.

The manuals containing procedures and instructions for quality-affecting activities at Energy Systems Group are:

Standard Operating Policies Manual
CRBRP Program Management Directives Manual
Engineering Management Procedures Manual
Corporate Material (Purchasing) Procedures Manual
ASME Code Section III Manual
Quality Assurance Operating Procedures Manual
Manufacturing Manual

Methods for complying with quality assurance criteria applicable to the ESG scope of work are defined in the preceeding manuals. A correlation of procedures, policies, and instructions from these manuals with the criteria of 10 CFR 50, Appendix B, is given in Figure 17J-4, and a summary description of the contents of each document referenced in this figure is given in Attachment 17J-I to this appendix.

Acceptance criteria for important activities defined by the aforementioned procedures and instructions are a part of each procedure, as applicable. For example, document formats and content are specified, as are release, approval, and distribution control requirements.

5.2 The requirements for activities affecting quality, as well as appropriate quantitative and qualitative criteria for determining that important activities have been satisfactorily accomplished, are specified in instructions, procedures, and drawings, including the following types of documents: (1) Design Specifications, (2) SDDs, (3) Procurement Documents, and (4) Test Procedures.

5.3 Provisions for preparation, content, quantitative and qualitative requirements review, revision, and control of drawings are contained in Sections 3.0 and 6.0 of this appendix. These provisions for manufacturing and inspection instructions and procedures are contained in Sections 6.0, 9.0, 10.0, and 13.0 of this appendix.

6.0 DOCUMENT CONTROL

6.1 Documents, such as design specifications, design drawings, computer programs, manufacturing drawings, equipment specifications, construction and preoperational test specifications, material processing specifications, and nondestructive examination procedures, are prepared, reviewed, approved, and issued in accordance with written procedures. Review methods may vary from a series of formalized reviews by a Design Review Board to individual reviews by personnel from involved organizations and the Quality Assurance Department. Organizations responsible for review and approval functions for a specific type of document are identified in a written procedure. Originals, prints, and/or reproducibles of these documents are controlled by the Engineering organization, which releases, distributes, stores, and maintains files and records of these documents. Document changes are prepared, reviewed, and approved in accordance with applicable procedures, only under the authority of the organization or function that prepared, reviewed, and approved the original. Drawings and drawing changes distributed to Manufacturing and Quality Assurance for items being fabricated by the Energy Systems Group require return of a document receipt to Engineering, as evidence that the documents were received by those organizations. Drawings for manufacturing and inspection purposes are further controlled through the Manufacturing Production Control Station. The personnel of this organization insure that correct drawings and revisions thereto are available for manufacturing and inspection planning, as well as for the subsequent manufacturing and inspection operations. Periodic audits are conducted to verify that active documents are in use and obsolete issues have been removed from use. The Engineering data base, containing the latest issues of drawings, specifications, and design basis documents, is updated daily. Terminals are available to all functions for assuring that obsolete issues are not used.

6.2 Procurement documents are controlled as described in Section 4.0 of this appendix. Source and receiving inspection documents are controlled as described in Section 7.0 of this appendix.

ESG Quality Assurance Manuals and department operating procedure are distributed and controlled in accordance with a procedure contained within each manual.

6.3 Manufacturing, inspection and testing instructions, and testing procedures are designated in Manufacturing Production Orders (MPOs) by instruction or procedure number and by applicable revision letter or revision number. The instructions and procedures either accompany the MPO or are maintained available at the location where the work is performed. Changes to MPOs, necessitated for any reason, require the prior review and approval of Quality Assurance, as do changes in manufacturing inspection and test instructions, and test procedures.

6.4 A listing is periodically issued of design documents and their revisions which includes system design descriptions, drawings, specifications, engineering reports, engineering orders, nonconformance reports, manufacturing process procedures, test procedures, and nondestructive examination procedures. The administrative policies and procedures listed in Figure 17J-4 are contained in the CRBRP Quality Assurance Program Index. These listings are used to assure that obsolete issues of the aforementioned documents are not used.

6.5 Assurance that receiving and source inspection is performed to the latest purchase order change is achieved through a system that routes purchase requisitions and orders and changes thereto to the Quality Assurance Engineering Department function. At the time that a change is received by this organization, it is reviewed for quality requirements, and the source or receiving inspection instructions are revised as necessary. Copies of revised inspection instructions and the change orders are sent to the Receiving and Source Inspection functions.

6.6 Assurance that approved changes are included in specifications, drawings, and procedures prior to their implementation is achieved through review and approval of the implementing documents (purchase requisitions and manufacturing travelers) by Quality Assurance Engineering Department personnel and enforcement actions of the QA Department Inspection functions. Quality Assurance Engineering Department personnel review and approve purchase requisitions and manufacturing travelers prior to their release to insure that the correct revisions of specifications, drawings, and procedures are given therein. After issuance, purchase orders are reviewed to assure that there are no unauthorized changes from the purchase requisition. Source, Receiving, and In-Process Inspection inspects to the requirements document revision given in the purchase orders and travelers.

6.7 As-built drawings and documentation are a requirement of contracts for components and are required to be delivered with the item. Quality Assurance source surveillance and document review prior to authorizing shipment to the CRBRP site assures that as-built documentation is received in a timely manner.

7.0 CONTROL OF PURCHASED MATERIAL, EQUIPMENT, AND SERVICES

7.1 Each supplier of materials, structures, systems, and components is evaluated to assess his capability to provide acceptable services and products. Evaluation of major item suppliers for which there is no recent capability information is performed by a team, consisting of representatives of Purchasing, the Program Office, Quality Assurance, and Manufacturing Departments as appropriate. Representatives of Design Engineering, Materials and Processes Engineering, and other units of the Engineering Department participate in the evaluation as necessary.

The details of the evaluation include reviews of past performance, evaluation of procedures and capability descriptions provided by the supplier, surveys of the supplier's facility and Quality Assurance Program in operation, and/or experience of other CRBRP participants with the supplier. The evaluation considers the supplier's capability to supply a product which satisfies all requirements. Results of this evaluation are documented and retained on file at ESG.

7.2 ESG Quality Assurance Department personnel perform surveillance of suppliers during fabrication, processing, inspection, testing, and shipment of products. These surveillance activities are planned and performed in accordance with written procedures. The plans provide instructions which specify the characteristics or processes to be witnessed or verified, the documentation required, and the acceptance criteria which must be met. Sufficient surveillance is performed to verify that quality is achieved in items which cannot be inspected upon receipt. This surveillance ends with written approval to ship the item to ESG or the construction site, given by appropriate Quality Assurance Department personnel.

7.3 Receiving inspection is performed on products delivered to ESG to assure their acceptability prior to use. This inspection is carried out in accordance with written inspection plans. The product is evaluated to determine that it is properly identified, that it meets inspection criteria, that necessary inspection and testing records are included with the product, and that the accepted product is identified as to its acceptability before being released for use or storage. Nonconforming items are segregated, controlled, and clearly identified pending proper disposition. ESG Quality Assurance Department personnel provide written instructions for receiving inspection of items purchased by ESG and delivered directly to the construction site from the supplier.

7.4 ESG requires that the supplier furnish, as a minimum, certifications that identify (e.g., by the purchase order number) the product and the specific requirements (codes, standards, specifications) met by the item. The supplier is further required to submit a report, identifying any requirements which have not been met, and indicating his disposition of such nonconformances. Certifications and test reports are reviewed and approved by appropriate Quality Assurance Department personnel. Acceptable certificates of compliance, and data reports as required, are provided to the plant site with equipment delivery.

7.5 Procurement of spare or replacement spare parts will be conducted under the quality assurance program that is in effect at the time of order placement. Technical requirements, if not the same as for the initial plant item, will be evaluated to insure that they are equal to or better than those for the initial plant item.

7.6 "Off-the-shelf" items are subjected to special receiving or source inspections for critical characteristics. Specific inspection instructions are prepared on a case-by-case basis to accommodate the unique characteristics and use of each item.

7.7 Suppliers' certificates of compliance are validated by an established program of audits, independent inspections, and surveillance and overchecks. This is accomplished using itinerant or resident Quality Assurance site representatives or source inspectors, hold point release, and supplier audits. Additionally, procurement specifications require supporting technical data for certificates of compliance, and these data are reviewed for completeness before use of any item.

8.0 IDENTIFICATION AND CONTROL OF MATERIALS, PARTS, AND COMPONEN S

8.1 For purchased items, ESG delegates execution responsibility for activities of identification and control of materials, parts, and components to suppliers and assesses the effectiveness of these supplier activities, as described in Section 7.0 of this appendix.

8.2 For items fabricated by ESG, procedures and instructions establish identification and control requirements of materials (including consumables), parts, and components, from design through final assembly.

Identification requirements begin with specifications and drawings. Drafting procedures require that notes and location indicators appear on drawings that specify identification information and exact location. Specifications describe how the identification is to be accomplished (e.g., name plates, impression stencil, electrochemical etching). Identification requirements from drawings and specifications are referred to on the Manufacturing Production Order (MPO).

8.3 Traceability of parts, assemblies, components, and structures to drawings and specifications is achieved through the practice of the drawing number becoming the part number. Completed component and structure name plates reference the design or component specification number. In manufacturing and assembly, the MPO, which references drawings and specifications and directs the identification to be applied to the items, provides data for traceability to nonconformance reports, special process procedures, inspection procedures, purchase orders, and mill test reports.

8.4 Any adverse effect of the location or method of identification on quality or function of items identified is prevented by specifying these requirements in engineering drawings and specifications. These documents are reviewed and approved by specialists in stress, materials, processing, manufacturing, and quality assurance, to assure identification markings do not affect quality and function.

8.5 Verification of the correct identification of materials, parts, and components is performed by the Inspection function of the Quality Assurance Department for ESG fabricated items. Quality Assurance Engineering Department personnel are responsible for issuing instructions to Inspection for this verification to appear on the MPO. Upon completion of fabrication and assembly, Quality Assurance Engineering Department personnel review the MPO to assure the steps specifying identification and its verification are initiated and stamped to show completion of these operations. For supplier fabricated items, identification verification is accomplished by ESG itinerant or resident QA representatives.

9.0 CONTROL OF SPECIAL PROCESSES

9.1 For purchased items, ESG delegates execution responsibility for special process control activities to suppliers and assesses the effectiveness of supplier special process control activities, as described in Section 7.0 of this appendix.

9.2 For items fabricated by ESG, special processes, including but not limited to welding, brazing, heat-treating, cleaning, bonding, coating, soldering, plating, hard surfacing, forming, clean room operations, and nondestructive testing are controlled to the degree required by applicable codes, standards, specifications, and regulations. This control is accomplished by several means:

1) Fabrication Procedures are written by Manufacturing Engineering, and reviewed and approved by Design Engineering and Quality Assurance. Nondestructive examination procedures are reviewed and approved by certified NDE Level III Examiners.

2) Detail instructions in the Manufacturing Production Order (MPO), which serves as ESG's shop traveler, are written by Manufacturing Planning and reviewed and approved by Quality Assurance.

When Processing Procedures are used, they are made part of the MPO by reference.

9.3 Procedures, equipment, and personnel performing special processes are qualified and certified by Quality Assurance Department personnel. Qualification is accomplished in accordance with applicable codes, standards, specifications, or internal requirements. Qualifications are reviewed and approved by Quality Assurance.

Special processes are performed by trained, qualified personnel working to written qualified instructions using qualified equipment. Evidence of performance or verification is recorded on the MPO which accompanies each structure, system, or component during manufacture. Evidence of performance is either recorded or verified by qualified Quality Assurance personnel.

9.4 Qualification records of procedures, equipment, and personnel for performing special processes are established, filed, and maintained current in compliance with written ESG procedures. Periodic audits of these records are performed by Quality Assurance to ensure their adequacy.

10.0 INSPECTION

10.1 For purchased items, ESG delegates execution responsibility for inspection activities to suppliers and assesses the effectiveness of these inspection activities, as described in Section 7.0 of this appendix.

10.2 For items fabricated at ESG, inspections, examinations, and quality verification testing of systems, structures, and components are performed by Inspection and Test Unit personnel of the Quality Assurance Department. The manager of this function reports directly to the Quality Assurance Director, who reports directly to the President of Energy Systems Group, thus providing the inspection function freedom effectively to perform its responsibilities.

10.3 The shop traveler for the control of manufacturing and inspection activities is the Manufacturing Production Order (MPO). The MPO is a single document that authorizes and directs both manufacturing and inspection activities. For inspection, the MPO serves as the test and inspection checklist.

The MPO specifies the characteristics to be inspected and the specific point in the manufacturing process where the inspection must be accomplished. It also specifies, by line entry, the specific department and group responsible for performing the operations, including inspections and tests. Inspection points are selected by Quality Assurance Department staff.

Acceptance and rejection criteria and the description of the method of inspection, including any special requirements such as use of particular equipment, are specified on the MPO or are contained in documents specifically referenced by the MPO. These are entered on the MPO by Quality Assurance Department staff.

The inspector who performs the inspection operation stamps the MPO entry when he completes an inspection activity. When the manufacturing and inspection effort on the MPO is completed, the MPO is reviewed by the Quality Assurance Engineering personnel of the Quality Assurance Department to verify and certify acceptable completion of all specified manufacturing, inspection, and test operations.

Each system, structure, component, or subtier detail is fabricated against an individual MPO. Established procedures require that a copy of each drawing and procedure referenced on the MPO be at the manufacturing and inspection work station for use by personnel during the work operation.

10.4 Inspectors are trained and indoctrinated, as required, to assure proficiency in their assignments. In addition, nondestructive examination personnel are formally trained, qualified, and certified to SNT-TC-1A as supplemented by Section III of the ASME Boiler and Pressure Vessel Code (see paragraph 2.10).

10.5 Modifications, repairs, and replacements are fabricated under the same Manufacturing-Inspection control system as new items, and receive the same reviews and approvals as original item fabrication.

10.6 Hold points for witness by the authorized Code Inspector and/or customer representatives are provided for and established, as required by these agencies, on the MPO by Quality Assurance Engineering personnel, prior to release for fabrication.

10.7 Procedures require Quality Assurance Department personnel monitoring of special processes, where direct inspection is not possible. Process procedures are used which specify control measures and acceptability requirements.

11.0 TEST CONTROL

11.1 For purchased items, Energy Systems Group delegates execution responsibility for test programs to suppliers, and assesses the effectiveness of these programs through surveillance actions, as described in Section 7.0 of this appendix.

11.2 For items produced by Energy Systems Group, test programs are identified by Design Engineering, as appropriate, to demonstrate that items will perform satisfactorily in service. Testing is accomplished in accordance with written and controlled procedures. These procedures are prepared by Engineering or Quality Assurance Department personnel from the group or unit responsible for conducting the test. They are reviewed and approved by the cognizant Quality Assurance Department personnel having responsibility that quality and quality assurance requirements are met and by Program Office cognizant engineers having responsibility that technical requirements are met.

11.3 Test procedures include appropriate requirements for test article identification, test purpose and objectives, test prerequisites, test condition limits, instruments and calibration, equipment, environmental warnings and cautions, authority for test restart after interruptions, accept/reject criteria, data type, method of documentation, and records collection, and storage requirements, Quality Assurance Department, authorized inspection, or customer witness requirements, personnel qualification requirements, and step-by-step procedure requirements with provision for performer signoff and Quality Assurance Department witness verification signoff or stamp.

11.4 Test data are analyzed by qualified personnel and a written report prepared in which results are documented, evaluated, and the acceptability of the item for performing its function satisfactorily in service stated.

11.5 Tested items that have subsequently been modified, repaired, or have been replaced in whole or in part are retested to the original test requirements. If the repair, modification, or replacement involves a design change and modified testing requirements, all design and test documents are revised prior to this work in accordance with the procedures and control described in Sections 3.0, 5.0, and 6.0 of Appendix J.

12.0 CONTROL OF MEASURING AND TEST EQUIPMENT

12.1 For purchased items, Energy Systems Group delegates execution responsibility for control of measuring and test equipment to suppliers and assesses the effectiveness of these activities, as defined in Section 7.0 of this appendix.

12.2 For items produced or tested by Energy Systems Group, procedures define the requirements and responsibilities for calibration, calibration standards, and control of measuring and test equipment used for fabrication, testing, and inspection. The Quality Assurance Department has the responsibility for implementing and maintaining the program for calibration and control of measuring and test equipment. Calibration operations are conducted by the Quality Assurance Department, Engineering Department, other Rockwell International Divisions, and qualified suppliers.

12.3 Each item of measuring and test equipment is given a unique serial number, and the records containing calibration and test data are identified and filed by that serial number.

The calibration system procedures require that measuring and test equipment be calibrated at specified intervals and that these intervals be based on usage, stability, accuracy, and history. Calibration procedures are prepared by the calibrating function and are reviewed and approved by cognizant Quality Assurance management.

The complete calibration status of measurement and test equipment is maintained, using a computerized calibration inventory and recall system, which provides the basic calibration system control, by forcing a listing of equipment requiring calibration and the periodic recall notification to the instrument user and calibration function.

Measuring and test tools and instruments are labeled to show calibration status, i.e., out of use, indication only, and next calibration due date for in-use equipment. Out-of-use tools and instruments are labeled "Calibrate Before Using."

12.4 Calibration procedures specifically state that the calibration standards against which the measuring and test equipment is calibrated have an error no more than one-fourth of tolerance of the equipment (including standards) being calibrated, unless prohibited by the state-of-the-art. A greater error may be permitted after discussion between management of the using organization and the Manager of Inspection and Test.

Energy Systems Group maintains working standards against which measuring and test equipment are calibrated. Working standards are calibrated for traceability to the National Bureau of Standards. This is accomplished by procuring standards or calibration services directly from the NBS or from suppliers which, in turn, can demonstrate NBS traceability. Where NBS standards do not exist, calibration of standards is accomplished by such methods as inter-laboratory comparisons or internal development of a standard.

12.5 When discrepancies from accepted tolerance are found for measuring and test instruments during calibration, this finding is reported to the Manager of the using organization who initiates an investigation of items inspected since the previous calibration. The validity of previous inspection performed with the suspect instrument is evaluated, and the results, along with appropriate actions, documented for the record and follow-up.

13.0 HANDLING, STORAGE, AND SHIPPING

13.1 For purchased items, Energy Systems Group delegates execution responsibility for cleaning, handling, storage, and shipping activities to the suppliers and assesses the effectiveness of these activities, as defined in Section 7.0 of this appendix.

13.2 For items produced by Energy Systems Group, special handling, preservation, storage, packaging, and shipping requirements are specified by packaging engineering specialists. Any special cleaning requirements are specified by manufacturing planning. Operations involving these activities are accomplished by qualified individuals, in accordance with written work and inspection instructions. Handling and cleaning instructions are detailed in procedures referenced in the Manufacturing Production Order (MPO).

All specifications and instructions covering cleaning, handling, preservation, storage, packaging, and shipping reflect design and specification requirements of the material, components, or system being processed. Special attention is given to prevention of loss, damage, or deterioration due to adverse environmental conditions, such as temperature or humidity.

By the time of shipment to the construction site, instructions for handling and storage are transmitted to the Constructor.

14.0 INSPECTION, TEST, AND OPERATING STATUS

14.1 For purchased items, Energy Systems Group delegates execution responsibility for identifying and maintaining inspection, test, and operating status. Assessment of the effectiveness of inspection, test, and operating status is obtained from surveillance activities described in Section 7.0 of this appendix.

14.2 For items produced by Energy Systems Group, the inspection and test status of structures, systems, and components, throughout manufacturing, is identified by the utilization of a shop traveler, known as a Manufacturing Production Order (MPO). The MPO is a comprehensive manufacturing, inspection, and testing planning document written by the Manufacturing Planning Unit of the Manufacturing Department. It is reviewed and approved by Quality Assurance Department personnel to assure that adequate inspection and test controls are included. Inspections and tests are performed or witnessed by qualified Quality Assurance Department inspection personnel, and the status of the inspection or test is indicated on the MPO with the inspector's stamp. Finished items also receive the Quality Assurance Department inspector's stamp; or, if too small to be stamped, are bagged and tagged with the status indicator applied to the tag.

Quality Assurance Department personnel perform periodic and final reviews of the MPO, to assure that all inspections and tests have been performed and their status properly indicated. Thus, bypassing of inspections, tests, and other critical operations is precluded. Application and removal of inspection status indicators, such as tags, markings, labels, and stamps are performed or witnessed by Quality Assurance Department personnel. Welding stamp indications are applied by the welder, as required by the MPO and are verified by Quality Assurance Department personnel.

14.3 The status of nonconforming, inoperative, or malfunctioning structures, systems, or components is identified by Quality Assurance Department personnel to prevent inadvertent use. Details of the control system are described in Section 15.0 of this appendix.

15.0 NONCONFORMING MATERIALS, PARTS, OR COMPONENTS

15.1 For purchased items, Energy Systems Group delegates execution responsibility for nonconforming materials, parts, or components control measures to suppliers. Assessment of the effectiveness of these measures is obtained from surveillance activities described in Section 7.0 of this appendix. Nonconformances that affect safety-related functions or utility that are proposed for "accept as is" or "repair" dispositions are submitted to Energy Systems Group for approval; and if ESG approval is granted, then to the customer for approval.

