# COMANCHE PEAK STEAM ELECTRIC STATION
# FINAL SAFETY ANALYSIS REPORT
# INSTRUCTION SHEET

The following instructional information and check list is being furnished to help insert Amendment 71 into the Comanche Peak Steam Electric Station FSAR. A description of this amendment is provided in TXX-88445, May 27, 1988.

Since in most cases the original FSAR contains information printed on both sides of the sheet of loose leaf papers, a new sheet is furnished to replace sheets containing superseded material. Therefore, the front or back of a sheet may contain information that is merely reprinted rather than changed.

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Regulatory Guide 1.16

Reporting of Operating Information - Appendix A Technical Specifications

Discussion

In addition to the applicable reporting requirements of Title 10, Code of Federal Regulations, reporting of operating information will comply with Revision 4 (8/75) of this regulatory guide.

Also refer to Section 16.2 | 8

Regulatory Guide 1.17

Protection of Nuclear Power Plants Against Industrial Sabotage

Discussion

CPSES FSAR Section 13.6 and the site Security Plan are in conformance | 69
with the intent of Revision 1 (6/73) of this regulatory guide, and |
with Section 73.55, "Requirements for Physical Protection of Licensed |
Activities in Nuclear Power Reactors Against Radiological Sabotage," |
Part 73, Title 10, Chapter 1, Code of Federal Regulations -Energy. |
Regulatory Guide 1.17 endorses the requirements and recommendations |
contained in ANSI N18.17-1973. CPSES implements the criteria of |
ANSI/ANS 3.3-1982, which is a revision of ANSI N18.17-1973 and |
reflects the changes as described in revisions to 10CFR73, since 1973. |

Regulatory Guide 1.18

Structural Acceptance Test for Concrete Primary Reactor Containments (Revision 1, December 28, 1972)

Discussion

18 | The structural acceptance test for the CPSES Concrete Containments are in accordance with paragraph CC-6000 of the ASME B&PV Code, Section III, Division 2, 1980 Edition with Summer 1980 Addenda (as applicable to non-prototype containments). As such, this test is in conformance with Revision 1 of this regulatory guide except as follows:

18 | Radial deflections of the containment walls are measured along four azimuths only.

18 | Vertical deflections along one azimuth are measured at two equally spaced intermediate points between the dome apex and the springline and along four azimuths at the dome springline. Vertical deflection is also measured at the dome apex.

18 | Only radial deflections at 12 points around the largest opening (the equipment hatch) are measured. In addition, the increase in diameter of the opening is measured in two mutually perpendicular directions.

18 | See Subsection 3.8.1.7.1 for description of the test.

Regulatory Guide 1.19

Nondestructive Examination of Primary Containment Liner Welds

Discussion

66 | The requirements for nondestructive examination of the CPSES containment liner welds are in conformance with the intent of Revision 1 (08/11/72) of this regulatory guide by use of ASME-ACI 359 Code applicable to this type of structure and the alternate requirements as discussed in Sections 3.8.1 and 3.8.2. Acceptance criteria are those provided in Subsection 3.8.1.6.5.

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## 2.1 GEOGRAPHY AND DEMOGRAPHY

### 2.1.1 SITE LOCATION AND DESCRIPTION

#### 2.1.1.1 Specification of Location

The CPSES site is located in Somervell County in North Central Texas. Squaw Creek Reservoir (SCR), established for station cooling, extends | 12
northward into Hood County. The 7,669 acre site is owned by the |
Applicants. The site is situated along Squaw Creek, a tributary of |
the Paluxy River, which is a tributary of the Brazos River. The |
station site is over 30 miles southwest of the nearest portion of Fort Worth and approximately 4.5 miles north-northwest of Glen Rose, the nearest community (see Figure 2.1-1). Site coordinates are:

| | Unit No. 1 | Unit No. 2 |
|---|---|---|
| Texas Grid (Feet) | Y = 229,723.96<br>X = 1,911,921.11 | Y = 230,010.86<br>X = 1,911,951.27 |
| U.T.M. Grid (Zone 14) (Meters) | N = 3,573,903<br>E = 614,393 | N = 3,537,991<br>E = 614,401 |
| Latitude | 32° 17' 52.02" | 32° 17' 54.85" |
| Longitude | 97° 47' 06.15" | 97° 47' 05.79" |

#### 2.1.1.2 Site Area

The site area map (Figure 2.1-2) shows the concurrent plant property and site boundary line, the Exclusion Area, and Squaw Creek Reservoir (SCR). The site area is approximately 7,669 acres. Site area access | 32
is by a plant railroad, which connects to the Atchison, Topeka and |
Santa Fe Railroad Company main line at Tolar, Texas, by a plant access |
road which connects to State Highway 201 and by County road 213 which |
connects to State Highway 144. |

The plant railroad and access road are owned and controlled by the Applicants. There are no other highways, railways or navigable waterways which traverse or are immediately adjacent to the site.
32 | Squaw Creek Park, Inc. maintains a commercial operation on the North
| side of Squaw Creek Reservoir, providing public access to the lake for
| recreational activities. This commercial activity consists of an
| office building, fishing tackle shop and a restaurant. All public
| access to Squaw Creek Reservoir is controlled by Squaw Creek Park,
| Inc. A letter of agreement between Squaw Creek Park, Inc. and TUGCO
32 | that details the responsibilities of Squaw Creek Park, Inc. is
| contained in the CPSES Emergency Plan. This agreement insures that
| the applicant controls activities within the exclusion area.

Principal plant structures are also shown on Figure 2.1-2.

2.1.1.3 Boundaries For Establishing Effluent Release Limits

The Exclusion Area consists of approximately 4,170 acres. Figure
12 | 2.1-2 depicts the Exclusion Area boundary. This boundary is used for
| establishing effluent release limits and enables the owners to fulfill
| their obligations with respect to the requirements of 10 CFR Parts 20
| and 100 (see Section 2.1.2.1.5).

Figure 2.1-2 shows that the points of release for each of the two units are located closer to the southwest property line than any other segment of the property line. This southwesterly distance coincides with the minimum Exclusion Area boundary distance, which is 5,067 feet (1544 meters) from the midpoint of the centerline between the Containment buildings.

## 2.1.2 EXCLUSION AREA AUTHORITY AND CONTROL

### 2.1.2.1 Authority

#### 2.1.2.1.1 Surface Rights | 6

The Applicants have acquired and will maintain surface ownership of all the land within the Exclusion Area (see Figure 2.1-2A). Accordingly, the Applicants have the authority to determine all activities within the Exclusion Area, except for certain improbable and de minimus mineral exploration activities as discussed in greater detail below. | 12

That portion of Squaw Creek Reservoir which is within the Exclusion Area is subject to the waterway exclusion provided in 10 CFR Part 100.3(a). Consistent with that regulation, appropriate and effective arrangements will be made to control traffic on the reservoir to protect the public health and safety in case of emergency. The Exclusion Area is not traversed by any public highway or railroad. See Figure 2.1-2. The nearest primary public road, Texas State Highway 201, lies outside the Exclusion Area approximately 8900 feet southwest of the center line between the Containment buildings. The Applicants own and TUGCO operates the plant railroad from the plant to its junction with the Atchison, Topeka and Santa Fe Railroad at Tolar, Texas, approximately 11 miles from the site. | 12

#### 2.1.2.1.2 Mineral Rights

The Applicants have acquired mineral rights beneath all seismic Category I structures (see Figure 2.1-2C). Portions of the remainder of the Exclusion Area are subject to certain outstanding mineral rights. As noted above, the Applicants own the surface rights for the entire Exclusion Area. | 12

Q312.14 |

Q361.22 |

12 | As to the mineral rights within the Exclusion Area not owned by the Applicants, TUGCO will assure that the exercise of such mineral rights will pose no health and safety threat during normal reactor operation or in the event of an accident. The only outstanding mineral rights in the Exclusion Area for CPSES, and surrounding areas, relate to the exploration for and production of oil, gas, and other subsurface minerals. There are no outstanding rights which permit the production of surface minerals. As discussed in Section 2.5.1, the potential for commercial production of minerals at CPSES and in the surrounding area is low. Thus, it is anticipated that the exercise of such outstanding mineral rights would involve only sporadic, exploratory activity, and little or no production.

12 | Nevertheless, TUGCO will maintain sufficient authority and control over, and knowledge of, attempted ingress into the Exclusion Area to ensure that no unauthorized entry is allowed, as follows. The CPSES site is fenced on the perimeter and all gates are either locked or guarded to prevent ingress by unauthorized persons or for unauthorized purposes. Ingress for the purpose of exercising mineral rights in any area within 2250 feet of a seismic Category I building (See Section 2.2.3.2.1) or within 2800 feet of either Containment Building (See Section 2.1.2.1.5) will be prohibited. This area has been designated in Figure 2.1-2C as the "External Hazard Free Zone." The distances of 2250 and 2800 feet are based upon the analysis of a postulated gas well in Section 2.2.3. Ingress to the remaining outer areas of the Exclusion Area will only be permitted pursuant to written agreements between the Applicants and the necessary parties which would provide that TUGCO has absolute authority to determine all activities within the Exclusion Area, including removal of personnel and equipment.

| Q312.14
| Q361.22

A mineral owner or lessee has no legal right to use physical force or to create a public disturbance to obtain access to the Exclusion Area for purposes of mineral exploration or extraction. If such access is sought as to areas within the "External Hazard Free Zone", TUGCO will refuse to allow access under any circumstances. If such access is sought as to areas outside the "External Hazard Free Zone" TUGCO likewise will refuse to allow access unless the written agreement discussed above has been executed by the mineral owner or lessee. In either case, legal remedy of a mineral owner or lessee to obtain access to the surface of the Exclusion Area after being so excluded would be to file a lawsuit in the State District Court for the county where the land is located (either Somervell or Hood County). Should such a suit be filed, the Applicants would then file an immediate cross-action to condemn the mineral rights of the party seeking ingress and thereby prevent the ingress. The Applicants have statutory authority to do so. Article 3269, V.A.T.S. | 12

In this manner, TUGCO will have absolute authority to determine all activities within the Exclusion Area, including the authority to exclude or remove persons. Thus, the exercise of mineral rights in the Exclusion Area will pose no health and safety threat during normal reactor operation or in the event of an accident. In view of the unusual nature and limited scope of activities associated with the mineral rights and the plan and commitments by the Applicants to control all activities within the Exclusion Area, the present status of ownership is deemed to be of de minimis safety consequence. | 12

As stated above, the Applicants have acquired the mineral rights beneath all seismic Category I structures as well as beneath the Squaw Creek Dam (See Figure 2.1-2C). No measurable subsidence due to mineral extraction is anticipated. See Section 2.5.1.2.6 for a discussion of the effects of mineral extraction in the area of the site.

2.1.2.1.3 Easements

A 6-inch natural gas pipeline and a 26-inch crude oil pipeline traverse the Exclusion Area about 4,900 feet southwest of the midpoint of the centerline between the Containment buildings as shown on Figure
12 | 2.1-2B. These pipelines are also described in Section 2.2.3. The
| Applicants have granted the pipeline owners easements which retain for
| the Applicant absolute control to determine all such activities within
| the Exclusion Area including ingress and egress for the purpose of
| maintaining the pipelines and their right-of-way.

2.1.2.1.4 Status of Ownership

12 | The Applicants have acquired all of the land which will constitute the
| site property. Two small tracts of land within the site area have
7 | been excluded from purchase by the joint owners: a 20 acre tract
| north of the plant and the Hopewell cemetary east of the plant (see
| Figure 2.1-2). Both of these tracts are outside the Exclusion Area
| and are fenced off from the site property.

6 | 2.1.2.1.5 Minimum Exclusion Area Distance

12 | The minimum distance to the Exclusion Area boundary from the midpoint
| of the centerline between the Containment buildings is 5,067 feet
| (1,544 meters) to the west-southwest. The minimum Exclusion Area
| boundary distance is substantially larger, and therefore more
| conservative, than the distance which literal compliance with 10 CFR
| 100 would dictate (See Section 15.6).

### 2.1.2.2 Control of Activities Unrelated to Plant Operation

Activities unrelated to plant operation which may be permitted within | 12
the Exclusion Area include the exercising of mineral rights and the |
maintenance of pipelines as described in Sections 2.1.2.1.2 and |
2.1.2.1.3 above. The Applicants will have the necessary control to | 40
determine these activities and will require that all persons involved |
in them report to the CPSES Manager, Plant Operations or his |
designated representative prior to engaging in the activities. |

Public recreational activities within the Exclusion Area are limited | 71
to Squaw Creek Reservoir, Squaw Creek Park, and the CPSES recreational |
facility. Appropriate and effective arrangements have been made (in |
coordination with the appropriate agencies) to control access to, |
activities on, and the removal of persons and property from the |
reservoir and the CPSES recreational facility in case of emergency. |
Arrangements for recreational use and emergency procedures governing | 40
such use have been completed. The Applicants have the authority to |
exclude or remove any person from this area at any time. |

The plant staff will have knowledge of the approximate number and | 12
location of persons within the Exclusion Area engaged in such activ- |
ities. Normal evacuation of persons within the Exclusion Area will |
take no more than two hours. |

### 2.1.2.3 Arrangements for Traffic Control

In the event of an emergency, traffic on the plant access road and the visitor's overlook access road will be controlled by the Applicant.

If Squaw Creek Reservoir is opened to the public, arrangements will be made to control traffic in the event of an emergency (see Section 2.1.2.2, above).

2.1.2.4 Abandonment or Relocation of Roads

An unpaved county road which traversed the northeast corner of the Exclusion Area was abandoned in April 1975 because of the construction of Squaw Creek Dam and Reservoir. Arrangements for the closing of this section of road were made with the Somervell County Commissioner's Court in December 1974. No other public roads traverse the Exclusion Area.

2.1.3 POPULATION DISTRIBUTION

The purpose of this section is to provide detailed estimates of the present and projected size and distribution of population within a 50-miles radius of CPSES. The population estimates provided in the PSAR have been reviewed, revised, and updated for purposes of the FSAR. Estimates of population distribution are provided for 1970 (most recent census year), 1976 (current year), and for census decades 1980 through 2020.

In reviewing and updating the population estimates in the PSAR, it was recognized that the actual centerline locations of the containment structures for Units 1 and 2 differ slightly (approximately 88 feet) from the locations as originally shown. In these revised population estimates, the actual centerline of the Unit 1 containment structure has been taken as the point of origin for the sector lines and concentric distance circles which form the sector-areas used in portraying population distribution within the 50-mile radius of CPSES. While the 1970 county-by-county population base in the CPSES area

remains the same as shown in the PSAR, the slight difference in Unit 1 location causes some change in location of sector lines and distance circles. Thus, very small changes are found in this updated population study in the 1970 distribution of population by sector-areas.

The territory included within the 50-mile radius of CPSES includes all or a part of 19 counties, all in Texas. The general location of CPSES in Somervell County and the locations of the rest of the counties located within 50 miles of the plant site are shown in Figures 2.1-3 and 2.1-4. The population of these 19 counties is given in Table 2.1-1 for the census decades 1930 through 1970; in addition, the table provides an estimate of the 1976 population for each county and the projected future population for each census decade 1980 through 2020. Footnotes to the table provide brief comment regarding the sources of the historical data and the projections. Within the 50-mile radius of CPSES, there is wide diversity in land use, urbanization, and population density. The plant site is located in Hood and Somervell counties, which are essentially rural, sparsely-populated areas. The entire population of Somervell County was 2,793 residents in 1970. Hood County, which is much larger in area than Somervell County (as may be seen in Figure 2.1-3), had a population of 6,368 inhabitants in 1970. In 1970, there were three small communities with a total of 4,339 people within the 10-mile area around the CPSES site. The total population within the 10-mile area at that time was 5,353, or an overall population density of approximately 17 persons per square mile.

The sparsely-settled rural character extends well beyond the 10-mile radius, as indicated in Table 2.1-2, which lists all incorporated communities and all unincorporated settlements with over 1,000 inhabitants within the entire 50-mile radius of the site. The area extending from 10 to 20 miles out from the CPSES site is even more

sparsely populated than the 0 to 10-mile area. As the table shows, in 1970 there were two communities totaling 1,028 people within the entire 10 to 20-mile area around the CPSES site, and the total population in this area was 7,532 (this is a 1970 population density of only 8 persons per square mile). Beyond the 20-mile radius there are more communities, and the 30 to 50-mile area to the northeast is dominated by the Fort Worth metropolitan complex.

In reviewing the county-by-county population projections which were given in the PSAR, it was found that most of the county population projections should be revised somewhat in accordance with current population estimates and the most recent projections prepared by the councils-of-government and the state agencies. Accordingly, in providing updated county population data (Table 2.1-1), current estimates for 1976 are given along with the revised projections for the years 1980 through 2020. It should be noted that the current estimates and the projections of expected population growth in Hood and Somervell counties are based upon an enumeration of housing units in the two counties in mid-1976 and an updated evaluation of recent and probable future trends in recreational development in the local area. Moreover, the estimates for Hood and Somervell counties include detailed consideration of the current and possible future impact of CPSES construction and operation on population growth. As a general procedure in determining population distribution, the 1970 population of each county (wholly or partially within the 50-mile radius of the plan) was allocated to sector-areas within the county on the basis of (1) the population of each community and enumeration district located wholly within a particular sector-area, and (2) a percentage share of the population of each enumeration district and community partially within a particular sector-area (the percentage share of population of an enumeration district to be allocated to a particular sector-area was generally assumed to be equal to the percentage portion of the area of the enumeration district within the particular sector-area).

In the case of Hood and Somervell counties, the county and enumeration district populations were allocated to sector-areas on the basis of (1) an actual count of housing units within each sector-area, and (2) the estimated number of residents per housing unit, considering available census data for the particular local area. The housing count for Hood and Somervell counties for the PSAR was made in 1973 utilizing a combination of available mapping, aerial photography, and field survey resources. The housing unit count made in mid-1976 for the FSAR was based on a comprehensive field survey and housing enumeration for all of Hood and Somervell counties. The estimates of population within individual sector-areas have been reconciled to the population totals for each county (or a portion of a county).

The percentage ratio of the total population of a county which was estimated to be within each individual sector-area in the county in 1970 (1976 in the case of Hood and Somervell counties) was assumed to remain the same in 1980 and beyond. This assumption was made after concluding that there is little possibility of a significant and radical change in the basic pattern of current population distribution within individual counties in the 50-mile area.

### 2.1.3.1 Population Within 10 Miles

The area within the 10-mile radius of CPSES is predominantly a rural agricultural area. In 1970, there were three small communities having more than 100 residents. The total population of Hood and Somervell counties changed little over the period from 1930 to 1970 (see Table 2.1-1).

2.1.3.1.1 Current Population Within 10 Miles

Since 1970, Hood and Somervell counties have experienced increases in population, as indicated by the following:

| County (and Community) | Population 1970 (census) | Population 1976 (estimate) |
|---|---|---|
| Hood County | 6,368 | 15,601 |
| Granbury (county seat) | 2,473 | 3,526 |
| Tolar | 312 | 435 |
| Somervell County | 2,793 | 5,216 |
| Glen Rose (county seat) | 1,554 | 2,790 |

The estimates for 1976 are based upon the July/August 1976 enumeration of housing units in the two counties (including the communities). The growth of Granbury may be understated in comparing the data above because much of the urban growth of the community has taken place beyond the city limits.

The increase in population of Hood County since 1970 is largely related to the attractions of Lake Granbury for residential developments. These developments are attracting large numbers of permanent residents as well as vacation and recreational visitors. In 1970, there were 2,628 housing units in use as permanent residences in Hood County. By 1976, there were 5,566 housing units accounting for an estimated population of 15,601 full-time residents in Hood County and there were an additional 1,648 housing units in use primarily during weekends and vacations. A significant portion of the increase in housing units has been in mobile homes used both as vacation homes and permanent residences. The increase in permanent residents in Hood County is partially accounted for by attractive living conditions;

many people that have moved into Hood County are commuting to jobs elsewhere. Significant numbers of retired people have established their permanent residence in Hood County. With the above, and the general stimulus of vacation and recreational activity, there has been an increase in local economic activity and job opportunity within the county.

The number of permanent housing units in Somervell County increased from 1,203 in 1970 (but only 1,035 households at that time) to an estimated 1,856 housing units in 1976. An additional 26 vacation homes were located in the housing enumeration, but as the data indicates, virtually the entire housing inventory of Somervell County (fixed structures, mobile homes, and apartments or courts) was permanently occupied in mid-1976. Somervell County has participated only peripherally in the Lake Granbury stimulus to housing development and recreational activity.

In addition to the foregoing, it should be noted that the influx of construction workers employed on CPSES accounts for a significant portion of the population increase from 1970 to 1976, particularly in the case of Somervell County. For example, at the end of July 1976, there were 2,285 workers regularly employed at the CPSES construction site. Of that number, 216 had moved into Somervell County specifically to work at CPSES. In addition to the 2,285 man active work force as of the end of July 1976, there was a total of 1,958 workers who had been terminated since the start of construction on CPSES in October 1974. Of these terminated employees, 177 had moved into Somervell County for the purpose of employment at CPSES. Data on the CPSES work force indicates that, on the average, each worker had 1.8 dependents. Thus, considering both active and terminated workers, a total of 1,100 workers and dependents had moved into Somervell County as of July 1976.

The tabulation below provides a summary showing the total number of CPSES workers who have moved into Hood and Somervell counties through July 1976:

| | Total No. of Workers as of July 1976 | |
|---|---|---|
| | Active | Terminated |
| Total (on-site work force) | 2,285 | 1,968 |
| Residing in Somervell County: | | |
| Local Hire | 160 | 138 |
| Relocated | 216 | 177 |
| Residing in Hood County: | | |
| Local Hire | 278 | 240 |
| Relocated | 201 | 173 |

The total number of workers (both active and terminated) and dependents relocating to Hood and Somervell counties through July 1976 is estimated as follows:

| | Total Workers | Dependents | Total |
|---|---|---|---|
| Hood County | 374 | 673 | 1,047 |
| Somervell County | 393 | 707 | 1,100 |

While 45 to 47 percent of these totals are represented by now terminated CPSES employees and dependents, there are strong indications that a large portion of the terminated employees who originally moved with their dependents into the local area to work on CPSES actually stayed in the area after termination of employment at CPSES. The overall growth of population in both counties is creating increasing opportunities for employment in local service industries. Moreover, as indicated earlier, substantial numbers of new residents in Hood and Somervell counties are commuting to jobs outside the local area.

Table 2.1-3 shows estimated population distribution by sector and mileage zones within 10 miles of CPSES for the years 1970 and 1976 and for the census decades 1980 through 2020. Figure 2.1-3 indicates the location of the plant in Somervell County and the sector areas out to a 10-mile radius. As may be seen from the data in the table, a substantial part of the increase in population in the two counties from 1970 to 1976 has occurred in or near the established communities. The population of the remainder of Somervell County has increased by an estimated 95 percent over the same period (1970-1976) and examination of the data in the table indicated that this growth was widely distributed in the county.

In some contrast to Somervell County, the population growth in Hood County has been more highly concentrated (in the areas near Lake Granbury). The population of the county seat of Granbury (within the city limits) increased by an estimated 42 percent from 1970 to 1976. The population of the balance of Hood County increased by well over 300 percent. Much of this increase has occurred in the north, north-north-east, and northwest sectors in the 5 to 10-mile area and the 10 to 20-mile area. These increased concentrations of population within particular sector-areas in Hood County are clearly evident in a comparison of the 1970 and 1976 data in Table 2.1-3.

2.1.3.1.2 Projected Population Within 10 Miles

The size and distribution of population within 10 miles of the CPSES plant site as projected for the census decades 1980 through 2020 are shown in Table 2.1-3 (along with estimates for 1970 and 1976). These projections of future population distribution within the 10-mile radius of the site are fully reconciled to the overall population projections for Hood and Somervell counties (as described earlier). These projections take into account the size and residential distribution of the CPSES construction work force and the expected phase-out of construction activity over the period 1980-1982.

It is expected that the continued growth of population and employment opportunities associated with lake-oriented residential community development and recreational activities in Hood County will tend to offset the sharp drop in construction employment on CPSES. It is also expected that the completion of CPSES will cause an actual decline in population in Somervell County after 1980 (for a period of two to three years), but by 1990 the loss will be regained due to the underlying slow rate of growth expected for the county.

2.1.3.1.3 Age Distribution of Population Within 10 Miles

To provide an estimate of the population by age groups, it was necessary first to compare the 1970 population distribution by age group for Somervell County and the U.S. as a whole. Because the percentage distribution by age groups 0 to 11, 12 to 18, and 19 and over for Somervell County and for the U.S. for 1970 differed by less than 10 percent, the distributions for the year 2000 for the project area were assumed to be the same as the Bureau of Census age-group distribution projections for the U.S. for the year 2000. If the difference had been greater than 10 percent, the U.S. percentages would have required adjustment based on projections for the North Central Texas region.

The U.S. projection for the year 2000 came from Table No. 3 of the "U.S. Statistical Abstract, 1975." The data had to be modified slightly, however, to compensate for somewhat different age groupings. The population projection for the 10-mile area of CPSES came from Table 2.1-3. The resulting population distribution by age group for the 10-mile area around CPSES for the year 2000 (the mid-point of expected plant life) is given in Table 2.1-4.

### 2.1.3.2 Population Within 10 to 50 Miles

The population within the 10 to 50-mile radius of CPSES includes the population of a large number of communities and cities including Fort Worth, as listed in Table 2.1-2. The location of all population centers is shown on Figure 2.1-4, which also shows sector lines and distance circles out to the 50-mile radius from CPSES.