15.2 For Energy Systems Group fabricated items, procedures are implemented whereby nonconforming item identification, documentation, segregation, review, and disposition are performed. The administrative system for nonconformance control routinely provides for notification of appropriate affected organizations (Manufacturing, Purchasing, Engineering, Quality Assurance Engineering LMFBR Programs) of the existence of nonconforming conditions.

The shop traveler, or Manufacturing Production Order (MPO), described in Section 10.0 of this appendix initiates identification of a nonconformance of inprocess items, with the Quality Assurance Department inspector affixing his discrepancy stamp to the line items on the MPO for the inspection operation. This identification of the item, the nonconformance, and the acceptance criteria involved are transferred to a nonconformance report form by Quality Assurance Department personnel, and the serial number of this report is transcribed onto the MPO. The nonconformance report form and the procedure controlling its use provide for documentation of the disposition of the nonconformance, signature approval of individuals authorized to determine dispositions, and distribution of the report. A similar approach is used for supplier nonconformances detected at receiving or source inspection.

Nonconformance procedures define the individuals and groups responsible for the disposition of nonconforming items.

15.3 Nonconforming items are physically segregated from acceptable items in controlled access hold rooms. The hold rooms are controlled by the Quality Assurance Department Inspection Unit. Items too large to be placed in the rooms are prominently tagged to identify their hold status. Release from hold areas or removal of hold status tags can only be performed by appropriate Quality Assurance Department personnel, after receipt of an approved nonconformance report.

Nonconformances in services will normally be written against affected hardware. Where that is not practical (e.g., defective computer codes), the Corrective Action Request (see Section 16.0) is used to control further operations and/or hardware as appropriate, and to track resolution.

15.4 Repair and rework operations of materials, parts, components, systems, and structures is accomplished by a revision to the original MPO. This revision of the MPO is prepared, reviewed, and approved in the same manner as the initial issuance, which is described in Section 10.0 of this appendix. This revision specifies the repair, rework, and inspection procedures to be used. The inspection methods used are, as a minimum, those used for the original inspection.

15.5 Nonconformances that affect safety-related functions or utility of the items that are proposed for "accept as is" or "repair" dispositions are submitted to the customer for approval. Approved nonconformance reports, with the dispositions, "accept as is" or "repair", are maintained by Quality Assurance, and are submitted with the item at the time of shipment, in accordance with contract requirements.

15.6 Nonconformance reports are summarized and analyzed for trends at least monthly by QA Audits and Controls and Quality Assurance Engineering and the summary is distributed to managers of Quality Assurance, Manufacturing, and Purchasing. Nonconformance reports are submitted to the customer as required by contract.

16.0 CORRECTIVE ACTION

16.1 For procured items, Energy Systems Group delegates execution responsibility to suppliers for establishing and maintaining corrective action measures. Assessment of the effectiveness of these measures is obtained from the supplier surveillance activities provided for in Section 7.0 of this appendix.

16.2 For activities within Energy Systems Group, a documented corrective action system, under the control of the Quality Assurance Department, is established in accordance with procedures for handling nonconformance to technical requirements and technical procedures. Technical requirements are those contained in design drawings, specifications, fabrication procedures, and inspection and test procedures. Technical requirement nonconformances, therefore, are reflected by hardware nonconformance. Technical procedure requirements are those that guide the general processes of documenting and disseminating design, performance, configuration, procurement, manufacturing, and inspection requirements. These technical procedures are those in the Quality Assurance Manuals and functional manuals of quality-affecting organizations.

16.3 Corrective actions for technical requirement violations are an integral part of the nonconforming item system described in Section 15.0 of this appendix. Corrective action for technical procedure nonconformance are defined in procedures covering audits and the basic corrective action system.

Corrective action is initiated during (a) nonconformance evaluation and resolution and (b) following the determination of a condition adverse to quality, to preclude reoccurrence. Appropriate completion periods are assigned as parts of the corrective action commitments. To assure timely resolution, corrective action completion dates are monitored by the Quality Assurance Audits and Controls function; and, in the event of a delinquency, these facts are brought to the attention of the management of Quality Assurance and the affected organizations.

Implementation of corrective action is verified by Quality Assurance, and this is the basis for close-out of corrective actions.

All corrective actions are based on conditions that do or may adversely affect quality. These conditions and their causes are summarized in monthly reports to management, along with status of the corrective action implementation (i.e., complete, on schedule, or delinquent).

17.0 QUALITY ASSURANCE RECORDS

17.1 Policies, plans, and procedures have been implemented by Energy Systems Group to obtain applicable quality assurance records in ANSI N45.2.9 (1974). These policies, plans, and procedures also provide for storage and preservation of the quality assurance records while at ESG. Generic quality record categories have been identified and organizational retention responsibility assigned for these. At the time of contract award for equipment items, a specific list of quality records to be obtained is prepared based on the generic listing. Quality records include system design descriptions, specifications, drawings, design reports, design verification test procedures and reports, purchase orders, design review reports, manufacturing process procedures and instructions, material test reports, personnel and process qualification results, nonconformance reports, audits, inspection results, acceptance test reports, calibration procedures and records, and quality surveillance reports. The records program procedures also provide for responsibilities for its management and operation, records collection, definition of terms unique to the records program, verification of such characteristics as legibility, completeness, inventory control, and transfer to the Owner.

17.2 The organizations involved in the quality records program are Quality Assurance, Engineering, Purchasing, and Manufacturing. Responsibilities of these organizations for specifying, generating, collection, verification, filing, storage, and preservation are given in appropriate procedures.

17.3 Inspection and test records for items examined contain the following information:

1) The inspection or test performed

2) The date and results (acceptable/unacceptable) of the inspection or test

3) A notation of the acceptability of parts, assemblies, or operations

4) A signature or stamp of the individual performing or verifying inspections and tests

5) Notification that nonconformances exist, information relating to nonconformances, and disposition of the nonconforming item, and specific repair or rework actions.

17.4 Record storage facilities and files minimize the possibility of destruction by fire, flooding, theft, biodegradation, and deterioration by environmental conditions such as temperature, humidity, and corrosive fumes.

18.0 AUDITS

18.1 EXTERNAL AUDITS

Energy Systems Group has an audit program for auditing suppliers of structures, systems, and components. Quality Assurance Department personnel perform audit planning, scheduling, audit team selection, audit coordination and contact, report issuance, and follow-up to verify implementation of effective corrective action. Audits are planned on an annual basis. Unscheduled audits may be performed when deemed necessary. Audits are scheduled, based on supplier activity status, to evaluate the effectiveness of supplier Quality Assurance Programs. Checklists are prepared to guide the conduct of audits. Personnel experienced in the conduct of audits are selected as audit team leaders.

The responsibility for the execution of audits within their own and subtier suppliers' is delegated to suppliers in procurement documents.

18.2 INTERNAL AUDITS

18.2.1 Internal quality assurance audits are conducted in accordance with pre-established procedures and checklists. Personnel experienced in the conduct of audits perform the audits, or are team leaders when the team approach is used. Audit personnel are selected to prevent their having direct responsibilities in the areas being audited.

Auditors document their findings, and these findings are reviewed with managers having responsibility for the area audited. At the time of this review, the affected manager accepts a commitment to implement corrective action for deficiencies, and a specified date when implementation will be complete. Upon notification of completion of a corrective action commitment, that area is re-audited to assure the corrections have been accomplished.

18.2.2 Audits are conducted of systems and procedures, processes, and products. The procedures audited are first evaluated against code, standard, and contract requirements, and then the effectiveness of their implementation to on-going work effort is established during audits. A review of documents and records is an integral part of all audits.

Quality audits are performed by personnel from the Quality Assurance Department, or, in the instance of team audits, personnel from other functions under the direction of a Quality Assurance Department lead auditor certified to the requirements of ANSI N45.2.23.

Audits are scheduled yearly, in advance, to cover all elements where there is on-going activity. The audit activity is initiated concurrent with initiation of conceptual design and is conducted throughout the life of the program, so that discrepancies noted can be corrected early enough that end products will not be affected.

18.2.3 Audit results and status are reported monthly to program and functional managers. A summary report of problems affecting timely corrective action is sent to the ESG President and executive level functional managers monthly.

Yearly summarization and analysis of CRBRP Audit Results are conducted and reported to management for review and assessment and as required by contract requirements.

18.3 ACTIVITIES AUDITED

Activities audited are those Quality Assurance program elements indicated in Figure 17J-3.

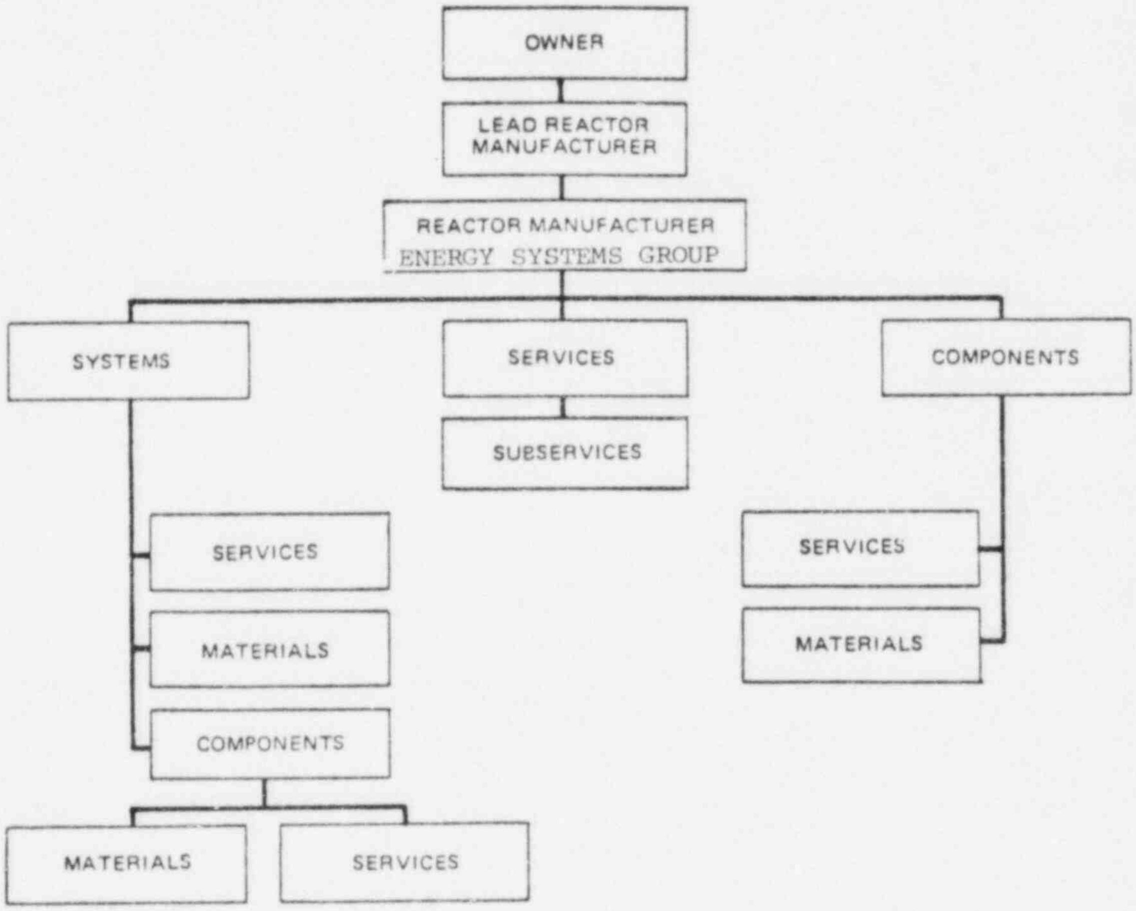


Figure 17J-1. Overall Energy Systems Group Reactor Manufacturer Quality Assurance Program Functional Organization of Program Participation

Amend. 73
Nov. 1982

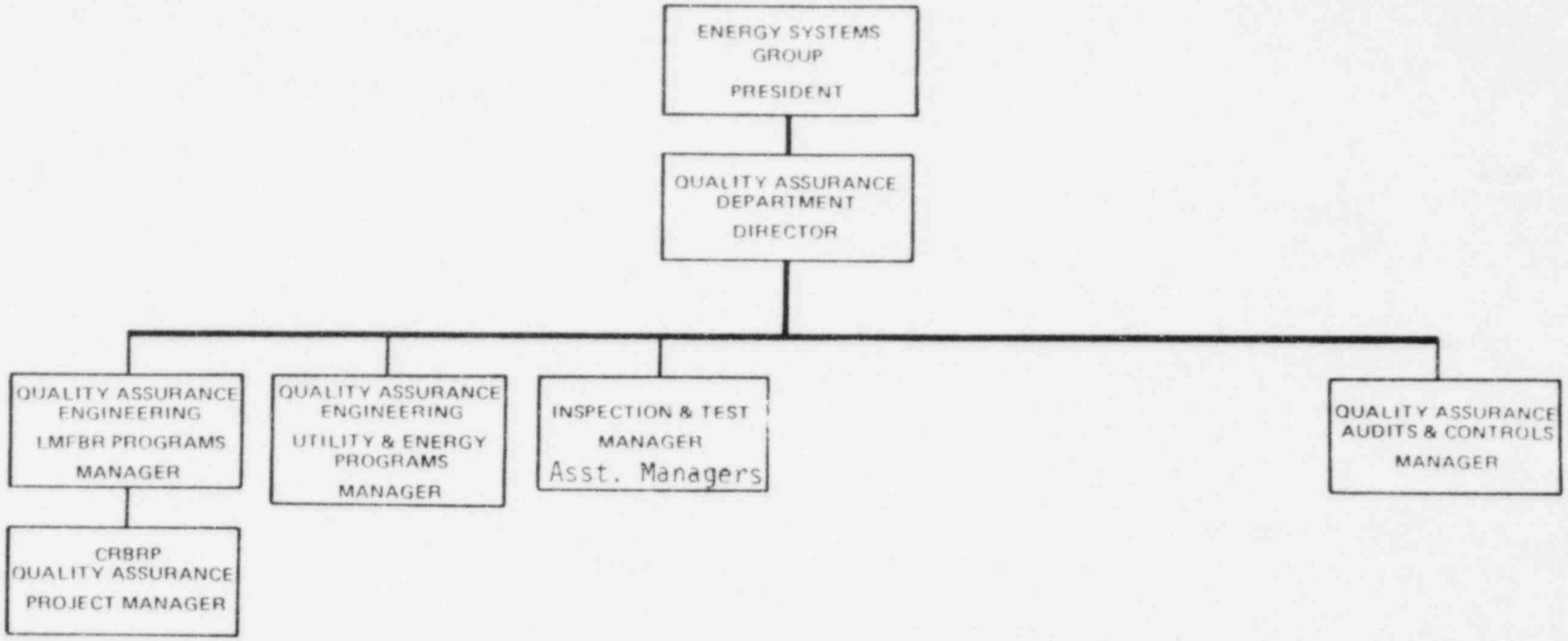


FIGURE 17J-2. ENERGY SYSTEMS GROUP QUALITY ASSURANCE DEPARTMENT ORGANIZATION

PROGRAM MANAGEMENT

QUALITY ASSURANCE PROGRAM
1. Planning
2. Quality Assurance Program Index

ORGANIZATION
1. Responsibility and Authority
2. Training and Indoctrination
3. Personnel Qualification

DOCUMENTATION
1. Policies and Procedures
2. Quality Records
3. Quality Status Reports

AUDITS AND REVIEWS
1. Quality Audits
2. Management Reviews

CORRECTIVE ACTION

ENGINEERING HOLDS

UNUSUAL OCCURRENCE REPORTING

DESIGN AND DEVELOPMENT

Design Planning

Design Definition and Control
1. Design Criteria
2. Codes, Standards and Practices
3. Engineering Studies
4. Parts, Materials and Processes
5. Design Descriptions
6. Specifications, Drawings and Instructions
7. Identification
8. Acceptance Criteria
9. Interface Control

Document Review and Control
1. Document Reviews
2. Document Control
3. Engineering Drawing Lists

Design Reviews

Development

Failure Reporting and Corrective Action

PROCUREMENT

Procurement Planning

Procurement Requirements

Procurement Document Reviews

Evaluation and Selection of Procurement Sources
1. General Requirements
2. Acceptable Source List
3. Pre-Award Evaluation
4. Interchange of Source Capability Information

Control of Configuration
1. Contract Change Control
2. As-Built Verification

Equipment Calibration and Standards

Source Surveillance and Inspection

Receiving Inspection
1. Planning and Inspection
2. Documentation
3. Dispositioning of Received Items

Control of Nonconforming Items

Control of Received Items

MANUFACTURING, FABRICATION AND ASSEMBLY

Planning

Inspection and Test Plan

Material Identification and Control

Control of Processes
1. Fabrication and Assembly Processes
2. Process Qualification
3. Nondestructive Examination
4. Cleaning

Inspection and Tests
1. General Requirements
2. Procedures
3. Completed Item Inspection and Test
4. Inspection Status Indication
5. Certification

Document Control

Equipment Calibration and Standards
1. Equipment Evaluation
2. Control of Inspection Measuring and Test Equipment
3. Calibration Standards
4. Discrepancy Equipment

Statistical Quality Control and Analysis

Control of Nonconforming Items

Corrective Action

Handling, Preservation, Packaging, Storage and Shipping
1. Handling
2. Preservation, Packaging and Storage
3. Shipping

Figure 17J-3. Major Elements of the Energy Systems Group Reactor Manufacturer Quality Assurance Program

Amend. 73
Nov. 1982

Appendix B Criterion	ESG Implementing Document or Procedure Number	Title
I. Organization	SOP M-10	Program Management
	SOP Q-10	ESG Quality Assurance Program
	QAOP N1.21	Quality Assurance Plans
II. Quality Assurance	SOP A-01	ESG Policies and Procedures
	SOP M-10	Program Management
	SOP Q-10	ESG Quality Assurance Program
	SOP Q-16	Quality Assurance (QA) - Program Support Functions
	SOP Q-12	Quality Assurance Program Audits
	SOP Q-18	ESG Quality Records
	SOP Q-26	Product Integrity
	PMD No. 16	Quality Assurance Management Reviews
	PMD No. 11	CRBRP Document Hold Status System
	PMD No. 20	CRBRP Training and Indoctrination
	PMD No. 27	CRBRP Document Status System
	EMP 3-1	Engineering Documentation Process
	CMP 2.35	Case File Documentation
	QAOP N1.00	Preface to Quality Assurance Manual
	QAOP N1.01	Quality Assurance Department Functions
	QAOP N1.03	Vision Requirements for Quality Assurance Personnel
	QAOP N1.21	Quality Assurance Plans
	QAOP N1.23	Quality Status Reports
	QAOP N6.02 CS3M2.4	Qualification and Certification of Nondestructive Examination Personnel
	QAOP N7.02	Qualification and Certification of Visual and Dimensional Inspection Personnel
	QAOP N8.00	Statistical Quality Control Program
	QAOP N13.02	Quality Assurance Data Packages
	CS3M2.3	Training and Indoctrination

Figure 17J-4. Quality Assurance Procedure Index vs Requirements of 10 CFR 50, Appendix B (Sheet 1 of 12)

Appendix B Criterion	ESG Implementing Document or Procedure	
	Number	Title
II. Quality Assurance Program (cont'd)	CS3M17	Quality Assurance Records
	PMD-13	CRBRP Licensing Administrator
III. Design Control	SOP M-10	Program Management
	SOP N-16	Configuration Management
	PMD No. 1	CRBRP Correspondence Control
	PMD No. 11	CRBRP Document Hold Status System
	PMD No. 15	Schedule Development and Control
	PMD No. 19	CRBRP SDD Preparation and Revision
	PMD No. 21	CRBRP Development Activities
	PMD No. 25	CRBRP Parts Standardization
	PMD No. 26	Use of Controlled Information Data Transmittal (CINDT)
	PMD No. 27	CRBRP Document Status System
	PMD No. 30	CRBRP Specifications
	PMD No. 32	CRBRP Design Reviews and Release
	PMD No. 34	Application of Additions to ASME Code Requirements
	PMD No. 36	Engineering Drawings
	PMD No. 40	Materials and Processes for CRBRP
	PMD No. 41	Baselining of Documents
	PMD No. 54	SHRS Reliability Program
	PMD No. 56	Acceptance Test Requirements and Specifications
	EMP 1-0	Preface to Engineering Management Procedures Manual
	EMP 2-8	Engineering Studies
	EMP 2-9	Design and Acceptance Criteria
	EMP 3-5	Engineering Release System
	EMP 3-42	Engineering Management System for Specifications

Figure 17J-4. Quality Assurance Procedure Index vs
Requirements of 10 CFR 50, Appendix B
(Sheet 2 of 12)

Appendix B Criterion	ESG Implementing Document or Procedure	
	Number	Title
III. Design Control (continued)	EMP 3-21	Engineering Change Control
	EMP 3-22	Interface Control
	EMP 3-24	Control of Engineering Drawings
	EMP 3-25	Engineering Orders - Preparation Instructions
	EMP 3-26	Preparation and Control of Supporting Documents
	EMP 3-28	Component Traceability
	EMP 3-29	Engineering Requirements for Serialization
	EMP 3-51	Weldment Checklist
	EMP 3-52	Engineering Release Plan of Action
	EMP 3-63	Documentation Release and Control of Scientific and Technical Computer Programs
	EMP 5-3	Design Reviews
	EMP 5-17	Checking of Engineering Drawings
	EMP 5-21	Materials and Processes Control System
	EMP 5-24	Application of Standards
	CS3M 3, 6	Design and Document Control
	M-3-13	Numbering and Control of Manufacturing Material Processing Procedures (MPP)
IV. Procurement Document Control	SOP J-12	Preparation and Processing of the Purchase Requisition
	SOP M-10	Program Management
	PMD No. 22	Use of CRBRP Administrative Specification in Procurements
	PMD No. 23	Subcontract Preprocurement Planning
	PMD No. 24	Preparation, Review, Approval, and Processing of Purchase Requisitions
	AIMP 1.1.1	Procurement Policy
	AIMP 3.109.1	Procurement from Approved Supplier

Figure 17J-4. Quality Assurance Procedure Index vs Requirements of 10 CFR 50, Appendix B (Sheet 3 of 12)

Appendix B Criterion	ESG Implementing Document or Procedure	
	Number	Title
IV. Procurement Document Control (continued)	CMP 2.14	Changes to Purchase Orders and Other Direction to Suppliers
	CMP 2.35	Case File Documentation
	QAOP N4.00	Procurement Documents
	QAI N4.00A	CRBRP Procurement Document Review
	CS3M 4	Subcontractor Fabricated Items
	CS3M, Appendix A	Contracting for the Fabrication of a Code Item as an N-Certificate Holder Retaining Overall Responsibility for Certification and Stamping
V. Instructions, Procedures, and Drawings	SOP A-01	ESG Policies and Procedures
	SOP Q-10	ESG Quality Assurance Program
	SOP Q-28	Unusual Occurrence Reports - RDT Programs
	SOP Q-18	ESG Quality Records
	SOP Q-20	Reports to the Nuclear Regulatory Commission (NRC) Concerning Defects and Noncompliances
	PMD No. 35	Change Control
	PMD No. 36	Engineering Drawings
	PMD No. 48	Unusual Occurrence Reporting
	EMP 2-9	Design and Acceptance Criteria
	EMP 3-1	Engineering Documentation Process
	EMP 3-4	Numbering of Engineering Documents
	EMP 3-5	Engineering Release System
	EMP 3-42	Engineering Management Systems for Specifications
	EMP 3-29	Engineering Requirements for Serialization
	SOP L-12	Laboratory and Engineering Notebooks
	EMP 4-4	Test Procedures
	EMP 4-5	Test Reports

Figure 17J-4. Quality Assurance Procedure Index vs Requirements of 10 CFR 50, Appendix B (Sheet 4 of 12)

Appendix B Criterion	ESG Implementing Document or Procedure	
	Number	Title
V. Instructions, Procedures, and Drawings (continued)	CMP 2.35	Case File Documentation
	QAOP N1.21	Quality Assurance Plans
	QAOP N1.22	Quality Assurance Acceptance Procedures
	QAOP N1.23	Quality Status Reports
	CS3M 5.11	Cleaning Procedures
	CS3M 9	Control of Fabrication Processes
	QAOP N6.01	Qualification of Welding Procedures and Welding Personnel
	QAOP N6.02	Qualification and Certification of Nondestructive Examination Personnel
	CS3M 2.4	Qualification and Certification of Nondestructive Examination Personnel
	QAOP N6.05	Qualification of Special Processes
	CS3M 5.4	Welding Procedures
	CS3M 9.3	Control of Welding Operations
	CS3M 5.5	Heat-Treating Procedures
	CS3M 5.9	Nondestructive Examination Procedures
	CS3M 7.10	Subcontracted Nondestructive Examination Services
	CS3M 10, 11, 5.10	In-Process and Final Examination and Tests
	CS3M 2.6	Authorized Inspector
	CS3M 17	Quality Assurance Records
	MM M-3-15	Qualification of Welders, Welding Operators, and Welding Procedures
	CS3M 3, 6	Design and Document Control
VI. Document Control	SOP J-12	Preparation and Processing of the Purchase Requisition
	PMD No. 1	CRBRP Correspondence Control
	PMD No. 36	Engineering Drawings
	PMD No. 12	Quality Assurance Review and Approval of Engineering Requirements Documents
	PMD No. 35	Change Control
	PMD No. 56	Acceptance Test Requirements and Specifications

Figure 17J-4. Quality Assurance Procedure Index vs Requirements of 10 CFR 50, Appendix B (Sheet 5 of 12)

Appendix B Criterion	ESG Implementing Document or Procedure	
	Number	Title
VI. Document Control (continued)	EMP 3-42	Engineering Management System for Specifications
	EMP 3-21	Engineering Change Control
	EMP 3-24	Control of Engineering Drawings
	EMP 3-25	Engineering Orders - Preparation Instructions
	EMP 3-26	Preparation and Control of Supporting Documents
	EMP 3-36	Request for Document Change
	EMP 3-52	Engineering Release Plan of Action
	EMP 3-63	Documentation, Release, and Control of Scientific and Technical Computer Programs
	CMP 2.14	Changes to Purchase Order and Other Directions to Suppliers
	QAOP N2.03	Document Control
	CS3M 3, 6	Design and Document Control
	M-3-13	Numbering and Control of Manufacturing Material Processing Procedures (MPP)
VII. Control of Purchased Material, Equipment and Service	SOP J-12	Preparation and Processing of the Purchase Requisition
	SOP K-90	Receiving and Inspection of Incoming Material and Equipment
	SOP K-84	Warehousing of Direct-Charged Purchased Materials by Traffic and Warehousing
	SOP P-46	Handling and Storage of Project Critical Hardware
	SOP K-78	Procurement and Control of Supplier Data
	PMD No. 23	Subcontract Preprocurement Planning
	PMD No. 43	Review of Supplier Data
	PMD No. 55	Instructions for Required Documentation and Procedures for Shipment of Components to CRBRP Site or Other Designated Areas
	CMP 3.121	Source Selection
	QAOP N4.01	Supplier Evaluation and Approval
	QAOP N4.02	Procurement Quality Verification Instructions

Figure 17J-4. Quality Assurance Procedure Index vs Requirements of 10 CFR 50, Appendix B
(Sheet 6 of 12)

Appendix B Criterion	ESG Implementing Document or Procedure Number	Title
VII. Control of Purchased Material, Equipment and Service (cont'd)	QAOP N4.03	Procurement Quality Assurance - Source Inspection/Surveillance
	QAOP N4.04	Procurement Quality Assurance - Receiving Inspection
	QAOP N4.04C	CRBRP Receiving Inspection Overcheck Requirements
	CS3M 7.2	Approved Procurement Sources
	CS3M 4	Procurement Document Control
	CS3M 5.3	Procurement Quality Verification Instructions
	CS3M 7.3, 7.4	Procurement Verification (Source and Receiving Verification)
	CS3M 8	Identification and Control of Materials and Items
VIII. Identification and Control of Materials, Parts and Components	SOP K-90	Receiving and Inspection of Incoming Material and Equipment
	SOP K-84	Warehousing of Direct-Charged Purchased Materials by Traffic and Warehousing
	SOP P-46	Handling and Storage of Project Critical Hardware
	EMP 3-28	Component Traceability
	EMP 3-29	Engineering Requirements for Serialization
	QAOP N4.02	Procurement Quality Verification Instructions
	QAOP N4.04	Procurement Quality Assurance - Receiving Inspection
	QAOP N5.01	Manufacturing Production Order (Shop Travelers)
	QAOP N6.04	Weld Material Control
	QAOP N9.00	Stamp Control
	CS3M 14.2	Issuance, Use, and Control of Stamps
	QAOP N9.02	Serialization of Hardware
	QAOP N10.0	Nonconforming Materials and Items
	CS3M 4	Procurement Document Control
	CS3M 5.3	Procurement Quality Verification Instructions
	CS3M 7.3, 7.4	Procurement Verification (Source and Receiving Verification)
	CS3M 8	Identification and Control of Materials and Items

Figure 17J-4. Quality Assurance Procedure Index vs Requirements of 10 CFR 50, Appendix B (Sheet 7 of 12)

Appendix B Criterion	ESG Implementing Document or Procedure	
	Number	Title
VIII. Identification and Control of Materials, Parts and Components (continued)	CS3M 9	Control of Construction Processes
	CS3M 15	Nonconforming Materials and Items
	MM M-2-4	Control Stations
	MM M-3-6	Material Control
IX. Control of Special Processes	EMP 5-21	Materials and Processes Control System
	QAOP N3.02	ESG Special Tooling
	QAOP N5.01	Manufacturing Production Order (Shop Travelers)
	CS3M 9	Control of Construction Processes
	QAOP N6.01	Qualification of Welding Procedures and Welding Personnel
	QAOP N6.02	Qualification and Certification of Nondestructive Examination Personnel
	CS3M 2.4	Qualification and Certification of Nondestructive Examination Personnel
	CS3M 5.11	Cleaning Procedures
	QAOP N6.03	Nondestructive Examination Procedures
	CS3M 5.9	Nondestructive Examination Procedures
	QAOP N6.05	Qualification of Special Processes
	CS3M 5.4	Welding Procedures, Specifications, and Personnel
	CS3M 9.3	Control of Welding Operations
	CS3M 5.5	Heat-Treating Procedures
	CS3M 7.10	Subcontracted Nondestructive Examination Services
	MM M-3-15	Qualification of Welders, Welding Operators, and Welding Procedures
X. Inspection	SOP K-90	Receiving and Inspection of Incoming Material and Equipment
	QAOP N1.21	Quality Assurance Plans
	QAOP N1.22	Quality Assurance Acceptance Procedures
	QAOP N4.02	Procurement Quality Verification Instructions

Figure 17J-4. Quality Assurance Procedure Index vs Requirements of 10 CFR 50, Appendix B (Sheet 8 of 12)

Appendix B Criterion	ESG Implementing Document or Procedure Number	Title
X. Inspection (continued)	QAOP N4.04	Receiving Inspection
	QAOP N4.03	Procurement Quality Assurance - Source Inspection/Surveillance
	QAOP N4.04	Procurement Quality Assurance - Receiving Inspection
	QAOP N4.04C	CRBRP Receiving Inspection Overcheck Requirements
	QAOP N5.01	Manufacturing Production Order (Shop Travelers)
	QAOP N6.03	Nondestructive Examination Procedures
	CS3M 5.9	Nondestructive Examination Procedures
	QAOP N6.05	Qualification of Special Processes
	QAOP N7.00	Product Acceptance Tests
	QAOP N7.01	Pressure Testing
	CS3M 5.3	Procurement Quality Verification
	CS3M 7.3, 7.4	Procurement Inspection (Source and Receiving Inspection)
	CS3M 9	Control of Construction Processes
	CS3M 10	Examination, Tests, and Inspections
	CS3M 2.6	Authorized Inspector
XI. Test Control	SOP L-12	Laboratory and Engineering Notebooks
	EMP 4-4	Test Procedures
	EMP 4-5	Test Reports
XII. Control of Measuring and Test Equipment	SOP Q-24	Calibration of Measuring Instruments and Equipment
	QAOP N3.00	Control of Measuring and Test Equipment (M&TE)
	QAOP N3.02	ESG Special Tooling
	CS3M 12	Control of Measurement and Test Equipment
XIII. Handling, Storage and Shipping	SOP P-46	Handling and Storage of Project Critical Hardware
	SOP K-44	Shipping
	SOP P-48	Material Handling Equipment (MHE)
	CS3M 5.11	Cleaning Procedures
	PMD 55	Instructions For Required Documentation and Procedures for Shipment of Components to CRBRP Site or Other Designated Area
	PMD 57	Storage, Maintenance, and Inspection of Material, Parts, and Components

Figure 17J-4. Quality Assurance Procedure Index vs
Requirements of 10 CFR 50, Appendix B
(Sheet 9 of 12)

Appendix B Criterion	ESG Implementing Document or Procedure Number	Title
XIII. Handling, Storage and Shipping (continued)	QAOP N12.00	Packaging and Shipping Inspection
	CS3M 13	Handling, Preservation, Storage, and Shipping
	MM M-2-4	Control Stations
	MM M-3-10	Packaging and Shipping
XIV. Inspection, Test and Operating Status	SOP K-90	Receiving and Inspection of Incoming Material and Equipment
	SOP K-84	Warehousing of Direct-Charged Purchased Materials by Traffic and Warehousing
	SOP P-46	Handling and Storage of Project Critical Hardware
	SOP Q-18	ESG Quality Records
	QAOP N1.21	Quality Assurance Plans
	QAOP N3.02	ESG Special Tooling
	QAOP N4.04	Procurement Quality Assurance - Receiving Inspection
	QAOP N5.01	Manufacturing Production Order (Shop Travelers)
	CS3M 9	Control of Construction Processes
	QAOP N6.04	Weld Material Control
	QAOP N7.00	Product Acceptance Tests
	QAOP N7.01	Pressure Testing
	QAOP N9.00	Stamp Control
	CS3M 14.2	Issuance and Control of Stamps
	QAOP N9.02	Serialization of Hardware
	QAOP N10.00	Nonconforming Materials and Items
	CS3M 7.3, 7.4	Source Quality Verification and Receiving Inspection
	CS3M 8.0	Identification and Control of Materials and Items
	CS3M 9.3	Control of Welding Operations
	CS3M 5.5	Heat-Treating Procedures
	CS3M 10, 11	Examination, Tests, and Inspections, Test Control
	CS3M 15	Nonconforming Materials and Items
	CS3M 2.6	Authorized Inspector
	MM M-2-4	Control Stations
	MM M-3-6	Material Control

Figure 17J-4. Quality Assurance Procedure Index vs
Requirements of 10 CFR 50, Appendix B
(Sheet 10 of 12)

Appendix B Criterion	ESG Implementing Document or Procedure	
	Number	Title
XV. Nonconforming Materials, Parts, or Components	SOP K-90	Receiving and Inspection of Incoming Material and Equipment
	SOP Q-18	ESG Quality Records
	QAOP N5.01	Manufacturing Production Order (Shop Travelers)
	QAOP N10.00	Nonconforming Materials and Items
	QAI N10.00D	CRBRP Hardware Nonconformance Processing
	QAOP N13.02	Quality Assurance Data Packages
	CS3M 9	Control of Construction Processes
	CS3M 15	Nonconforming Materials and Items
	CS3M 17	Quality Assurance Records
XVI. Corrective Action	SOP K-90	Receiving and Inspection of Incoming Material and Equipment
	SOP Q-14	Corrective Action System
	SOP Q-28	Unusual Occurrence Reports - RDT Programs
	PMD No. 48	Unusual Occurrence Reporting
	EMP 5-19	Failure Reports
	EMP 5-20	Incident Reports
	QAOP N4.03	Procurement Quality Assurance - Source Inspection/Surveillance
	QAOP N4.04	Procurement Quality Assurance - Receiving Inspection
	QAOP N10.00	Nonconforming Materials and Items
	QAOP N14.00	Corrective Action
	CS3M 16	Corrective Action
	SOP Q-20	Reports to the Nuclear Regulatory Commission (NRC) Concerning Defects and Noncompliances
XVII. Quality Assurance Records	SOP Q-18	ESG Quality Records
	SOP K-78	Procurement and Control of Supplier Data
	CS3M	Quality Assurance Records
	PMD 18	CRBRP Quality Records Management System
	N099QRP000001	Quality Records Management Plan for CRBRP
	N099DWP410001	Quality Records Management Procedures

Figure 17J-4. Quality Assurance Procedure Index vs Requirements of 10 CFR 50, Appendix B (Sheet 11 of 12)

Appendix B Criterion	ESG Implementing Document or Procedure	
	Number	Title
XVIII. Audits	SOP Q-12	Quality Assurance Program Audits
	QAOP N1.04	Quality Assurance Audits
	CS3M 18	Audits

Figure 17J-4. Quality Assurance Procedure Index vs Requirements of 10 CFR 50, Appendix B (Sheet 12 of 12)

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QUALITY ASSURANCE MANUAL
PROCEDURE DESCRIPTIONS

STANDARD OPERATING POLICIES (SOP's)

SOP A-01 - ESG Policy and Procedures

This SOP defines the types of ESG administrative policies and procedures authorized, and establishes minimum format and distribution requirements for such policies and procedures.

It identifies the highest level of management, corporate or otherwise, responsible for establishing quality policies, goals, and objectives. A clear path of communication between Quality Assurance organization and corporate management is defined.

Positions and groups responsible for defining both content and changes to the Quality Assurance Program and manuals are identified, in addition to the management level responsible for the approval of the Quality Assurance Program and manuals. Provisions are established for controlling and distribution of Quality Assurance manuals and revisions.

SOP J-12 - Preparation and Processing of the Purchase Requisition

This SOP establishes methods and policies applicable to the preparation and processing of the Purchase Requisitions (Form N25-R-2). The requisition is used for authorizing procurement, through Purchasing, of materials, equipment, and services from suppliers.

Procedures are established that delineate the sequence of actions to be accomplished in preparation, review, approval, and control of the Purchase Requisition.

SOP K-90 - Receiving of Incoming Material and Equipment

Receiving inspection of supplier-furnished material and equipment is performed in accordance with the following. The material is properly identified and corresponds with receiving documentation. Inspection is performed and judged acceptable, in accordance with predetermined instructions, prior to use. Items accepted and released are identified as to their inspection status, prior to release. Nonconforming items are segregated, controlled, and identified until proper disposition is made.

SOP K-84 - Warehousing of Direct-Charged Purchased Materials by Traffic and Warehousing

Methods are specified to identify and control materials. Verification of correct identification of material, prior to release, is required. Material shall be protected against loss, damage, and deterioration from environmental conditions.

SOP P-46 - Handling and Storage of Project Critical Hardware

Special handling, preservation, storage, packaging, and shipping requirements are specified and performed by qualified personnel under predetermined instructions.

SOP K-44 - Shipping

Special packaging and shipping requirements are specified and accomplished by qualified individuals, in accordance with predetermined instructions. Procedures are prepared in accordance with design and specification requirements which control the packaging and shipping of materials, components, and systems to preclude damage, loss, and deterioration.

SOP P-48 - Material Handling Equipment

Special handling requirements are specified and accomplished by qualified individuals, in accordance with predetermined instructions. Procedures are prepared in accordance with design and specification requirements which control the handling of materials, components, and systems, to prevent damage.

SOP Q-24 - Calibration of Measuring Instruments and Equipment

Procedures describe the calibration technique and frequency, maintenance, and control for all measuring instruments and test equipment which are used for obtaining data, where traceable calibrations are required, measuring and test equipment is identified, and the calibration test data is identified with the associated equipment. Measurement and test equipment are calibrated at specified intervals, based on the conditions affecting the measurement. When measuring and test equipment is found to be out of calibration, any items measured with this equipment are withheld until the accuracy of the results is evaluated. The complete status of all items under the calibration is recorded and maintained. Reference and transfer standards are traceable to national standards. If national standards do not exist, the basis for calibration is documented.

SOP Q-26 - Product Integrity

Implements Rockwell International quality policy and directive for ESG operations by establishing the Product Integrity Program. Defines 14 areas to be covered, makes ESG Quality Assurance Director Product Integrity Program Coordinator, and establishes a Product Integrity Committee consisting of ESG executive management.

SOP L-12 - Laboratory and Engineering Notebooks

It is the policy of the company to record all scientific and laboratory research and development activities in laboratory and engineering notebooks to be used by scientific and engineering personnel, primarily to record results of scientific studies and lab work, whether company or customer oriented. Innovations, inventions, discoveries, and improvements will be recorded for the purpose of fulfilling contractual obligations and protecting company interests.

SOP K-78 - Procurement and Control of Supplier Data

Procedures are established for preparation, review, and control of instructions, procedures, drawings and changes thereto. These documents and changes thereto are procedurally controlled to assure adequacy. Provisions are established, identifying the personnel responsible for these activities. Changes are reviewed by the same organizations that performed the original review, unless delegated by the applicant to qualified responsible organizations. Approved changes are promptly included in the appropriate documents.

SOP M-10 - Program Management

This SOP sets forth principles and guidelines for the managements of Energy Systems Group Business Programs. The Guidelines include organizational framework, program management processes, performance monitoring, and reporting systems.

SOP N-16 - Configuration Management

This SOP establishes the policies, methods, and responsibilities for the preparation, issuance, and use of Configuration Summary Reports.

The primary purpose of this report is to aid the Manufacturing, Quality Assurance, and Engineering functions in determining configuration and effectivity requirements for product hardware.

SOP Q-14 - Corrective Action System

Evaluation of nonconformances and determination of the need for corrective action follow established procedures. Prompt corrective action is initiated, following the determination of nonconformance to procedural or technical requirements. Adverse conditions significant to quality, their causes, and corrective actions, are reported to the appropriate levels of management.

SOP Q-10 - ESG Quality Assurance Program

This procedure defines the Quality Assurance Program to be applied to all ESG products and services, in compliance with applicable contract, federal, or state requirements. Management (above or outside of Quality Assurance and to the highest corporate level) regularly assesses the Quality Assurance Program effectiveness. The establishment of indoctrination and training progress review is specified.