#### 2.1.3.2.1 Current Population Within 10 to 50 Miles

The distribution of the 1970 population and the estimated 1976 population within the 10 to 50-mile radius of CPSES is shown by sector-area in Table 2.1-5. The estimates of population distribution by sector-area for 1976 are correlated with the county-by-county projections, as described earlier. There was a 13.4 percent increase in population within the entire 10 to 50 mile area from 1970 to 1976 (compared with the 127 percent increase within the 10-mile area). Within the 10 to 50-mile area there are significant differences among counties with respect to population increase (or loss) from 1970 to 1976 as may be seen in reviewing Table 2.1-1. For example, the population of Johnson County (to the east of the site) increased by 20 percent while Stephens County (to the west of the site) decreased by 3 percent. These differences in recent growth trends among the counties are reflected in the estimates of current population distribution by sector-area.

### 2.1.3.2.2 Projected Population Within 10 to 50 Miles

The present and projected population growth through the year 2020 is shown by county in Table 2.1-1 for all counties within the 50-mile radius of CPSES. Table 2.1-5 provides estimates of the distribution of projected population by sector-area for the census decades 1980 through 2020 (along with comparable estimates for 1970 and 1976). As may be seen in a comparison of the cumulative estimates of population for 0 to 10 miles, 0 to 20 miles, etc., for each of the census years (summarized at the end of Table 2.1-5), population growth for the entire 0 to 50-mile area is projected to increase at a much slower rate than for the 0 to 10-mile area, as shown below:

| Area (radius) | Population (000) | | Percent |
|---|---|---|---|
| | 1976 | 2020 | Increase |
| 0-10 | 12.1 | 31.1 | 156 |
| 0-20 | 24.7 | 64.9 | 163 |
| 0-30 | 83.8 | 198.5 | 137 |
| 0-40 | 438.8 | 1,024.8 | 134 |
| 0-50 | 894.0 | 2,090.5 | 134 |

2.1.3.2.3 Age Distribution of Population Within 10 to 50 Miles

The age distribution of the population of Somervell County (in which the plant is located) in 1970 differed by less than 10 percent from the 1970 age distribution for the populations of the United States as a whole. Accordingly, the projected percentage age distribution for the United States for the year 2000 (mid-point of plant life) was assumed for the population within the 10 to 50-mile area around CPSES for the year 2000. The projected populated distribution by age group for the 10 to 50-mile area is provided in Table 2.1-6.

2.1.3.3 Transient Population

After consideration of the overall patterns of settlement, land use, and population distribution within the entire 50-mile radius of the site, it was concluded that transient population movements and daily and seasonal variations in population distribution and concentration within the 10-mile radius of CPSES should be examined in some detail. It was also concluded that no such examination and projections should be made of transient movements in the 10 to 50-mile area. There are large-scale movements of daily commuters (in all directions) within the Fort Worth metropolitan complex. However, but the potential significance and meaning of such movements (compared with the potential significance of movements within the 10-mile area) does not appear to justify the inordinate effort that would be required to characterize, analyze, and project transient population movements within the 10 to 50-mile area. Accordingly, the discussions below pertain only to transient population within the 10-mile radius of CPSES.

2.1.3.3.1 Seasonal Variation

This category of transient population is specifically concerned with overnight visitors coming into the 10-mile area. As will be shown, there are many more overnight visitors in the summer season than during other times of the year, but overnight visitors are found in the area throughout the year. The seasonal or overnight category of transients includes visitors staying for several days or weeks (this category excludes consideration of daily transients, regardless of the season). This category of transient population (seasonal or overnight visitors) includes visitors that would be found in hotel/motels, campgrounds, recreational vehicle parks, organized camps (church groups, youth groups, etc.), mobile home-parks, and vacation homes. It also includes live-in students in a children's home despite the fact that their stays are for extended periods. These children are not included as part of the permanent population.

Because this category of transients is predominantly comprised of recreational and vacationing visitors, there is a distinct peaking in the summer season of total transients in the area at any one time. Moreover, normal and holiday weekend peaking is different and weekdays differ from week-ends, both in summer and winter. See Table 2.1-7 for estimates of the length of stay of various types of transients.

In developing the estimates of seasonal transient population given in Table 2.1-8, consideration has been given to (1) the location and capacity of various facilities that accommodate overnight visitors, and (2) the actual patterns or levels of use which are typically experienced by the facilities at various time of the year. The table presents estimates of weekly, typical weekend and holiday week, and daily and overnite transient during summer and winter.

With respect to the projection of future levels of seasonal or overnight transients, different assumptions were made for the several different types of facilities. Sector-area estimates of vacation home and hotel/motel visitors were assumed to increase from 1980 through 2020 in proportion to the projected increase in population for the county as a whole (in which the sector-areas are located). Organized camp attendance is expected to remain at 1976 levels and the children's institution will remain stable from 1980 onward. [illegible] at various types of facilities along Lake Granbury is expected [illegible] reach its peak by 1990 (achieving levels similar to those at other older facilities in North Central Texas) and level off thereafter. Camping elsewhere in the 10-mile area (away from Lake Granbury) was estimated to grow in general accordance with the population growth projected for Dallas and Tarrant counties (major counties in the larger metroplex).

2.1.3.3.2 Daily Variation

This category of transient population is concerned with daily movements of population into and within the 10-mile area and peaking in the number of transients found in a particular sector-area at any given time. Estimates of daily transient movements and population concentration include consideration of movements to such facilities as public schools, private schools, urban and community shopping centers, and recreational facilities such as parks and lakes. Estimates have been made of daily visitor recreational use of Lake Granbury (in addition to use by overnight and vacationing visitors). Beginning in 1980, when it will have been filled, it is assumed that limited daily visitor recreational use will be permitted at a non-camping park facility on Squaw Creek Reservoir.

It is apparent from Table 2.1-8 that there are great differences in daily transient population movements depending on the season of the year and on the time of the week (weekday, normal weekend, and holiday weekend). It should be noted that the table does not provide estimates of the total number of daily visitors (of different types) but rather it provides estimates of the maximum number of visitors that might be expected in a sector-area during the peak hours of the day. It is also important to note that the estimates of peak daily transient population concentration in a particular sector-area are not accompanied by corresponding decreases in population in sector-area from which the transients originated. This is the situation where large numbers of school children (from numerous sector-areas) are concentrated daily in a single sector-area. This is simply a recognition that peak population concentration in different sector-areas may occur at different times of the day.

The general approach in estimating daily transient movements in 1976 was to utilize empirical data wherever possible, as in the case of school enrollments and the daytime use of some recreational and park facilities. The experience of state parks and other older reservoirs and water-oriented facilities was used as a basis for estimating current and projected daytime use of Lake Granbury and Squaw Creek Reservoir. The numbers and movement patterns of permanent and vacation residents in making use of shipping facilities in Granbury and Glen Rose was estimated on the basis of the geographical distribution of households and a number of working assumptions regarding the frequency and time of week for shoppers coming from various distances. It was assumed that the above communities served only the areas of their respective counties. Again, the estimates indicate the peak number of transients that would be in a sector-area at a particular time and not the total number of transients during a day.

With respect to the projections of daily transients for future years, several assumptions were made as in the case of the seasonal population estimates. Projections of daily transients associated with school enrollments and community shopping activity were related to basic population projections. Recreational use of Lake Granbury and Squaw Creek Reservoir was assumed to reach mature levels by 1990 and level off thereafter at levels found at similar, but older, water-related facilities elsewhere in North Central Texas. It is noted that Unit 2 of CPSES will not be completed until 1982 or thereafter and that a construction work force will remain on site after completion and start of operations (at least in a test mode) of Unit 1 in late 1980.

#### 2.1.3.3.3 Summary Effect of Transient Population Movements in 10-Mile Area

The most conservative estimate of area population, provided in Table 2.1-9, is the sum of the permanent population and the maximum transient population estimate (summer holiday weekend daily transients). Similar estimates for other transient periods may be obtained by simply summing the permanent population estimate (Table 2.1-4) and the appropriate transient population estimate. Comparison of Table 2.1-4 and 2.1-9 shows that inclusion of the maximum transient population increases total population by nearly 60 percent.

### 2.1.3.4 Low Population Zone

In accordance with 10 CFR Part 100 guidance, the low population zone shown in Figure 2.1-5 is defined as that area falling within a four-mile radius of the center of the station site. The present number of residents (approximately 500 persons according to the 1976 estimate) within this area is sufficiently small to ensure a reasonable probability that appropriate protective action could be taken in their behalf in the event of a serious accident as required by 10 CFR 100.3. Section 15.6 shows that this area is of sufficient size to preclude an individual located on its outer boundary from receiving a total dose following a postulated accident in excess of requirements in 10 CFR Part 100.11. Resident and transient populations within the zone have been discussed in detail in Sections 2.1.3.1 through 2.1.3.3.

### 2.1.3.5 Population Center

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The nearest population center (defined in 10 CFR Part 100 as more than 25,000 people) is Fort Worth, Texas. According to the 1970 census, Fort Worth has a population of 393,476 people (approximately 613,000 in metropolitan area). The growth rate was 10.4 percent between 1960 and 1970. The geographic center of Fort Worth, which is approximately 41 miles northeast from CPSES, does not differ significantly from its population center. Dallas, with 844,401 inhabitants (1,555,950 in
2 | metropolitan area), is 67 miles northeast of the station. Cleburne,
| 23 miles east of the station site with a population of 16,015 people
| is the next largest community in the area. Cleburne is expected to
| reach a population of 25,000 by the mid 1980's, thus becoming the
| nearest population center as defined by 10 CFR Part 100.

### 2.1.3.6 Population Density

The cumulative resident population projected for the year of initial plant operation (1980) is compared with a cumulative population resulting from a uniform population density of 500 people/square mile in all directions from the plant in Figure 2.1-6. A similar comparison is made for the end of plant life (2020), but compared with a cumulative population resulting from a uniform population density of 1,000 people/square mile in Figure 2.1-7.

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3.6B.2.2.2 High-Energy Piping Other Than RCS Main Loop

The time dependent function representing the thrust forces caused by the jet flow from a postulated pipe break or crack includes the combined effects of the thrust impulse resulting from the sudden pressure drop at the initial moment of pipe rupture, the thrust transient resulting from wave propagation and reflection, and the blowdown thrust resulting from buildup of the discharge flow rate which may reach steady state if there is a fluid energy reservoir having sufficient capacity to develop a steady jet for a significant interval. Alternatively, in a simplified method, the jet thrust force is represented by a steady state function. This function, representing the force, would have a magnitude not less than:

$$F_{ss} = C_t PA$$ | 71

where: | 31

$F_{ss}$ = steady state thrust force ($lb_f$) | 31

P = system pressure prior to pipe break ($lb_f/in^2$) | 31

A = pipe break area ($in^2$) | 31

$C_t$ = steady state thrust coefficient | 71

The steady state thrust coefficient $C_t$ is dependent on the fluid state and the frictional loss terms. The value of steady state thrust coefficient and the time to reach steady state flow conditions are calculated from references [15], [16] and [22]. | 71 | 68

The rigorous time dependent blowdown forces resulting from a postulated pipe rupture are determined using the RELAP-5 computer code [6]. RELAP-5 is a thermal/hydraulic program commonly used in | 68

68 | the nuclear industry to evaluate the behavior of water cooled reactor
| systems during postulated accidents such as pipe ruptures. The
program is acceptable (see Reference [7]) as a means of determining
71 | the hydraulic forcing function at the pipe break. CALCULF-II [20],
| Post Processor Program to RELAP Program, is used to develop the break
| force time - history plots.

68 | The RELAP-5 program solves the transient energy, momentum, and fluid
| state equations to determine the system flow, pressure, and
| thermodynamic conditions. The break force is computed using the
one-dimensional momentum equation and the appropriate density,
internal energy, and pressure values. The rupture load is the
summation of the pressure, momentum, and change in momentum terms at
the time interval in question.

68 | RELAP-5 has the capability of solving the fluid state equation for
| subcooled water, flashing water, two-phase steam/water mixtures, and
| superheated steam. The ASME steam tables [9] have been incorporated
| into RELAP-5 so that the fluid state properties are accurately
71 | determined. RELAP-5 has a provision for modeling components such
| as valves, check valves, pumps, heat exchangers, and reactors along
| with the associated piping.

Transients can be initiated by the control card added to the program
which is used to describe leaks (pipe breaks), valves opening and
closing, check valve pressure drop-flow-characteristics, pump
coastdowns, and so forth.

The flow system is described as a series of volumes connected by flow
68 | paths or junctions. RELAP-5 requires input data that completely

describe the thermodynamic conditions and physical data of the system being analyzed. Pressure, temperature, and flow conditions along with physical dimensions, flow areas, friction characteristics must all be specified as initial conditions. The break area can be reduced by an analytically or experimentally derived discharge coefficient. However, in lieu of such data it is conservatively assumed that the discharge coefficient is 1.0 for both longitudinal and circumferential breaks. In a similar manner, the break area is assumed to open within one millisecond (0.001 second). | 71 | 68

The piping dynamic responses resulting from a postulated pipe rupture are determined using the PIPERUP [13], SHPLAST 2267 [24] or ABAQUS [21] computer codes. The programs are adaptations of the finite element method to the requirements of pipe rupture analyses. They perform a dynamic, nonlinear, elastic plastic analysis of piping systems subjected to time-history forcing functions. These forces result from fluid jet thrust at the location of a postulated longitudinal or circumferential rupture of high energy piping and ensuing acoustic disturbances within the piping. | 68 | 71

The piping is mathematically modeled in the PIPERUP, SHPLAST 2267 or ABAQUS program as an assembly of weightless structural members connecting discrete nodal points. A typical pipe whip mathematical model is shown in Figure 3.6B-6. Weight of the system, including distributed weight of the piping and concentrated weights (e.g., valves), is lumped at selected mass points (lumped parameter analysis model). Nodal points are placed in such a manner as to isolate particular types of piping elements such as straight runs of pipe, valves, elbows etc. for which force-deformation characteristics may be determined. Nodal points are also placed at all discontinuities such as piping restraints, branch lines, and changes in cross-section. Piping restraints are modeled with an initial gap and in PIPERUP with a bilinear stiffness curve, or, in SHPLAST 2267 and ABAQUS with multilinear stiffness curve. A typical piping stress-strain curve is shown in Figure 3.6B-7. The first stiffness represents linear elastic behavior and the second stiffness models linear strain hardening | 68 | 71 | 68

71 | behavior. All three programs utilize a direct step-by-step
| integration method to determine the time history response of the
| ruptured piping system. A typical restraint impact curve is shown in
Figure 3.6B-8. An incremental procedure is used to account for the
nonlinear deformation and elastic-plastic effect of the pipe and
restraints.

71 |

### 3.6B.2.3 Dynamic Analysis Methods to Verify Integrity and Operability

#### 3.6B.2.3.1 Reactor Coolant System Main Loop

61 | The leak-before-break technology has been applied to CPSES Units 1 and
| 2 to exclude from the design basis the dynamic effects of postulated
| ruptures in the RCS main loop piping. This applies, in particular,
| to jet impingement loads on components and supports.

61 | Jet loads from large branch nozzle breaks are addressed in Section
| 3.6B.2.3.2.

#### 3.6B.2.3.2 High-Energy Piping Other than the RCS Main Loop

Pipe beaks are postulated in high-energy piping in accordance with the criteria in Section 3.6B.2.1.2. The analyses for determining the dynamic effects of pipe break are as follows:

A. Jet Impingement

A circumferential or longitudinal break in a high energy line results in a jet of fluid emanating from the break point. For subcooled high energy lines where the fluid temperature is less than its saturation temperature at the surrounding environmental pressure, the discharge jet is characterized by a nearly constant diameter jet approximately equal to the break diameter. Since the fluid temperature is below saturation it will not flash but instead will form an incompressible fluid jet. | 71

In general, most of the high energy line breaks result in a two-phase choked (critical) flow at the break exit plane. Fluid pressure at the exit plane is in general at some pressure greater than ambient. As the fluid leaves the pipe break area, it expands as the jet pressure decreases from the higher exit (break) plane pressure to the atmospheric pressure surrounding the jet. | 71

A jet discharging from a saturated steam line will accelerate and expand due to the pressure differential, and it will partially condense to a low-moisture wet steam with the liquid phase in the form of dispersed, entrained water droplets. A jet discharging from a subcooled or saturated hot water line (greater than 212$^{o}$F) will flash to a low quality wet steam. The flashing will cause the jet diameter to expand very rapidly. | 71

ANSI/ANS 58.2 Working Draft Revision 7, August 1987 [22] provides an acceptable basis (including conservative analytical models) for the evaluation of jet impingement loads. The CPSES jet impingement methodologies and models are consistent with ANSI/ANS 58.2, as briefly described in the following sections: | 71

71 | a. Jet Category and Geometry

71 | The area of the break is assumed to be equal to the flow area of the ruptured pipe. All the high energy line break jets can be summarized into the following three categories:

71 | a.1 Category I Jets - Non-Expanding Jets

71 | For the liquid jets whose temperature is below the saturation temperature at ambient pressure, the initial free expansion does not occur. Incompressible liquid jets are assumed to travel with no increase in jet area. However, for target identification a conservative zone of influence of two diameters is utilized. The pressure is assumed to be uniform throughout the jet area.

71 | a.2 Category II Jets - Steam and Flashing Water Jets which meet the Criteria of NUREG-2913:

71 | The high energy two-phase jet is a complicated multidimensional flow phenomena. The high pressure and high temperature fluid that exits the break expands with supersonic velocities downstream of the break. Upon encountering a target (or obstacle) a shock wave forms in the flow field, and it is the thermodynamic properties downstream of this shock that determine the pressure field and load on the target. A multidimensional analysis, such as demonstrated in NUREG/CR-2913 [25], more realistically evaluates the thermodynamic properties of these jets. These Category II jets are assumed to expand radially at a 45 degree angle [25]. The NUREG-2913 model provides a method for calculating target loads for initial pipe rupture fluid conditions of pressure between 60 and 170 bars (870 psia - 2466 psia) and with subcooling of 0°C (0°F) to 70°C (126°F).

a.3 ategory III Jets - All other steam and flashing water jets: | 71

Category III jets are assumed to expand as a three region cone defined in Figure 3.6B - 96A for circumferential breaks and Figure 3.6B - 96B for longitudinal breaks [22]. | 71

a.3.1 Circumferential Break with Full Separation: | 71

Jet Region 1 ($L < L_c$). Region 1 includes a cone-shaped region containing the jet core and the remainder of the jet. This geometry is shown in Figure 3.6B-96C. | 71

The jet core length is related to the jet subcooling at the jet break plane and has been correlated using the following expression | 71

$$L_c / D_e = 0.26 \left( \sqrt{\Delta T_{sub}} \right) + 0.5 \quad (1)$$ | 71

where: | 71

$L_c$ = core length | 71

$D_c$ = pipe inside diameter | 71

$\Delta T_{sub}$ = jet subcooling at stagnation conditions of °F at the break plane | 71 | 71

Figure 3.6B-96D can be used to relate jet stagnation subcooling at the break plane to stagnation conditions in the vessel supplying the jet flow, accounting for irreversible losses in the blowdown line. | 71

71 | In Region 1, for $0 \leq L \leq L_c$, the jet core diameter, $D_c$, is given
| by

71 | $$\frac{D_c}{D_e} = \left(\sqrt{C_{Te}}\right)\left(1 - \frac{L}{L_c}\right) \qquad (2)$$

71 | Jet area at the break plane, $A_{je}$, is given by

71 | $$A_{je} = C_{Te}{}^{*}A_e$$

71 | where

71 | 71 | 71 | $$C_{Te}{}^{*} = \begin{cases} 2.0 \text{ for } \Delta T_{sub} > 0 \\ 1.26 \text{ for } \Delta T_{sub} = 0 \end{cases}$$

71 | $A_e$ = inside cross sectional area of the pipe

71 | L = distance from break plane to target

71 | The outside area of the jet is given by equation (6) and will be
| discussed in the following sections.

71 | Jet Region 2 ($L_c < L < L_a$). In Region 2, the jet expands to its
| asymptotic area which can be calculated as:

71 | $$A_a / A_e = G_e{}^2 / (g_c \rho_{ma} C_T P_o) \qquad (3)$$

71 | where

71 | $A_a$ = jet area at the asymptotic plane

71 | $A_e$ = break plane area

$C_T$ = steady-state thrust coefficient |71

$G_e$ = mass flow rate per unit area from the break plane |71

$g_c$ = gravitational constant |71

$P_o$ = initial total (stagnation) pressure in the vessel |71

$\rho_{ma}$ = asymptotic plane density. If two-phase, density will be given by |71 |71

$\rho_{ma}$ = $1/[x/\ \rho g + (1-x)/\ \rho_f]$ |71

x = mixture vapor mass fraction i.e. quality, at the asymptotic plane pressure, $P_a$, and stagnation enthalpy |71 |71

$\rho_f$ = saturated liquid density at the asymptotic plane pressure |71 |71

$\rho_g$ = saturated vapor density at the asymptotic plane pressure |71

[Note: Figure 3.6B-96E may be used in place of Equation (3)] |71

The jet pressure at the asymptotic plane, $P_a$ can be expressed as the following expression |71 |

$$\frac{P_a}{P_{amb}} = 1 - 0.5 \left(1 - \frac{2P_{amb}}{P_o}\right) f(h_o) \qquad (4)$$ |71

where |71

$P_{amb}$ = ambient pressure |71

$P_a$ = asymptotic plane static pressure |71

71 |

71 |

71 |

71 |

71 |

71 |

71 |

$$f(h_o) = \begin{cases} \sqrt{0.1 + \dfrac{h_o + h_f}{h_{fg}}} & \text{for} \left( \dfrac{h_o - h_f}{h_{fg}} \right) > -0.1 \\ 0 & \text{for} \left( \dfrac{h_o - h_f}{h_{fg}} \right) < -0.1 \end{cases}$$

71 | $h_o$ = stagnation enthalpy in the vessel*

71 | $h_f$, $h_{fg}$ = saturated liquid enthalpy and heat of vaporization

71 | in the vessel

71 | *$h_o$ in the vessel and at the break plane are assumed to be equal.

71 | The distance from the break plane to the asymptotic plane is defined

| by:

71 | $$\frac{L_a}{D_e} = 1/2 \left( \sqrt{\frac{A_a}{A_e}} - 1 \right) \qquad (5)$$

71 | The jet area at any location from the break plane to the asymptotic

| plane (Regions 1 and 2) may be calculated from the following

| relationship:

71 | $$A_j/A_{je} = [1 + L/L_a \, (A_a/A_{je} - 1)], \qquad (6)$$

71 | where

71 | $A_j$ = jet area

71 | $A_{je}$ = jet area at break plane

Jet Region 3 ($L \geq L_a$). In Region 3, the jet area is given by | 71

$$A_j / A_a = (1 + (2(L - L_a)/D_a)(\tan 10^\circ))^2 \quad (7)$$ | 71

where | 71

$D_a$ = jet diameter at the asymptotic plane | 71

a.3.2 Longitudinal Break | 71

The jet shape for longitudinal breaks, as shown in Figure 3.6B-96B shall be assumed to be the same as the circumferencial break defined in a.3.1. A jet diameter for a circular break of the same area may be used and the jet direction taken to be perpendicular to the axis of the pipe. | 71

B. Effective Target Distance | 71

b.1 Category II Jets | 71

For steam and flashing water jets within the limits of NUREG/CR-2913 [i.e., stagnation pressure from 60 bars (870 psia) to 170 bars (2466 psia) and subcooling of 0°C (0°F) to 70°C (126°F)] the effective target distance is taken as ten (10) times the inside diameter of the ruptured pipes [25]. | 71

b.2 Category I & III Jets | 71

For all other high energy line break jets, jets are assumed to travel until impact with a target or a barrier. | 71

71 | C. Jet Force

71 | c.1 Category I Jets

71 | If the stagnation pressure at the break flow area is sufficiently close to the ambient pressure, the core length, $L_c$, calculated by equation (1) may be greater than the distance to the asymptotic surface $L_a$, calculated by equation (5). For this bounding case, the core length may be set to zero ($L_c = 0$) and the jet pressure distribution assumed to be uniform over the jet cross section and equal to $F_j/A_j$.

71 | For liquid jets whose temperature is below the saturation temperature at ambient pressure and for gas jets whose pressure at the break plane is equal to the ambient pressure, a uniform pressure over the jet cross-section can be assumed, which is consistent with the jet area and the total jet force as defined by equation (8) or (9) as shown in the following:

71 | The generalized momentum equation that describes the jet force is;

71 | $$F_J = \frac{G_e^2 A_e}{\rho_e g_c} + A_e (P_e - P_{amb}) \qquad (8)$$

71 | where

71 | $P_e$ = fluid pressure at the break flow area

71 | $\rho_e$ = fluid density at the break flow area

And for calculating target loads a conservative quasi-steady-state jet force is used: | 71

$$F_j = A_c(C_T P_o - P_{amb}) \approx C_T P_o A_e \qquad (9)$$ | 71

However, the above equation for $F_j$ is modified as follows: | 71

1. For jets where $\Delta T_{sub} > 0$, $C_T$ will be increased by $(2.0/C_{Te})$ in region 1. $C_{Te}$ is defined in C.3. | 71

2. Unless otherwise justified, $F_j$ is not to be less than the initial jet force based on equation (8). | 71

c.2 Category II Jets | 71

The jet force is a function of the pressure field downstream of the shock wave that forms in the flow field when a target or obstacle is encountered. The jet force is given by: | 71

$$F_j = F_r = \int P_j \, dA_t \qquad (10)$$ | 71

where $F_r$ = total target force given in NUREG/CR-2913 [25]. | 71

c.3 Category III Jets | 71

The jet force is a function of jet geometry as discussed below. | 71

c.3.1 | 71

Region 1, defined as $0 \leq L \leq L_c$, the jet pressure in the core and outside the core is given by | 71

71 | Jet Core; for $0 \leq r \leq D_c/2$,

71 | $$P_j = P_{oe} = (C_1/C_{Te})P_o \qquad (11)$$

71 | where

71 | $C_{Te} = C_T$ based on $FL/D = 0$ and the break flow area stagnation conditions. Where these conditions are not known and $\Delta T_{sub}>0$, $C_{Te}$ and $P_{oe}$ can be determined through an interative process, first using vessel conditions to estimate $C_{Te}$, then the resulting estimate for $P_{oc}$, etc. (Note that $h_o$ at the break may be assumed equal to $h_e$ in the vessel).