SOP Q-28 - Unusual Occurrence Reports - RDT Programs

This SOP establishes methods and responsibilities for reporting to the customer of unusual occurrences affecting ESG programs under the requirements of RDT Standard F 1-3T.

SOP Q-20 - Reports to the Nuclear Regulatory Commission (NRC) Concerning Defects and Noncompliances

The purpose of this SOP is to comply with requirements of 10CFR21 including requirements to adopt procedures to 1) provide for: a) evaluating deviations or b) informing licensees or purchasers of deviations; and 2) assure that a responsible officer is informed of: a) failures to comply with the Atomic Energy Act of 1954, as amended, or any applicable rule, regulation order or license of NRC relating to Substantial Safety Hazard, or b) defects in the construction or operation of a facility or activity licensed or otherwise regulated pursuant to the Atomic Energy Act of 1954, as amended.

This SOP designates the President, Energy Systems Group, as the responsible officer to be informed and provides methods for informing the President, Energy Systems Group, and provides for delegating his authority for reporting to the NRC.

SOP Q-16 - Quality Assurance Program Support Functions

This procedure establishes policy on the utilization of ESG Quality Assurance Department functions on ESG programs and describes the Quality Assurance Department functions and interfaces with other ESG departments.

It summarizes the provisions for resolving disputes arising from a difference of opinion between Quality Assurance - Quality Control and other department personnel.

The procedure outlines the safety-related structures, systems, and components controlled by the Quality Assurance Program, and the respective organization executing Quality Assurance - related functions on these items during the design, engineering, procurement, inspection, manufacturing, construction, and testing phases. Quality-related activities (inspection and test, etc.) performed with appropriate equipment and under suitable environmental conditions are described.

SOP Q-12 - Quality Assurance Program Audit

Procedures and responsibilities for assuring the adequacy and effectiveness of the ESG Quality Assurance Program through audits of procedures, standards, methods, and practices used in producing ESG hardware or software products are established by this SOP.

Audits are performed in accordance with pre-established written procedures or checklists and are conducted by trained personnel not having direct responsibilities in the areas being audited. The audits include an objective evaluation of quality-related practices, procedures, and instructions, and the effectiveness of implementation and conformance with policy directives.

Audit data are analyzed and reports indicating quality trends and the effectiveness of the Quality Assurance Program are provided to management. The audit results are documented and then reviewed with management having responsibility in the area audited. Subsequently, responsible management takes the necessary action to correct the deficiencies revealed by audit.

SOP Q-18 - ESG Quality Records

ESG Quality Records are defined, and responsibilities for their retention are established by this SOP. Its purpose is to establish standards for meeting ESG and customer requirements for filing, storing, and retrieving of quality history information on ESG products and services.

Quality Assurance records include: 1) operating logs, 2) results of reviews, inspections, tests, audits, and material analyses, 3) monitoring of work performance, 4) qualification of personnel, procedures, and equipment, and 5) other documentation, such as drawings, specification, procurement documents, calibration procedures and reports, and nonconforming and corrective action reports. The records are to be readily identifiable and retrievable.

Requirements and responsibilities for record transmittals, retention and maintenance subject to work completion must be consistent with applicable codes, standards, and procurement documents.

Record storage facilities are to be constructed, located, and secured to prevent loss or destruction of the records or their deterioration by environmental conditions.

CRBRP PROGRAM MANAGEMENT DIRECTIVES (PMD's)

PMD-1 - CRBRP Correspondence Control

This procedure delineates the method for identifying, controlling, and accounting for all incoming and outgoing correspondence, and for capturing commitments on the Commitment Status Report system.

PMD-11 - CRBRP Document Hold Status System

This procedure applies to holds and TBD's on all released (for project use) Principal Design Data for which ESG is responsible. The current status of each Hold and TBD in these documents which impacts Level 2 or Level 3 activities is maintained in the Document Hold system as described in this directive.

PMD-12 - Quality Assurance Review and Approval of Engineering Requirements Documents

This directive establishes the requirement and procedure for formal review and approval by Quality Assurance personnel of ESG-generated 1) drawings, 2) specifications, 3) specification amendments, 4) Engineering's Change Proposals, 5) System Design Descriptions (SDD), and 6) Engineering Orders.

PMD-13 - CRBRP Licensing Administrator

This directive defines the responsibilities of the ESG CRBRP Licensing Administrator for implementing and controlling licensing criteria in accordance with Section 9.0 of the Management Policies and Requirements (MPR).

PMD-15 - Schedule Development and Control

This directive delineates the method for development, processing, approval, maintenance and change control of the ESG schedule hierarchy which defines the CRBRP effort within the requirements of ESG Program Management System.

This directive defines both the vertical integration of schedules for CRBRP from the contractual interface to the detailed work package structure and the horizontal breakout over the time of the various schedular levels and documents.

PMD-16 - Quality Assurance Management Reviews

This procedure implements a Quality Program requirement for periodic quality assurance management review meetings to assess CRBRP Project quality accomplishments, discuss program quality audits, and resolve management problems affecting quality.

PMD-18 - CRBRP Quality Records Management System

This procedure implements the quality records requirements of the CRBRP Management Policies and Requirements Document, Section 11.0, "Project Records Management", for ESGRM activities.

PMD-19 - CRBRP SDD Preparation and Revision

This procedure defines the methods for preparation and maintenance of CRBRP System Design Descriptions.

PMD-20 - CRBRP Training and Indoctrination

This procedure implements CRBRP Project requirements for training and indoctrination of personnel whose activities may have an effect on quality.

PMD-21 - CRBRP Development Activities

This directive defines the methods for initiating and controlling development activities required for the CRBRP Program and includes directions for 1) preparation, review and release of development activities, 2) revision and control of approved development activities, 3) review and control of development activities, and 4) control of development hardware.

PMD-22 - Use of CRBRP Administrative Specifications in Procurements

This procedure describes the use of administrative specifications for Quality Assurance administration of purchase orders between Energy Systems Group and the sellers of services or items.

PMD-23 - Subcontract Preprocurement Planning

This procedure provides the guidelines required to accomplish a thorough subcontract preprocurement planning function by the Purchasing Department. It outlines purchasing policies that are consistent with requirements established in the Management Policies and Requirements (MPR) for the Clinch River Breeder Reactor Plant (CRBRP), and with policies delineated in the Rockwell Corporate Material Procedures (CMP's).

PMD-24 - Preparation, Review, Approval and Processing of Purchase Requisitions

This directive describes the procedure for preparing, reviewing, approving and processing Purchase Requisitions. These instructions augment those in SOP J-12.

The directive applies to Purchase Requisitions for CRBRP items prepared by the CRBRP Program Office or the Engineering Department. It does not apply to Purchase Requisitions prepared by Manufacturing in support of hardware "make" items.

PMD-25 - CRBRP Parts Standardization

All CRBRP design activities performed within ESG will utilize the ESG parts standardization system as described in "Preferred Parts and Design Standards", published by the Checking and Design Standards function. Changes to that publication will be applicable to the CRBRP Program immediately upon release for general ESG use and will not require revision to this directive.

PMD-26 - Use of Controlled Information Data Transmittal (CINDT)

This procedure establishes a method for the controlled dissemination of CRBRP technical information and to assure that information used as a basis for design is obtained only from controlled sources.

PMD-27 - CRBRP Document Status System

This procedure defines the operation of the Documentation Status System (DSS) module (WARD-D-0059) and the ESG responsibilities and interface with the Westinghouse ARD computer. The DSS assures that principal design data is identified, measured and statused to provide information required to manage said CRBRP Program data.

PMD-30 - CRBRP Specifications

This procedure modifies the requirements of the standard ESG specification revision system to certain specific requirements of the CRBRP Project.

PMD-32 - CRBRP Design Reviews and Release

This procedure implements the CRBRP policy relating to design reviews of systems and components, to supplement the standard ESG design review practice.

PMD-34 - Application of Additions to ASME Code Requirements

This directive covers all CRBRP components including piping systems designed and constructed under ASME Section III, ASME Section VIII, and ANSI B31.1.

PMD-35 - Change Control

This procedure provides direction for revision of all ESG documents which have been defined to be part of the CRBRP Baseline.

PMD-36 - CRBRP Engineering Drawings

This procedure defines the methods to be used for release and revision of CRBRP engineering drawings.

PMD-40 - Materials and Processes for CRBRP

This directive is established to ensure that all CRBRP design work will be based upon one common set of materials data as well as on consistent extrapolations and interpretations of these data.

PMD-41 - Baselining of Documents

This procedure gives the method for defining documentation as part of the CRBRP baseline.

PMD-43 - Review of Supplier Data

This directive establishes specific requirements for the review of supplier data and augments the general requirements of SOP K-78.

PMD-48 - Unusual Occurrence Reporting

The purpose of this procedure is to provide for DOE Unusual Occurrence Reporting and for identification of those occurrences which require special consideration as deficiencies reportable under 10CFR50.55(e) and 10CFR21.

PMD-54 - SHRS Reliability Program

This directive defines the requirements of the reliability program at ESG on CRBRP.

PMD-55 - Instructions for Required Documentation and Procedures for Shipment of Components to CRBRP Site or Other Designated Areas

This directive describes the required documentation and the submittal sequence to be followed prior to and during shipment of components and equipment to the CRBRP Constructor, Stone and Webster Engineering Company.

PMD-56 - Acceptance Test Requirements and Specifications

This directive defines the requirements for systems acceptance testing specifications which are to be prepared by AI-ESG.

PMD-57 - Storage, Maintenance, and Inspection of Material Parts and Components.

This directive describes the requirements and responsibilities for storage, maintenance, and inspection of material, parts, and components for CRBRP that are under the cognizance of ESG.

ENGINEERING MANAGEMENT PROCEDURES (EMPs)

EMP 1-0 - Preface to the Engineering Management Procedures Manual

This procedure describes the scope of the Engineering Management Procedures (EMP) Manual.

EMP 2-8 - Engineering Studies

This procedure establishes the requirement for conducting studies to establish that the design meets the design criteria, is based upon proven practices or analysis, and is adequate for the intended service. It describes the method for preparing, releasing, and controlling Engineering Studies.

EMP 2-9 - Design and Acceptance Criteria

This procedure delineates the need for design and acceptance criteria to be defined and published in the appropriate design basis documents.

EMP 3-1 - Engineering Documentation Process

This procedure describes the scope of the procedures which control the preparation, release, and control of specifications, drawings, and reports by Engineering.

EMP 3-5 - Engineering Release System

This procedure provides instructions for the preparation, numbering, release, and control of drawings for the Engineering Release System, and provides guidelines for application of the standard release. EMPs 3-5.1, 3-5.2 and EMP 3-5.3 provide for procedural details for the ASME Code, standard and experimental release systems.

EMP 3-4 - Numbering of Engineering Documents

This procedure and its sub-procedures (3-4.1, 3-4.2, 3-4.3, 3-4.4, 3-4.5, 3-4.6 and 3-4.10) defines the requirements and means for uniquely numbering various types of ESG engineering documents including drawings, specifications, supporting documents, O&M manuals, subcontractor memos, and software control documents.

EMP 3-21 - Engineering Change Control

This procedure defines the method for requesting, evaluating, approving, and executing engineering changes.

EMP 3-22 - Interface Control

This procedure establishes the criteria for interface definition and the methods for describing and controlling the interface in appropriate documentation drawings and specifications.

EMP 3-24 - Control of Engineering Documents

This procedure describes the methods for control of drawing originals and prints, released by both the Standard or Limited Release Systems.

EMP 3-25 - Engineering Orders - Preparation Instructions

This procedure describes the preparation and use of an Engineering Order to release drawings or specifications, and defines requirements. EMP's 3-25.1 through 3-25.17 provide details for various types of Engineering Orders.

EMP 3-26 - Preparation and Control of Supporting Documents

This procedure establishes the types of supporting documents and defines the requirements for their preparation, release, and change.

EMP 3-28 - Component Traceability

This procedure describes the elements and responsibility for establishing item traceability.

EMP 3-29 - Engineering Requirements for Serialization

This procedure sets conditions under which Engineering requires serialization of components or parts for traceability purposes.

EMP 3-36 - Request for Document Change

This procedure describes the formal means for requesting a change to a released drawing or specification and the approval and processing of that request.

EMP 3-42 - Engineering Management System for Specifications

This procedure defines the method for the preparation and control of Engineering specifications.

EMP 3-51 - Weldment Checklist

This procedure provides the checklist to be completed for critical weldments, and the system for its implementation.

EMP 3-52 - Engineering Release Plan of Action

This procedure gives the format and requirements for a plan describing the means of preparation and release and approval of program documents.

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EMP 3-63 - Documentation, Release, and Control of Scientific and Technical Computer Programs

This procedure describes the documentation formats for scientific and technical (S&T) computer programs used and/or produced within the Research and Engineering Department. Those S&T programs that are developed outside of ESG shall also be documented to the same extent specified by this EMP allowing for vendor documentation formats.

EMP 4-4 - Test Procedures

This procedure gives the format for preparation of Test Procedures.

EMP 4-5 - Test Reports

This procedure gives the format for preparation of Test Reports.

EMP 5-3 - Design Reviews

This procedure establishes the requirements for independent design reviews, and the means of their scheduling, conduct, and reporting.

EMP 5-17 - Checking of Engineering Drawings

This procedure establishes the responsibilities for checking of all engineering drawings.

EMP 5-19 - Failure Reports

Failure Reports are to be used when a component or system under test has failed or deviated from expected conditions on all ESG programs as defined in Paragraph 3.1.

EMP 5-20 - Incident Reports

Incident Reports are to be used when an incident or failure occurs in a test other than on the component being tested on all ESG programs as defined in Paragraph 3.1.

EMP 5-21 - Materials and Processes Control System

This procedure establishes the policy and responsibilities for control of materials and processes.

EMP 5-24 - Application of Standards

This procedure provides guidance and direction for the application of codes and standards. It categorizes various types of standards and establishes responsibilities for their collection and application.

CORPORATE AND AI MATERIAL PROCEDURES (CMP's/AIMP's)

AIMP 1.1.1 - Procurement Policy

This procedure describes the procurement policy of Rockwell International, and supplements it to cover procurement reflecting DOE requirements.

CMP 3.121 - Source Selection

This procedure defines Rockwell International's practice concerning selection of procurement sources and making commitments.

CMP 2.14 - Changes to Purchase Orders and Other Directions to Suppliers

This procedure establishes standards for accomplishing changes to purchase orders and effecting other direction to suppliers.

CMP 2.35 - Case File Documentation

This procedure establishes the documentation required to be accumulated in procurement case files.

AIMP 3.109.1 - Procurement from Approved Suppliers

This procedure requires procurements to Code requirements, to ensure that Quality Assurance-approved suppliers are obtained.

QUALITY ASSURANCE MANUALS* PROCEDURES

QAOP N1.00 - Preface to Quality Assurance Manual

The preface to each Quality Assurance Manual delineates the purpose and authority of the manual.

QAOP N1.01 - Quality Assurance Department Functions

This document outlines the functions of the individual groups within the Quality Assurance Department.

QAOP N1.03 - Vision Requirements for Quality Assurance Personnel

This procedure establishes vision standards for Quality Assurance Department personnel and defines responsibilities for administering an eye examination program.

QAOP N1.04, CS3M 18 - Quality Assurance Audits

These procedures outline the Quality Assurance responsibilities for implementing and maintaining an audit program to determine the overall effectiveness of the ESG and supplier quality programs and to identify areas where corrective prevention action is required.

QAOP N1.21 - Quality Assurance Plans

This procedure defines Quality Assurance Department responsibilities for participating in the preparation of Quality Assurance Program Plans or Quality Assurance Program Indexes and for preparing Quality Assurance Functional Plans.

QAOP N1.22 - Quality Assurance Acceptance Procedures

This procedure defines requirements and responsibilities of the Quality Assurance Department for the preparation, release, and control of Quality Assurance Acceptance Procedures (QAP's).

QAOP N1.23 - Quality Status Reports

This procedure establishes Quality Assurance Department requirements and responsibilities for preparation of periodic Quality Assurance Program Status Reports and for submittal of the reports to Energy Systems Group customers.

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*Energy Systems Group Quality Assurance Department Procedures (QAOP)
Energy Systems Group ASME Code Section III Manual (CS3M)

QAOP N2.03 - Document Control

This procedure provides direction for the control of engineering and shop drawings, including customer drawings applicable to products to be fabricated in the ESG Manufacturing Shops. The purpose of such control is to assure the fabrication, processing, inspection, and testing of products to the proper drawings.

| QAOP N3.00, CS3M 12 - Control of Measuring and Test Equipment

These procedures define requirements for calibration control of tools, gauges, instruments, and test equipment used by Manufacturing and Quality Assurance to measure products (materials, parts, components, and appurtenances) or to control processes related to the product.

QAOP N3.02 - ESG Special Tooling

This procedure defines the requirements and responsibilities for control of tooling used by Manufacturing and Quality Assurance Departments in product fabrication.

| QAOP N4.00, QAI N4.00A, CS3M 4 - Procurement Document Control

These procedures define requirements and responsibilities for preparation, review, and approval of procurement documents associated with the purchase of materials, parts, and services.

QAOP N4.01, CS3M 7.2 - Approved Procurement Sources

These procedures define Quality Assurance Department requirements for evaluation and approval of procurement sources (suppliers) of material, parts, and services used in ESG products.

QAOP N4.02, CS3M 5.3 - Procurement Quality Verification Instructions

These procedures define Quality Assurance Department requirements and responsibilities for preparing inspection instructions applicable to procured items and services.

QAOP N4.03 - Procurement Quality Assurance - Source Inspection/Surveillance

This procedure defines Quality Assurance Department requirements and responsibilities for quality verification of procured items and services at a supplier's facility.

QAOP N4.04 - Procurement Quality Assurance - Receiving Inspection

These procedures define Quality Assurance Department requirements and responsibilities for inspecting and testing incoming procured items and services.

QAOP N5.01 - Manufacturing Production Order (Shop Travellers)

This procedure defines the requirements and responsibilities for the preparation and utilization of the Manufacturing Production Order (MPO).

CS3M 9 - Control of Construction Processes

These procedures define the guidelines used to authorize and control the process, fabrication, installation, inspection, examination, and testing of components, parts, and appurtenances.

| QAOP N6.01, CS3M 5.4 - Welding Procedures

These procedures establish requirements and responsibilities for qualifying welding and brazing procedure specifications and welding and brazing personnel (welding, welding operators, brazers, and brazing operators) employed in fabrication of Code items.

QAOP N6.02, CS3M 2.4 - Qualification and Certification of Nondestructive Examination Personnel

These procedures establish requirements and responsibilities for the training, examination, qualification, and certification of Energy Systems Group personnel engaged in the following nondestructive examination processes:

Radiographic	Liquid Penetrant
Magnetic Particle	Eddy Current
Ultrasonic	Leak Detection

QAOP N6.03, CS3M 5.9 - Nondestructive Examination Procedures

These procedures establish requirements and assign responsibilities for preparing and controlling nondestructive examination (NDE) procedures used for determining compliance of products to requirements of applicable codes and standards.

QAOP N6.04 - Weld Material Control

This procedure defines requirements and responsibilities for issuance and control of welding materials (electrodes, rods, spools, and flux).

QAOP N6.05 - Qualification of Special Processes

This procedure defines requirements and responsibilities for qualification of special processes used during fabrication or inspection of products at Energy Systems Group.

QAOP N7.00 - Product Acceptance Tests

This procedure defines requirements and responsibilities of Quality Assurance Department personnel in performing acceptance tests, or witnessing acceptance tests performed by others on parts, material, subassemblies, assemblies, subsystems, and systems (items) that require acceptance by Quality Assurance.

QAOP N7.01 - Pressure Testing

This procedure defines the requirements and responsibilities for performing hydrostatic or pneumatic tests of ESG-fabricated ASME Code or other products.

QAOP N7.02 - Qualification and Certification of Visual and Dimensional Inspection Personnel

This procedure defines requirements and responsibilities to provide a mandatory program of training, examination, and certification for personnel performing dimensional inspection. The program will provide periodic updating to accommodate changes in requirements and maintain the level of knowledge necessary to perform dimensional inspection assignments.

QAOP N8.00 - Statistical Quality Control Program

This procedure establishes Quality Assurance Department requirements and responsibilities for implementing and maintaining a Statistical Quality Control Program.

QAOP N9.00, CS3M 14.2, 14.3, 14.4 - Issuance, Use, and Control of Stamps

These procedures define the requirements and responsibilities for the issuance, application, and control of stamps used for markings that identify personnel performing examination, inspection, test, welding, and brazing operations.

QAOP N9.02 - Serialization of Hardware

This procedure defines Manufacturing and Quality Assurance Department requirements associated with the serialization of parts and assemblies that are fabricated or procured by Manufacturing.

QAOP N10.00, CS3M 15 - Nonconforming Materials and Items

These procedures define requirements and responsibilities for control and disposition of nonconforming materials and items in the product manufacturing/procurement processes.

QAI N10.00D - CRBRP Hardware Nonconformance Processing

This instruction supplements Procedure N10.00D by providing specific details for CRBRP nonconformance items in accordance with LRM and Owner requirements.

QAOP N12.00 - Packaging and Shipping Inspection

This procedure defines Quality Assurance Department responsibilities for inspecting and packaging and the preparation for shipment of ESG products. It applies to products requiring Quality Assurance acceptance that are shipped from ESG, to an ESG construction site, to an ESG customer, or to an ESG supplier.

QAOP N13.02 - Quality Assurance Data Packages

This procedure provides format requirements for the preparation of Quality Assurance Data Packages for transmittal to the customer. Contractual requirements take precedence over this procedure, in case of conflict.

QAOP N14.00, CS3M 16 - Corrective Action for Nonconformance Products

These procedures establish requirements for taking action to correct conditions causing nonconforming material, parts, and components. Its purpose is to provide increased assurance that ESG products will meet design, configuration, and performance requirements.

CS3M 2.3 - Training and Indoctrination

This procedure defines requirements and responsibilities for training and indoctrination of personnel performing activities affecting quality or Code compliance, as necessary, to assure that suitable proficiency is achieved and maintained.

CS3M 3, 6 - Design and Document Control

These procedures establish the requirements and responsibilities as an Owner's Agent, and for the control of design activities and documents associated with items being constructed in accordance with the requirements of the Code.

CS3M 7.3, 7.4 - Procurement Verification (Source and Receiving Verification)

These procedures define requirements for source and receiving inspection, examination, and test of procured materials, parts, and services.

CS3M 8 - Identification and Control of Materials and Items

These procedures define requirements and responsibilities for implementing and maintaining material checklists required by the Code.

CS3M and Appendix A - Contracting for the Fabrication of a Code Item as an N-Certificate Holder Retaining Overall Responsibility for Certification and Stamping

This procedure covers the situations where ESG as an N-Certificate holder retains overall responsibility for a Code item, including design, certification, and stamping can contract for fabrication of the items.

CS3M 13, 5.7, 5.8 - Handling, Preservation, Storage, and Shipment

These procedures establish measures for handling, preservation, packaging, storage, and shipping to prevent damage to Code items.

CS3M 8.4 - Material Checklists

This procedure defines requirements and responsibilities for implementing and maintaining material checklists required by the Code.

CS3M 8.3 - Welding and Brazing Materials

These procedures define requirements and responsibilities for control of Code welding and brazing materials (electrodes, filler wire, fluxes, gases, and weld insert materials) used in fabrication and assembly of Code items.

CS3M 9.3 - Control of Welding Operations

These procedures define requirements and responsibilities for controlling production welding and brazing operations on Code items.

CS3M 5.5 - Heat-Treating Procedures

These procedures define requirements for controlling heat treating processes performed by Energy Systems Group. It is applicable to heat-treating processes other than weld preheat and interpass temperature, which are controlled in accordance with methods specified in qualified weld procedure specifications.

CS3M 7.8 - Subcontracted Furnace Brazing Services

This procedure defines requirements and responsibilities for control of subcontracted furnace brazing services.

CS3M 7.9 - Subcontracted Heat Treat Services

This procedure defines requirements and responsibilities for control of subcontracted heat treat services.

CS3M 7.10 - Subcontracted Nondestructive Examination Services

This procedure defines requirements and responsibilities for control of subcontracted nondestructive examination operations performed on Code materials and items.

CS3M 10, 11, 5.10 - In-Process and Final Examination, Tests, and Inspections

These procedures define requirements and responsibilities for examinations and tests of Code items, during fabrication and upon completion of fabrication to assure their compliance with Code requirements.

CS3M 2.6 - Authorized Nuclear Inspector

This procedure defines Energy Systems Group requirements and responsibilities for assisting the Authorized Inspector in performing his duties, in accordance with Code requirements.

CS3M 7.11 - Procurement Quality Verification Records

This procedure defines requirements and responsibilities for accumulating records generated during design and/or fabrication of Code items at Energy Systems Group, transmitting records to the owner or customer, and retention of records by Energy Systems Group.

CS3M 5.11 - Cleaning Procedures

This procedure defines requirements and responsibilities for preparing and controlling cleaning procedures.

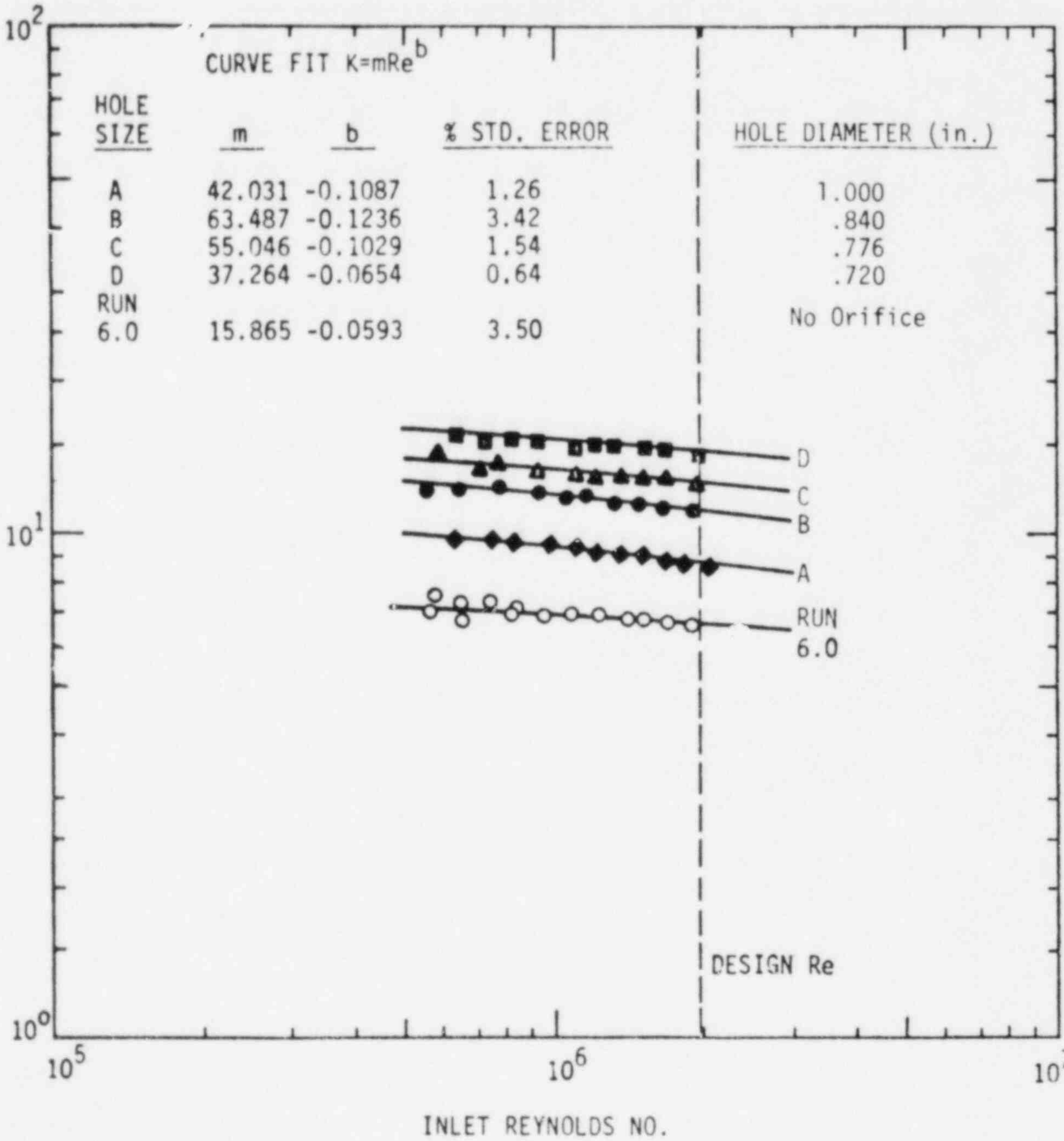

Figure A.36-2 **Fuel Assembly Inlet Nozzle Flow Resistance vs Reynolds Number; Single Plate Orifices and No Orifice Plate** (from Reference **4**).

A.37 FORE-2M

FORE-2M, which is an improved version of FORE-II, is a coupled thermal-hydraulics point-kinetic digital computer code designed to calculate significant reactor core parameters under steady state conditions or as functions of time during transients. Variable inlet coolant flow rate and temperature are considered. The code calculates the reactor power, the individual reactivity feedbacks, and the temperature of coolant, cladding, fuel, structure, and additional material for up to seven axial positions. Various Plant Protection System trip functions can be simulated, and the control rod shutdown worth prescribed as a function of time from the trip signal. By specifying appropriate hot channel/spot factors, the transient behavior of an average, peak and hot fuel rod can be analyzed. The heat of fusion accompanying fuel melting and the spatial/time variation of the fuel-cladding gap coefficient (e.g., due to changes in gap size) are considered. The feedback reactivity includes contributions due to the Doppler effect, coolant density changes and dimensional changes (including bowing and radial expansion). FORE-2M is valid while the core retains its initial geometry.

The original FORE-II computer model (Reference 1) was renamed FORE-2M following the incorporation of several major changes which were made to the program (Reference 2). Since then, additional modifications have been made to the code. These include updated modeling of the gap conductance heat transfer, changes affecting material properties, modifications in transient coolant flow characteristics, simulation of inter- and intra-assembly flow and heat redistribution, reactivity feedback and decay heat modifications, model changes to allow for alternate fuel rod characteristics and program improvements to provide user flexibility. These changes are described in Reference 3 which also provides the required input variables associated with these modifications.

Availability

The FORE-2M code described in References 2 and 3, is available on the Westinghouse Power Systems CDC-7600 and CRAY-1computers located at the Monroeville Nuclear Center.

Verification

FORE-2M transient results have been compared to thermal-hydraulic and nuclear calculations of other codes (e.g., DEMO, FX-2, IANUS and TAP-B). Other checks by hand calculations were made for quasi-steady state temperature distributions. The original FORE-II code has been used extensively over the last 17 years in the nuclear industry.

Application

The FORE-2M code is used to calculate the nuclear kinetic response of the core as well as the average, peak and hot rod behavior at steady state conditions, or as a function of time during transients.

References

1. J. N. Fox, B. E. Lawler, H. R. Butz, "FORE-II; A Computational Program for the Analysis of Steady State and Transient Reactor Performance," GEAP-5273, September, 1965.

2. J. V. Miller, R. D. Coffield, "FORE-2M: A Modified Version of the FORE-II Computer Program for the Analysis of LMFBR Transients," WARD-D-0142, May, 1976.

3. J. V. Miller, R. D. Coffield, K. D. Daschke, et.al., "Supplementary Manual for the FORE-2M Computer Program," CRBRP-ARD-0257, September, 1982.

TABLE B-1

PRELIMINARY DESIGN DUTY CYCLE EVENT FREQUENCIES

Event		Frequency
1. Normal Events		
N-1	Dry system heatup and cooldown, sodium fill and drain	5 total system + 8 per loop + 17 additional for entire intermediate loop exclusive of IHX
N-2a	Startup from refueling	140
N-2b	Startup from hot standby	700
N-3a	Shutdown to refueling	60
N-3b	Shutdown to hot standby	210
N-4a	Loading and unloading	9300 (loading) 9300 (unloading)
N-4b	Load fluctuations	46500 (up) 46500 (down)
N-5	Step load changes of ± 10% of full load	750 (+10%) 750 (-10%)
N-6	Steady state temperature fluctuations	30×10^6
N-7	Steady state flow induced vibrations	10^{10} (sodium)
2. Upset Events		
U-1a	Reactor trip from full power with normal decay heat	180[1] (U-1a, U-1b and U-1c together)
U-1b	Reactor trip from full power with minimum decay heat	
U-1c	Reactor trip from partial power with minimum decay heat	
U-2a	Uncontrolled rod insertion	10
U-2b	Uncontrolled rod withdrawal from 100% power	10

(1) - The total frequency for U-1 is associated with normal decay heat from full power so as to balance the trips associated with partial decay heat for events U-2 through U-23.

TABLE B-1 (Continued)

	Event		Frequency
	U-2c	Uncontrolled rod withdrawal from startup with automatic trip	17
47	U-2d	Uncontrolled rod withdrawal from startup to trip point with delayed manual trip	3
	U-2e	Plant loading at max. rod withdrawal rate	10
48 47	U-2f	Reactor startup with excessive step power change	50[(2)]
	U-3a	Partial loss of primary pump	2 per loop
	U-3b	Loss of power to one primary pump	5 per loop
	U-4a	Partial loss of one intermediate pump	2 per loop
	U-4b	Loss of power to one intermediate pump	5 per loop
	U-5a	Loss of AC power to one feedwater pump motor	10
	U-5b	Loss of feedwater flow to all steam generators	5
45			
	U-7a	Primary pump speed increase	5
	U-7b	Intermediate pump speed increase	5
	U-8	Primary pump pony motor failure	5 per pump
	U-9	Intermediate pump pony motor failure	5 per pump
	U-10a	Evaporator module inlet isolation valve closure	4 per loop
	U-10b	Superheater module inlet isolation valve closure	2 per loop
	U-10d	Superheater module outlet isolation valve closure	2 per loop

47 (2) - These events are part of the startups specified for event N-2b and should not be added as separate startups.

CLINCH RIVER

BREEDER REACTOR PROJECT

PRELIMINARY SAFETY ANALYSIS REPORT

APPENDIX J

PRA PROGRAM PLAN

PROJECT MANAGEMENT CORPORATION

TABLE OF CONTENTS

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TABLE OF CONTENTS (Continued)

PROGRAM PLAN FOR THE CLINCH RIVER BREEDER REACTOR PLANT

PROBABILISTIC RISK ASSESSMENT (PRA)

1.0 INTRODUCTION

This Program Plan describes the plan for the CRBRP PRA and applications of the study. The PRA was initiated principally related to the desire of the project to perform an integrated safety assessment as one ingredient in the decision process leading to safe design and operation. The PRA will also satisfy the requirements of NUREG-0718, Section II.B.8 and it is consistent with the current direction of the NRC in development of safety goals and PRA applications. As details are developed, they will be incorporated into this Program Plan. This review process is discussed in Sections 2.6 and 3.0. The PRA will be used as an aid in evaluation of the current design and alternative designs and as a tool to provide further assurance of safe plant operation.

The PRA will be, in the terminology of the PRA Procedures Guide (NUREG/CR-2300, Rev. 1), a Level III PRA. In addition to the tasks which comprise a Level III PRA, several tasks will support application of the study. These tasks include use of the PRA models to support operational programs such as emergency procedure preparation and operator training. The purpose of using the PRA in this way is that it can serve as a basis for defining potential operational incidents, thereby helping to reduce uncertainties caused by the limited availability of LMFBR operating experience.

2.0 OVERVIEW OF THE RISK ASSESSMENT PROGRAM

The PRA can be divided into the following major elements: accident initiator development, plant logic models for system functional event trees, and system functional fault trees, phenomenological event trees, and release and consequences analysis. The phenomenological event trees are divided into two groups; those that describe the phenomena from core melt to breach of the reactor vessel (i.e., core damage phenomenological event trees) and those that describe the phenomena from breach of the reactor vessel to containment integrity failure (i.e., containment phenomenological event trees). Refer to Figure 1 for a flowchart depicting how major elements will be tied together. These elements will be discussed in the following subsections.

2.1 ACCIDENT INITIATOR DEVELOPMENT

The approach being taken to logic model construction emphasizes the investigative nature of the task and results in an iterative model building process which ensures the accuracy of the final logic models. The following describes the iterative investigative method to be used.

A preliminary list of initiating events will be developed by extracting information from a variety of relevant sources. These sources include:

- o <u>Compilations of Generic Experience:</u> Examples are NUREG-0460 and EPRI NP-2230. In addition, NSAC has produced a screened list of LERs which identifies a number of risk significant PWR initiating events.

- o Previous PRAs: A numbor of other PRAs have been completed or are on-going. Each of these PRAs has compiled a list of initiating events (often from the generic sources listed above).

- o CRBRP Project Documentation: A number of design-specific documents are being screened to identify potential initiating events. These include the PSAR, plant design descriptions, Key Systems Review, Availability Analyses, and the existing Reactor Shutdown System (RSS) and the Shutdown Heat Removal System (SHRS) reliability assessments, (see PSAR Appendix C).

- o Breeder Reactor Experience: Including foreign and domestic sodium and/or breeder experience.

The resultant list of initiating events will allow the event tree and fault tree analyses to commence, but is not considered the final list. It is important that information gained during the event tree/fault tree analyses be continuously fed back into the task of identifying initiating events. By definition, an important initiating event is one that can evolve into an important sequence. It is impossible, therefore, to confidently list all the important initators before the event tree and fault tree analyses have been performed. This process systematically utilizes knowledge gained in the event tree/fault tree analyses to ensure that all important initiating events are identified. This approach is based upon the recognition that: (1) important initiators are either relatively high frequency events or are events which adversely impact the ability of the safety systems to respond, and (2) an initiating event must, by definition, require an active plant response to avoid core damage. The cut-sets of the fault tree models will be systematically examined for their relationship to event tree headings (developed for the preliminary list of initiators). It is then possible to identify any failure events which both call for an active plant response and adversely impact the performance of the safety systems. These types of events will be considered as potential initiating events.

The initiating event development requires performance of a fault tree analyses of the initiating event where appropriate. By comparing the cut-sets of the initiator with those of safety systems required to respond to the initiator it is possible to ascertain whether the specific cause of the initiator could also impact the ability of safety systems to respond. This additional step in initiating event identification ensures the accurate quantification of conditional probabilities and allows an initiating event to be broken down into subevents to highlight potential dependencies between the initiator and subsequent events. As an example of this step, the "loss of offsite power" event would be identified in the cut-sets of a "loss of feedwater" initiator and also show up as an element in the cut-sets of the Shutdown Heat Removal Systems; accordingly, "loss of offsite power" is always identified as a separate initiating event.

Thus, the proposed approach is an iterative process of initiating event identification which starts with the application of available compilations of operating experience and design information and feeds back crucial information from the ensuing event tree/fault tree analysis. In this way, completeness is assured not only by searching available compilations of data but also by explicitly and systematically investigating the CRBRP plant design.

2.2 PLANT LOGIC MODEL DEVELOPMENT AND QUANTIFICATION

Considerable attention will be devoted to the task of constructing accurate logic models. The design of the CRBRP which is being analyzed was that in place as of February 1, 1982. The analysis will be updated to reflect the current design at several stages during the PRA; specifically, any changes derived from the Construction Permit licensing review will be included in the final models.

The specific activities included under the general heading of Plant Model Development and Quantification are the development of system functional event tree and fault tree logic models, the analyses of plant response, accident sequence quantification, uncertainty analyses, and common cause failure analyses. The result of the plant model development and quantification tasks is a compilation of those probabilistically quantified accident sequences which lead to core damage and their particular plant state. These plant states are then the entry point to the analysis of the severity of damage resulting from an uncoolable core within the primary coolant boundary (i.e., core damage phenomenological event trees) and to the severity of challenge to containment integrity associated with the accident sequences which breach the primary coolant boundary (i.e., containment phenomenological event trees). Damage analyses will be discussed in subsequent subsections.

2.2.1 System Functional Event Tree Development

System functional event trees (ET) will be constructed for the initiating events discussed in Section 2.1. Before actual event tree construction begins, the numerous individual initiating events will be grouped into preliminary categories based upon their impact on the plant and the subsequent demands upon the plant safety systems. The approach to be used to perform the event tree analyses following preliminary categorization of initiating events is as follows:

1. Determine the functional requirements which must be met in response to the initiating event. Examples of such functions are reactor shutdown and decay heat removal.

2. Define the plant systems available to perform each of the necessary functions.

3. List all of the supporting systems which are common to the plant systems identified in Step 3. Examples of supporting systems are service water, instrument air, and electrical power. This information will assist in the identification of potential dependencies between systems and will affect the identification and ordering of event tree headings.

4. Identify operator actions associated with the systems identified in Steps 2 and 3.

5. Define potential functional dependencies between the plant systems identified in Step 2. This is the first step in an iterative process of identifying important system interrelationships which are not apparent by merely listing common hardware.

6. Perform the necessary analyses to determine timing of events, systems requirements, and the corresponding failure state definitions.

7. Construct the system level event trees. The two elements of constructing system event trees are determining: (1) the definition of the individual event headings and (2) the ordering of the events to produce the logic model for the event tree.

8. Document the event trees. The assumptions and reasoning which produced the event tree form are carefully documented.

Although the above outline describes a step-by-step process, the event tree construction process will be an iterative one in which the failure state definitions, timing, and system headings are continuously influenced by information fed back from the fault tree development and the plant response analyses.

2.2.2 System Functional Fault Tree Development

Fault trees will be drawn for most of the event tree headings. Decisions concerning the necessity to develop individual fault trees will be based upon the recognition that the purpose of a fault tree is to: (1) quantify the probability of an event for which no statistically acceptable data exist by logically breaking down the event into its constituent parts for which acceptable data do exist, and/or (2) identify potential dependencies among multiple systems. Fault trees will not be drawn for systems for which: (1) acceptable data exist for the event heading and no significant dependencies could exist between this event and subsequent headings, or (2) the event heading could not be involved in any risk-important accident sequences even if its conditional failure probability were extremely high.