71 | Outside Core; for $D_c/2 \leq r \leq D_j/2$,

71 | $$\frac{P_j}{P_{oc}} = \left(\frac{D_j - 2r}{D_j - D_c}\right)\left[1 - \frac{2\left[D_j^2 + D_jD_c + D_c^2 - 3D_c^2\, C_{Te}^*\right]}{(D_j^2 - D_c^2)}\left(\frac{2r - D_c}{D_j - D_c}\right)\right] \qquad (12)$$

71 | C.3.2 For Region 2, defined as $L_c < L < L_a$, the jet pressure is given by

71 | $$\frac{P_j}{P_{jc}} = \left(1 - \frac{2r}{D_j}\right)\left[1 - 2\left(\frac{2r}{D_j}\right)\left[1 - 3C_{Te}\left(\frac{D_e}{D_j}\right)^2\left(\frac{P_{oe}}{P_{jc}}\right)\right]\right] \qquad (13)$$

where | 71

$$\frac{P_{jc}}{P_{oe}} = 1 - \left[1 - 3C_{Te}\left(\frac{D_e}{D_a}\right)^2\right] \frac{L_a(L-L_c)}{L(L_a-L_c)} = \text{Jet centerline pressure for } (L_c < L < L_a) \quad (14)$$ | 71

c.3.3 For Region 3, defined as $L \geq L_a$, the jet pressure is given by | 71

$$\frac{P_j}{P_{jc}} = \left(\frac{D_j - Z_r}{D_j}\right) \quad (15)$$ | 71

where | 71

$$P_{jc} = 3F_j/A_j, \text{ jet centerline pressure for } (L > L_a) \quad (16)$$ | 71

D. Jet Impingement Force | 71

The jet impingement force which is applied to a given target is a function of the fraction of the jet which is intercepted by the target. If the entire jet is intercepted, then the entire jet force is applied to the target. | 71

$$F_{jt} = F_j \quad (17)$$ | 71

If the target intercepts a fraction of the jet, but not the entire jet, the jet pressure distribution over the target must me integrated to obtain the jet force. | 71

71 | $F_{jt} = \int P_j \, dA_t$ (18)

71 | where

71 | $P_j$ = radial jet pressure distribution at the impingement plane, as described in Section C above.

71 | $A_t$ = Target area

71 | The impingement load may be estimated from the jet axial force and an approximate correction factor,

71 | $F_{imp} = K\phi \; F_{jt}(DLF)$ (19)

71 | Where

71 | $F_{imp}$ = impingement force on the target, as a function of time

71 | $K\phi$ = the shape factor, a measure of the target's potential for changing the momentum of the jet, as described in Appendix D of Reference 22.

71 | DLF = Dynamic Load Factor [26]

B. Pipe Whip Dynamic Analysis Criteria

An analysis of the pipe run or branch is performed for each longitudinal and/or circumferential postulated rupture at the break locations determined in accordance with the criteria of Section 3.6B.2.1.2. The loading condition of a pipe run or branch prior to postulated rupture, in terms of internal pressure, temperature and stress state, is assumed to be the condition associated with the normal plant operating condition.

For a circumferential rupture, pipe whip dynamic analyses are only performed for that end (or ends) of the pipe or branch that is connected to a contained fluid energy reservoir having sufficient capacity to develop a jet stream. Dynamic analytical methods used for calculating the piping and piping/restraint system response to the jet thrust developed after a postulated rupture adequately account for the effects of the following:

a. Translational masses (and rotational masses for major components) and stiffness properties of the piping system, restraint system, major components and support walls.

b. Transient forcing function(s) acting on the piping system and jet thrusts on affected structures.

c. Elastic and inelastic deformation of piping and/or restraint.

A 10 percent increase of minimum specified design yield strength ($S_y$) is used to account for strain rate effects in inelastic nonlinear analyses.

3.6B.2.3.3 Pipe Whip Restraint Design Criteria

A. Design Bases

Pipe whip restraints function primarily as a load carrying member for the low probability occurrence of a pipe break. The restraints are designed for one time use only and function to control the movement of the ruptured pipe. The design basis for the pipe break event is that of a faulted condition. The restraints and the structure which supports them are analyzed accordingly.

B. Functional Requirements

68 High-energy pipe whip restraints are designed to ensure that the pipe whip will be eliminated or minimized. On the other hand, the restraints are designed to permit the predicted thermal and seismic movements of the pipes.

C. Design Parameters

After the pipe restraint locations are identified, the following design parameters are determined:

1. Jet thrust force

2. Pipe seismic displacements

3. Pipe thermal displacements

4. Pipe insulation thickness

5. Minimum allowable tolerance between restraint and pipe insulation.

6. Maximum allowable pipe movement.

The jet thrust force and maximum allowable pipe movement are used in the analysis process. Tolerance, insulation, and seismic and thermal movements are used in determining the minimum gap between the restraint and pipe surfaces.

The pipe whip restraints used for the CPSES project are U-bar, crushable pipe, crushable pad (honeycomb), and elastic hard restraints as shown in Figures 3.6B-1 through 3.6B-4.

D. Analysis and Design

The maximum allowable design limits for the restraints are as follows:

| Q112.5
| 68

a. The permanent strain in the metallic ductile materials is limited to fifty percent of the minimum ultimate uniform strain (strain corresponding to the maximum stress point on the appropriate engineering stress-strain curve) based on restraint material tests and/or ASME Code [4].

b. The design limit for crushable pipe restraints longer than three outside pipe diameters is 50 percent of energy absorbing capacity (crushed to 70 percent of inside diameter of pipe).

c. The permissible diameter deformations limit for crushable pipe restraints shorter than two outside pipe diameters is the lesser of D/2 or ASTM where;

D = initial outside diameter of the crushable pipe

ASTM = maximum flattening limit for A106 Gr. B carbon steel pipe as prescribed by ASTM A 530-76.

31 | d. If a crushable material, such as honeycomb, is used, the allowable capacity of crushable material shall be limited to 80% of its rated energy dissipating capacity as determined by dynamic testing, at loading rates within ± 50% of the specified design loading rate. The rated energy dissipating capacity shall be taken as not greater than the area under the load-deflection curve. The portion of the curve in which the value of load vs. deflection has departed from the essentially horizontal portion shall not be used.

Typical characteristics of pipe whip restraint components are as follows:

a. Energy absorption members of yielding type restraints are those which, under the influence of the whipping pipe, absorb energy by significant plastic deformation. U-bars, crushable pipe, and crushable pad assemblies, designed with materials having high ultimate strain and relatively high energy absorption capacity are used in CPSES.

b. Elastic pipe whip restraints are also used. They are essentially plane frames or space frames. Upon rupture, the energy of the whipping pipe is completely absorbed by the steel restraint structure. Movement of the ruptured

pipe is controlled by permitting deformation of the elements of the structural restraints within the elastic range of the material.

c. Restraint connecting members are components which form a direct link between the plastic yielding restraint members and the structure (e.g., clevises, brackets, and pins of a U-bar restraint).

d. Restraint connecting member structural attachments are fasteners which provide the means of securing the restraint connecting members of the structure (e.g., weld attachments and bolts).

e. Structural and civil components are steel and concrete structures which ultimately carry the restraint load (e.g., walls, frames, columns, and beams). A dynamic load factor is considered in the design of these structural and civil components. This factor depends on the natural frequency of these components and the restraint force time history. It is evaluated for each postulated break affecting a specific structural or civil component.

f. The design of the pipe whip restraint is for one time usage.

In designing a restraint, the following three loading conditions are considered:

a. An in-plane (the plane of the U-bar) impact loading at an angle up to 45 degrees from the axis of the U-bar.

b. An out-of-plane (the plane of the U-bar) impact loading at an angle up to 10 degrees from the axis of the U-bar.

c. An impact loading at an angle up to 10 degrees from the normal to the crushable pad/pipe axis.

The materials used in restraint design are selected to ensure ductile behavior. The U-bars are made of SA 479 type 304 annealed stainless steel. The crushable pipes are made of SA 106 Grade B carbon steel. The crushable pads are metalurgically bonded type 304 stainless steel sheets. The elastic restraints are made of ASTM A-588 Grade 50 steel. The other restraint components, such as pins, bolts, and anchors, are designed to remain within their elastic limits.

### 3.6B.2.4 Guard Pipe Assembly Design Criteria

The CPSES containment is of single barrier design. Guard pipes are not used in the penetration design.

### 3.6B.2.5 Material to be Submitted for the Operating License Review

This section presents a summary of the dynamic analyses applicable to high-energy piping systems resulting from postulated pipe breaks. The following information is provided for the various high energy systems in the subparagraphs of this Section:

1. Implementation of the stress criteria as outlined in Section 3.6B.2.1

2. The type, number, and location of postulated breaks on which the dynamic analyses are based.

3. The number and locations of pipe whip restraints required to protect essential systems.

4. The results of the jet thrust, impingement functions, and pipe break analysis as described in Section 3.6B.2.2 and 3.6B.2.3 consistent with Reference [5], where the stress intensity ranges and/or usage factors exceed the criteria of 2.4 $S_m$ and 0.2, respectively.

5. The design adequacy of essential systems and components to ensure that their design-intended functions will not be impaired to an unacceptable level of integrity or operability as the result of high-energy pipe breaks.

6. Description of protective enclosures provided to protect safety-related equipment from the effects of a possible rupture in a high energy fluid piping system, including openings in these enclosures.

The implementation of criteria for inservice inspection is discussed in Section 6.6.8.

3.6B.2.5.1 Reactor Coolant System Main Loop Piping

Table 3.6B.2 and Figure 3.6B.9 identify the RCS main loop break locations. The eight main loop piping break locations (breaks 1 to 8 in Table 3.6B.2 and Figure 3.6B.9) are included in the CPSES design basis for containment design, ECCS and environmental qualification requirements. These eight breaks are not part of the design basis for dynamic effects, as discussed in section 3.6B.2.1.1. The three large branch nozzle breaks (breaks 9 to 11 in Table 3.6B.2 and Figure 3.6B.9) are included in the design basis for dynamic effects. | 61

The primary plus secondary stress intensity ranges and the fatigue cumulative usage factors at the design break locations specified in Reference [5] are given in Table 3.6B.3 for a reference fatigue analysis. The reference analysis has been prepared to be applicable for many plants. It utilizes seismic umbrella moments which are higher than those used in Reference [5] such that the primary stress is equal to the limits of equation (9) in NB-3650 (Section III of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code) at many locations in the system where in Reference [5] one location was at the limit. Therefore, the results of the reference analysis may differ slightly from Reference [5], but the philosophy and conclusions of Reference [5] are valid. There are no other locations in the model used in the reference fatigue analysis,

Actual plant moments for the CPSES are also given in Table 3.6B.3 at the design basis break location so that the reference fatigue analysis can be shown to be applicable for this plant. By showing actual plant moments to be no greater than those used in the reference analysis, it follows that the stress intensity ranges and usage factors for the CPSES will be less than those for comparable locations in the reference mode. By this means it is shown that there are no locations other than those identified in Reference [5] where the stress intensity ranges and/or usage factors for the CPSES might exceed the criteria of 2.4 $S_m$ and 0.2, respectively. Thus, the applicability of Reference [5] to the CPSES has been verified.

Design loading combinations and applicable criteria for ASME Class 1
61 | components and supports are provided in Section 3.9N. The forces
| associated with rupture of the branch nozzles (9 to 11, Table 3.6B.2)
| to the reactor coolant loop piping systems are considered in
| combination with normal operating loads and earthquake loads for the
| reactor coolant loop design in order to assure continued integrity of
| vital components and engineered safety features. Pipe rupture loads
include not only the jet thrust forces acting on the piping but also jet impingement loads on the primary equipment supports.

61 | Barriers and layout are used to provide protection from pipe whip,
| blowdown jet and reactive forces. Some of the barriers utilized for protection against pipe whip are as follows. The steam generator compartment walls serve as a barrier between the reactor coolant loops and the containment liner. In addition, the refueling cavity walls, various structural beams, the operating floor, and the steam generator compartment walls enclosed each reactor coolant loop into a separate compartment, thereby preventing an accident, which may occur in any loop, from affecting another loop or the containment liner. The portion of the steam and feedwater lines within the containment have been routed behind barriers which separate these lines from all reactor coolant piping. The barriers described above will withstand loadings caused by jet forces and pipe whip impact forces.

Other than for the Emergency Core Cooling System lines, which must circulate cooling water to the vessel, the engineered safety features are located outside of the steam generator compartment walls. The Emergency Core Cooling System lines which penetrate the steam generator compartment walls are routed around and outside the walls to penetrate the walls in the vicinity of the loop to which they are attached.

3.6B.2.5.2 High-Energy Piping Other Than RCS Main Loop

In this section, a summary is presented giving the results of the detailed stress analysis and, describing methods of protection employed to protect essential equipment against the effects of pipe breaks for the high energy systems outlined in Section 3.6B.1.2.1.

1. Main Steam System

A. General Description

The main steam piping inside containment is carbon steel ASME SA-155, Grade KCF 70 material designed in accordance with the ASME Code, Section III, Class 2 criteria. The main steam system inside containment consists of four 32 inch OD (1.25 inch minimum wall thickness) lines running from each steam generator to the containment penetrations.

The main steam piping outside containment from the containment penetrations to the main steam isolation valve moment restraints is the same as the main steam piping inside containment. The piping from the MSIV moment restraints to the high pressure turbine is carbon steel ASME SA-155 Grade KC 70 material designed in accordance with ANSI B31.1 as non-nuclear class piping. These lines are 34 inch OD (1.25 inch minimum wall thickness). The piping connected to the main steam drip pots are of carbon steel material with portions designed in accordance with ANSI B31.1 and ASME Code, Section III, Class 2 criteria. The Class 2 portion of the system consists of ASME SA-333 Grade 6, two inch schedule 80 pipe and the non-nuclear portion of the system consists of ASME SA-106 Grade B, two inch schedule 80 pipe. The location and configuration of the main steam lines with respect to structures, equipment, and other piping are shown on Figures 1.2-8, 1.2-14 and 1.2-25. The criteria described above and as follows is applicable for both Units 1 and 2.

B. Pipe Whip Analysis

Isometrics of the main steam lines inside Containment indicating the location of the highest stress node points, postulated breakpoints, and restraints are provided in Figures 3.6B-11 through 3.6B-14. The systems and equipment necessary to mitigate the consequences of a main steam line
68 | break are described in Section 3.6B.1. Breakpoints were
| postulated at the terminal ends of the piping run and at
| intermediate locations in accordance with the criteria
| outlined in Section 3.6B.2.1. The steam generator nozzles
and the flued heads at the containment penetrations are
68 | considered terminal ends. Intermediate breaks are
| postulated as shown. A circumferential break is
postulated

to occur at any one of these points. Restraints are provided on each line to prevent impact on essential components. The pipe whip restraints are designed to prevent plastic hinge formation and thereby preclude adverse pipe whip effects.

Isometrics of the main steam lines outside containment indicating the location of postulated breakpoints and restraints are provided in Figures 3.6B-15 through 3.6B-18. Since these lines consist of non-nuclear piping, pipe breaks are postulated at each fitting, valve, or welded attachment. Since these lines are greater than 4 inches in diameter, circumferential or longitudinal breaks are postulated. Pipe whip restraints are provided as necessary that are designed to prevent plastic hinge formation and thereby preclude adverse pipe whip effects. A portion of the main steam lines between the containment penetrations and isolation valves, are designed in accordance with the criteria in Section 3.6B.2.1.2. Therefore, circumferential | 40
pipe breaks are not postulated in the regions between the |
penetrations and the moment restraints after the isolation |
valves. However, a one square foot crack is postulated |
and evaluated for environmental effects, in accordance with |
the criteria in BTP ASB 3-1. As shown on Figure 3.6B-25, |
pipe breaks are postulated in the main steam blowdown lines outside containment. Since these lines consist of non-nuclear piping, break points are postulated at terminal ends and at each intermediate fitting, valve or welded attachment with the exception of the four break exclusion areas as shown.

Review of the piping layout and plant arrangement showed that breaks in portions of the main steam lines could adversely impact the safeguards, switchgear, electrical and

controls and turbine buildings. Accordingly, these lines are restrained as necessary to protect the structures. The pipe whip restraints are designed to prevent plastic hinge formation and thereby preclude adverse pipe whip effects on the structures. Since there are no essential systems or components in the turbine building, protection is primarily provided to protect the structures noted above from a main steam pipe break.

C. Jet Impingement Analysis

40 | The jet impingement analysis for this system is performed to determine the effects of jet impingement loading on essential components (as defined in Section 3.6B.1.2.1), associated supports and building structures.

40 | In those cases where the analysis shows that the component or structure is not capable of withstanding the load then protection is required. Protection consists of either relocating the target, or installing jet shield or barriers to protect the target.

40 | D. Environmental Analysis

40 | The safety-related systems required to mitigate the consequences of a main steam line break inside Containment are designed to perform their safety function under the environmental conditions resulting from a LOCA or MSLB as discussed in Section 3.11.

40 | Any one of the main steam lines is postulated to develop a 1 $ft^2$ crack in the penetration area outside Containment. The postulation of this crack is in accordance with Branch Technical Position ASB 3-1.

The penetration area is isolated from the rest of the safeguards building by the seismic gap seal between the safeguards building and the containment wall, fast closing isolation dampers in the interconnecting HVAC ducts and the pressure resisting watertight doors. These features preclude this crack from producing any detrimental environmental effects on the rest of the plant. | 40

2. Feedwater System

A. General Description

The main feedwater lines inside containment are carbon steel ASME SA-333, Grade 6 material designed in accordance with the ASME Code, Section III, Class 2 criteria. Each of the lines consists of an 18 inch schedule 80 seamless pipe running from the Containment penetration to each steam generator. The main feedwater piping outside Containment from the containment penetration to the feedwater containment isolation valve is the same as the feedwater piping inside Containment. The piping from the feedwater containment isolation valve to the feedwater control valve moment restraint is also the same as the feedwater piping inside containment, except that these lines are 18 inch schedule 140 seamless pipe. The main feedwater lines from the feedwater control valve moment restraint connect to the main feedwater header combining into one main feedwater line which originates from the feedwater heater in the turbine building. The feedwater lines to the main feedwater header and the feedwater control valve by-pass lines are carbon steel ASME SA-106, Grade B material designed in accordance with ANSI B31.1 as non-nuclear class piping. These lines consist of 18 inch schedule 140 and eight inch schedule 120 pipe. The main feedwater header

and feedwater line in the turbine building are carbon steel ASME SA-155 Grade KC 60 material designed in accordance with ANSI B31.1 as non-nuclear class piping. These lines are 30 inch OD (2.125 inch minimum wall thickness) pipe. The location and configuration of the feedwater lines with respect to structures, equipment, and other piping are shown in Figures 1.2-8, 1.2-13 and 1.2-25.

The criteria described above and as follows is applicable for both Units 1 and 2.

B. Pipe Whip Analysis

Isometrics of the main feedwater lines inside Containment indicating the location of the highest stress node points, postulated breakpoints, and restraints are provided in Figures 3.6B-19 through 3.6B-22. The systems and equipment necessary to mitigate the consequences of a main feedwater
68 | line break are described in Section 3.6B.1. Breakpoints
| were postulated at the terminal ends of the piping run and
| at intermediate locations in accordance with the criteria
| outlined in Section 3.6B.2.1. The flued heads at the
containment penetrations and the steam generator nozzles
68 | are considered terminal ends. Intermediate breaks are
| postulated as shown. A circumferential break is
postulated to occur at any one of these points. Pipe whip restraints are provided as required to prevent impact on essential components. The pipe whip restraints are designed to prevent plastic hinge formation and thereby preclude adverse pipe whip effects.

Isometrics of the main feedwater lines outside containment, indicating the location of postulated breakpoints and restraints, are provided in Figures 3.6B-23 and 3.6B-24.

Since these lines consist largely of non-nuclear piping, pipe breaks are postulated at each fitting, valve, or welded attachment. For all lines, circumferential or longitudinal breaks are postulated. Pipe whip restraints are provided to prevent unacceptable damage to essential components and building structures. The pipe whip restraints are designed to prevent plastic hinge formation to preclude adverse pipe whip effects. A portion of the main feedwater lines between the containment penetrations and the feedwater control valves, is designed in accordance with the criteria in Section 3.6B.2.1.2. Therefore, pipe breaks are not postulated in the regions between the penetrations and the moment restraints after the control valves. However, a one square foot crack is postulated and | 40
evaluated for environmental effects in accordance with the |
criteria in BTP ASB 3-1. |

Review of the piping layout and plant arrangement showed that breaks in portions of the main feedwater lines could adversely impact the safeguards, switchgear, electrical and controls and turbine buildings. Accordingly, these lines are restrained as necessary to protect the structures. The pipe whip restraints are designed to prevent plastic hinge formation and thereby preclude adverse pipe whip effects on the structures. Since there are no essential systems or components in the turbine building, protection is primarily provided to protect the structures noted above from a feedwater line break.

C. Jet Impingement Analysis

40 The jet impingement analysis for this system is performed to determine the effects of jet impingement loading on essential components (as defined in Section 3.6B.1.2.1), associated supports and building structures.

40 In those cases where the analysis shows that the component or structure is not capable of withstanding the load then protection is required. Protection consists of either relocating the target, or installing jet shield or barriers to protect the target.

40

D. Environmental Analysis

40 The safety-related systems required to mitigate the consequences of a main feedwater line break inside Containment are designed to perform their safety function under the environmental conditions resulting from a LOCA or MSLB as discussed in Section 3.11.

40 Any one of the main feedwater lines is postulated to develop a 1 $ft^2$ crack in the penetration area outside Containment. The postulation of this crack is in accordance with Branch Technical Position ASB 3-1.

40 The penetration area is isolated from the rest of the safeguards building by the seismic gap seal between the safeguards building and the containment wall, fast closing isolation dampers in the interconnecting HVAC ducts and the pressure resisting watertight doors. These features preclude this crack from producing any detrimental environmental effects on the rest of the plant.

High energy flooding is evaluated in the same manner as moderate energy flooding per Section 3.6B.2.5.3. | 40

3. Auxiliary Feedwater System | 14

A. General Description | 14

The Auxiliary Feedwater System lines are carbon steel, ASME SA 106, Grade B material designed in accordance with ASME Code Section III, Class 2 or 3 criteria as applicable. The suction lines of the auxiliary feedwater pumps consist of 10, 8 and 6 inch category 152 piping which is schedule 40, with design pressure of 150 psig. These lines run from the condensate storage tank and service water piping to the suction of each auxiliary feedwater pump. The discharge lines of the auxiliary feedwater pumps consist of 6, 4 and 3 inch category 2002 (category 2003, directly after the isolation valve) piping which is schedule 160 up to 3 inches, and schedule 120 for sizes above 3 inches. The design pressure is 1800 psig. The piping that connects to the main feedwater piping after the last auxiliary feedwater isolation valves is category 1303 which is schedule 80, with a design pressure of 1200 psig to match the main feedwater piping. The discharge lines of the auxiliary feedwater pumps connect to the main feedwater lines. The location and configuration of the auxiliary feedwater lines with respect to structures, equipment and other piping are shown in Figure 1.2-10. The criteria described above and as follows are applicable for both Units 1 and 2. | 14

14 | B. Pipe Whip Analysis

14 | Isometrics of the Auxiliary Feedwater System lines indicating the location of the highest stress node points, postulated breakpoints and restraints are provided in Figures 3.6B-26 through 3.6B-33. The systems and equipment necessary to mitigate the consequences of a Auxiliary Feedwater System line break are described in
68 | Section 3.6B.1. Breakpoints were postulated at the terminal ends of the piping run and at intermediate locations in accordance with the criteria outlined in Section 3.6B.2.1. Intermediate breaks are postulated as shown. A circumferential break is postulated to occur at
14 | each of these points. Pipe whip restraints are provided as required to prevent impact on essential components. The pipe whip restraints are designed to prevent plastic hinge formation and thereby preclude adverse pipe whip effects.

40 | C. Jet Impingement Analysis

40 | The jet impingement analysis for this system is performed to determine the effects of jet impingement loading on essential components (as defined in Section 3.6B.1.2.1), associated supports and building structures.

40 | In those cases where the analysis shows that the component or structure is not capable of withstanding the load then protection is required. Protection consists of either relocating the target, or installing jet shield or barriers to protect the target.

D. Environmental Analysis

The environmental conditions resulting from a break in an Auxiliary Feedwater System line do not affect the operation of safety-related systems required to mitigate the consequences of the accident. | 40

The Auxiliary Feedwater System is high energy only on the basis of the system pressure. Auxiliary feedwater is only cold water so an auxiliary feedwater break cannot generate a steam atmosphere. | 40

High energy flooding is evaluated in the same manner as moderate energy flooding per Section 3.6B.2.5.3. | 40

4. Auxiliary Steam System

A. General Description

The Auxiliary Steam System Piping is comprised of nuclear safety related carbon steel, ASME SA-106 Grade B material. The auxiliary steam system supplies steam to both Units 1 and 2 components.