The fault tree (FT) analyses will be performed using procedures and symbols presented in NRC's Fault Tree Handbook (NUREG-0492) or in the PRA Procedures Guide (NUREG/CR-2300, Rev. 1).

A package of FTs will be provided for:

- Shutdown Heat Removal System Top Logic
- Primary and Intermediate Heat Transport Systems
- Steam Generator System
- Main Feedwater and Condensate
- Turbine Bypass Valves and Condenser
- Steam Generator Auxiliary Heat Removal System
- Auxiliary Feedwater
- Direct Heat Removal Service
- Normal & Emergency Chilled Water

o Plant Service Water

o Class 1E Electrical

o Containment Cleanup

o Annulus Filtration

o Annulus Air Cooling

o Compressed Gas

o Containment Isolation

Each FT will include all known support systems such as electric power, instrument and control, instrument air, and service water.

In addition, a fault tree data base will be produced which will allow quantification of all fault trees. The data base will be derived from the same sources as those identified for accident initiator development.

2.2.3 Analyses of Plant Response

Analyses of realistic plant responses to postulated accidents will be performed throughout the course of the PRA to ensure that the plant logic models for ETs and FTs represent an accurate picture of the plant response and that all dominant risk contributors have been identified. Analyses will also be performed to assure that the system success criteria (i.e., successful system function) is realistically based on the physical capabilities of the plant.

A key element of the approach to this task is the efficient, systematic identification of specific analytical needs. Due to the costs and time delays in obtaining best-estimate plant response data, it is crucial that the analyst be able to determine: (1) what analyses are necessary for the PRA, and (2) what are the specific inputs and desired outputs of the analyses. Event trees will be systematically used to make these determinations. At each branch point in the event tree, the analyst will ask:

o What is required of the plant systems to maintain the necessary functions?

o What are the existing plant conditions important to maintenance of these functions?

o What are the realistic capabilities of the systems under these conditions?

These questions will determine the basic analytical requirements. When answers to these questions are not readily available to the PRA analyst, one of three avenues will be pursued to supply the needed information:

(1) Locate applicable analyses in available documentation.

(2) Perform hand calculations or extrapolation of existing analyses. Analytical needs not satisfied by available documentation can be satisfied by hand calculations where appropriate.

(3) Perform additional computer analyses. This avenue will be used only when documented analyses are not available and hand calculations would be insufficient. The role of the risk analyst at this point is to ensure that the results of the PRA are truly sensitive to the results of the desired analyses and to define the analytical requirements as carefully as possible.

The plant logic models will be modified where incorporation of best-estimate calculations will more accurately model actual plant behavior under accident conditions.

The heat transport and heat sink systems will be characterized in terms of their heat removal capabilities. Best-estimate calculations will provide the heat removal rate for one-, two-, and three-loop operation of the heat transport system under forced and natural circulation conditions. The characterization will also assess the amount of heat transported to the steam drum in excess of the capability of the closed-cycle sinks (i.e., Protected Air Cooling Condensers). In regard to the heat sinks, the capabilities of the PACCs will also be characterized for forced and natural draft and capabilities. The Steam Generator Auxiliary Heat Removal System vents will be characterized for operation with different Auxiliary Feedwater pumps and vents. Characteristic values of the heat transport and heat sink systems will allow determination whether various Loss of Heat Sink sequences will satisfy the success criterion.

The success criterion (prevention of core damage) for the loss-of-heat-sink event will be formulated and the analysis supporting the rationale leading to the criterion will be provided. The analyses will be best-estimate and the criterion will be simply-stated but will be broadly applicable to accident sequences leading to a loss-of-heat-sink.

The core damage event tree will trace through the phenomenological steps from the initial conditions in the core to the release of core material from the reactor vessel, if any. Event trees will be developed for all accidents identified by the event trees as leading to core damage. The plant states identified in the event trees will be carried through the core damage event tree to the containment event trees. Quantification at each node will be derived from an understanding of the basic phenomenological processes involved in the event.

2.2.4 Accident Sequence Quantification

Using the initiating events, ETs, FTs, and associated data bases, the dominant accident sequences will be quantified. The products of this task will include:

- A description of the process used to "link" the fault trees together and to ensure that all dependencies among system fault trees are identified and incorporated into sequence quantification.

- o A listing of the dominant accident sequences and a description of each including the individual events comprising each sequence.
- o A systematic justification for omitting any ET sequence from the dominant list (e.g., sequence Z, while producing the same effects, has an occurrence frequency four orders of magnitude less than sequence A).

The computer code which will be used in the generation of cut-sets and accident sequence quantification is COMCAN III (COMmon Cause ANalysis) developed by Idaho National Engineering Laboratory (INEL). Quantification will be an iterative process in which early analyses are used to help focus the more detailed common cause failure analyses, (see Section 2.2.6).

2.2.5 Uncertainty Analyses

Early in the PRA sensitivity studies will be utilized to provide information on the relative importance of equipment and human failures. Detailed uncertainty analyses will be delayed until later in the PRA program.

After the best-estimate quantification, a detailed uncertainty analysis will be performed in order to establish uncertainty bounds in the overall results of the PRA study. Estimates will be made of the probability distributions or confidence limits for those component failure rates and event frequencies which are potentially important to risk. The limitations of the uncertainty analyses will be addressed. The assessment methodology will include evaluation of the uncertainties on the importance of accident sequences which are known to have large uncertainties. The work will also establish confidence limits for total core damage frequency and a cumulative probability distribution curve. Probability distributions or confidence limits will be estimated only for those component failure rates and event frequencies which are potentially important to risk. For sequences, such as seismic, which are known to have large uncertainties, the assessment methodology will include evaluation of the effects of these uncertainties on the importance of the accident sequences. Any uncertainties which cannot be quantified will be qualitatively discussed.

Sensitivity analyses will be performed using the plant logic models to identify those input data or assumptions which significantly affect the dominant accident sequence list. These sensitivity analyses will focus on (1) uncertain failure rates, or (2) uncertain assumptions concerning success criteria or system dependencies. The final product of this task will include:

- o A description of each sensitivity analysis, including motivation,
- o The results of each analysis,
- o Interpretation of each analysis including the impact on detailed common cause failure analyses.

2.2.6 Common Cause Failure Analyses (CCFA)

The common cause failure analyses are broken down into four subtasks. These include: explicit modeling of dependencies, qualitative CCFA, detailed CCFA, and special CCFA investigations. These subtasks are delineated in the following four sections.

The CCFA is an assessment of common failure susceptibility and opportunity, including quantification of common cause events for:

a. internal events (such as temperature and pressure extremes and transients, common locations, proximity to degrading influences, fires); and

b. external events (such as seismic events, tornados, floods, lightning, chemical, radiation, explosions and aircraft or missile impacts).

2.2.6.1 Explicit Modeling of Dependencies

This portion of the CCFA entails those efforts required to ensure that all common support systems and functional dependencies between and among plant systems are explicitly and accurately included in the plant logic models. This task will be carried out in the process of constructing the event and fault trees.

All known inter- and intra-system dependencies will be modelled (such as common support systems identified in the fault trees), and performance of preliminary analyses of functional dependencies in which the physical response of the plant to the failure of one system has an adverse affect on the ability of another system to operate, and potential operator errors which can disable multiple systems or provide the link between failure of one system and another. The specific products of this task will include:

- A description of all known inter-system dependencies resulting from common support or interfacing systems.
- A "system level" failure modes and effects analysis (FMEA) in which the physical plant response to all event tree failure modes is described in terms of the behavior of major parameters (e.g., failure of system A to start will result in a rapidly rising pressure in system B).
- A listing for each event tree of the potential impacts of major parametric changes (e.g., a rapidly rising pressure will trip off pump C and cause failure of system B).
- A description of the more detailed dependency analyses to be performed and a preliminary approach for performing these analyses. An approach to treating external events such as seismic events will be included.

2.2.6.2 Qualitative CCFA

There may be failure causes common to multiple components which fall below the practical level of resolution in the event trees and fault trees. Examples of such potential common failure causes are:

- o manufacturing, installation, or maintenance errors
- o adverse environmental influences such as high temperature, humidity, or radiation
- o corrosion, carburization, rust, or other chemical degradation processes.

In this subtask, these types of common cause failures which could potentially have a significant impact on plant risk will be identified. This will be achieved by a conservative filtering process. This filtering process will allow the subsequent, more detailed analyses decribed below to focus on those dependencies which could actually be important to risk. This filtering process is based upon the recognition that for a common cause failure to occur, two criteria must be met:

(1) Both components must be susceptible to failure by the common cause (e.g., two different valve operators might both be susceptible to failure due to flooding, but a pipe and valve do not share a common susceptibility to failure by flooding).

(2) The common cause must have the opportunity to affect both components.

Based on this recognition, a two-step qualitative CCFA will be performed. The first step involves determination of which redundant components are susceptible to failure by the common cause. The second step involves determination of which susceptible redundant components (identified in the first step) are located such that an event could subject them to the common cause. Any susceptible redundant components so located are considered common cause candidates.

2.2.6.3 Detailed CCFA

The input to this subtask will be the relatively small number of common cause candidates which survive the screening process discussed above. In this subtask a more detailed assessment of common failure susceptibility and opportunity will be performed and probabilities estimated for these common cause events.

The detailed CCFA will address an extensive list of potential common failure causes (e.g., vibration, high temperature, etc.) for each component and will determine the potential for these mechanisms coincidentally affecting the components. For redundant components in different locations, this will entail evaluating the likelihood that causes can be coincidentally present in both locations. For components in the same location, this will entail a determination of whether the components are both (or all) susceptible to the same causes and the likelihood of those causes existing in that particular location.

2.2.6.4 Special CCFA Investigations

The above three subtasks will allow a practical, effective CCFA to be performed for most potential failure mechanisms. However, there are additional potential causes for multiple failures which will be addressed separately. These are fires, seismic events, and other significant external events.

Fires

The common location analysis performed (see Section 2.2.6.2) will form the basis for the fire analysis. The location analysis will provide:

- o List of key locations with potential for exposure to combustibles, an oxidizer, and an ignition source.
- o Key components in these locations
- o Fire related failure modes of these key components.

Based on this information, a preliminary scoping fire analysis will be performed to determine if fire-related accident sequences could contribute significantly to risk at the CRBRP.

Should the above scoping analysis identify any single or double location cut-sets which could realistically support a fire of sufficient size and duration to fail the components associated with these cut-sets, a more detailed fire analysis will be performed for these specific locations. Thus, the scoping fire analysis will be used to focus any detailed fire analyses which are required on those particular fire-related sequences which could potentially contribute to risk.

Seismic and Other External Events

External events such as seismic events, tornados, floods, explosions, aircraft or missile impacts, etc. will be evaluated to ascertain their significance to risk. Also, a detailed seismic methodology will be developed.

The preliminary analysis will be comprised of six basic steps:

(1) Estimate the frequency of occurrence of each external event.

(2) Identify the specific components or systems which could be adversely impacted by the event.

(3) Calculate the failure probability of such equipment and recalculate the probability of core damage with these components or systems unavailable.

(4) Multiply the frequency of occurrence from (1) by the conditional probability of core damage from (3).

(5) Compare the results of (4) to the baseline core damage frequency.

(6) If the frequency comparison in (4) indicates the sequence is risk significant, consider phenomenological aspects of the sequences.

If the results of the preliminary investigation indicate that there are potentially risk significant sequences initiated by one of the external events a more detailed analysis will be performed. The approach to this more detailed analysis will be very similar to that outlined above for the preliminary analysis. However, conservatisms in the preliminary investigation will be replaced by realistic evaluations of the impacts of the initiating event on plant systems. The overall risk shall include the contribution from external events.

2.3 CORE AND CONTAINMENT ACCIDENT MODELING

The result of the tasks on Plant Logic Model Development and Quantification will be a set of probabilistically quantified dominant accident sequences each of which is expected to produce damage to the core. Sequences which do not lead to core damage will be identified. Associated with each accident sequence leading to core damage will be a plant state which will include:

1. An indication of the successful operation of the Plant Protection System.

2. An indication of the availability of mitigating systems, (i.e., Containment Isolation, Annulus Air Cooling, etc.).

3. An indication of the capability of structures and surfaces to act as static and convective heat sinks during the accident sequences.

The definition of plant state for accident sequences terminated by core damage will allow two evaluations to be performed. First, the potential for various degrees of mechanical damage to the primary system resulting from energetic disassembly of the core can be evaluated. Second, the potential for failure of the containment system to maintain its integrity following a variety of severe accident sequences can be evaluated.

2.3.1 Phenomenological Event Trees

Phenomenological event trees will be prepared for both core damage and containment behavior resulting from accident sequences that lead to core damage (i.e. core damage phenomenological event trees and containment phenomenological event trees). The accident sequences will include those which could potentially lead to core energetics as well as those which have no significant energetics associated with the core disruption. The combined core damage and containment event trees will sequentially start with a definition of the plant state and sequentially terminate with a description of either a stable coolable state for the core debris or the time and size of the containment failure. As part of this evaluation, the radioactive source term above the operating floor at the time of a stable end point or containment failure will be defined. The event trees will describe, in detail, the major physical processes occurring within the primary system and containment which precede, cause, and follow, hydrodynamic core disassembly and/or loss of core coolability. This will include consideration of the thermal margins provided by the CRBRP design to mitigate the consequences of core damage as well as the structural margins to mitigate energetic effects and minimize a direct release of sodium and radionuclides from the primary system through the reactor vessel head. Both the core damage and containment event trees will be quantified.

The bases for selecting probabilities for each node will be documented. Development of the phenomenological event trees will include analyses, as follows:

- Thermal-hydraulics evaluation of the loss of decay heat removal following reactor shutdown including thermodynamic and heat transfer evaluation of the primary heat transport system.
- Extrapolation of currently available CACECO analyses to apply to the loss of decay heat removal following reactor shutdown.
- Structural calculations to assess the structural integrity of systems and components where necessary to support the phenomenological event trees.

The products of these analyses will include definition and probabilistic quantification of the range of potential sequences by which large quantities of radionuclides might be released from containment following a variety of accident sequences which produce core damage. These containment phenomenological sequences will define the conditions under which detailed analyses of the radionuclide source term from containment will be completed.

The core damage event tree will trace through the phenomenological steps from the initial conditions in the core to the release of core material from the reactor vessel, if any. Event trees will be developed for all accidents identified by the event trees as leading to core damage. The plant states identified in the event trees will be carried through the core damage event tree to the containment event trees. Quantification at each node will be derived from an understanding of the basic phenomenological processes involved in the event.

These phenomenological processes and the considerations leading to the selection of the quantification will be documented. The resulting core damage states will be grouped on the basis of energetics (ability of structurally loading the primary system) and on the basis of the degree of core melting (ability of thermally loading the primary system).

The containment event tree will combine the phenomenology of the molten core and sodium reacting with the environment outside the reactor vessel and the response of the containment/confinement system, beginning with the plant states previously identified and a small number of core damage states. The quantification of the phenomenological branch will be based on the understanding of the processes, the results from existing analysis and new supporting calculations where necessary. Quantification of the availability of containment system responses will be provided in the plant states.

2.3.2 Source Term Evaluation

An analysis will be performed to define the environmental source term for each of the unique paths through the containment phenomenological event trees for which significant releases of radionuclides are expected. Existing computer codes which will be utilized in this analyses include CACECO, HAA-3, and COMRADEX.

The potential for release and related health effects from ex-core sources of radionuclides will be defined. These sources will be evaluated using fault tree analysis techniques and the appropriate source terms given various plant system responses. Ex-core sources include radioactive cover gas, ex-vessel spent fuel storage, and other auxiliary systems.

2.4 HEALTH CONSEQUENCE ANALYSIS

The ex-plant consequence analysis will characterize the distribution of public health effects which can result from accidents involving core damage and significant radionuclide releases to the environment. Results from this analysis will assess the uncertainties in public health effect distributions which result from uncertainties in predicted accident sequence probabilities and radionuclide releases from containment.

The characterization of health consequences will be accomplished using the CRAC II computer code together with the meteorological and demographic data for the CRBRP site.

The health consequences associated with the release will be defined based on the source terms derived for each release category. The study will use state-of-the-art modeling codes which accurately project doses for the LMFBR source terms. The health consequences will examine both acute fatalities and latent cancer fatalities.

2.5 RISK ANALYSIS

Based on health consequences and sequence probabilities derived in the above tasks, an overall assessment of the risk shall be provided, including a breakdown of the major contributors to the risk. This assessment of the dominant contributors to risk shall include design and operational aspects, and sensitivity to key assumptions, and shall be kept current with knowledge of the plant and the PRA model.

2.6 PRA APPLICATIONS TASKS

The purpose of this section of the plan is to summarize the tasks which will be used for application of the PRA.

A number of PRA applications will be implemented. These applications rely on two characteristics of the PRA results:

1. The PRA is a complete description of the accident sequences which have the potential to cause damage to the core;

2. The PRA incorporates sufficient information to provide a quantitative ranking of the importance of equipment failures and human errors to both the frequency of core damage and the public health risk.

The use of these characteristics in a variety of application tasks is discussed below.

2.6.1 Operator Action Event Trees

Operator Action Event Trees (OAETs) will be developed. OAETs are a method to investigate the role of the plant operation staff in important accident sequences (Ref. NUREG/CR-1440). The analysis addresses three fundamental questions:

1. What actions can (or must) the operator take in response to a specific accident condition?

2. What information is required by the operator to take this action?

3. What instrumentation is necessary and sufficient to provide this information?

By developing logic models and supporting information which allow these questions to be addressed systematically, a very detailed description of the operator's role in managing an accident sequence can be developed. This description will also provide information about the specific role of plant instrumentation in informing the operator of the status of the plant. The complete set of OAETs WILL consist of one tree applicable for each dominant accident sequence. Common characteristics of a number of dominant sequences will allow the total number of OAETs required to be reduced to fewer than the number of dominant sequences.

2.6.2 Assessment of the Effectiveness of Postulated Design Variations Including Consequence Mitigation Features

Models developed during the PRA will be utilized to assess the potential benefits or lack thereof associated with postulated changes in plant design. These changes may be oriented toward reducing the frequency of events which produce core damage or mitigating the consequences of these events.

The present design of the CRBRP containment includes a number of systems designed to mitigate accident consequences. A quantitative display of the effects of these features on the risk from the CRBRP will be developed. Such a comparative evaluation is called for in NUREG-0718, Item II.B.8. This evaluation will include sensitivity studies in which the effectiveness both of currently designed and of postulated consequence mitigation systems can be assessed.

In addition, a search of dominant accident sequences will be conducted to assess whether cost effective modifications to the existing design can be postulated. Where such potentially useful modifications are identified, a more detailed evaluation of alternative approaches to reducing the risk contribution from one or more dominant accident sequences can be performed. This evaluation can include assessment of feasibility, effectiveness, and cost of a variety of postulated changes.

2.6.3 Improve Understanding of the Plant

Additional PRA applications will be undertaken to factor insights gained in the conduct of the PRA into the design and operation of the plant. These applications will:

1. Supplement the existing programs designed to address operator aids including Reg. Guides 1.47, 1.97, and NUREG-0497. The PRA will be used to define and rank the risk significance of alarms and instrumentation which are designed to improve the operator's ability to prevent and mitigate the consequences of severe accident sequences.

2. Assist in the development and validation of emergency procedure guidelines.

3. Provide information on the integrated performance of plant systems and instrumentation for use in evaluating the design and utilization of the plant simulator, as well as to train operators and other plant personnel.

4. Assess of the sensitivity of the CRBRP risk to uncertainties in the reliability of equipment required to perform its function in a degraded environment. If appropriate, alternative design features intended to reduce the sensitivity of the overall plant risk to these uncertainties will be defined and evaluated.

5. Evaluate the risk contribution and sensitivities to the testing interval of equipment and to the allowable on-line maintenance interval. This evaluation will allow Technical Specifications to be implemented in a manner which assures the minimum plant risk without unnecessarily restricting plant operation during the maintenance of safety-related equipment.

2.6.4 Characterization of Risk From Early Life Failures

The approach used to assess with the failures anticipated to occur during early years of operation will include two important elements. Both of these elements involve the careful screening of available operational data and results from the PRA. The first element is to analyze the data to focus on the potential for systematic recurring failure causes and to identify measures which have been successfully used in the past to contend with these causes. The second element is to focus on the equipment which has or is expected to produce the most significant operational problems and to define operational, maintenance, or training programs which might reduce the severity of these specific equipment failures.

2.6.5 Implementation of a Continuing Risk Management Program

The PRA will have application as a tool to evaluate operational experience and to address licensing issues which will arise during the operation of the plant. Implementation of such a continuing risk management program will include:

1. Formalization of the models and documentation developed during the PRA to facilitate ease of long-term utilization;

2. Transfer of the PRA technology and associated tools to the TVA operatons staff;

3. Definition of a TVA program by which the PRA and its associated documentation cna be updated to reflect the current state of the plant design and operation as well as current operational experience.

The risk management program will allow applications to be carried out by the TVA plant staff throughout the life of the plant. The program will include evaluating operational experience and addressing licensing issues which might arise during operation of the plant.

The program will also provide assurance that operational and back-fit decisions will be based on a realistic and complete understanding of the important safety characteristics of the plant. This understanding will be influenced by experience gained in the operation of the plant.