The steam supply piping to the floor drain waste evaporator package, WPS waste evaporator package, BRS recycle evaporator package and CVCS boric acid batching tank, all located in the Auxiliary Building, are 10, 6, 4 and 2 inch, schedule 40 category 152 Class 5 piping with a design pressure of 150 psig. These lines run from the auxiliary steam header of the components described above and are seismically supported. The return lines of the above components are 2, 1-1/2 and 3/4 inch schedule 40, category 152 Class 5 piping with a design pressure of 150 psig. The

return lines are connected to the auxiliary steam drain tank. The location and configuration of the auxiliary steam lines with respect to structures, equipment and other piping are shown in Figures 1.2-31 and 1.2-32.

The auxiliary boiler and its associated piping is category 152G piping and is located in the Turbine Building.

B. Pipe Whip Analysis

Isometric drawings of the Auxiliary Steam System Piping indicating the locations of the highest stresses, postulated breakpoints and restraints are provided in Figures 3.6B-58 through 3.6B-63. The systems and equipment necessary to mitigate the consequences of an Auxiliary Steam System line break are described in Section 3.6B.1. Break locations were postulated at the terminal ends of the piping run and at intermediate locations in accordance with the criteria outlined in Section 3.6B.2.1. A circumferential break is postulated to occur at each of these points. Pipe whip restraints are provided as required to prevent impact on essential components. The pipe whip restraints are designed to prevent plastic hinge formation and thereby preclude adverse pipe whip effects.

C. Jet Impingement Analysis

40 | The jet impingement analysis for this system is performed
| to determine the effects of jet impingement loading on
| essential components (as defined in Section 3.6B.1.2.1),
| associated supports and building structures.

40 | In those cases where the analysis shows that the component
| or structure is not capable of withstanding the load then

protection is required. Protection consists of either relocating the target, or installing jet shield or barriers to protect the target. | 40

D. Environmental Analysis | 40

The environmental conditions resulting from a break in an Auxiliary Steam System line do not affect the operation of safety-related systems required to mitigate the consequences of the accident. | 40

The most significant environmental conditions generated by breaks in the auxiliary steam system are the various elevated temperatures. The pressure transients are very slight and do not pose a threat to the safe operation or the structure of the plant. The temperature transients caused by any of the auxiliary system breaks do not affect the safe shutdown of the plant because: 1) equipment required for safe shutdown is located in an area not affected by the break; 2) the equipment is qualified to parameters higher than those experienced during the break; 3) the equipment fails in a safe position; or 4) the equipment has been analyzed to show that the short-duration increased temperatures will not cause appreciable degradation in performance or qualified life. | 40

Blowdown from any of the postulated auxiliary steam system line breaks is terminated automatically. The transients were analyzed for the full period of the blowdown. | 40

Details of the instrumentation required to mitigate the blowdown is in Section 7.6.12. | 45

5. Steam Generator Blowdown Cleanup System

A. General Description

The Steam Generator Blowdown Cleanup System Piping is comprised of non-nuclear safety related, carbon steel ASME SA-106 Grade B material, or non-nuclear safety related stainless steel ASTM A-312 TP 304 material.

The blowdown lines from each steam generator up to the isolation valve moment restraints are 3" or 4" safety class 2, Schedule 80, category 1303 piping with a design pressure of 1200 psig. The piping connecting the 8-inch header of the steam generator blowdown heat exchanger to the pressure reducing valve PV-5180 is schedule 80, category 1302, Class 5, with a design pressure of 1200 psig. The portion of the blowdown piping on the Switchgear Building roof is category 1302G, and not seismically supported. The piping from valve PV-5180 up to valve SB-170 is 8-inch, category 302, Class 5, schedule 40, with a design pressure of 450 psig. The piping from valve SB-170 to the filters and demineralizers is 6-inch, category 301, Class 5, schedule 40S with a design pressure of 370 psig. The piping that connects the discharge of relief valve SB020 to the condenser is 4 and 8 inch, category 302, Class 5, Schedule 40, with a design pressure of 450 psig. The piping downstream of the filters is moderate energy piping. The location of the steam generator blowdown cleanup system with respect to structures and equipment are shown in Figures 1.2-31 and 1.2-35.

B. Pipe Whip Analysis

Isometrics of the Steam Generator Blowdown Cleanup System Piping indicating the locations of the highest stresses postulated breakpoints and restraints are provided in Figures 3.6B-38 through 3.6B-47. The systems and equipment necessary to mitigate the consequences of a Steam Generator Blowdown Cleanup System line break are described in Section 3.6B.1. Break locations were postulated at the terminal | 68
ends of the piping run and at intermediate locations in |
accordance with the criteria outlined in Section 3.6B.2.1 |
except for category 1302G piping, where breaks are |
postulated at terminal ends and at each intermediate |
fitting, valve or welded attachment. A circumferential |
break is postulated to occur at each of these points. Pipe whip restraints are provided as required to prevent impact on essential components. The pipe whip restraints are designed to prevent plastic hinge formation and thereby preclude adverse pipe whip effects.

C. Jet Impingement Analysis

The jet impingement analysis for this system is performed | 40
to determine the effects of jet impingement loading on |
essential components (as defined in Section 3.6B.1.2.1), |
associated supports and building structures. |

In those cases where the analysis shows that the component | 40
or structure is not capable of withstanding the load then |
protection is required. Protection consists of either |
relocating the target, or installing jet shield or barriers |
to protect the target. |

40 | D. Environmental Analysis

40 | The environmental conditions resulting from a break in a Steam Generator Blowdown System line do not affect the operation of safety-related systems required to mitigate the consequences of the accident.

40 | The most significant environmental conditions generated by breaks in the blowdown system are the various elevated temperatures. The pressure transients are small and do not pose a threat to the safe operation or the structure of the plant. The temperature transients caused by any of the blowdown system breaks do not affect the safe shutdown of the plant because: 1) equipment required for safe shutdown is located in an area not affected by the break; 2) the equipment is qualified to parameters higher than those experienced during the break; 3) the equipment fails in a safe position; or 4) the equipment has been analyzed to show that the short-duration increased temperatures will not cause appreciable degradation in performance or qualified life.

40 | Blowdown from any of the postulated blowdown line breaks is terminated automatically. The transients were analyzed for the full period of the blowdown.

45 | Details of the instrumentation required to mitigate the blowdown is in Section 7.6.12.

40 | High energy flooding is evaluated in the same manner as moderate energy flooding per Section 3.6B.2.5.3.

6. Chemical & Volume Control System

A. General Description

The Chemical and Volume Control System lines are of stainless steel ASME SA-312, TP 304 material or stainless steel ASME SA-312 TP 304 material or stainless steel ASME SA-376 TP 304 material designed in accordance with ASME Code Section III, Class 1, 2 or 3 criteria as applicable. The letdown line from the cold leg of the RCS to the letdown orifices consists of 3 and 2 in category 2501 schedule 160 piping with a design pressure of 2485 psig. The letdown orifices on the low pressure letdown valve PCV-131 is 2 and 3 inch category 601, schedule 40S piping with a design pressure of 700 psig. The letdown line from the low pressure letdown valve to the demineralizers and RHT of the BRS is 3 inch category 301, Schedule 40S, with a design pressure of 370 psig. The suction lines of the charging pumps consist of 1, 2, 3, 4 and 6 inch category 151, schedule 40S piping with a design pressure of 150 psig. These lines run from the volume control tank, CVCS boric acid tank and chemical mixing tank to the suction of the charging pumps. The discharge lines of the charging pumps consist of 4, 3 and 2 inch category 2501 schedule 160 piping, with a design pressure of 2485 psig. These lines run from the charging pumps to the cold leg of the RCS and the RCP seals. The location and configuration of the CVCS lines with respect to structures and equipment are shown in Figures 1.2-11, 1.2-12, 1.2-17, 1.2-18 and 1.2-32.

B. Pipe Whip Analysis

Isometrics of the CVS system piping indicating location of the highest stresses, postulated breakpoints and restraints

are provided in Figures 3.6B-70 thru 3.6B-88. The systems and equipment necessary to mitigate the consequences of a CVC system line break are described in Section 3.6B.1. Breakpoints were postulated at the terminal ends of the piping run and at intermediate locations in accordance with the criteria outlined in Section 3.6B.2.1. A circumferential break is postulated to occur at each of these points. Pipe whip restraints are provided as required to prevent impact on essential components. The pipe whip restraints are designed to prevent plastic hinge formation and thereby preclude adverse pipe whip effects.

C. Jet Impingement Analysis

40 | The jet impingement analysis for this system is performed to determine the effects of jet impingement loading on essential components (as defined in Section 3.6B.1.2.1), associated supports and building structures.

40 | In those cases where the analysis shows that the component or structure is not capable of withstanding the load then protection is required. Protection consists of either relocating the target, or installing jet shields or barriers to protect the target.

40 | D. Environmental Analysis

40 | The environmental conditions resulting from a break in an CVC System line do not affect the operation of safety-related systems required to mitigate the consequences of the accident.

40 | The most significant environmental conditions generated by breaks in the CVC system are the various elevated

temperatures. The pressure transients are small and do not pose a threat to the safe operation or the structure of the plant. The temperature transients caused by any of the CVCS system breaks do not affect the safe shutdown of the plant because: 1) equipment required for safe shutdown is located in an area not affected by the break; 2) the equipment is qualified to parameters higher than those experienced during the break; 3) the equipment fails in a safe position; or 4) the equipment has been analyzed to show that the short-duration increased temperatures will not cause appreciable degradation in performance or qualified life. | 40

Details of the instrumentation required to mitigate the blowdown is in Section 7.6.12. | 45

High energy flooding is evaluated in the same manner as moderate energy flooding per Section 3.6B.2.5.3. | 40

7. Residual Heat Removal System

A. General Description

The Residual Heat Removal System piping from the RCS hot leg of loop 1 and 2 to the second isolation valve are of stainless steel, ASME SA-376 TP 316 material designed in accordance with ASME Code Section III, Class 1 criteria. These lines consist of 12 inch category 2501, schedule 140 piping with a design pressure of 2485 psig. The piping from the second isolation valve to the containment penetrations is of stainless steel ASME SA-312 TP 304 material designed in accordance with ASME Code section III, Class 2 criteria. These lines are 12 inch category 601, schedule 40S piping with a design pressure of 600 psig. The piping from the containment penetration to the suction of the RHR pumps is of stainless steel ASME SA-358, Class

1. These lines are 16 inch (0.5 inch minimum wall thickness) category 601 with a design pressure of 600 psig. The discharge lines of the Residual Heat Removal pumps are of stainless steel, ASME SA-312 TP 304 material designed in accordance with ASME Code Section III, Class 2 criteria. These lines consist of 8, 10 and 12 inch category 601, schedule 40S piping with a design pressure of 600 psig. The discharge lines of the residual heat removal pumps connect to safety injection system cold leg injection headers. The location of the Residual Heat Removal System piping with respect to structures and equipment is shown in Figures 1.2-10 and 1.2-16.

B. Pipe Whip Analysis

Isometric drawings of the RHR System piping indicating the locations of the highest stresses postulated breakpoints and restraints are provided in Figure 3.6B-64. The systems and equipment necessary to mitigate the consequences of a RHR system line break are described in Section 3.6B.1. Breakpoints were postulated at the terminal ends of the piping run and at intermediate locations in accordance with the criteria outlined in Section 3.6B.2.1. A circumferential break is postulated to occur at each of these points. Pipe whip restraints are provided as required to prevent impact on essential components. The pipe whip restraints are designed to prevent plastic hinge formation and thereby preclude adverse pipe whip effects.

C. Jet Impingement Analysis

40 The jet impingement analysis for this system is performed to determine the effects of jet impingement loading on essential components (as defined in Section 3.6B.1.2.1), associated supports and building structures.

In those cases where the analysis shows that the component or structure is not capable of withstanding the load then protection is required. Protection consists of either relocating the target, or installing jet shield or barriers to protect the target. | 40

D. Environmental Analysis

The RHR System is considered a moderate energy system outside containment in accordance with Branch Technical Position MEB 3-1. | 40

Moderate energy flooding is evaluated in accordance with Section 3.6B.2.5.3. | 40

8. Safety Injection System

A. General Description

The Safety Injection System Piping from the discharge header of the charging pumps to the Reactor Coolant System loop cold legs are stainless steel, ASME SA-376 TP 304 or TP 316 material, designed in accordance with ASME Code Section III, Class 1 or 2 criteria, as applicable. These lines consist of 1, 1-1/2, 2, 3, 4 and 6 inch category 2501, schedule 160 piping with a design pressure of 2485 psig. The piping from the accumulators to the Reactor Coolant System loop cold legs is stainless steel, ASME SA-376 TP 304 or TP 316 material, designed in accordance with ASME Code Section III, Class 1 or 2 criteria, as applicable. These lines are 10 inch category 2501 schedule 140 piping with a design pressure of 2485 psig.

The safety injection pump discharge piping up to the isolation valves outside the containment are stainless steel ASME SA-312 TP 304 or TP 316 material, designed in accordance with ASME Code Section III, Class 2 criteria. These lines consist of 3 and 4 inch category 1501, Schedule 80S piping with a design pressure of 1400 psig. The safety injection pump discharge piping from the isolation valves outside the containment to the Reactor Coolant System hot legs and Safety Injection System cold legs is stainless steel ASME SA-376 TP 304 or TP 316 material, designed in accordance with ASME Code Section III, Class 1 or 2 criteria as applicable. These lines consist of 3/4, 2, 4, 6, 8 and 10 inch category 2501, schedule 160 or 140 piping, as applicable, with a design pressure of 2485 psig. The safety injection pump suction piping is of stainless steel, ASME SA-312, TP 304 or TP 316 material, designed in accordance with ASME Code Section III, Class 2 criteria. These lines consist of 6 and 8 inch category 151 schedule 40S piping with a design pressure of 150 psig. The location of the Safety Injection System piping with respect to structures and equipment are shown in Figures 1.2-10, 1.2-11, 1.2-16 and 1.2-17.

B. Pipe Whip Analysis

Isometric drawings of the Safety Injection System lines indicating the locations of the highest stresses postulated breakpoints and restraints are provided in Figures 3.6B-48 through 3.6B-57. The systems and equipment necessary to mitigate the consequences of a Safety Injection System line break are described in Section 3.6B.1. Breakpoints were postulated at the terminal ends of the piping run and at intermediate locations in accordance with the criteria outlined in Section 3.6B.2.1. A circumferential break is

postulated to occur at each of these points. Pipe whip restraints are provided as required to prevent impact on essential components. The pipe whip restraints are designed to prevent plastic hinge formation and thereby preclude adverse pipe whip effects.

C. Jet Impingement Analysis

The jet impingement analysis for this system is performed to determine the effects of jet impingement loading on essential components, associated supports and building structures. | 40

In those cases where the analysis shows that the component or structure is not capable of withstanding the load then protection is required. Protection consists of either relocating the target, or installing jet shield or barriers to protect the target. | 40

D. Environmental Analysis | 40

The environmental conditions resulting from a break in an SI System line do not affect the operation of safety-related systems required to mitigate the consequences of the accident. | 40

Those portions of the Safety Injection System which are considered high energy, outside the containment, are based on the system pressure. The piping is considered as containing cold water so a break in a line cannot generate a steam atmosphere. | 40

High energy flooding is evaluated in the same manner as moderate energy flooding per Section 3.6B.2.5.3. | 40

40 | 3.6B.2.5.3 Moderate Energy Piping

40 | In evaluating the effects of a moderate energy system piping failure, | the postulated failure is a crack which results in neither pipe whip | nor jet impingement but rather in spraying water streams. As such, | the consequences are of an environmental/flooding nature. The | effects of cracks, as postulated in Section 3.6B.2.1.4, are evaluated | for all essential equipment on a case by case basis.

40 | If it is determined that an essential component is not qualified or | cannot be demonstrated to [illegible] under the adverse conditions caused | by the crack then the essential component is protected. Protection | is accomplished either by relocating the component, installing a | barrier or curb or by designing a shield.

REFERENCES

1. NRC Regulatory Guide 1.46, Protection Against Pipe Whip Inside Containment, U.S. Nuclear Regulatory Commission, 5/73.

2. Acceptance Criteria of NRC Standard Review Plan, Section 3.6.1, Plant Design For Protection Against Postulated Piping Failures in Fluid Systems Outside Containment and Section 3.6.2, Determination of Break Locations and Dynamic Effects Associated with the Postulated Rupture of Piping. Also Branch Technical Position MEB 3-1, Postulated Breaks and Leakage Locations in Fluid System Piping Outside Containment.

3. Branch Technical Position APCSB 3-1, Protection Against Postulated Piping Failures in Fluid Systems Outside Containment.

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5. WCAP-8082-P-A (Proprietary), January 1975, and WCAP 8172 A (Nonproprietary), January 1975, Pipe Breaks for the LOCA Analysis of the Westinghouse Primary Coolant Loop.

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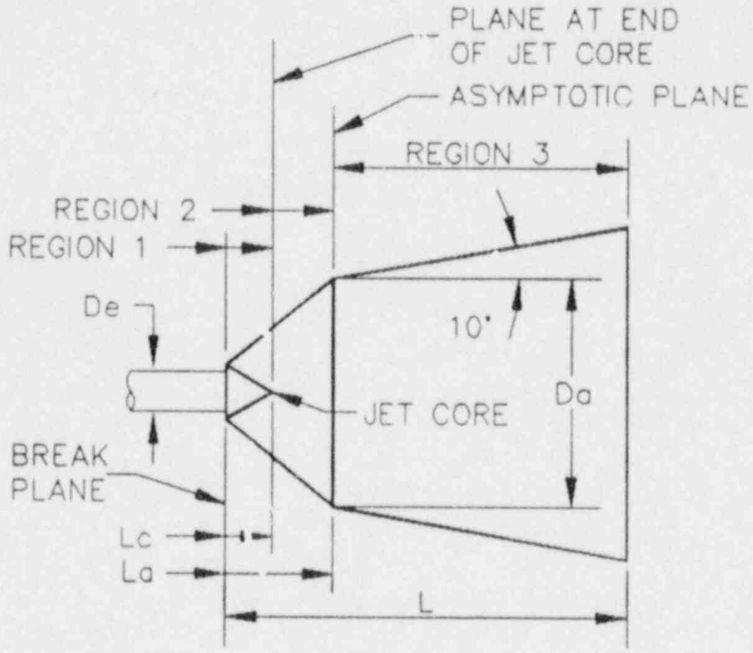


Amendment 71
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COMANCHE PEAK S.E.S.
FINAL SAFETY ANALYSIS REPORT
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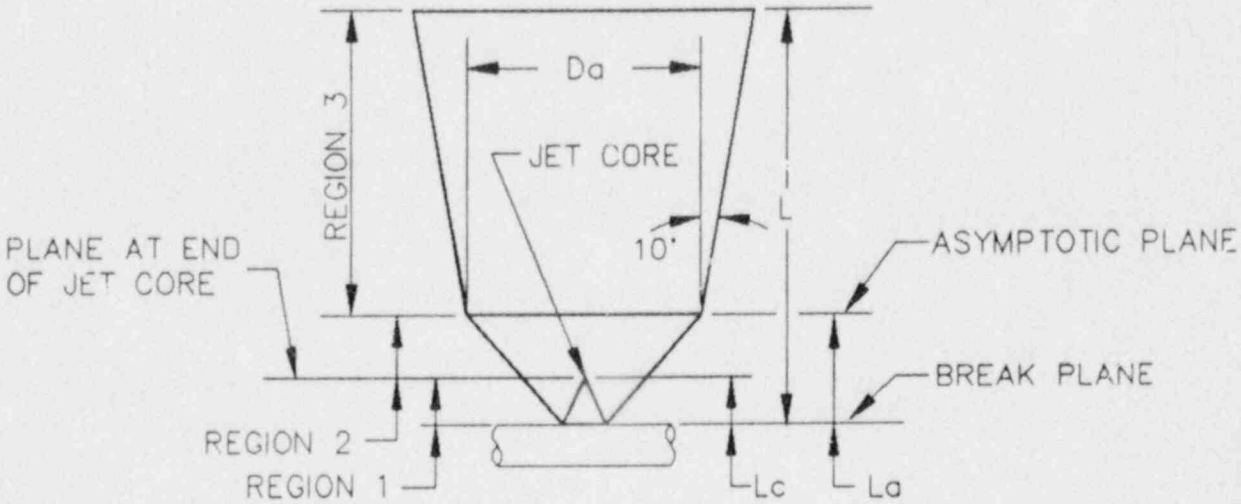
CIRCUMFERENTIAL PIPE BREAK
WITH FULL SEPARATION
JET CONE

FIGURE 3.6B-96A

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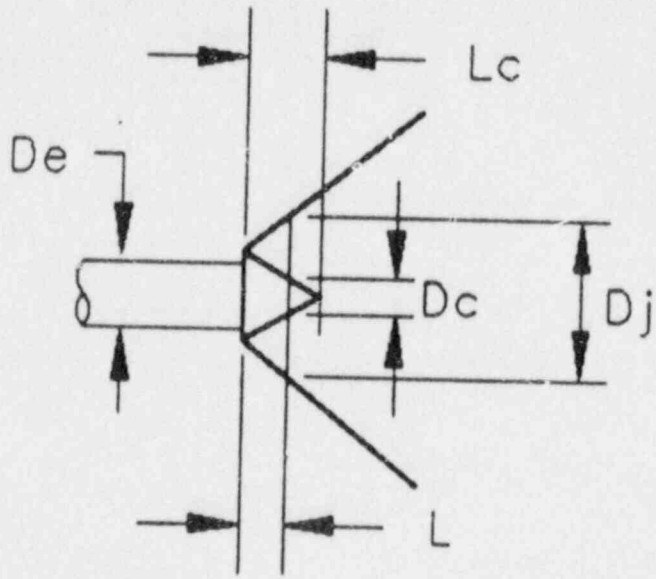
LONGITUDINAL PIPE BREAK
JET CONE

FIGURE 3.6B-96B

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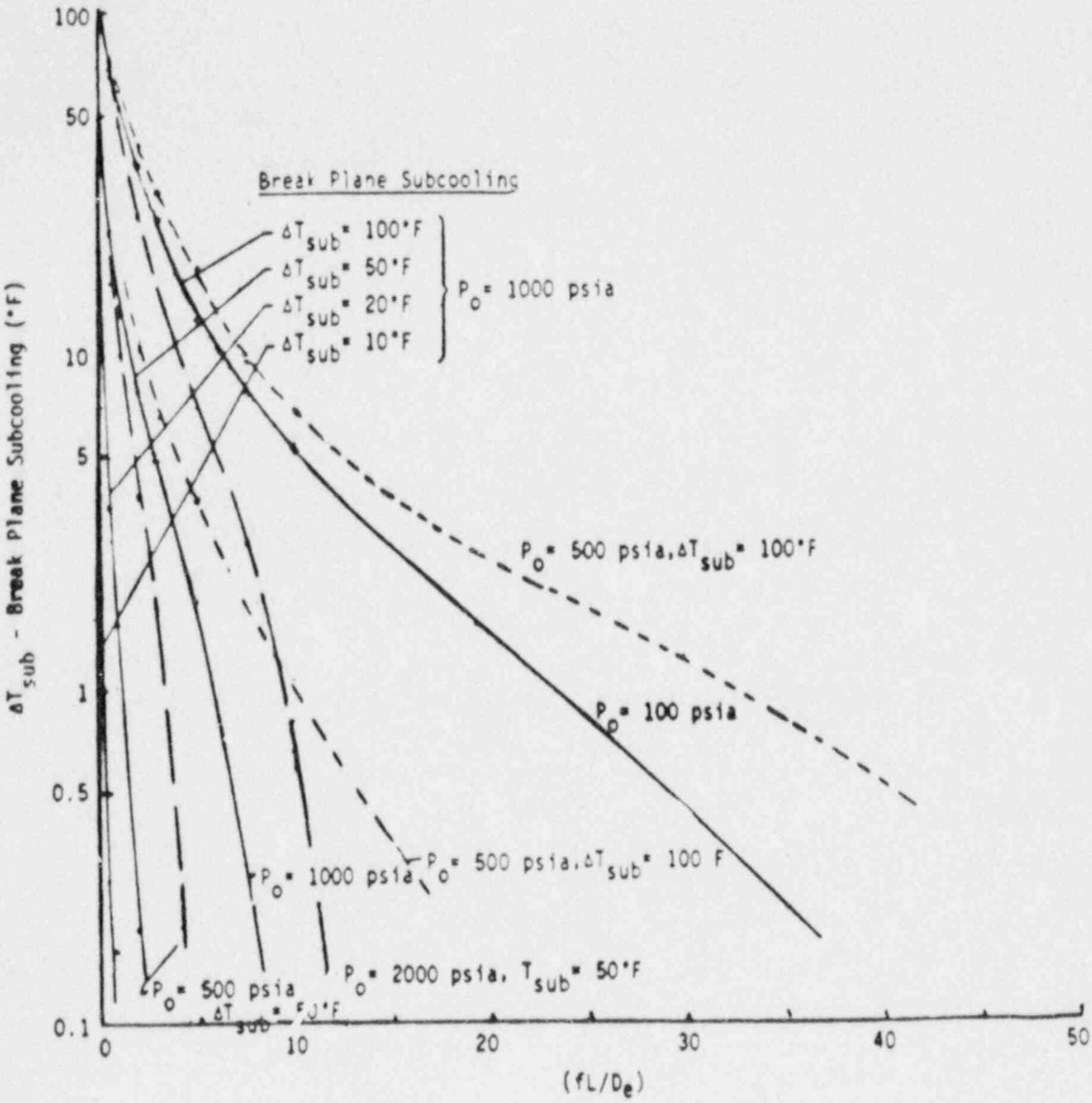
JET CORE REGION GEOMETRY FOR
A CIRCUMFERENTIAL PIPE BREAK
WITH FULL SEPERATION