2.6.6 Input to the Site Emergency Procedures

The PRA will be used in the development and implementation of the site emergency procedures. The use of the PRA in this role is supported by the fact that it embodies a description of important accident sequences which includes estimates of the timing of significant radionuclide releases relative to the occurrence of the initiating event and the subsequent system failures which lead to significant core damage.

By using the PRA estimates for the timing of the accident together with a description in the CRAC-II code of the effect of meteorology and demography on population exposure, various strategies will be developed and assessed to determine the combination of evacuation and shielding (i.e., non-evacuation) which minimize population exposure given a set of meteorological conditions.

2.7 INTERACTION WITH THE NRC

The Project plans to support an interactive, phased review process on a schedule acceptable to both NRC and the Project. The review will promote an improved understanding of the PRA complexities, uncertainties, and validity. NRC is expected to provide comments on schedule, scope, and detailed implementation for consideration as the work progresses.

This review process will be carried out at appropriate intervals during the PRA program in a two-stage format. The first stage will be an overview to provide information to NRC management on the overall status of the effort and the significant results. The second stage will involve informal detailed discussions of methodology and interim results. This latter stage is aimed at providing technical detail to the NRC staff and its consultants.

As noted earlier, as the PRA progresses a more detailed definition of methodology to be used in such analyses as seismic risk characterization will be developed. It is expected that this more detailed methodology will be presented at appropriate NRC review meetings and that comments will be considered on the selected methodology as it relates to issues which the NRC considers to be candidates for resolution or prioritization using the PRA.

2.8 ACCIDENT DELINEATION

The CRBRP Project is currently pursuing a program to assure that all appropriate sequences are included within the plant design bases. A complete set of initiators together with a well formulated and quantified set of event trees and fault trees will provide a set of accident sequences in a probabilistic context. An assessment will be performed to determine if all appropriate accident initiators and accident sequences are included in CRBRP's Design Basis Accidents. This assessment will provide the decision criteria for the conclusions presented. This review will include the following considerations:

1. Development of a set of criteria on which definition of sequences comprising the design envelope should be based will be presented in the referenced project documentation.

2. Characterization of accident sequences identified in the PRA (including sequences which do not result in core damage) by:

   a. Occurrence frequency;

   b. Number of active failures following the initiating event (minimum);

   c. Number of passive failures following the initiating event (minimum);

   d. Severity of sequence impact on the environment surrounding safety-related equipment;

   e. Severity of sequence challenge to systems designed to remove d heat (e.g., how many different systems are capable or availabl remove decay heat at the end of the sequence);

   f. Severity of sequence challenge to reactor structures, including the containment building;

   g. The availability of support systems in important sequences at point in the sequence at which a particular system is required to perform its function.

3. Consideration of both plant induced and external initiating event sequences in this analysis;

4. Select sequences based on the criteria in (1) and the characteristics in (2);

5. Compare the selected sequences with those which currently comprise the design envelope and group the sequences by the various measures of severity defined in (2). The result of this comparison and grouping should be a reduced set of sequences. Any significant new events which are identified will be added to the design basis.

The product of this effort will be presented and discussed a, one of the NRC program review meetings.

2.9 STUDY LIMITATIONS

A brief listing of the study limitations is presented below:

1. COMPLETENESS AND LEVEL OF DETAIL OF THE MODELS- The completeness and level of detail of the models will be limited as a result of the state of the design and the unavailability of details of construction. These limitations can, however, also be viewed as strengths since there is the opportunity to utilize the PRA in reviewing these design details for their risk implications as they are established.

2. HUMAN FACTORS ANALYSIS- The role of the plant operations staff in the initiation, aggravation, and mitigation of an accident will be modeled in the fault trees and event trees developed to describe the sequence of events. The ability of the models and quantification methods is limited. However, a supplementary approach will be utilized. In this approach, operator action event trees will be used to investigate the role of the operations staff in severe accident sequences.

3. EXTERNAL EVENT QUANTIFICATION- Experience with the analysis of risk from external events (e. g., seismic events) has shown that the associated uncertainties are significantly larger than for accident sequences initiated by in-plant causes (which typically have a less pervasive effect on equipment reliability). Nevertheless, external events have in some cases been assessed to be significant contributors to plant risk. This analysis with its inherent uncertainties has, therefore, been included within the scope of the PRA.

4. FAILURE DATA- A significant quantity of failure data is available for equipment in many systems (i.e., steam, fire protection, electrical, control, and communication) of the CRBRP. These data have uncertainties no greater than those associated with L·"s. Components in the liquid metals systems and at the interface between the sodium and other systems are less well characterized. Although uncertainties in the reliability of these components exist, the implications of these uncertainties to the risk profile can be characterized using sensitivity studies carried out within the PRA. Other areas in which significant uncertainties exist which may be important to the overall description of plant risk incl de

   a. Initiator frequency;

   b. Equipment reliability in a degraded environment;

   c. Equipment repair time distributions and allowable on-line maintenance intervals.

5. ACCIDENT CHARACTERISTICS- The response of the core to conditions which will produce core degradation and the response of the

containment to severe accident sequences are somewhat uncertain. These uncertainties are being handled by the use of phenomenological event trees developed to describe physical processes which can lead to accident energetics and to containment failure following core damage.

6. SITE SPECIFIC CHARACTERISTICS- The effects of uncertainties in site meteorology and demography as well as in emergency response procedures can produce significant uncertainties in overall risk. Again, the effect of these uncertainties will be investigated using sensitivity analysis.

3.0 PRA PERFORMANCE AND REVIEW

A program of plans and actions will be implemented to control and verify quality of the results from the PRA.

This program will include measures and documentation to assure that:

1. data is reviewed and evaluated systematically to verify completeness and correctness with respect to the PRA requirements. This includes assurance that analyses are verified by the PRA analysts and appropriate design organizations that the work has been performed satisfactorily; and

2. the methods used for verification are identified and the verification results are documented.

Organizations which are presently involved in implementation of the study are shown in Figure 2. Also shown on the figure in a box separated from the PRA performers are the design organizations. These organizations will serve to provide information about the plant features to the PRA performers and to review the technical results of the study for accuracy and completeness.

The overall review program is pictured in Figure 3. As shown, four levels of review by the CRBRP Project Office. The first level is a working review by the performing organizations designed to assure the technical accuracy, clarity, and consistency of elements of the product. The second level is a review by CRBRP Project interfacing organizations to assure consistency of the elements of the analysis with plant design and operational characteristics. The third level of review will be conducted by a project management review committee to assess the validity of the approach taken to project integration and to assure proper implementation of the approach. Finally, the fourth step is an overall review by a peer review-group made up of participants external to the Project. The purpose of this final review is to assess the adequacy of the program integration and to evaluate the consistency of the methods used with the state-of-the-art.

The CRBRP Project Office will ultimately be responsible for utilizing the results and insights from the risk assessment to help ensure that the systems designed to shutdown the plant, to cool the core, and to mitigate the effects of severe accident sequences are designed and operated to be consistent with the results of the PRA. Decisions on possible changes to the plant design will be made through established Project procedures. These procedures ensure both consideration and review of proposals by all affected personnel throughout the project.

4.0 SCHEDULE, MILESTONES, AND RESOURCE ALLOCATION

The PRA products are listed in Table 1 and the schedule for key milestones for the entire PRA is depicted on Figure 4. As shown, the program is expected to produce a final report in late 1984.

Table 2 provides estimates of the resource allocation for each task. The values in the table will fluctuate over the course of the PRA, but the table communicates relative levels of effort for each task. Table 3 provides the planned completion dates for the tasks. The results of these tasks will be available for NRC review after the completion dates.

TABLE 1
CRBRP PRA PRODUCTS

PRODUCTS

- o INITIATING EVENT TOP LOGIC AND INITIATOR COMPLETENESS ANALYSIS
- o PROBABILISTICALLY QUANTIFIED ACCIDENT SEQUENCES AND THEIR BASIS
    - A. SYSTEM FUNCTIONAL EVENT TREES
    - B. FAULT TREES
    - C. DETAILED COMMON CAUSE FAILURE ANALYSIS (SYSTEMS INTERACTION EVALUATION)
    - D. EXTERNAL EVENT EVALUATION (SEISMIC, ETC.)
- o CORE DAMAGE PHENOMENOLOGICAL EVENT TREES AND QUANTIFICATION
- o CONTAINMENT PHENOMENOLOGICAL EVENT TREES AND QUANTIFICATION
- o UNCERTAINTY ANALYSIS
- o RADIONUCLIDE RELEASE ANALYSIS
- o HEALTH CONSEQUENCE ANALYSIS
- o ANALYSIS OF EX-CORE SOURCES OF RADIONUCLIDES
- o DEFINITION OF PROGRAM TO SUPPORT CONTINUING OPERATIONAL APPLICATIONS
- o OPERATOR ACTION EVENT TREES AND APPLICATIONS TO OPERATIONS SUPPPORT AND TRAINING PROGRAMS
- o DEFINITION OF AN ON-GOING RISK MANAGEMENT PROGRAM
- o EVALUATION OF POTENTIAL RISK REDUCTION ASSOCIATED WITH SUGGESTED DESIGN CHANGES
- o EVALUATION OF RISK CONTRIBUTION AND SENSITIVITIES TO EQUIPMENT TESTING INTERNALS (TECH. SPEC. IMPACT)
- o DETAILED DOCUMENTATION OF STUDY AND FINAL REPORT

TABLE 2
RESOURCE ALLOCATION

Listed below is each major task associated with the risk assessment and the manpower estimated for that task.

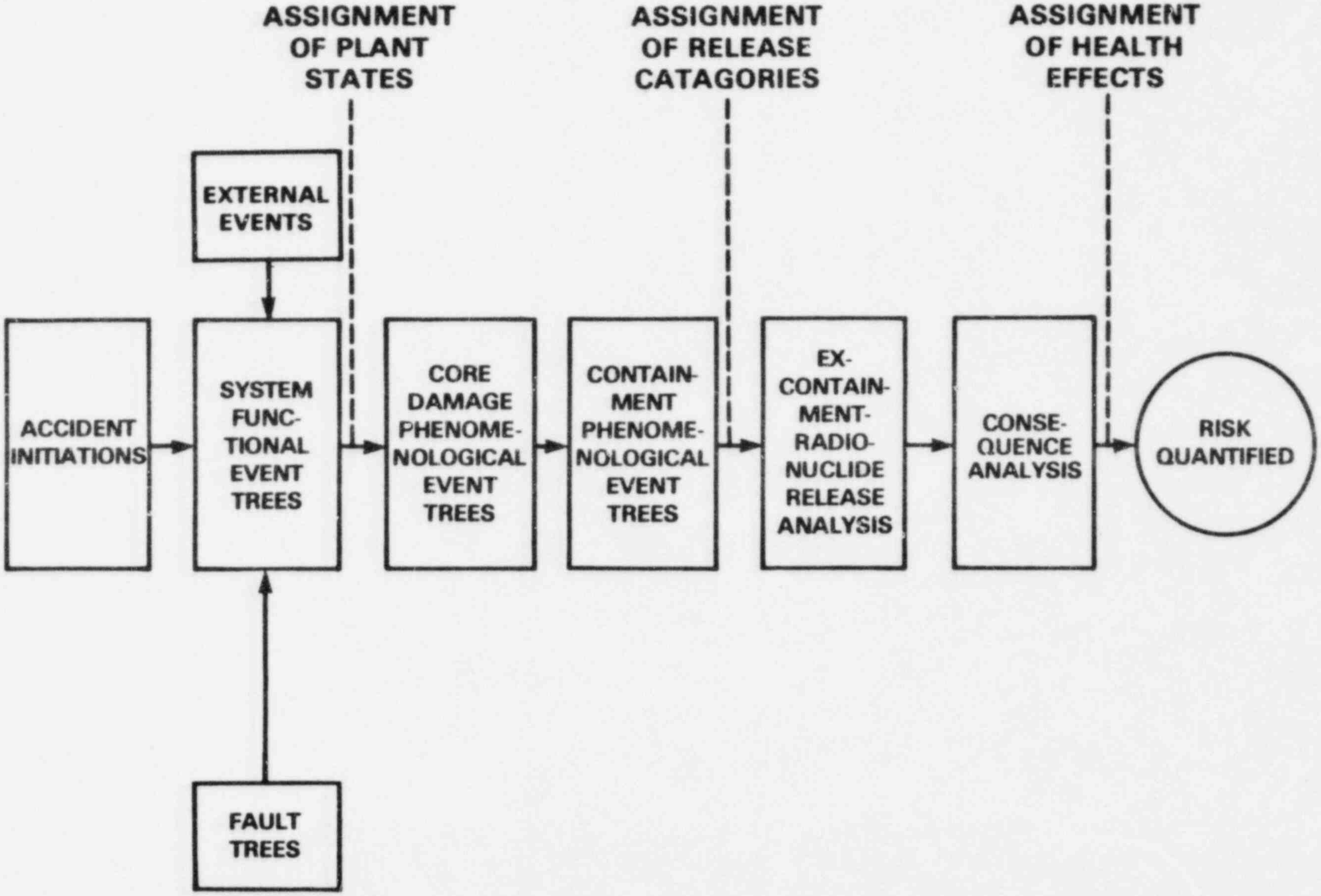
Task	Man-Months
Study Direction	28.0
Accident Initiator Identification	4.6
Event Tree Development	25.7
Initiating Event Data	3.3
System Fault Tree Development	65.8
Component Failure Data	1.0
Fault Tree Quantification	25.6
Event Tree Quantification	5.3
Common Cause Failure Analysis	22
Sensitivity Analysis	10.3
Dependency Analysis	12.2
Systems Failure Criteria	6.3
Core Response Event Trees	11.2
Containment Response Event Trees	11.2
Source Term	27
Consequence	12
Risk Analysis	9
Ex-core Sources	7
Uncertainty	7
OAET	13
Site Emergency	8
Input LCOs	7
Accident Delineation	6
On Going Risk Management	9

TABLE 3
CURRENT SCHEDULE OF UNCOMPLETED TASKS

DESCRIPTION	DUE DATE
Provide final written Accident Sequence Definition Review	3/31/83
Provide final written Radionuclide Release Analysis	12/31/83
Provide final written Uncertainty Analysis	10/31/84
Provide final written Detailed Common Cause Failure Analysis	10/31/84
Provide final written Accident Delineation Report	10/31/84
Provide final written Health Consequence Analysis	10/31/84
Provide written Risk Management Program Report	12/31/84
Provide written Operator Action Event Trees Report	12/31/84
Provide written input to Operational Procedures and Testing Interval	12/31/84
Provide written input to Site Emergency Plan	12/31/84
Provide final written Report	12/31/84

FIGURE 1

PRA FLOWCHART



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Amend. 73
Nov. 1982

Figure 2

CRBRP PRA ORGANIZATION

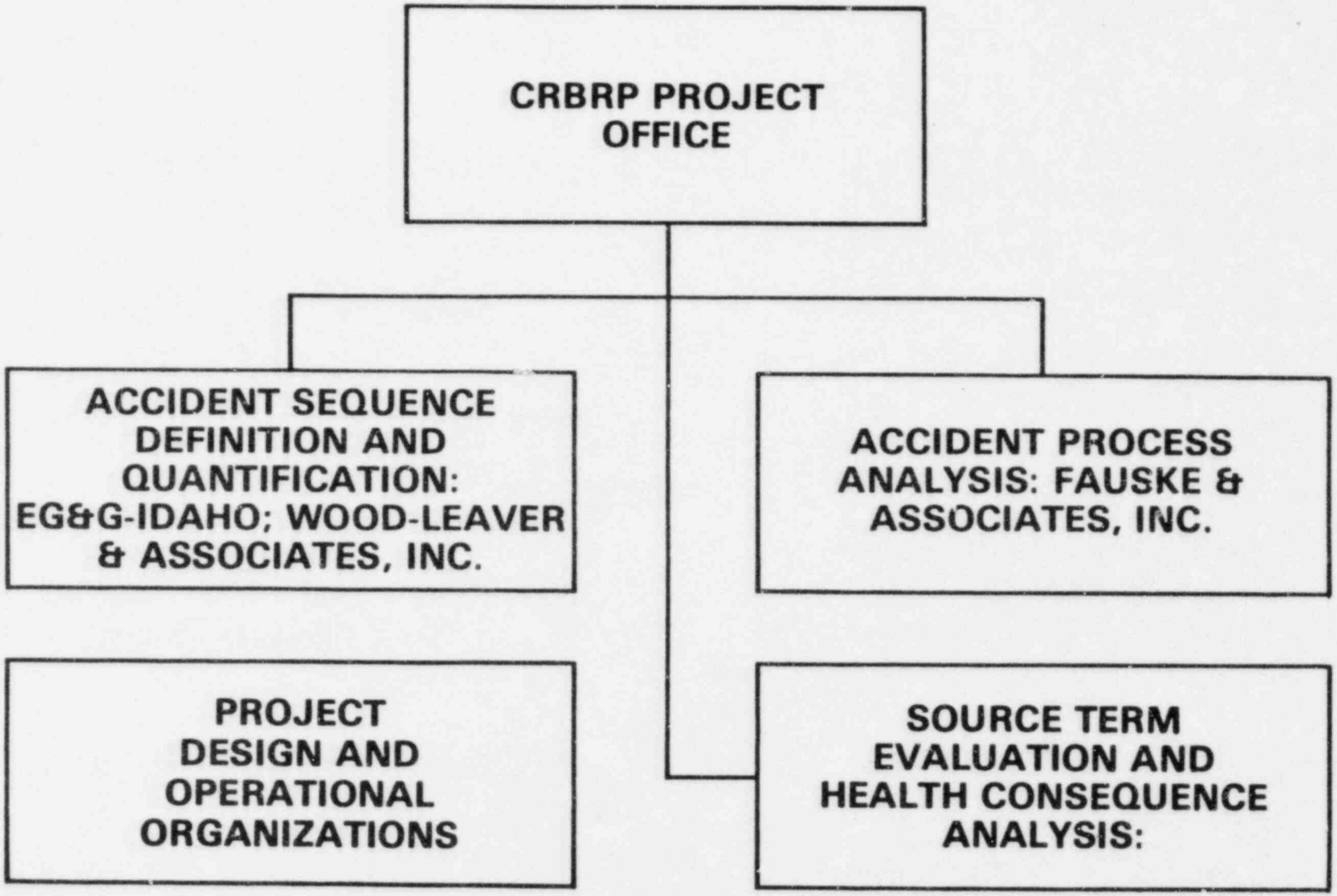

FIGURE 3

ANTICIPATED PRA INTERNAL REVIEW PLAN

ELEMENTS

INTERNAL REVIEW BY ORIGINATING ORGANIZATION

REVIEW BY PROJECT INTERFACING ORGANIZATIONS (DESIGNERS, SAFETY AND LICENSING)

OVERALL REVIEW BY DESIGNATED PROJECT COMMITTEE

OVERALL REVIEW BY PROJECT AND EXTERNAL PEER REVIEW BOARD

PURPOSE

- **ASSURE QUALITY, CLARITY, AND CONSISTENCY OF ELEMENTS OF PRODUCT**
- **ASSURE CONSISTENCY OF ELEMENTS OF ANALYSIS WITH DESIGN AND OPERATIONAL CHARACTERISTICS**
- **ASSURE PROPER INTEGRATION OF PRODUCT ELEMENTS AND ACCURACY OF APPROACH TO INTEGRATION**
- **PEER REVIEW OF INTEGRATION APPROACH FOR ACCURACY AND CONSISTENCY WITH STATE-OF-THE-ART IN PRA**

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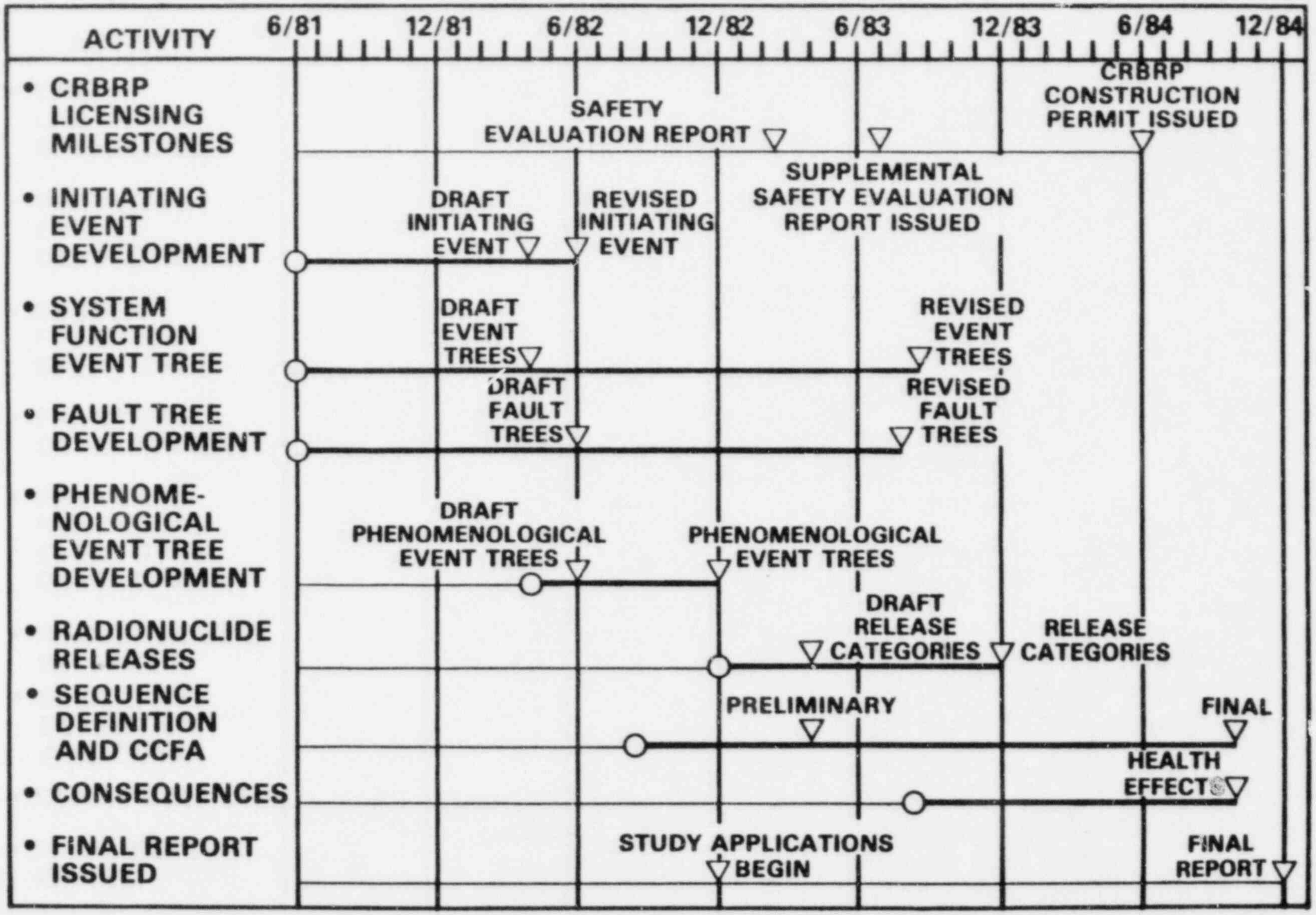
Figure 4

EXPECTED SCHEDULE OF PRA PRODUCTS



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Amend. 73
Nov. 1982

AMENDMENT 73

LIST OF RESPONSES TO NRC QUESTIONS

There are no new NRC Questions in Amendment 73.