FIGURE 3.6B-96C

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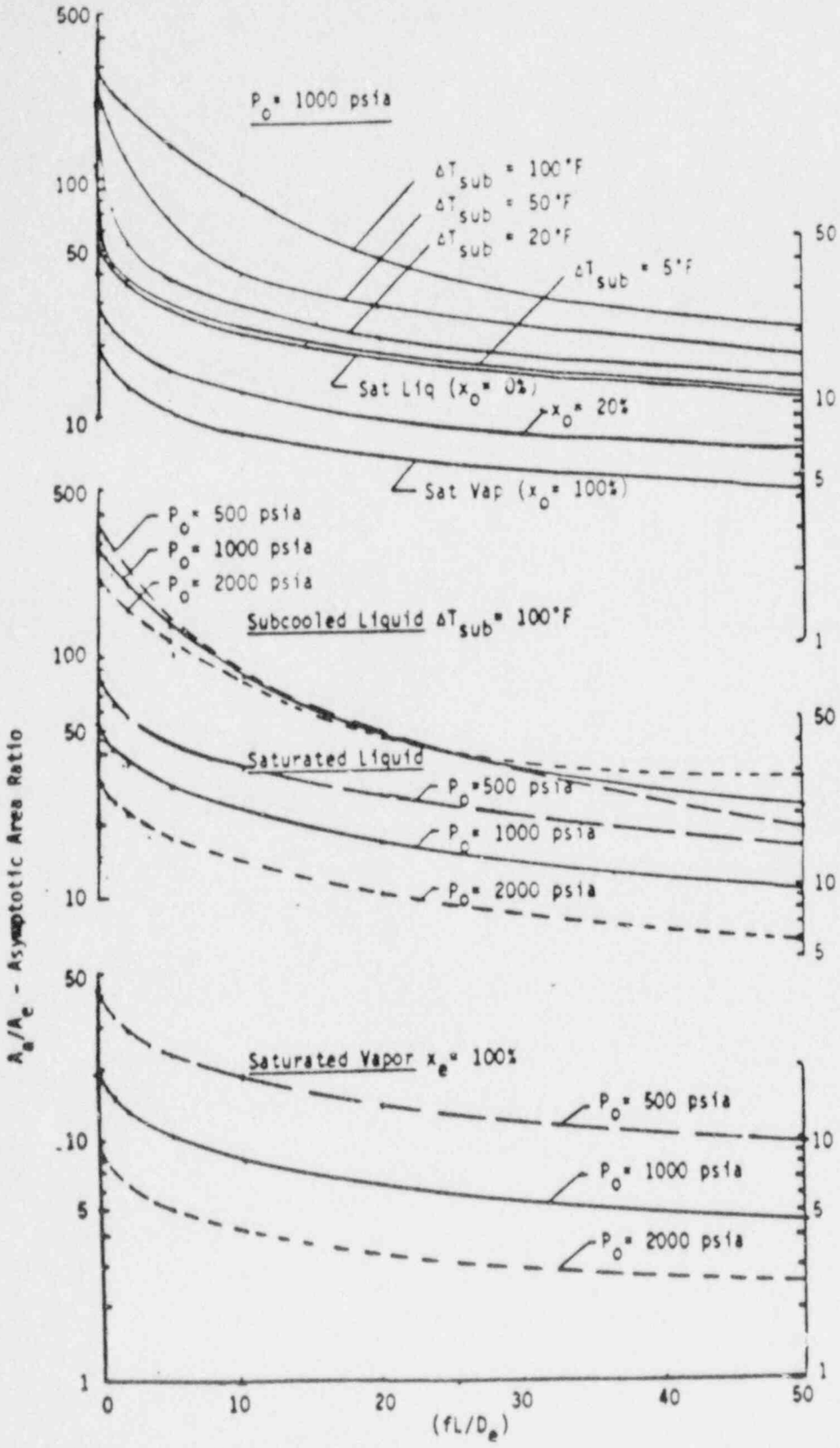
May 27, 1988

| |
|---|
| COMANCHE PEAK S.E.S.<br>FINAL SAFETY ANALYSIS REPORT<br>UNITS 1 & 2 |
| EFFECT OF IRREVERSIBLE LOSSES<br>ON JET SUBCOOLING |
| FIGURE 3.6B-96D |

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COMANCHE PEAK S.E.S.
FINAL SAFETY ANALYSIS REPORT
UNITS 1 & 2

EFFECT OF IRREVERSIBLE LOSSES OF ASYMPTOTIC AREA RATIO

FIGURE 3.6B-96E

| | Loading Combinations | Stress Limits | |
|---|---|---|---|
| Components | 3.9B-1A | Note 1 | 20 |
| Piping | 3.9B-1B | 3.9B-1B | 20 |
| Piping Supports | 3.9B-1C | 3.9B-1D | 20 |
| | | 3.9B-1E | 20 |

Note 1 Stress limits for each of the loading combinations are presented in Tables 3.9B-2, 3.9B-3, 3.9B-4, and 3.9B-5 for vessels, inactive* pumps, active pumps, and valves respectively. 66

The design loading combinations are categorized with respect to normal, upset, emergency, and faulted plant conditions. (Refer to Section 3.9B.1.1 for definition of plant conditions). Peak dynamic responses from loadings shown in Tables 3.9B-1A and 3.9B-1B are combined using the Square Root of the Sums of the Squares (SRSS) technique. This method of combining dynamic responses is consistent with the position outlined in NUREG-0484, "Methodology for Combining Dynamic Responses," Revision 1 dated May, 1980. Active** pumps and valves are discussed in Subsection 3.9B.3.2. Table 3.9B-8 lists all non-NSSS active pumps by system. Table 3.9B-10 lists all non-NSSS active valves including their design parameter and safety function. The component supports are designed in accordance with subsection NF of the ASME B&PV Code, Section III. 20 66 20 71 11

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* Inactive components are those whose operability is not relied upon to perform a safety function while being subjected to the loading combinations associated with the respective plant operating condition categories.

** Active components are those whose operability is relied upon to perform a safety function while being subjected to the loading combinations associated with the respective plant operating condition categories.

---

61 | Systems which are required to operate during and after a postulated plant accident condition comply with the functional capability requirements delineated in References [5], [6], [7], and [8] in addition to the ASME Code requirements.

61 | This requirement will ensure that the piping system will maintain its capability to deliver the rated flow and retain its dimensional stability under events specified above.

61 | References [7] and [8] provides an alternative functional capability evaluation for stainless steel elbows and bends.

### 3.9B.3.2 Pump and Valve Operability Assurance

71 | A list that identifies all active Code Class 2 and 3 pumps and valves is presented in Tables 3.9.B-8 and 3.9B-10.

The plant conditions and load combinations for Class 2 and Class 3 components are shown in Table 3.9B-1A. The safety related component supports are designated with the same safety class as their respective components and are subject to the same plant conditions and loading combinations. | 61

3.9B.3.4.3 Instrument Impulse Tubing Supports for ASME III Class 2 and Class 3 Safety Related Applications | 10 | 10

a. All instrument impulse tubing, valves and fittings connecting instruments to ASME III Class 2 and Class 3 piping root valves will be seismically supported. | 10

b. All instrument impulse tubing, valves and fittings connecting nuclear safety related instruments to Non-ASME piping or ducting will be seismically supported. | 10

c. The support design will consider pressure, gravity, seismic and thermal loading combinations and will conform to the ASME stress allowables for class 2 and 3 components when combined in accordance with the loading combinations specified in ASME Section III Equations 8 thru 11. | 10

d. Any welding of the support system will be per AWS specifications consistent with that performed on other nuclear safety related, Non-ASME supports. | 10

e. Subsection NF supports will be employed on the ASME III main line piping including the instrument root valve. | 10

f. The material used for fabrication of the tubing supports will be purchased with certificates of compliance to applicable ASTM standards. | 10

10 | g. Other seismically designed support systems such as cable tray supports, pipe supports or conduit supports may be used for tubing if paragraph c above is met. Any necessary re-analysis will be performed to justify the additional loads.

66 | h. AISC, "Specification for the Design, Fabrication and Erection of Structural Steel for Buildings" Nov. 1, 1978 including Supplement 1 March 11, 1986 may be utilized in the analysis of structural tubing.

3.9B.4 CONTROL ROD DRIVE SYSTEM (CRDS)

Refer to Section 3.9N.4

3.9B.5 REACTOR VESSEL INTERNALS

Refer to Section 3.9N.5

3.9B.6 INSERVICE TESTING OF PUMPS & VALVES

3.9B.6.1 Inservice Testing of Pumps

3.9B.6.1.1 Scope

66 | Inservice testing of pumps shall be in accordance with Subsection IWP of Section XI, ASME Boiler & Pressure Vessel Code (Edition and Addenda as required by 10CFR50.55a).

3.9B.6.1.2 Test Program

Establishment of reference values and a periodic testing schedule shall be in accordance with IWP-3000. The allowable ranges of inservice test quantities, corrective actions, and bearing temperature tests shall be in accordance with IWP-3200 and IWP-4300.

TABLE 3.9B-8
(Sheet 1 of 3)

ACTIVE PUMPS | 71

| PUMP | TAG NUMBER | SYSTEM | CLASS | NORMAL MODE | ACCIDENT MODE | ACTIVE FUNCTION | 71 |
|---|---|---|---|---|---|---|---|
| Auxiliary Feedwater (Motor Driven) | CP1&CP2-AFAPMD-01, 02 | AF | 3 | ON/OFF | ON | Required for Removing Reactor Decay Heat (Safe Hot Shutdown) | 71 |
| Auxiliary Feedwater (Turbine Driven) | CP1&CP2-AFAPTD-01 | AF | 3 | OFF | ON | Required for Removing Reactor Decay Heat (Safe Hot Shutdown) | 71 |
| Service Water | CP1&CP2-SWAPSW-01, 02 | SW | 3 | ON/OFF | ON | Required for Transferring Heat from Primary Plant Safeguards Components to the Ultimate Heat Sink | 71 |
| Component Cooling Water | CP1&CP2-CCAPCC-01, 02 | CC | | ON/OFF | ON | Required for Transferring Heat from Components to the Service Water System | 71 |
| Containment Spray | CP1&CP2-CTAPCS-01, 02, 03, 04 | CT | 2 | OFF | ON | Required for Containment Heat Removal | 71 |

TABLE 3.9B-8

(Sheet 2)

ACTIVE PUMPS | 71

| PUMP | TAG NUMBER | SYSTEM | CLASS | NORMAL MODE | ACCIDENT MODE | ACTIVE FUNCTION | |
|---|---|---|---|---|---|---|---|
| | | | | | | | 71 |
| | | | | | | | 71 |
| Spent Fuel Pool | CPX-SFAPSF-01, 02 | SF | 3 | ON/OFF | ON | Required for Cooling of Spent Fuel | 71 |
| Reactor Makeup Water | CP1&CP2-DDAPRM-01 | DD | 3 | ON/OFF | ON/OFF | Required to Provide Seismic Category I Makeup for Spent Fuel Pool, Component Cooling Water, and Safety Chilled Water | 71 |
| Reactor Makeup Water | CPX-DDAPRM-01 | DD | 3 | ON/OFF | ON/OFF | Required to Provide Seismic Category I Makeup for Spent Fuel Pool, Component Cooling Water, and Safety Chilled Water | 71 |
| Safety Chilled Water | CP1&CP2-CHAPCP-05, 06 | CH | 3 | ON/OFF | ON | Required to Transfer the Heat Rejected by Engineering Safety Feature Pump Motors and Electrical Switchgear to CCW | 71 |

TABLE 3.9B-8

(Sheet 3)

ACTIVE PUMPS | 71

| PUMP | TAG NUMBER | SYSTEM | CLASS | NORMAL MODE | ACCIDENT MODE | ACTIVE FUNCTION | 71 |
|---|---|---|---|---|---|---|---|
| Diesel Generator Fuel Oil Transfer Pump | CP1&CP2-DOAPFT-01, 02, 03, 04 | DO | 3 | OFF | ON/OFF | Required to Transfer Fuel Oil to Day Tank from the Storage Tank | 71 |
| Safeguard Bldg Floor Drain Sump Pumps | CP1&CP2-WPAPSS-01, 02, 03, 04 | VD | 3 | ON/OFF | ON/OFF | Required to Detect and Mitigate Flooding of Safety Related Equipment | 71 |

Table 3.9B-10

(Sheet 5)

ACTIVE VALVES

| Valve Identification or Location No. | System | Valve Type and Actuator | Size In. | ANS Safety Class | Method of Actuation | Normal Position | Function | |
|---|---|---|---|---|---|---|---|---|
| MS-686 | MS | Check | 1/2 | 3 | Self-Actuated | Closed/Open | Prevent Air Loss From Accumulator Air Supply To S.G. PORV After Loss of Instrument Air | 68 |
| MS-687 | MS | Check | 1/2 | 3 | Self-Actuated | Closed/Open | Prevent Air Loss From Accumulator Air Supply To S.G. PORV After Loss of Instrument Air | 68 |
| HV-2397A | MS | Globe/Air | 3 | 2 | Auto Trip | Open | Steam Generator Isolation | 66 |
| HV-2398A | MS | Globe/Air | 3 | 2 | Auto Trip | Open | Steam Generator Isolation | 66 |
| HV-2399A | MS | Globe/Air | 3 | 2 | Auto Trip | Open | Steam Generator Isolation | 66 |
| HV-2400A | MS | Globe/Air | 3 | 2 | Auto Trip | Open | Steam Generator Isolation | 66 |
| HV-4075B/C | FF | Gate/Motor | 4 | 2 | Auto Trip | Closed | Containment Isolation | 66 |
| HV-2134 | FW | Gate Hydraulic | 18 | 2 | Auto Trip | Open | Feedwater Isolation | 66 |
| HV-2154 | FW | Globe/Air | 3/4 | 2 | Auto Trip | Open | Containment Isolation | |
| HV-2135 | FW | Gate Hydraulic | 18 | 2 | Auto Trip | Open | Feedwater Isolation | 56 |
| HV-2155 | FW | Globe/Air | 3/4 | 2 | Auto Trip | Open | Containment Isolation | |
| HV-2136 | FW | Gate Hydraulic | 18 | 2 | Auto Trip | Open | Containment Isolation | |
| HV-2137 | FW | Gate Hydraulic | 18 | 2 | Auto Trip | Open | Feedwater Isolation | 55 |
| HV-2185 | FW | Globe/Air | 3 | 2 | Auto Close | Closed | Feedwater Isolation | 11 |
| HV-2186 | FW | Globe/Air | 3 | 2 | Auto Close | Closed | Feedwater Isolation | 11 |
| HV-2187 | FW | Globe/Air | 3 | 2 | Auto Close | Closed | Feedwater Isolation | 11 |
| HV-2188 | FW | Globe/Air | 3 | 2 | Auto Close | Closed | Feedwater Isolation | 11 |
| FV-2193 | FW | Globe/Air | 6 | 2 | Auto Close | Closed | Feedwater Isolation | 71 |
| FV-2194 | FW | Globe/Air | 6 | 2 | Auto Close | Closed | Feedwater Isolation | 71 |
| FV-2195 | FW | Globe/Air | 6 | 2 | Auto Close | Closed | Feedwater Isolation | 71 |
| FV-2196 | FW | Globe/Air | 6 | 2 | Auto Close | Closed | Feedwater Isolation | 66 |
| FW-070 | FW | Check | 18 | 2 | Self-Actuated | Open | Feedwater Isolation | 66 |
| FW-076 | FW | Check | 18 | 2 | Self-Actuated | Open | Feedwater Isolation | 66 |
| FW-082 | FW | Check | 10 | 2 | Self-Actuated | Open | Feedwater Isolation | 66 |

Table 3.9B-10

(Sheet 6)

ACTIVE VALVES

| Valve Identification or Location No. | System | Valve Type and Actuator | Size In. | ANS Safety Class | Method of Actuation | Normal Position | Function | |
|---|---|---|---|---|---|---|---|---|
| FW-088 | FW | Check | 18 | 2 | Self-Actuated | Open | Feedwater Isolation | ; 66 |
| FW-195 | FW | Check | 6 | 2 | Self-Actuated | Closed | AFW Flow Path | ; 66 |
| FW-196 | FW | Check | 6 | 2 | Self-Actuated | Closed | AFW Flow Path | ; 66 |
| FW-197 | FW | Check | 6 | 2 | Self-Actuated | Closed | AFW Flow Path | ; 66 |
| FW-198 | FW | Check | 6 | 2 | Self-Actuated | Closed | AFW Flow Path | ; 66 |
| FW-199 | FW | Check | 6 | 2 | Self-Actuated | Open | AFW Flow Path | ; 66 |
| FW-200 | FW | Check | 6 | 2 | Self-Actuated | Open | AFW Flow Path | ; 66 |
| FW-201 | FW | Check | 6 | 2 | Self-Actuated | Open | AFW Flow Path | ; 66 |
| FW-202 | FW | Check | 6 | 2 | Self-Actuated | Open | AFW Flow Path | ; 66 |
| FW-191 | FW | Check | 6 | 2 | Self-Actuated | Closed | AFW Flow Path Boundary | ; 66 |
| FW-192 | FW | Check | 6 | 2 | Self-Actuated | Closed | AFW Flow Path Boundary | ; 66 |
| FW-193 | FW | Check | 6 | 2 | Self-Actuated | Closed | AFW Flow Path Boundary | ; 66 |
| FW-194 | FW | Check | 6 | 2 | Self-Actuated | Closed | AFW Flow Path Boundary | ; 66 |
| | | | | | | | | ; 66 |
| HV-2491A/B | AF | Gate/Motor | 4 | 2 | Remote Manual | Open | Containment Isolation | |
| FV-2181 | FW | Butterfly/Air | 6 | 2 | Auto Trip | Open | AFW Flow Path Boundary | ; 71 |
| FV-2182 | FW | Butterfly/Air | 6 | 2 | Auto Trip | Open | AFW Flow Path Boundary | ; 71 |
| FV-2183 | FW | Butterfly/Air | 6 | 2 | Auto Trip | Open | AFW Flow Path Boundary | ; 71 |
| FV-2184 | FW | Butterfly/Air | 6 | 2 | Auto Trip | Open | AFW Flow Path Boundary | ; 71 |
| HV-2492A/B | AF | Gate/Motor | 4 | 2 | Remote Manual | Open | Containment Isolation | |
| HV-2493A/B | AF | Gate/Motor | 4 | 2 | Remote Manual | Open | Containment Isolation | |
| HV-2494A/B | AF | Gate/Motor | 4 | 2 | Remote Manual | Open | Containment Isolation | |
| HV-2480 | AF | Gate/Motor | 6 | 3 | Remote Manual | Closed | SW Flow Path to Suction | |
| HV-2481 | AF | Gate/Motor | 6 | 3 | Remote Manual | Closed | SW Flow Path to Suction | |
| HV-2482 | AF | Gate/Motor | 6 | 3 | Remote Manual | Closed | SW Flow Path to Suction | |
| FV-2456 | AF | Globe/Air | 2 | 3 | Auto Trip | Open | Recirculation Flow Path | |
| FV-2457 | AF | Globe/Air | 2 | 3 | Auto Trip | Open | Recirculation Flow Path | |
| AF-014 | AF | Check | 6 | 3 | Self-Actuated | Closed | Suction from Condensate Storage Tank | ; 66 |

Table 3.9B-10

(Sheet 7)

ACTIVE VALVES

| Valve Identification or Location No. | System | Valve Type and Actuator | Size In. | ANS Safety Class | Method of Actuation | Normal Position | Function | |
|---|---|---|---|---|---|---|---|---|
| AF-024 | AF | Check | 6 | 3 | Self-Actuated | Closed | Suction from Condensate Storage Tank | 66 |
| AF-032 | AF | Check | 6 | 3 | Self-Actuated | Closed | Suction from Condensate Storage Tank | 66 |
| AF-065 | AF | Check | 6 | 3 | Self-Actuated | Closed | Discharge Flow Path | 66 |
| AF-051 | AF | Check | 6 | 3 | Self-Actuated | Closed | Discharge Flow Path | 66 |
| AF-038 | AF | Check | 6 | 3 | Self-Actuated | Closed | Discharge Flow Path | 66 |
| AF-093 | AF | Check | 4 | 2 | Self-Actuated | Closed | Discharge Flow Path | 66 |
| AF-098 | AF | Check | 4 | 2 | Self-Actuated | Closed | Discharge Flow Path | 66 |
| AF-083 | AF | Check | 4 | 2 | Self-Actuated | Closed | Discharge Flow Path | 66 |
| AF-086 | AF | Check | 4 | 2 | Self-Actuated | Closed | Discharge Flow Path | 66 |
| AF-075 | AF | Check | 4 | 2 | Self-Actuated | Closed | Discharge Flow Path | 66 |
| AF-078 | AF | Check | 4 | 2 | Self-Actuated | Closed | Discharge Flow Path | 66 |
| AF-101 | AF | Check | 4 | 2 | Self-Actuated | Closed | Discharge Flow Path | 66 |
| AF-106 | AF | Check | 4 | 2 | Self-Actuated | Closed | Discharge Flow Path | 66 |
| AF-215 | AF | Check | 1/2 | 3 | Self-Actuated | Closed/Open | Prevent Air Loss From Accumulator Air Supply to Aux. F. W. Reg Valve After Loss of Instrument Air | 68 |
| AF-216 | AF | Check | 1/2 | 3 | Self-Actuated | Closed/Open | Prevent Air Loss From Accumulator Air Supply to Aux. F. W. Reg Valve After Loss of Instrument Air | 68 |
| AF-217 | AF | Check | 1/2 | 3 | Self-Actuated | Closed/Open | Prevent Air Loss From Accumulator Air Supply to Aux. F. W. Reg Valve After Loss of Instrument Air | 68 |

# LIST OF FIGURES

TABLE 5.2-1

APPLICABLE CODE ADDENDA FOR
REACTOR COOLANT SYSTEM COMPONENTS

| | | |
|---|---|---|
| Reactor vessel | ASME III, 1971 Ed. thru Winter 72 | |
| Steam generator | ASME III, 1971 Ed. thru Summer 73 | |
| Pressurizer | ASME III, 1974 Ed. | |
| CRDM housing | | |
| Full length | ASME III, 1974 Ed. | |
| CRDM head adapter | ASME III, 1971 Ed. thru Winter 72 | \| 5 |
| Reactor coolant pump | ASME III, 1971 Ed. thru Summer 73 | |
| Reactor coolant pipe | ASME III, 1974 Ed. thru Summer 75 | \| 57 |
| Surge lines | ASME III, 1974 Ed. thru Winter 75 | |
| Valves | | |
| Pressurizer safety | ASME III, 1971 Ed. thru Winter 72 | |
| Motor operated | ASME III, 1974 Ed. thru Summer 74 | |
| Manual (3" and larger) | ASME III, 1971 Ed. thru Summer 73 | |
| Control | ASME III, 1974 Ed. thru Summer 75 | |

2. Failure of the Auxiliary Feedwater Pump Runout Protection

Limitation of maximum auxiliary feedwater flow to the broken loop steam generator is achieved through passive flow restrictors. Failure of passive flow restrictors is not considered credible.

3. Failure of Main Feedwater Pump Trip

No credit is taken for feedwater pump trip and coastdown in calculating main feedwater addition prior to feedwater line isolation. Therefore, this failure has no effect on the results presented.

4. Failure of a Steam Line Stop Valve

Failure of a main line stop valve increases the volume of steam piping which empties into the Containment.

The effects of this failure on calculated Containment pressures and temperatures were compared with the effects of the failure of one Containment spray train. With respect to the maximum Containment pressure, calculations showed that the adverse effects of a steam stop valve failure were considerably less than that of one Containment spray train failure. With respect to the maximum Containment temperature, no significant difference was found between the two failures.

5. Failure of One Containment Spray Train

The worst single failure following a steam line break is the failure of one of the two redundant Containment spray trains.

69 For the full DER, full spray flow is conservatively assumed to occur 60 seconds after the Containment pressure P signal setpoint (20 psig) is reached. This delay includes delays for the instrumentation signal, diesel generator start, sequencing the pump load on the class 1E bus, pump acceleration, Containment isolation valve opening, and system fill times.

69 Since the spray pumps startup is initiated at the S signal setpoint (5 psig), the partial DERs and split breaks result in activation of the spray only 38 seconds after the P signal setpoint is reached. This is because the delays associated with diesel start, load sequencing, and pump acceleration are already satisfied and the pumps are already running at the time the P signal setpoint is reached.

69 The above Containment pressure setpoints which are used in the analysis are conservatively assumed to be the upper limit values.

6.2.1.4.9 Mass and Energy Data

71 Table 6.2.1-4 presents the mass and energy release rate data for the design basis steam line break, 0.908-$ft^2$ split rupture at 70-percent power. This break results in the maximum temperature and pressure.

69 Mass and energy release data for all breaks analyzed are included in References [4] and [6].

6.2.1.5 Minimum Containment Pressure Analysis for Performance Capability Studies of Emergency Core Cooling System

The Containment backpressure used for the limiting case CD=0.6, DECLG break for the ECCS analysis presented in Section 15.6.5 is presented

### 6.4.1.4 Habitability System Operation During Emergencies

A detailed description of the Control Room Air-Conditioning System emergency modes of operation is presented in Section 9.4.

### 6.4.1.5 Emergency Monitors and Control Equipment

Radiation monitors used to switch the Control Room Air-Conditioning System into the emergency recirculation mode are located in the Control Room outside-air intakes. The outside-air intake monitors, located at opposite sides of the Control Building, are used to sample makeup and pressurization air flows introduced into the Control Room envelope. Chlorine gas monitors are also located at the outside-air intakes to switch the air-conditioning system to the isolation mode in the event of a toxic gas release. See Subsection 2.2.3. In this mode, the affected outside-air intake is isolated and its associated Control Room emergency pressurization unit is automatically stopped. During a postulated chlorine gas release, the Control Room operates at ambient pressure. | 68 | 46

### 6.4.1.6 Fire Protection Criteria

The Fire Protection System is designed to safeguard equipment and personnel. Combustible materials are excluded as far as practical from the Control Room to lessen the possibility of a fire. The fire stops serve a dual function. Fire stops are incorporated on all cables entering the Control Room to prevent the entry of a fire originating outside the Control Room. They also form a leak boundary which limits exfiltration of air from the Control Room envelope. Because any fire in the control panels would be very limited, due to the amount of combustible materials present, Control Room evacuation is not considered a necessity; however, remote shutdown capability is available as described in Section 7.4. Codes and guides used in the design of the Fire Protection System are given in Subsection 9.5.1. | 46

## 6.4.2 SYSTEM DESIGN

### 6.4.2.1 Definition of Control Room Envelope

71 | The Control Room pressurized envelope consists of the following areas
| where continuous or frequent operator or technical support personnel
| occupancy may be required during emergency operation:

| | Space | Elevation |
|---|---|---|
| 68 | East Control Room | 830'-0" |
| 68 | West Control Room | 830'-0" |
| 68 | Console and Control Room Unit 1 | 830'-0" |
| 68 | Console and Control Room Unit 2 | 830'-0" |
| 68 | Instrument Room Unit 1 | 830'-0" |
| 68 | Instrument Room Unit 2 | 830'-0" |
| 68 | Computer Room Unit 1 | 830'-0" |
| 68 | Computer Room Unit 2 | 830'-0" |
| 68 | File Room | 830'-0" |
| 68 | Production Supervisor's Office | 830'-0" |
| 68 | Corridor | 830'-0" |
| 68 | Toilet | 830'-0" |
| 68 | Locker Room | 830'-0" |
| 68 | Kitchen and Janitor Closet | 830'-0" |
| 68 | Charts and Supplies Storage Room | 830'-0" |
| 71 | Technical Support Center (Office and Corridor) | 840'-6" |
| 68 | Offices (2) | 840'-6" |
| 68 | Electrical Equipment Corridors (2) | 840'-6" |

71 |

68 | The Control Room Air Conditioning System (CRACS) mechanical equipment
| rooms, Trains A and B, located in the Control Building above the
| Control Room complex at elevation 854 ft 4 in., are pressurized and
| may require infrequent access by a Control Room operator during an
| emergency condition. The components located in the CRACS mechanical
| equipment rooms are described in detail in Section 9.4.

### 6.4.4.2 Toxic Gas Protection

A hazards analysis for each toxic material was performed as recommended in NRC Regulatory Guide 1.78 [4] and is presented in Section 2.2. The habitability of the Control Room envelope was evaluated to determine if a site-related accident involving a release of hazardous chemicals exceeds the toxicity limits as specified in NRC Regulatory Guide 1.78. Based on the analysis, monitors are provided in | 46
the Control Room outside air intakes (a total of two per intake) of |
the Control Room envelope to automatically switch to the isolation |
mode of operation. Chlorine sensors are placed at the outside-air |
intakes which are approximately 600 feet from the nearest chlorination
storage facility. These automatically switch the Air-Conditioning | 68
System to the isolation mode of operation when chlorine levels unsafe |
for Control Room personnel (as suggested in NRC Regulatory Guide 1.95 |
[5]) are detected. Chlorine is used as a biocide in the plant |
Circulating and Service Water systems. The Chlorination System is
described in Subsection 10.4.5.

A plant specific analysis based on Reference 9 has been performed to | 64
demonstrate that the chlorine concentration in the control room would |
be well within the protective action limit of 15 ppm based on a |
maximum isolation air exchange rate of 800 cfm. The acceptance test |
to verify the above isolation air exchange rate and the pressurization |
flow rate is that the control room can be maintained at greater than |
or equal to 0.125 in. wg with the pressurization flow rate less than |
or equal to 800 cfm. |

The Computer Rooms for Unit 1 and Unit 2 and the Technical Support | 68
Center, which are located inside the Control Room pressure boundary, |
employ ten non-seismic non-safety related supplementary cooling |
units. These areas do not contain safety related equipment and are |
not needed for continuous occupancy. An analysis based on Reference |
10 has been performed to demonstrate that refrigerant concentrations |
in these areas due to the release of the total refrigerant inventory |
associated with these units after a seismic event (DBE) will be within |
the limits specified in ANSI/ASHRAE 15-78 [10]. |

### 6.4.4.3 Evaluation of Heating, Ventilation, Air-Conditioning, and Filtration System

The HVAC and Filtration System readiness is ensured by the periodic testing program described in Section 6.4.5. Safe operation is ensured by having redundant equipment for the Control Room HVAC and Filtration System. A complete safety evaluation is given in Section 9.4.

## 6.4.5 TESTING AND INSPECTION

Preoperational tests are conducted on the Control Room HVAC and Filtration System to ensure that all equipment satisfies the design criteria during all modes of operation. Tests are also performed, as described in Section 9.4, to ensure overall system performance. The leakage tests will be conducted by closing all the access points to the Control Room.

Control Room pressure will be established by controlling the outside air intake flow of the emergency pressurization units until the design pressure is achieved. Should the outside makeup airflow through the emergency pressurization unit exceed the maximum allowable flow of approximately 800 scfm, a survey shall be conducted to locate points of excessive leakage and attempt to seal them. Tests shall be repeated as often as necessary until the above criteria are established.

55 | Control Room pressure is measured by the permanently installed
| differential pressure transmitters.

The result of the Control Room leak test is considered acceptable if the emergency pressurization airflow does not exceed 800 scfm with the
21 | Control Room envelope being maintained at 0.125-in. wg.

7.3.2.2.7 Manual Initiation of Protective Actions (Regulatory Guide 1.62) | 71 | 71

There are four individual main steam stop valve momentary control switches (one per loop) mounted on the control board. Each switch when actuated will isolate one of the main steam lines. In addition, there will be two system level switches. Each switch will actuate all four main steam line isolation and bypass valves of the system level. Manual initiation of switchover to recirculation is in compliance with Section 4.17 of IEEE Standard 279-1971 with the following comment. | 71 | 56

Manual initiation of either one of two redundant safety injection actuation main control board mounted switches provides for actuation of the components required for reactor protection and mitigation of adverse consequences of the postulated accident, including delayed actuation of sequenced started emergency electrical loads as well as components providing switchover from the safety injection mode to the cold leg recirculation mode following a loss of primary coolant accident. Therefore, once safety injection is initiated, those components of the Emergency Core Cooling System (see Section 6.3) which are automatically realigned as part of the semiautomatic switchover go to completion on low-low refueling water storage tank (RWST) water level without any manual action. Manual operation of other components or manual verification of proper position as part of emergency procedures is not precluded nor otherwise in conflict with the above described compliance to Section 4.17 of IEEE Standard 279-1971 of the semiautomatic switchover circuits. | 36

No exception to the requirements of IEEE Standard 279-1971 has been taken in the manual initiation circuit of safety injection. Although Section 4.17 of IEEE Standard 279-1971 requires that a single failure within common portions of the protective system shall not defeat the protective action by manual or automatic means, the standard does not specifically preclude the sharing of initiated circuitry logic between automatic and manual functions. It is true that the manual safety

injection initiation functions associated with one actuation train (e.g., train A) shares portions of the automatic initiation circuitry logic of the same logic train; however, a single failure in shared functions does not defeat the protective action of the redundant actuation train (e.g., train B). A single failure in shared functions does not defeat the protective action of the safety function. It is further noted that the sharing of the logic by manual and automatic initiation is consistent with the system level action requirements of the IEEE Standard 279-1971, Section 4.17, and the minimization of complexity.

Manual actuation of main steam line isolation (all valves), containment isolation (Phase A), and containment spray actuation conforms to the same criteria herein described for the manual safety injection manual actuation functions.

56 | 7.3.2.2.8 Component Control Switches

56 | The control switches for ESF final actuators, e.g., pumps, valves and
| dampers, are the spring-return-to-automatic type. This design
| feature assures the completion of the protective function once it has
| been initiated, regardless of the operational status of the final
| actuator prior to the initiation of the protective function.

56 | When operating conditions necessitate, the operator can manually
68 | override the automatic operation of individual components. The
| manual overrides are accomplished in the following manner:

68 | A. Valves and Dampers - The control switch must be held by the
| operator in the alternate position for the duration of the
| period that the alternate action is required. The automatic
| action is restored as soon as the operator releases the control
| switch.

## 7.8 ATWS MITIGATION SYSTEM ACTUATION CIRCUITRY (AMSAC) | 70

### 7.8.1 DESCRIPTION | 70

#### 7.8.1.1 System Description | 70

The ATWS (Anticipated Transient Without Scram) Mitigation System Actuation Circuitry (AMSAC) provides a backup to the Reactor Trip System (RTS) and ESF Actuation System (ESFAS) for initiating turbine trip and auxiliary feedwater flow in the event an anticipated transient results (e.g., the complete loss of main feedwater). The AMSAC is independent of and diverse from the Reactor Trip System and the ESF Actuation System with the exception of the analog steam generator level and turbine impulse pressure inputs, and the final actuation devices. It is a highly-reliable, microprocessor-based, non-safety related circuitry. | 70

The AMSAC continuously monitors level in the steam generators, which is an anticipatory indication of a loss of heat sink. AMSAC initiates certain functions when the level drops below a predetermined setpoint for a preselected time and for three of the four steam generator levels. These initiated functions are turbine trip auxiliary feedwater initiation, and steam generator blowdown and sample lines isolation. | 70

The AMSAC is designed to be highly reliable, resistant to inadvertent actuation, and easily maintained. Reliability is assured through the use of internal redundancy and continual self-testing within the system. Inadvertent actuations are minimized through the use of internal redundancy and majority voting at the output stage of the system. The time delay on low steam generator level and the coincidence logic also minimize inadvertent actuations. | 70

71 | The AMSAC automatically performs its actuations when the plant is
| above a preselected power level which is determined using turbine
| impulse chamber pressure. This signal remains armed sufficiently
70 | long after the pressure drops below the setpoint to ensure that its
| function will be performed in the event of a turbine trip.

70 | 7.8.1.2 Equipment Description

70 | The AMSAC equipment is located in a seismically qualified cabinet.

70 | The design of the AMSAC is based on the industry standard Intel
| multibus format, which permits the use of various readily available
| and widely used microprocessor cards on a common data bus for various
| functions.

70 | The AMSAC consists of the following:

70 | 1. Steam Generator (SG) Level

70 | SG level is measured with four existing differential pressure-
| type level transmitters, for each of the main steam generators.

70 | 2. Turbine Impulse Pressure

70 | Turbine Impulse Pressure is measured with two existing pressure
| transmitters located in the steam supply line near the turbine.

70 | 3. System Hardware

70 | The system hardware consists of two primary systems: the
| Actuation Logic System (ALS) and the Test/Maintenance System
| (T/MS).

### 7.8.1.4 AMSAC Interlocks | 70

A single interlock, designated as C-20 (See Table 7.7-1), is provided | 70
to allow for the automatic arming and blocking of the AMSAC. The |
system is blocked at sufficiently low reactor power levels when the |
actions taken by the AMSAC following an ATWS need not be automatically |
initiated. Turbine impulse chamber pressure in a two-out-of-two |
logic scheme is used for this permissive. Turbine impulse chamber |
pressure above the setpoint will automatically defeat any block, i.e., |
will arm the AMSAC. Dropping below this setpoint will automatically |
block the AMSAC. Removal of the C-20 permissive is automatically |
delayed for a predetermined time. The operating status of the AMSAC |
is displayed on the main control board. |

### 7.8.1.5 Steam Generator Level Sensor Arrangement | 70

SG level is determined by a differential pressure transmitter, | 70
measuring the level drop in the steam generator. These SG level |
signals are used as inputs to the AMSAC and are isolated signals from |
the Process Protection Cabinets. |

### 7.8.1.6 Turbine Impulse Chamber Pressure Arrangement | 70

Turbine impulse chamber pressure is determined by a differential | 70
pressure transmitter, measuring the pressure rise in the turbine. |
These pressure signals are used as input into AMSAC and are isolated |
signals from the Process Protection Cabinets. |

70 | 7.8.1.7 Trip System

70 | The differential pressure that is measured in the steam generator is
| used by the AMSAC to determine trip demand. Signal conditioning is
| performed on the transmitter output and used by each of the ALPs to
| derive a component actuation demand. If three of the four steam
| generators have a low level at a power level greater than the C-20
| permissive, then a trip demand signal is generated. This signal
| drives output relays for performing the necessary mitigative actions.

70 | 7.8.1.8 Isolation Devices

70 | AMSAC is independent of the Reactor Trip (RTS) and Engineered Safety
| Features Actuation Systems (ESFAS). The AMSAC inputs for measuring
| turbine impulse chamber pressure and narrow range steam generator
| water level are derived from existing transmitters and channels within
| the Process Protection System. Connections to these channels are
| made downstream of Class 1E isolation devices which are located within
| the Process Protection Cabinets. These isolation devices ensure that
| the existing protection system continues to meet all applicable safety
71 | criteria. Buffering of the AMSAC outputs from the safety related
| final actuation device circuits is achieved through Class 1E isolation
| relays located within the AMSAC cabinet. A credible fault occurring
70 | in the nonsafety-related AMSAC will not propagate through and degrade
| the RTS and ESFAS.

70 | 7.8.1.9 AMSAC Diversity from the Reactor Trip and Engineered
70 | Safety Features Actuation System

70 | The AMSAC utilizes equipment diverse from the RTS and ESFAS to prevent
| common mode failures that might affect the AMSAC and the RTS or
| ESFAS. The AMSAC is a digital, microprocessor-based system with
| the exception of the analog SG level and turbine impulse pressure
| transmitter inputs. The reactor trip system utilizes an analog based
| protection system. Also where similiar components are utilized for
| the same function in both AMSAC and the reactor trip system, the
| components used in AMSAC are provided from a different manufacturer.

Common mode failure of identical components in the analog portion of the Reactor Protection System (RPS) that could result in the inability of the system to generate a reactor trip signal, will not impact the ability of the digital AMSAC to generate its required mitigative functions. Similarly, a postulated common mode failure affecting analog components in ESFAS, which could affect its ability to initiate auxiliary feedwater, will not impact the ability of the digital based AMSAC to automatically initiate auxiliary feedwater. | 70

7.8.1.10 Power Supply | 70

The AMSAC power supply is a non-Class 1E Uninterruptable AC Power Supply (UPS) source, and battery backed. The AMSAC is an energize-to-actuate system capable of performing its mitigative functions with a loss of offsite power. | 70

7.8.1.11 Environmental Variations | 70

AMSAC equipment is not designed as safety-related equipment with the exception of the output isolation relays. Therefore, AMSAC is not fully required to be qualified as safety related. The AMSAC equipment is located in a controlled environment such that variations in the ambient conditions are minimized. No AMSAC equipment is located inside containment. The transmitters (steam generator level and turbine impulse chamber pressure) that supply the input into AMSAC are located inside containment and the turbine building, respectively. | 70

7.8.1.12 Setpoints | 70

The AMSAC makes use of two setpoints in the coincidence logic to determine if mitigative functions are required. Water level in each steam generator is sensed to determine if a loss of secondary heat sink is imminent. The low level setpoint is selected in such a manner that a true lowering of the level will be detected by the system. The normal small variations in steam generator level will not result in a spurious AMSAC signal. | 70

70 | The C-20 permissive setpoint is selected in order to be consistent
| with ATWS investigations showing that the mitigative actions performed
| by the AMSAC need not be automatically actuated below a certain power
| level. The maximum allowable value of the C-20 permissive setpoint
| is defined by these investigations.

70 | To avoid inadvertent AMSAC actuation on the complete loss of main
| feedwater, AMSAC actuation is delayed by a preselected time. This
| will ensure the Reactor Trip System will provide the first trip
| signal.

70 | To ensure that the AMSAC remains armed sufficiently long to permit its
| function in the event of a turbine trip, the C-20 permissive is
| maintained for a preset time delay after the turbine impulse chamber
| pressure drops below the setpoint.

70 | The AMSAC setpoints and setpoint modifications are administratively
| controlled.

70 | 7.8.2 ANALYSIS

70 | 7.8.2.1 Safety Classification/Safety-Related Interface

70 | The AMSAC is not a safety-related system and therefore need not meet
| the requirements of IEEE 279-1971. The AMSAC has been implemented
| such that the Reactor Trip System and the ESF Actuation System
| continue to meet all applicable safety-related criteria. The AMSAC
| is independent of the RTS and ESFAS. The isolation provided, between
| the RTS and the AMSAC and between the ESFAS and the AMSAC, by the
| isolator modules and the isolation relays ensures that the applicable
| safety-related criteria are met for the RTS and the ESFAS.

### 7.8.2.9 Testability at Power | 70

The AMSAC is testable at power. This testing is done via the system | 70
test/maintenance panel. The capability of the AMSAC to perform its |
mitigative actuations is bypassed at a system level while in the test |
mode. Total system testing is performed as a set of three |
sequential, partial, overlapping tests. The first of the tests |
checks the analog input portions of the AMSAC in order to verify |
accuracy. Each of the analog input modules is checked separately. |
The second test checks each of the ALPs to verify that the appropriate |
coincidence logic is sent to the majority voter. Each ALP is tested |
separately. The last test exercises the majority voter and the |
integrity of the associated output relays. The majority voter and |
associated output relays are tested by exercising all possible input |
combinations to the majority voter. The integrity of each of the |
output relays is checked by confirming continuity of the relay coils |
without operating the relays. The capability to individually operate |
the output relays confirm the integrity of the associated field |
wiring. Operation of the corresponding isolation relays and final |
actuation devices at plant shutdown is provided. |

### 7.8.2.10 Inadvertent Actuation | 70

The AMSAC is designed such that the frequency of inadvertent | 70
actuations is minimized. This high reliability is ensured through |
use of three redundant ALPs and a majority voting module. A single |
failure in any of these modules will not result in a spurious AMSAC |
actuation. In addition, the three-out-of-four low steam generator |
level coincidence logic and time delay minimize the potential for |
inadvertent actuations. |

70 | 7.8.2.11 Maintenance Bypasses

70 | The AMSAC is blocked at the system level during maintenance, repair, | calibration or testing. While the system is blocked, the bypass | conditions is continuously indicated on the main control board.

70 | 7.8.2.12 Operating Bypasses

70 | The AMSAC has been designed to allow for operational bypasses with the | inclusion of the C-20 permissive. Above the C-20 setpoint, the AMSAC | is automatically unblocked (i.e., armed); below the setpoint, the | system is automatically blocked. The operating status of the AMSAC | is continuously indicated on the main control board via an annunciator | window.

70 | 7.8.2.13 Indication of Bypasses

70 | Whenever the mitigative capabilities of the AMSAC are bypassed or | deliberately rendered inoperable, this condition is continuously | indicated on the main control board. In addition to the operating | bypass, any manual maintenance bypass is indicated via the AMSAC | general warning that is sent to the main control board.

70 | 7.8.2.14 Means for Bypassing

70 | A permanently installed system bypass selector switch is provided to | bypass the system. This is a two-position selector switch with | "NORMAL" and "BYPASS" positions. At no time is it necessary to use | any temporary means, such as installing jumpers or pulling fuses, to | bypass the system.

### 7.8.2.15 Completion of Mitigative Actions Once Initiated | 70

The AMSAC mitigative actions are initiated when the coincidence logic | 70
is satisfied and the time delay requirements are met. If the flow in |
the feedwater lines is re-initiated before the timer expires and the |
SG water level increases to above the low low setpoint, then the |
coincidence logic will no longer be satisfied and the actuation signal |
disappears. If the coincidence logic conditions are maintained for | 71
the duration of the time delay, then the mitigative actions are |
initiated. The auxiliary feedwater initiation signal is latched in |
at the component actuating devices and the turbine trip is latched at | 70
the turbine electro-hydraulic control system. Deliberate operator |
action is then necessary to terminate auxiliary feedwater flow, clear |
the turbine trip signal using the main control board turbine trip |
reset switch, and proceed with the reopening of the turbine stop |
valves. |

### 7.8.2.16 Manual Initiation | 70

Manual initiation of the AMSAC is not provided. The capability to | 70
initiate the AMSAC mitigative functions manually, i.e., initiate |
auxiliary feedwater, trip the turbine, and isolate steam generator |
blowdown and sampling lines, exists at the main control board. |

### 7.8.2.17 Information Readout | 70

The AMSAC has been designed such that the operating and maintenance | 70
staffs have accurate, complete and timely information pertinent to the |
status of the AMSAC. A system level general warning alarm is |
indicated in the control room. Diagnostic capability exists from the |
test/maintenance panel to determine the cause of any unanticipated |
inoperability or deviation. |

70 | 7.8.3 COMPLIANCE WITH STANDARDS AND DESIGN CRITERIA

70 | The AMSAC meets the applicable requirements of Part 50.62 of Title 10
| of the Code of Federal Regulations and the quality assurance
| requirements of NRC Generic Letter 85-06.

TABLE OF CONTENTS (Continued)

TABLE 9.1-3

(Sheet 1 of 4)

## SPENT FUEL POOL COOLING AND CLEANUP SYSTEM
## MAJOR COMPONENT PARAMETERS

### Spent Fuel Pool Cooling Water Pump

| | | |
|---|---|---|
| Quantity (shared) | 2 | |
| Design pressure, psig | 150 | |
| Design temperature, F | 200 | |
| Design flow, gpm | 3600 | |
| Total dynamic head, ft water | 209 | \| 68 |
| Material | SS | |

### Refueling Water Purification Pumps

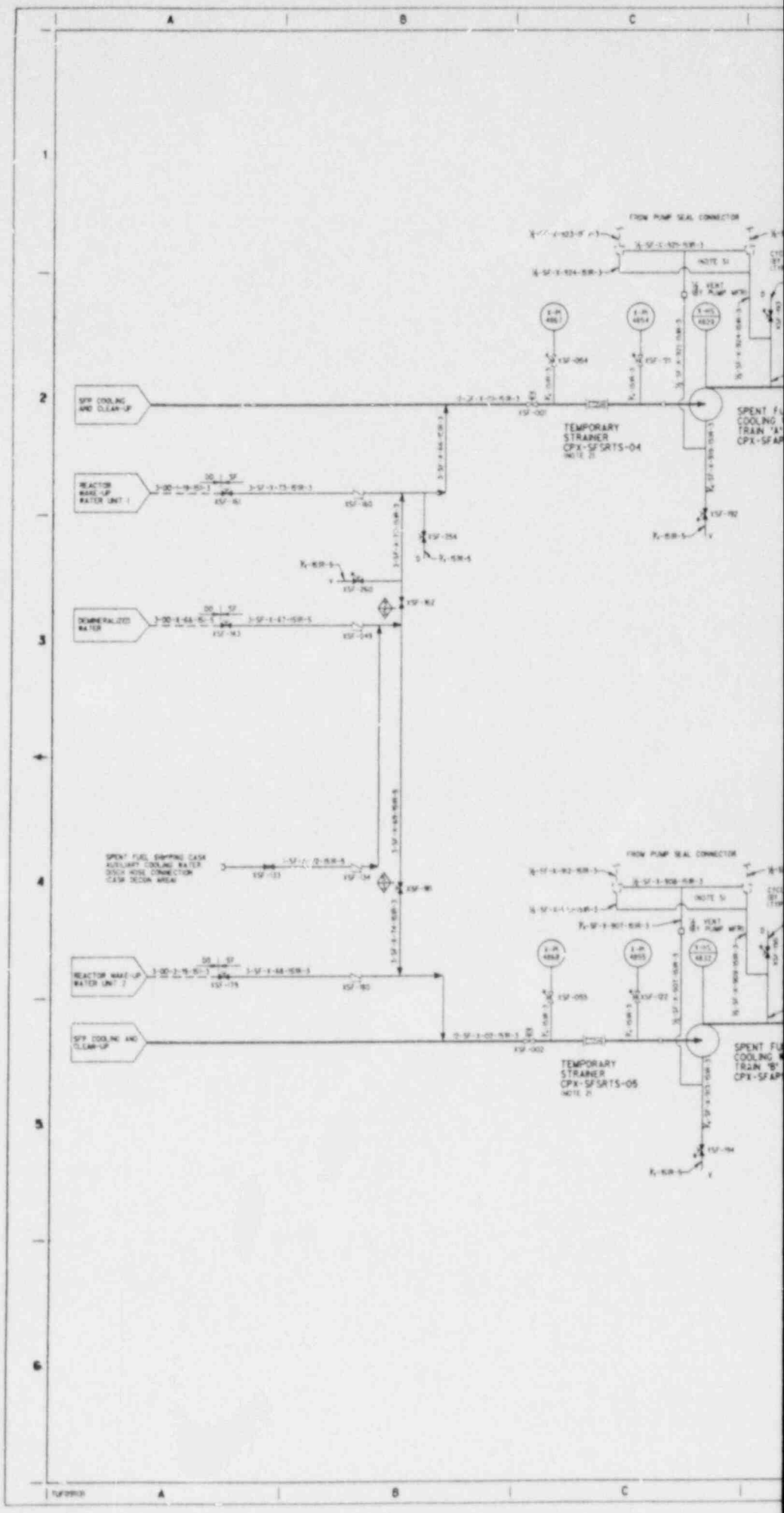
| | |
|---|---|
| Quantity (per unit) | 2 |
| Design pressure, psig | 150 |
| Design temperature, F | 200 |
| Design flow, gpm | 250 |
| Minimum developed head, ft water | 165 |
| Material | SS |