Question 001.245 (15.7.1.2.1)

Identify all safety related valves or instruments which require a compressed air supply.

Response:

See updated Table 15.7.1.2-1

Question CS760.60

The fuel life and coolant boiling constraints are quantified by defining equivalent limiting temperatures which shall not be exceeded. The constraints are defined for Plant Expected Operating Conditions (PEOC). The uncertainty factors are at the 2-sigma level of confidence. Assembly lifetime/burnup goals are achieved when both the cladding inelastic strain and cladding CDF are within established limits of 0.2% for the ductility strain limit and 0.7 for the CDF during steady state operation. Strain Equivalent Limiting Temperature (SELT) is defined as the end-of-life temperature which, if maintained throughout life, would cause for the particular assembly an EOL cumulative strain of 0.2%. A Damage Equivalent Limiting Temperature (DELT) is defined similarly as the equivalent EOL temperature corresponding to a CDF of 0.7 for fuel assemblies and 0.5 for blanket assemblies.

The calculation of the Transient Equivlant Limiting Temperature (TELT) is performed in three steps:

A. to provide an adequate margin to boiling, a temperature of 1550°F is defined as the maximum coolant temperature allowable during the natural circulation transient at a 3-sigma level of confidence assuming Thermal-Hydraulic Design Value (THDV) conditions.

B. this limiting temperature is translated into a temperature T_M which is defined as:

- the maximum steady state coolant temperature corresponding to a 1550°F transient maximum coolant temperature for

- PEOC

- at the 2-sigma confidence level

C. finally, T_M is translated into the Transient Equivalent Limiting Temperature TELT by multiplying the difference between T_M and the inlet temperature T_{in} by the ratio of the coolant temperature rises at EOL and the time in life when the maximum transient temperature occurs, considering also the axial position where this temperature is reached, and adding to this the inlet temperature and correcting for the ID temperatures needed. The assemption for this correction is that the temperature difference $T_M - T_{in}$ would increase/decrease with time in the same manner as the temperature difference $T_{Cool} - T_{in}$.

It is understood that the orificing is an iterative process whereby a flow distribution is assumed which yields SELTs, DELTs and TELTs. These numbers in turn provide for a new flow distrubution which yields new values for these temperatures, etc.

The design basis requires no fuel centerline melting at 115% overpower conditions.

Why has this criterion not been used for the flow orificing?

Response:

Fuel centerline temperatures are only a weak function of the cladding temperature; therefore the no fuel centerline melting would have been a "flow-insensitive" criterion if used for orificing. Rather, detailed ad hoc analyses were performed to guarantee that the no melting criterion is satisfied, as discussed in Section 4.4.3.3.6.

It should also be clarified that the orificing is only partially an iterative process, and the question statement "it is understood..." is only partially true. A flow distribution which yields SELTs, DELTs and TELTs is actually assumed. However, once the limiting temperatures are determined, the corresponding flow is calculated by the ØCTØPUS code and this represents the limiting flow adopted in the orificing process. Thus, there is no iteration process on the temperatures constraints; once they are determined the orificing configuration follows through. However, final verification that all design constraints are indeed satisfied is performed following calculation of the detailed performance prediction parameters reported in Section 4.4.3.3. Thus, orificing constraints are guidelines not limits. Guideline values have margins to any limits and provide guidance in core orificing (i.e., establishing the optimum flow allocations in core). Subsequent detailed structural analyses (PSAR Section 4.2) determine the design adequacy of core components, using as input the design data from Section 4.4.3.3.

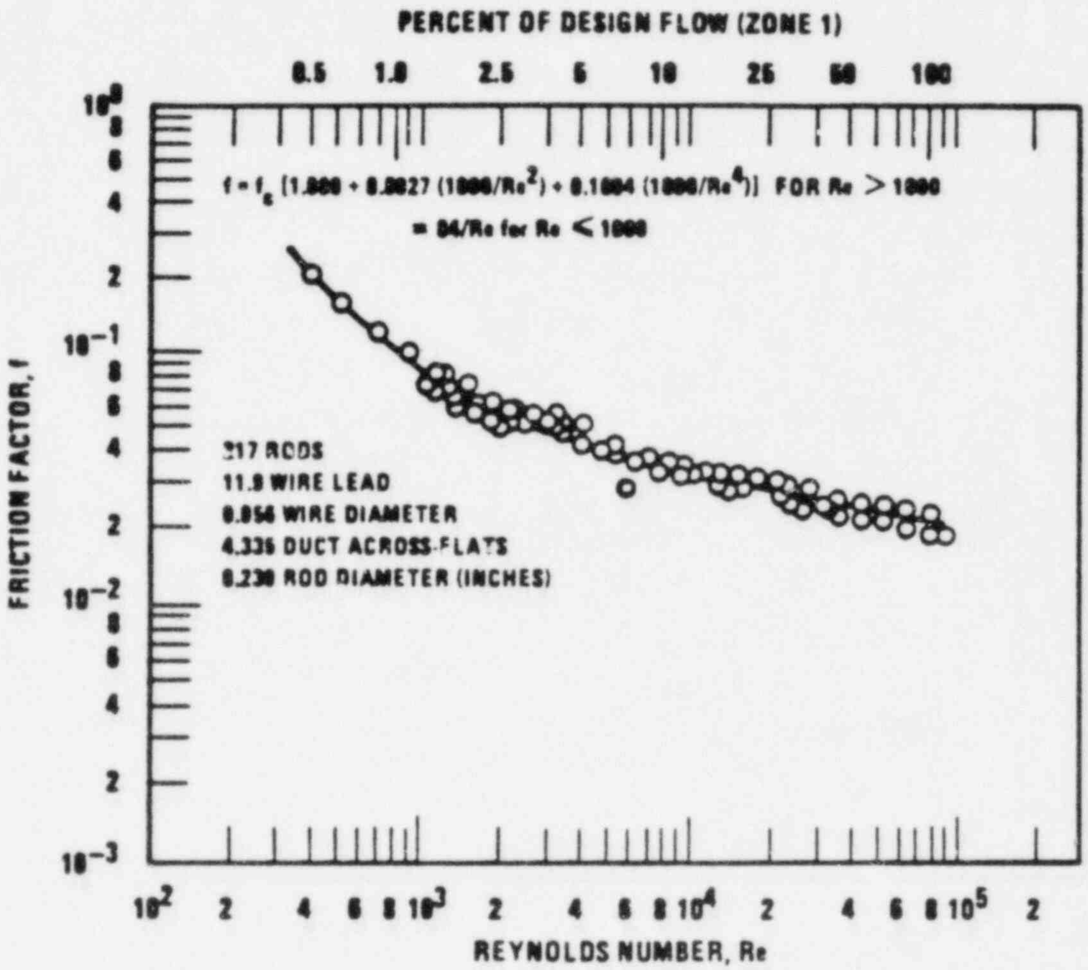

Figure QCS 760.77-1. Friction Factor Data and Correlation for 217 Pin Wire Wrap Spaced Fuel Assembly

7209-1

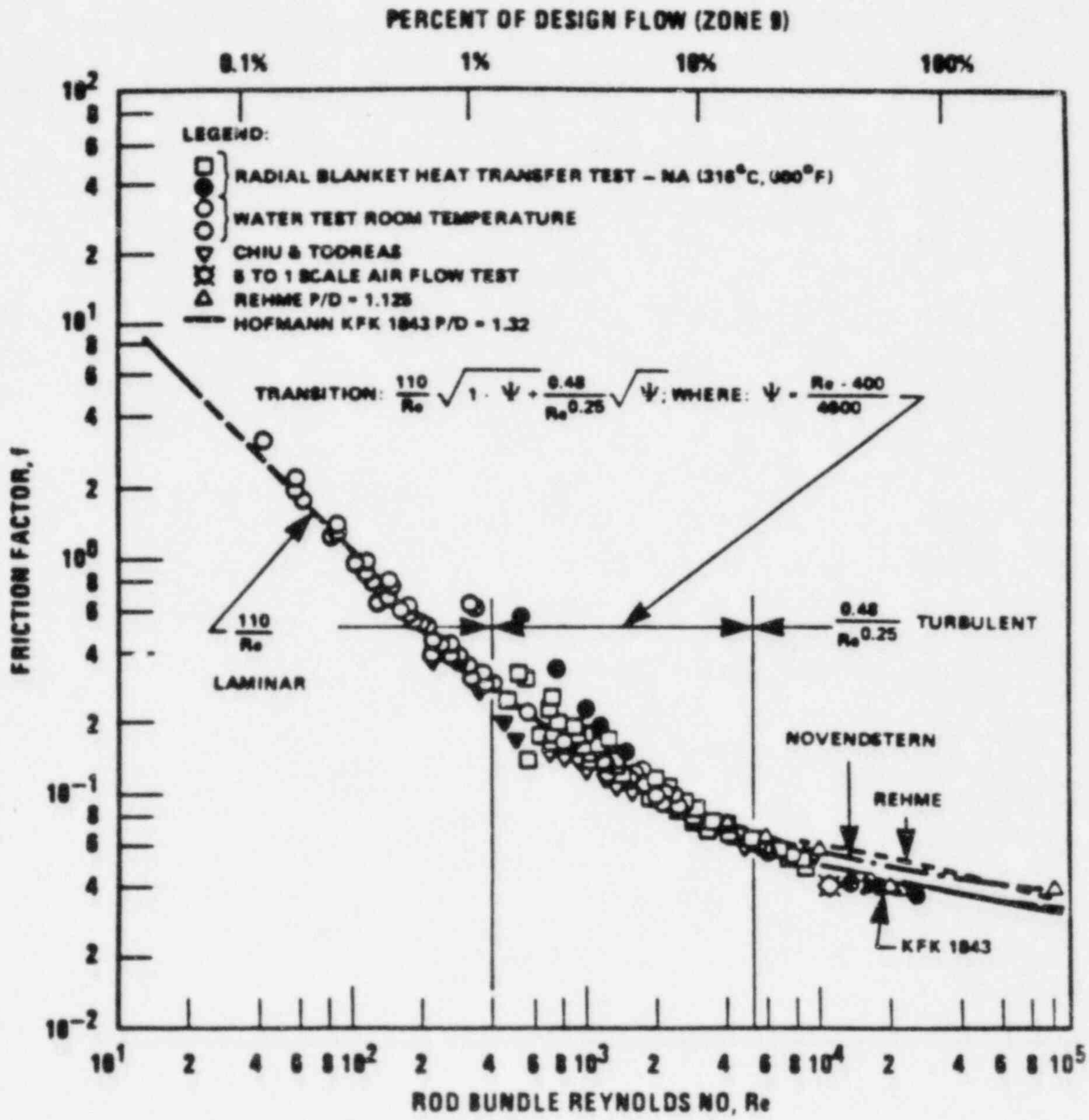

Figure QCS 760.77-2. Friction Factor Test Data for Tight Pitch to Diameter Rod Bundles With 4 Inch Wire Wrap Spacer Lead

7209-4

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QCS760.77-5

Amend. 73
Nov. 1982

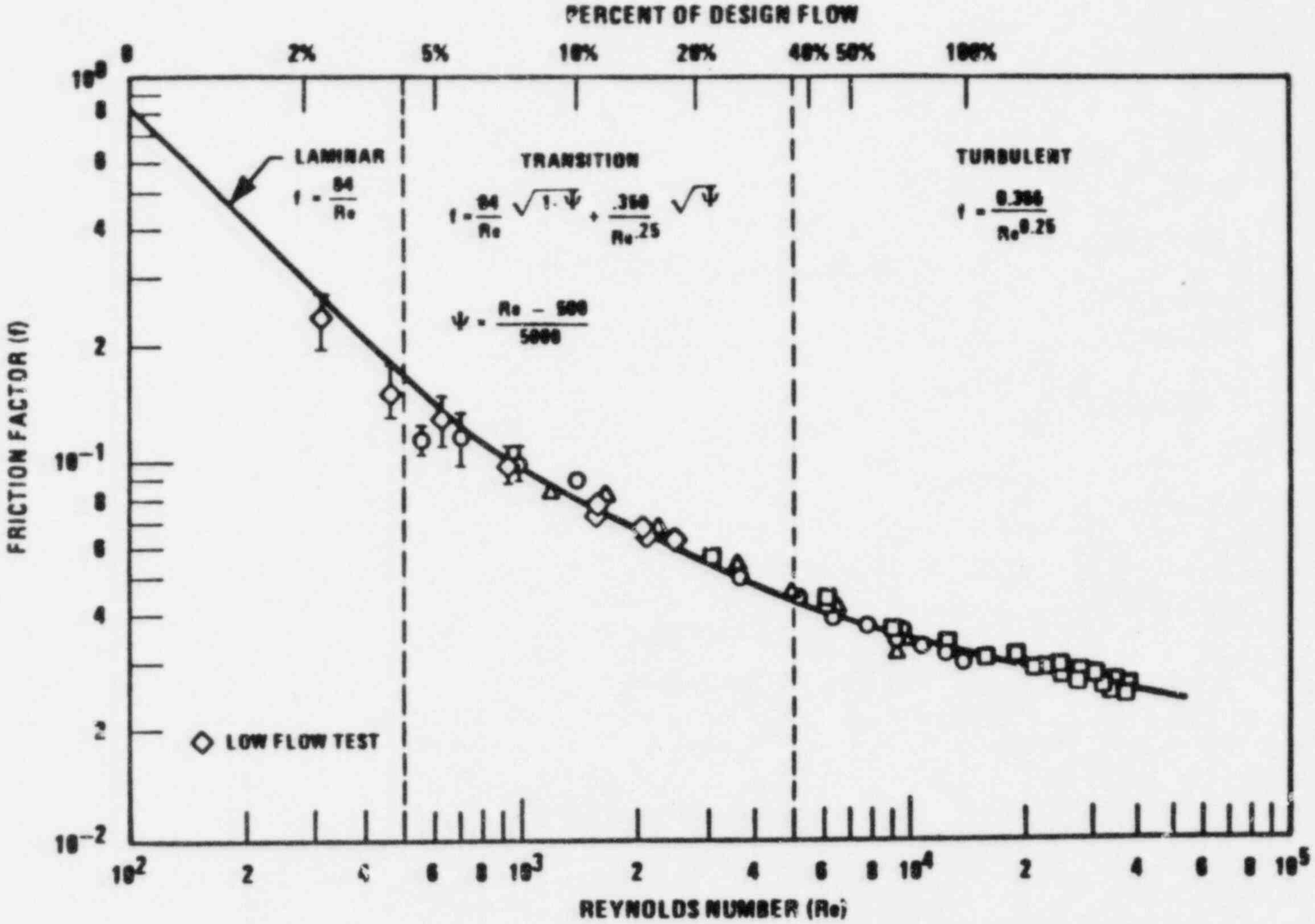

Figure QCS 760.77-3. Primary Control Assembly Rod Bundle Friction Factor

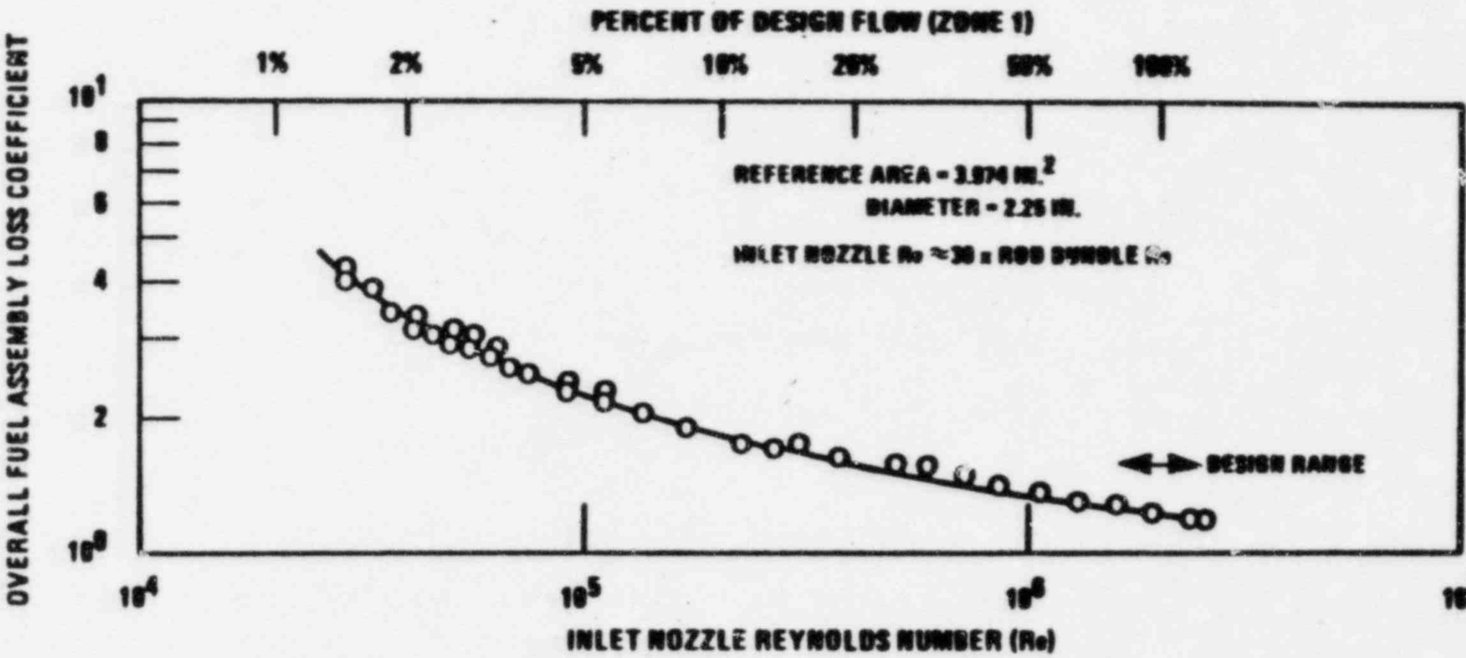

Figure QCS 760.77-4. Overall Fuel Assembly Loss Coefficient as a Function of Reynold Number from CRBRP Fuel Assembly Flow and Vibration Test

Question CS760.106

In the event of pipe breaks, what would cause the various isolation valves to close? It is stated in Section 5.6.1.2.1 that in at least one such break it is necessary for the operator to close an isolation valve to save the inventory of the PWST. How many such postulated breaks required operator intervention? How does the operator determine the break location?

Response

In the event of a large pipe break, in a steam generator loop or in an AFW loop downstream of the AFW check valves, the AFW isolation valves to the affected SGS loop will automatically close following the steam drum depressurization to <200 psig. All postulated breaks that do not allow steam drum depressurization will require operator action to isolate the AFWS if the breaks are large enough to initiate SGAHRS.

The information available to the operator to isolate these pipe breaks is described in PSAR Section 5.6.1.2.1.1 "Identification of Active and Passive Components which Inhibit Leaks".

Amend. 71
Sept. 1982

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PRELIMINARY SAFETY ANALYSIS REPORT

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