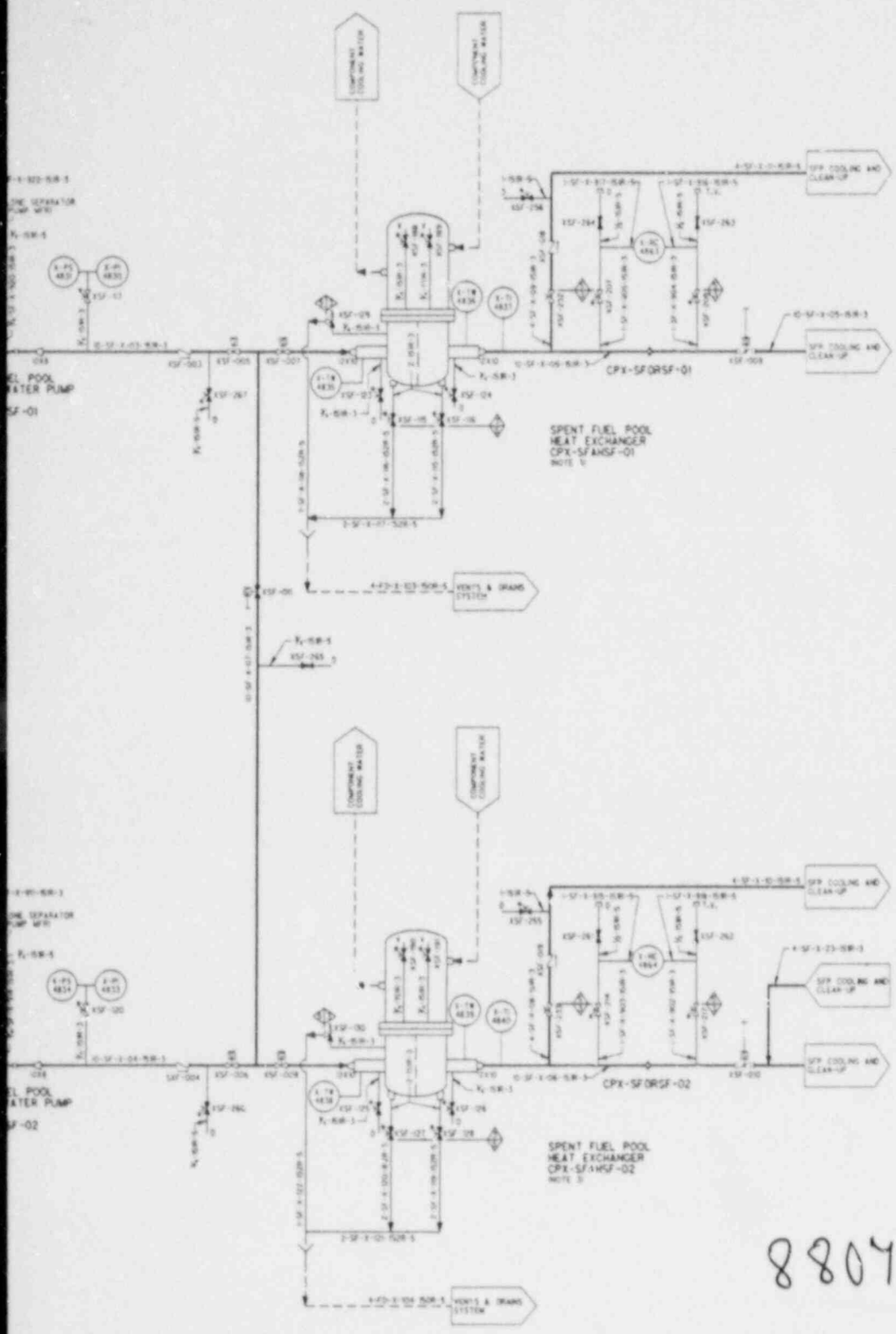
### Spent Fuel Pool Skimmer Pump

| | |
|---|---|
| Quantity (shared) | 1 |
| Design pressure, psig | 150 |
| Design temperature, F | 200 |
| Design flow, gpm | 200 |
| Fluid | Spent fuel pool water |
| Material | SS |

### Spent Fuel Pool Heat Exchanger

| | | |
|---|---|---|
| Quantity (shared) | 2 | |
| Design heat transfer, btu/hr | $13.6 \times 10^6$ | \| 71 |


A
B
C
1
2
3
4
5
6
FROM PUMP SEAL CONNECTOR
NOTE 5
SFP COOLING AND CLEAN-UP
TEMPORARY STRAINER CPX-SFSRTS-04
NOTE 2
REACTOR MAKE-UP WATER UNIT 1
DEMINERALIZED WATER
SPENT FUEL SHIPPING CASK AUXILIARY COOLING WATER DOCK HOSE CONNECTION (CASK DOCK AREA)
REACTOR MAKE-UP WATER UNIT 2
SFP COOLING AND CLEAN-UP
TEMPORARY STRAINER CPX-SFSRTS-05
NOTE 2
FROM PUMP SEAL CONNECTOR
NOTE 5




NOTES:

1. FOR MECHANICAL SYMBOLS AND NOTES SEE 2323-M-0200.
2. TEMPORARY STRAINERS ARE INSTALLED IN SUCTION PIPES DURING INITIAL FLUSHING OPERATIONS. STRAINERS AND TEMPORARY PRESSURE GAUGES ARE REMOVED FROM 1/2 SYSTEM STARTUP.
3. ALL PIPING TO THE SPENT FUEL POOL HEAT EXCHANGER SHELLS IS SHOWN ON THE COMPONENT COOLING WATER FLOW DIAGRAM.
4. CAPS WILL NOT BE PROVIDED ON VENTS & DRAINS LINES.
5. PIPING WAS ORIGINALLY SUPPLIED BY VENDOR AND DAMAGED. PIPING IS NOW FIELD SUPPLIED FOR PUMPS CPX-SFAPSF-02 AND CPX-SFAPSF-02.

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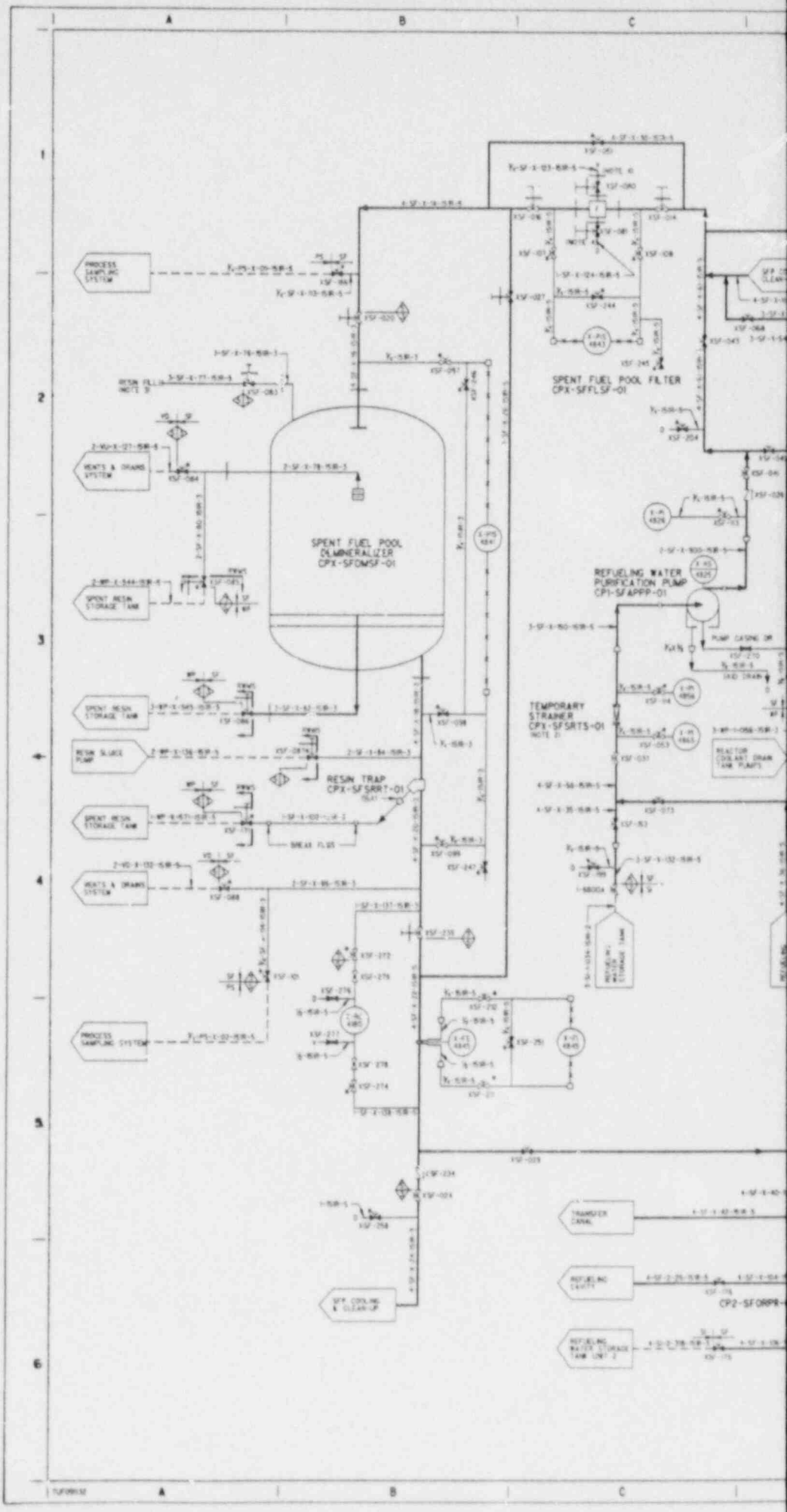
May 27, 1988

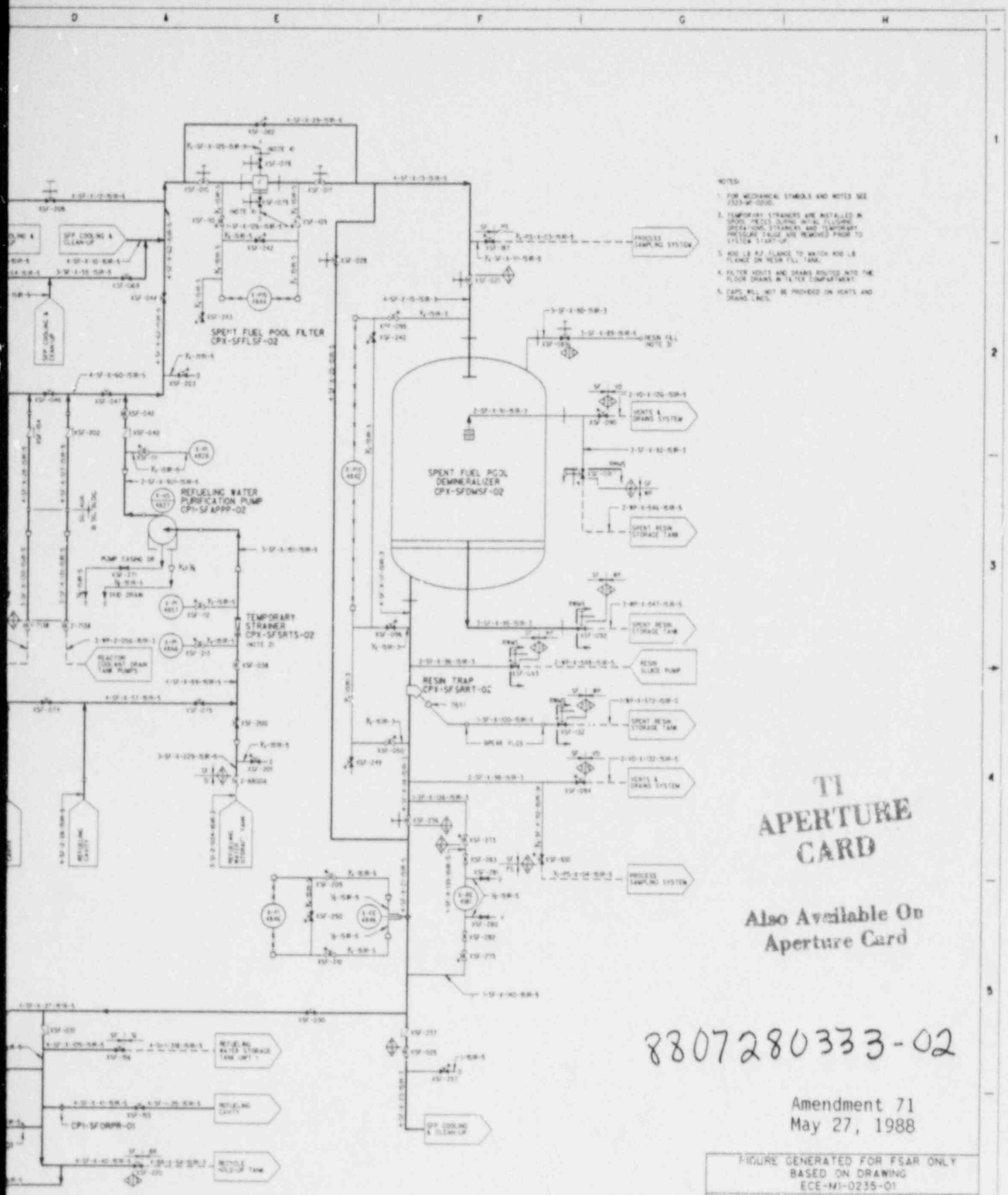
FIGURE GENERATED FOR FSAR ONLY BASED ON DRAWING 2323-M1-0235

COMANCHE PEAK S.E.S.
FINAL SAFETY ANALYSIS REPORT
UNITS 1 AND 2

FLOW DIAGRAM
SPENT FUEL POOL COOLING
AND CLEAN-UP SYSTEM

FIGURE 9.1-13 (4 1)


SPENT FUEL POOL FILTER
CPX-SFFLSF-01
SPENT FUEL POOL DEMINERALIZER
CPX-SFDMSF-01
REFUELING WATER PURIFICATION PUMP
CP1-SFAPPP-01
TEMPORARY STRAINER
CPX-SFSRTS-01
RESIN TRAP
CPX-SFSRRT-01
PROCESS SAMPLING SYSTEM
VENTS & DRAINS SYSTEM
SPENT RESIN STORAGE TANK
RESIN SLURRY PUMP
REACTOR COOLANT DRAIN TANK PUMPS
TRANSFER CANAL
REFUELING CAVITY
CP2-SFORPR
REFUELING WATER STORAGE TANK UNIT 2



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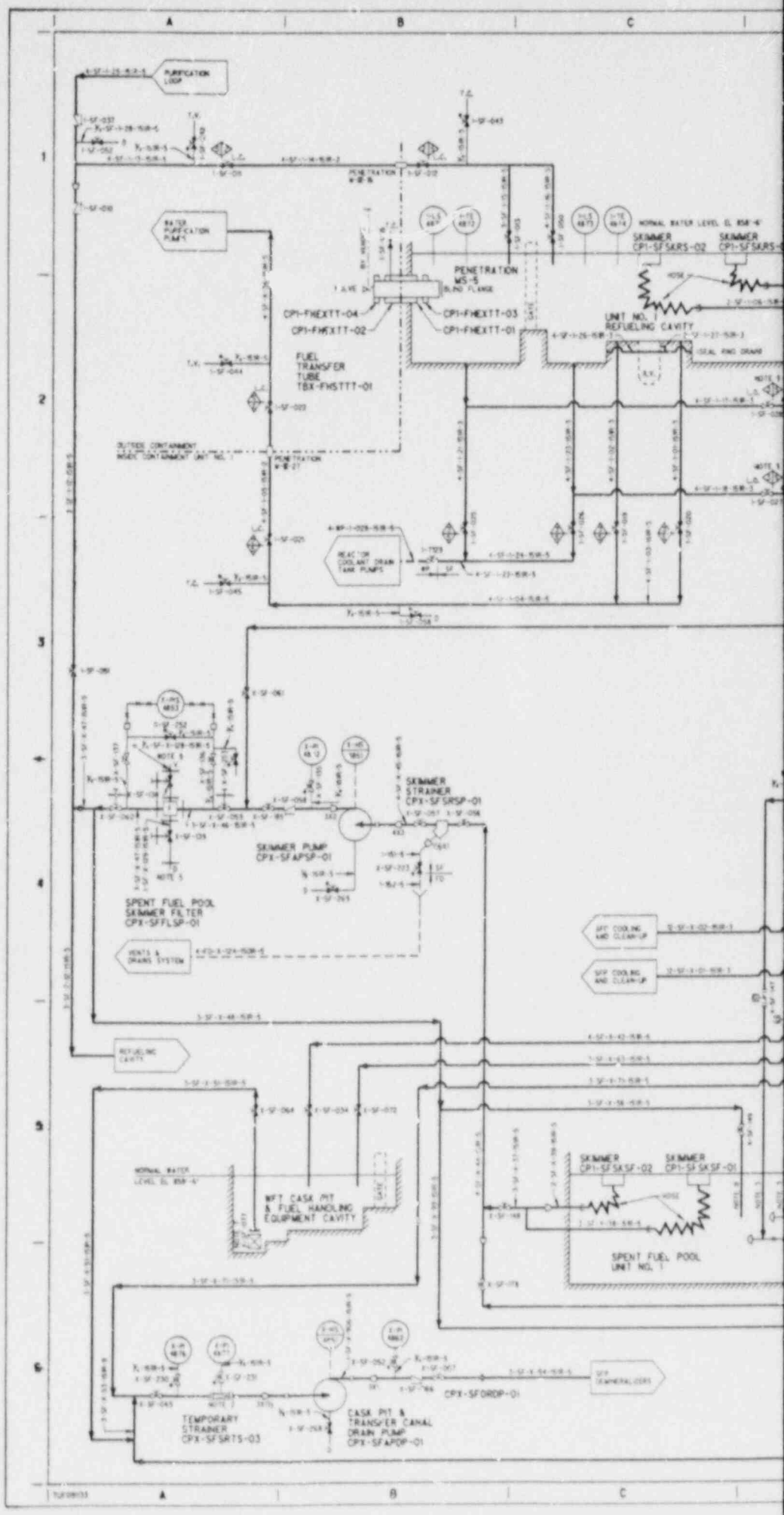
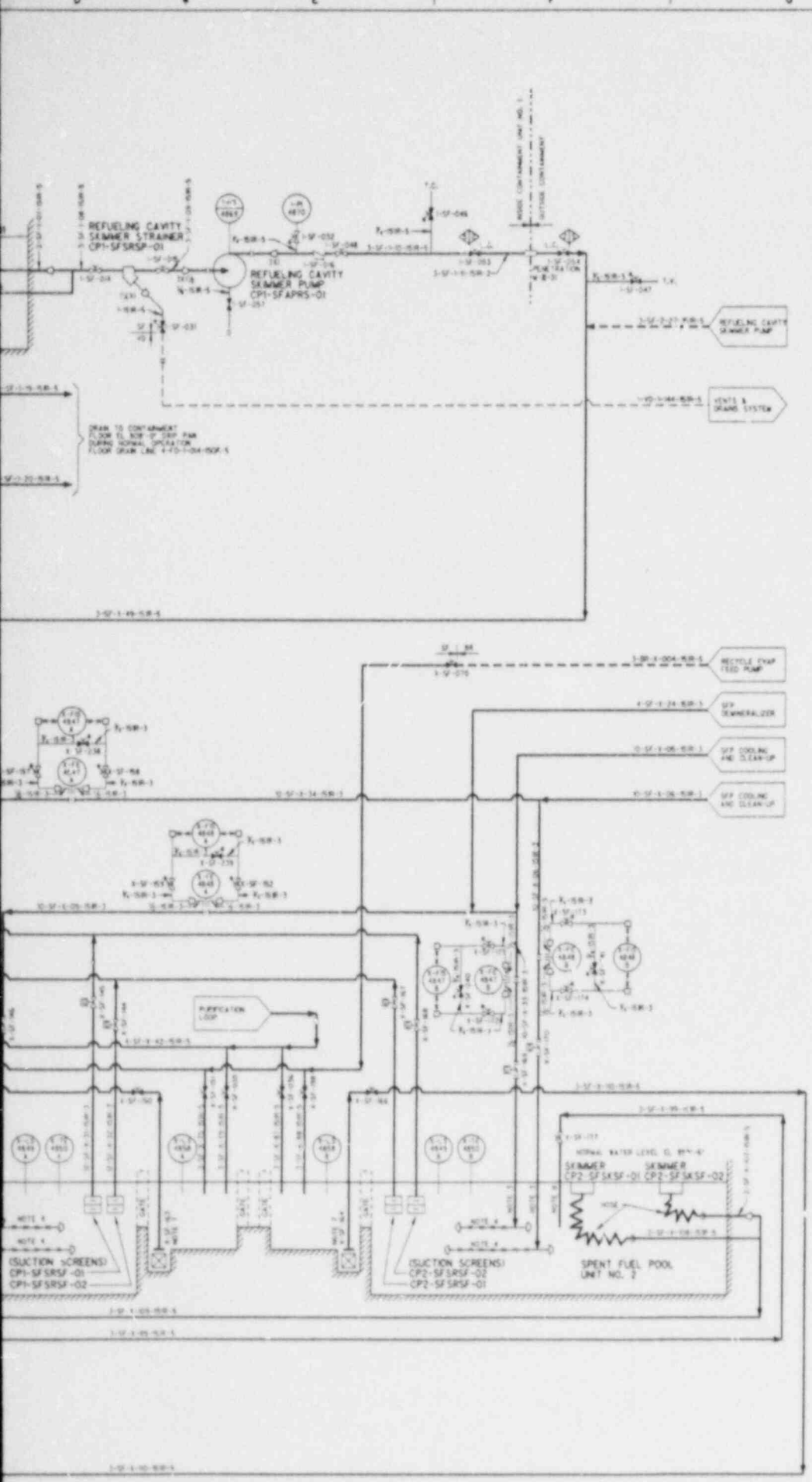
COMANCHE PEAK S.E.S.
FINAL SAFETY ANALYSIS REPORT
UNITS 1 AND 2

FLOW DIAGRAM
SPENT FUEL POOL COOLING
AND CLEAN-UP SYSTEM

FIGURE 9.1-13 SH 2


PURIFICATION LOOP
WATER PURIFICATION PUMPS
PENETRATION W-8-5
PENETRATION W-8-27
NORMAL WATER LEVEL EL 858'-4"
SKIMMER CP1-SFSKRS-02
SKIMMER CP1-SFSKRS-01
PENETRATION W5-5 BLIND FLANGE
CP1-FHEXTT-04
CP1-FHEXTT-02
CP1-FHEXTT-03
CP1-FHEXTT-01
UNIT NO. 1 REFUELING CAVITY
SEAL RING DRAIN
FUEL TRANSFER TUBE TBX-FHSTTT-01
OUTSIDE CONTAINMENT INSIDE CONTAINMENT (INT NO. 1)
REACTOR COOLANT DRAIN TANK PUMPS
SKIMMER STRAINER CPX-SFSRSP-01
SKIMMER PUMP CPX-SFAPSP-01
SPENT FUEL POOL SKIMMER FILTER CPX-SFFLSP-01
VENTS & DRAINS SYSTEM
RFT COOLING AND CLEANUP
SFP COOLING AND CLEANUP
REFUELING CAVITY
NORMAL WATER LEVEL EL 858'-4"
WET CASK PIT & FUEL HANDLING EQUIPMENT CAVITY
SKIMMER CP1-SFSKSF-02
SKIMMER CP1-SFSKSF-01
SPENT FUEL POOL UNIT NO. 1
CPX-SFDRDP-01
TEMPORARY STRAINER CPX-SFSRTS-03
CASK PIT & TRANSFER CANAL DRAIN PUMP CPX-SFAPDP-01
SFP CHEMICAL CLEAN




NOTES:

1. FOR MECHANICAL SYMBOLS AND NOTES SEE DRAWING 3323-MI-0200.
2. TEMPORARY STRAINERS ARE INSTALLED IN SPOOL PIECES DURING INITIAL FLUSHING OPERATIONS. STRAINERS AND TEMPORARY PRESSURE GAUGES ARE REMOVED PRIOR TO SYSTEM STARTUP.
3. LOCATE ⅛ INCH HOLE IN PIPE 7'-0" BELOW NORMAL WATER LEVEL.
4. SPARGER LOCATED 8 FEET ABOVE FUEL ASSEMBLIES.
5. FILTER VENTS ARE DRAINS routed INTO THE FLOOR DRAINS IN FILTER COMPARTMENT.
6. ,4FS WILL NOT BE PROVIDED ON VENTS & DRAINS LINES.
7. VALVES ARE VALMATIC CO 7-125 LB MODEL 1903 SURE SEAL FOOT VALVES W.I. 304 S.S. CONSTRUCTION WITH NEOPRENE SEAL RING.
8. LOCATE ⅛ INCH HOLE IN PIPE 7'-0" BELOW NORMAL WATER LEVEL.
9. LOCK OPEN EXCEPT UNDER MODE 6.



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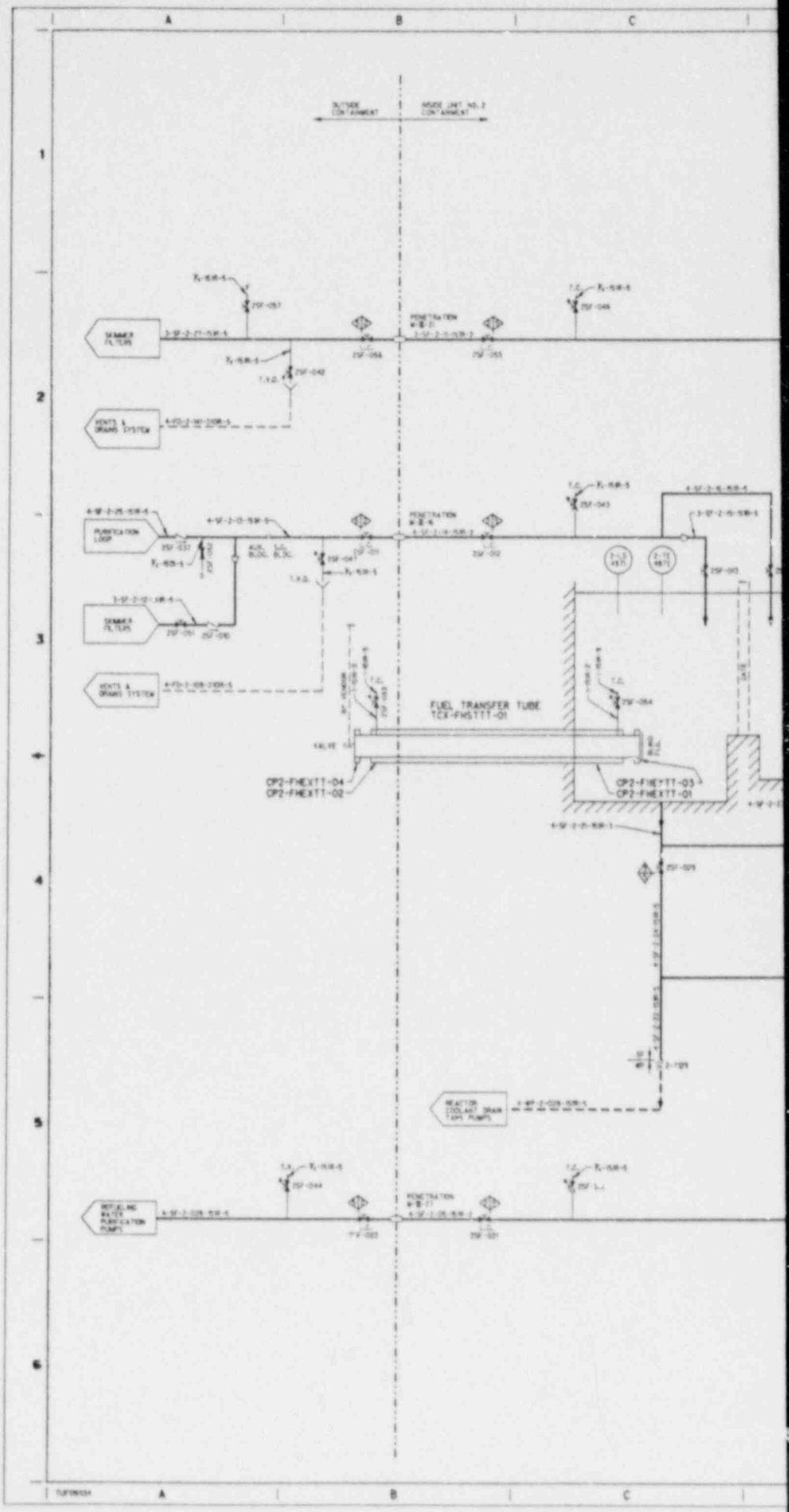
FIGURE GENERATED FOR FSAR ONLY BASED ON DRAWING ECE-MI-0235-02

COMANCHE PEAK S.E.S.
FINAL SAFETY ANALYSIS REPORT
UNITS 1 AND 2

FLOW DIAGRAM
SPENT FUEL POOL COOLING AND CLEAN-UP SYSTEM

FIGURE 9.1-13 SH 3


OUTSIDE CONTAINMENT
INSIDE UNIT NO. 2 CONTAINMENT
SKIMMER FILTERS
VENTS & DRAINS SYSTEM
PURIFICATION LOOP
SKIMMER FILTERS
VENTS & DRAINS SYSTEM
FUEL TRANSFER TUBE
TCX-FHSTTT-01
CP2-FHEXTT-04
CP2-FHEXTT-02
CP2-FHEXTT-03
CP2-FHEXTT-01
REACTOR COOLANT DRAIN TANK PUMPS
REFUELING WATER PURIFICATION PUMPS

NOTES:

1. FOR MECHANICAL SYMBOLS AND NOTES SEE DRAWING 2323-M-0200.

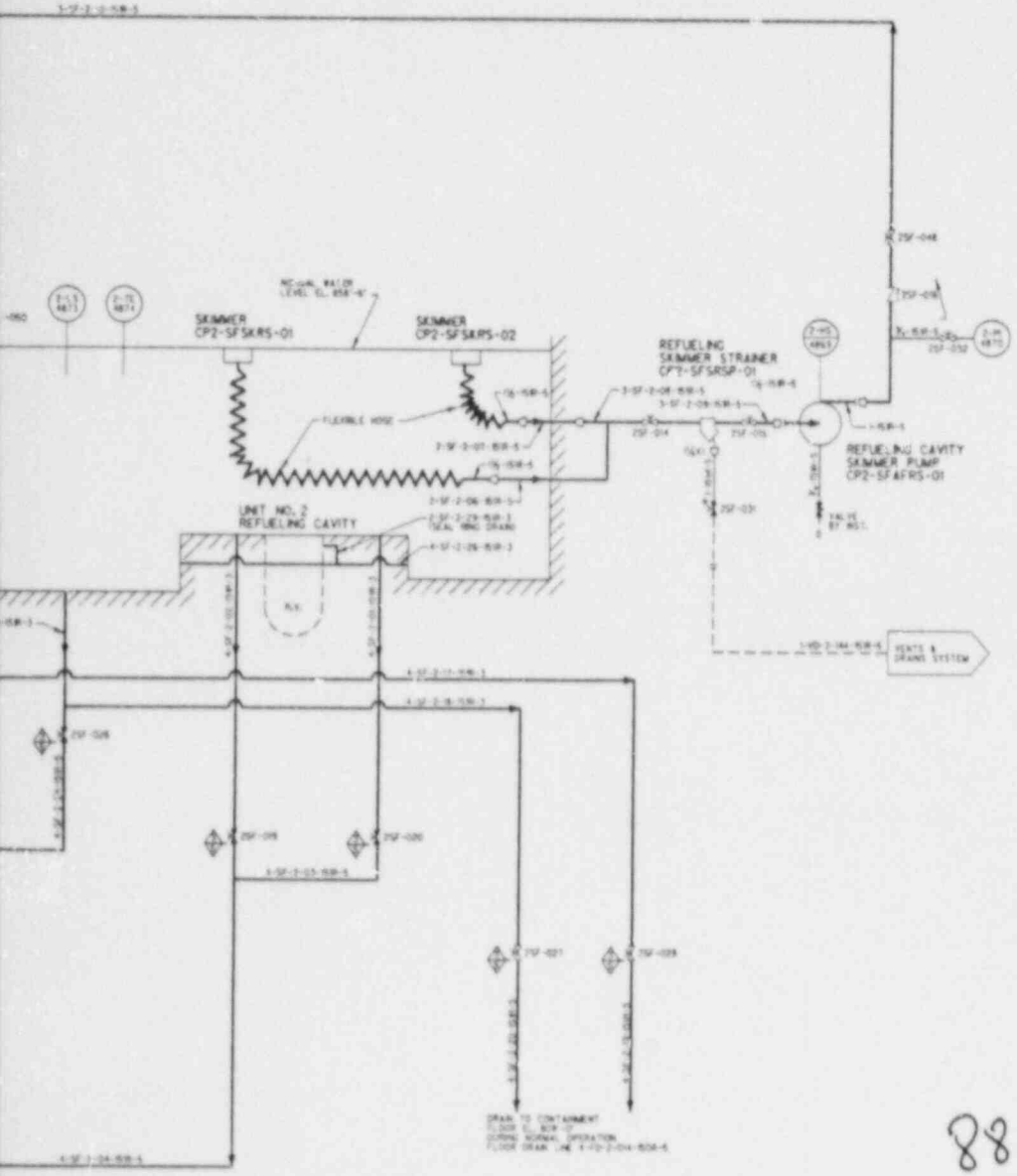



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FIGURE GENERATED FOR FSAR ONLY
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2323-M2-0235

CONVINCHS PEAK S.E.S.
FINAL SAFETY ANALYSIS REPORT
UNITS 1 AND 2

FLOW DIAGRAM
SPENT FUEL POOL COOLING
AND CLEAN-UP SYSTEM

FIGURE 9.1-13 SH. 4

## 9.4 AIR CONDITIONING, HEATING, COOLING, AND VENTILATION SYSTEMS

### 9.4.1 CONTROL ROOM AREA VENTILATION SYSTEM

#### 9.4.1.1 Design Bases

The Control Room HVAC and filtration systems are designed to maintain suitable and safe ambient conditions for operating personnel and equipment during all modes of operation including post-DBA conditions, in the following areas of the Control Building.

Areas on floor elevation 830 ft 0 in.:

| | |
|---|---|
| East Control Room | \| 68 |
| West Control Room | \| 68 |
| Console and Control Room Unit 1 | \| 68 |
| Console and Control Room Unit 2 | \| 68 |
| Instrument Room Unit 1 | \| 68 |
| Instrument Room Unit 2 | \| 68 |
| Computer Room Unit 1 | \| 68 |
| Computer Room Unit 2 | \| 68 |
| File Room | \| 68 |
| Production Supervisor's Office | \| 68 |
| Corridor | \| 68 |
| Toilet | \| 68 |
| Locker Room | \| 68 |
| Kitchen and Janitor Closet | \| 68 |
| Charts and Supplies Storage Room | \| 68 |

Areas on floor elevation 840 ft 6 in.:

71 | Technical Support Center (Office and Corridor)
71 |
71 | Offices (2)
71 |
68 | Electrical Equipment Corridor

Areas on floor elevation 854 ft 4 in.:

68 | Control Room Air Conditioning System mechanical equipment rooms, trains A and B.

66 | The Control Room, located on elevation 830 ft 0 in, is maintained at 75°F (±5°F) and 35-50 percent relative humidity. The Control Room HVAC and filtration equipment rooms are maintained between 40°F and 104°F. Miscellaneous areas on elevations 830 ft and 840 ft are also maintained between 40°F and 104°F. Other system design parameters are presented in Tables 9.4-1 and 9.4-2.

As described in the following paragraphs, the system is provided with sufficient redundancy in equipment and power supplies to enable the system to sustain a single failure of an active component without loss of function.

1. The system is equipped with four modular air-conditioning units. Each unit is rated at 50 percent of the Control Room HVAC and filtration systems capacity. Each pair of air-conditioning units is powered from an independent Class 1E bus and is physically separated by a dividing fire wall in the Control Room HVAC and filtration mechanical equipment room.

## 9.5 OTHER AUXILIARY SYSTEMS | 50

### 9.5.1 FIRE PROTECTION SYSTEM

#### 9.5.1.1 General

This section is a description of the Fire Protection Program of the | 50
CPSES units 1 and 2. The evaluation of fire hazards is included in | 71
the CPSES Fire Protection Report (FPR) which follows the format of the |
U.S. Nuclear Regulatory Commissions's "Supplementary Guidance on |
Information Needed for Fire Protection Program Evaluation" and the | 50
supplementary criteria in their September 30, 1976, letter. |

The overall Fire Protection Program was developed utilizing the defense in depth concept. This concept is a combination of:

1. Preventing fires from starting

2. Quickly detecting and suppressing fires that do occur to limit | 66
the extent of damage |

3. Designing plant safety systems so that a fire that becomes fully established and burns for a considerable time, in spite of the fire protection systems provided, will not prevent essential plant safety functions from being performed.

The FPR quantifies potential fire hazards throughout the plant in | 71
terms of combustible heat release loading. The Fire Protection and |
Detection Systems are designed based on this heat release loading and | 66
on the nature of the transient and in situ combustible material in the |
area. A summary of this information is presented in tabular form in | 71
the FPR. |

### 9.5.1.2 Method of Analysis

#### 9.5.1.2.1 Definitions

50 | Several terms with their definitions as they relate to the Fire
| Protection Program for CPSES are presented below. Unless the terms
22 | are noted below, the definitions are as stated in Section I of Branch
| Technical Position APCSB 9.5-1 Reference [2].

1. Fire area

The fire area is that section of a building or the plant that is separated from other areas of the plant by fire barriers with openings and penetrations protected by seals or closures having a fire resistance rating equal to the rating assigned to the barrier. The fire areas extend through more than one elevation where plant design requirements and low amounts of combustible
71 | material in a specific area allow. These areas are designated
| on FPR Figures.

2. Fire Barriers

50 | Fire barriers are those components of construction (walls,
| floors, or protective coverings) that are rated by approved
| laboratories or are constructed in accordance with the
| requirements stated by authorities having jurisdiction in hours
| of resistance to fire and used to prevent spread of fire.

3. Fire Zone

71 | The fire zone is a subdivision or portion of a fire area that is
| designated on the FPR Figures.

4. Fire Duration

Fire duration is the approximate time expressed in minutes that the tabulated combustible material will burn. The duration is based on the heat release that will produce an exposure equivalent to the standard time-temperature curve (ASTM E-119). | 65

5. Fire Break

The fire break is a physical barrier that prevents fire propagation, that is, the spreading of a fire from one component to another or the direct exposure of a component to the heat and flames of a fire, or both. | 50

6. Design Basis Fire

Design basis fire is a fire that is postulated to occur in a fire area or fire zone assuming no manual, automatic, or other firefighting action has been initiated. The combustibles in the area are totally consumed and the fire burns at a rate modeling the standard time-temperature curve (ASTM E-119). | 65

7. Enclosed

The term "enclosed" means being surrounded by a case which will prevent a person from accidentally contacting live electrical parts. It also applies to flammable liquids which are contained or encased in fire-resistant materials or buildings and to barriers which may or may not be fire rated that surround or encompass fire areas or fire zones.

8. Dry

The term "dry" indicates that the connecting piping between a deluge valve and the nozzles of a water system is not normally pressurized with water.

9. Wet

The term "wet" indicates that the connecting piping between the main loop and a hose station isolation valve or water nozzle is normally pressurized with water.

10. Radiation Zone

50 | Radiation zone is the classification of an area based on the expected dose equivalent rate (mrem/hr) within that area. See Section 12.3 for a detailed description.

65 | 11. Fire Safe Shutdown Essential System or Component

65 | An essential system or component is defined as a system or component which is required to be operational to safely shutdown the plant in the event of a fire.

71 | 12. Maximum Permissible Fire Loading

65 | The Maximum Permissible Fire Loading (MPFL) is the maximum fire loading (BTU/sq ft) which can be expected to be contained within a fire area by the fire area boundaries without compromising safe shutdown capability.

13. Fire Hazards Analysis Evaluation | 71

A Fire Hazard Analysis Evaluation is an assessment of the impact | 71
of a single fire hazard on redundant components or systems used |
to provide fire safe shutdown functions for the plant. A Fire |
Hazards Analysis Evaluation is performed by a Fire Protection |
Engineer and, if required a Systems Engineer. The purpose of a |
Fire Hazards Analysis Evaluation is to demonstrate compliance |
with BTP APCSB 9.5-1 Appendix A based on the following |
considerations: |

- potential transient and in situ combustible hazards are | 66
  considered. |

- protection provided is commensurate with the hazards. | 66

- the consequences of a fire on the plant's ability to safely | 66
  shutdown are considered. |

- The Fire Hazards Analysis Evaluation is written, organized | 71
  and maintained to facilitate review by a person who is not |
  involved in the evaluation. |

- The conclusions of the FHA Evaluations are summarized in | 71
  the applicable sections of the Fire Protection Report. |

9.5.1.2.2 Assumptions

The FHA Evaluation is based on the following assumptions: | 50

1. Generally, the minimum fire barrier rating is three hours except | 65
   for the barriers enclosing the stairwells and elevator shafts, |
   which are rated at two hours, the cable tray/conduit fire |
   barriers which are rated at 1-hour, and other special cases |
   where a rating of less than three hours is adequate. |

71 | 2. When it is determined that a fire involving a fire safe shutdown component or system will not affect its redundant counterpart, the redundant system is assumed to operate without failures.

71 | 3. The Maximum Permissible Fire Loading for a fire zone assumes a fire burning in the area which follows the characteristics of the standard time-temperature curve, or as noted in the FPR, Reference [19].

65 | 4. A fire involving a combustible loading, up to the Maximum Permissible Fire Loading for the fire zone, will be contained within the fire area by the passive and active/fire protection features (i.e. fire wall and sprinklers, etc.). Furthermore, it is assumed that if any of these passive or active fire protection features is inoperable and the compensatory actions required by Technical Specifications have been implemented then an equivalent level of protection is provided.

65 | 9.5.1.2.3 Methodology

65 | In order to evaluate potential fire hazards, provide adequate fire protection, ensure isolation of fire safe shutdown systems from these hazards, and prevent the release of radioactive material to the environment, the following method of design and analysis has been formulated and implemented for the entire plant:

54 | 1. The plant is divided into separate fire areas using plant walls
65 | and floors as barriers. Due consideration as-shown below is given to the separation of redundant fire safe shutdown components from each other, from non-fire safe shutdown components and from major concentrations of combustible
66 | materials. Considerations were also given to other area characteristics such as electrical cable routing into and through the area, the ductwork supplying and exhausting the area, access and egress routes for the area, and vent area for depressurization during a tornado.

2. For each fire area/fire zone, the heat of combustion for each in-situ combustible is calculated. The calculated heat of combustion for all in-situ combustibles is divided by the floor area to determine the combustible loading (BTU/sq ft) for the fire area/fire zone. In addition, the approximate fire duration (minutes) is determined based on the ASTM E-119 standard time-temperature curve. The transient combustibles and the in-situ combustibles will not exceed the Maximum Permissible Fire Loading without implementation of compensatory measures. | 65

3. The fire safe shutdown essential equipment in each area is tabulated. | 65

4. Once the fire area and combustible material information is tabulated, fire protection equipment is located throughout the plant based on the severity and configuration of the fire hazards, the calculated heat release of each fire area and the plant equipment and components located in the fire area.

5. Fire detectors are located in all areas of the plant where there is a significant combustible loading and in all areas containing equipment required for safe shutdown except as described in Section 9.5.1.6.1. | 66

6. Hose stations are installed in all safety related buildings of the plant such that an effective hose stream can reach any location in a safety related building except as described in Section 9.5.1.6.1. | 66

7. Portable extinguishers are located in all safety related buildings in accordance with NFPA 10 requirements.

8. Fixed automatic water suppression systems will generally be installed in safety related plant areas where any of the following conditions exist:

   a. A high fire hazard exists

65 | b. Redundant safe shutdown equipment or cabling outside the Containment Building is located in the same fire area and is not separated by a three hour fire barrier.

   c. There is a congestion of cabling.

71 | In areas where condition (a) and in areas where condition (b) described above exists, the type of protection that will be provided as a minimum will be a sprinkler system providing coverage adequate for the hazard in the area unless justification for deviations are provided per reference [19] and as described in 9.5.1.6.1. The water spray design density will
65 | be based on Section 9.5.1.6.1-E.3.c.
65 |
66 | Where the condition described in (c) exists, based on Section 9.5.1.D.3.c, sprinkler systems will be provided for cabling to augment other fire protection features in the area.

71 | 9. Where redundant fire safe [illegible]down equipment cabling is located in the same fire area a[illegible] not separated by a three hour fire barrier or a horizontal distance of 20 feet with negligible intervening combustibles or fire hazard, one train of this cabling will be enclosed by a one-hour fire barrier (or radiant energy shield inside containment) unless an alternate shutdown path is utilized or justification for deviations are provided per reference [19] except as described in Section 9.5.1.6.1.

10. The Cable Spreading Room contains equipment and cables belonging to both safety trains. The following fire protection systems will be provided:

    a. Hose stations for manual fire fighting

    b. Fixed Halon primary suppression system | 50

    c. Manual pre-action sprinkler system | 50

    d. Automatic fire detection system | 50

    e. An alternate shutdown system | 50

11. The plant will be capable of being safely shutdown in the event | 71
    any of the fires postulated in the Fire Protection Report |
    occurs. Alternate shutdown systems and procedures have been |
    developed using shutdown paths available to the operator which | 54
    are either free from fire damage or otherwise controllable in |
    spite of such fire damage. |

9.5.1.3 Fire Hazard Analysis Evaluation

See Reference [19], Fire Protection Report | 71

9.5.1.4 Fire Protection System Description

9.5.1.4.1 General

The Fire Protection System detects, alarms, and extinguishes fires. It is comprised of two subsystems: Fire Detection and Fire Suppression.

The Fire Detection System is a plant-wide system designed to detect fires in the plant, alert the Control Room operators, and alert the plant fire brigade of the fire and its location.

71 | The Fire-Suppression System is designed to extinguish any fire
| postulated to occur in the Fire Protection Report. It is comprised
50 | of a water supply system, fixed water sprinkler and spray systems,
| Halon systems, fire hose stations, and portable extinguishers.

9.5.1.4.2 System Design Parameters

1. Fire Detection System

The Fire Detection System consists of the following components:

50 | 1) Fire Detectors

50 | a) Ionization smoke detectors
50 | b) Thermal heat detectors
50 | c) Ultraviolet detectors
50 | d) Thermistor line detectors

50 | 2) Fire Detection Local Control Panels

50 | These panels provide local indication of the status of the
| protected area. Indication provided is annunication of alarms
| and system trouble status. These panels also provide automatic
| initiation of fire suppression where applicable.

50 | 3) Fire Detection Main Control Panel

50 | This panel is located in the control room. Any fire alarm that
| is detected in the plant will alarm on this panel in the control
| room. Trouble circuits of each local panel are also monitored.

The fire detectors are strategically located throughout the plant to detect, annunciate, and indicate in the Control Room, the location of a fire. | 50 | 71

The power supplies for the Plant Fire Detection system meets the requirements of NFPA 72D Section 2220. The Plant Fire Detection system can be provided power from any one of the following eight (8) sources: two (2) main generators, two (2) offsite power supplies, and four (4) standby diesel generators (plant emergency power supply). Each train of standby diesel generators consists of two diesel generators each is associated with its respective unit and is operational upon completion of that unit. | 46 | 50

The fire detection system is electrically supervised for a wiring break in the detection and alarm circuits. Loss of supervision causes an audible and visual trouble indication on the main fire detection control panel, located in the Control Room, in accordance with NFPA 72D requirements. Thermistor-line fire detection systems are supervised for a break or short circuit of the sensing element. Ground fault supervision is provided except as noted in Section 9.5.1.6.1-E.1. | 65

Ionization detectors are of the two-chamber-type design. The first chamber is a reference chamber to compensate for sensitivity changes caused by temperature, barometric pressure, and humidity variations. The second chamber is a sensing chamber open to the outside elements through a protective screen which permits combustion products to enter, while preventing insects and foreign matter from entering and causing false alarms.

66 | Thermal detectors are of the fixed-temperature, rate compensation
| types or continuous strip thermistor line type.

50 | Ultraviolet detectors respond directly to the presence of flame by
| sensing the ultraviolet radiation emanating from the flame.

2. Fire Suppression Systems

a. Water Supply Systems

71 | The water supply system was designed using NFPA Codes and
| BTP 9.5-1 Appendix A. The water supply network and the
66 | arrangement of the water extinguishing systems are shown
| on Figures 9.5-43 through 9.5-48 and Figures 9.5-61 and
71 | 9.5-62. The water extinguishing systems are designed to
| operate with the shortest portion of the Fire Protection
| yard-loop out of service. The water storage capacity is
| based on supplying water to the largest fixed extinguishing
| system and the manual hose stream requirements of Appendix
| A.

66 | Three 50 percent pumps (one electric motor-driven, two
| diesel engine-driven; each rated at 2000 gpm at a Total
| Dynamic Head of 370 ft) are provided for protection of both
| units. In addition, a jockey pump (rated at 60 gpm at a
| Total Dynamic Head of 330 ft) maintains the required water
| pressure throughout the system at all times.

2) Automatic Water Spray Systems | 66

When a fire is detected its location is annunciated on the local fire detection control panel and in the control room. The Fire Detection Local Control Panel, transmits a signal to open the proper deluge valve. A water-flow alarm sounds locally and in the control room indicating water flowing through the piping network. The deluge valves operate | 66
automatically as described above, or can be manually |
operated locally. Once actuated, deluge valves can |
only be reset manually. |

Water spray systems are provided for the following: | 65

- Diesel Fuel Oil Day Tank Rooms | 66
  | 71
- Turbine Building Hazards (i.e. Lube Oil, | 65
  Feedwater Turbines, Hydrogen Seal Oil) |

Water spray systems are also provided for the | 66
following atmospheric cleanup units charcoal absorber |
beds: |

a. Four Containment preaccess units
b. Sixteen controlled access exhaust units
c. Two hydrogen purge exhaust units
d. Two Control Room emergency filtration units
e. Two Control Room emergency pressurization units

Each charcoal absorber bed is equipped with strip thermistor heat type detectors.

Upon detection of an abnormally high temperature in any one of the charcoal absorber beds, a high temperature signal is generated locally and in the
66 control room. If the temperature of the charcoal bed continues to rise, the detection system will generate a high-high temperature signal which will automatically open the deluge type valve in the atmospheric cleanup unit and initiate water spray on the charcoal bed. When the temperature of the charcoal bed drops below the high-high set point, the deluge valve will close automatically. Deluge type valves for atmospheric cleanup units can only be operated automatically.

56 A high temperature signal detected in any of the four containment pre-access units will also initiate a
66 Demineralized Water Transfer Pump. This pump serves as part of the automatic water spray system for these
71 units. Should demineralized water be unavailable, the operator is alerted in the control room and he can manually route fire protection water through the demineralized water pipe supplying these water spray systems.

Upon detection of a fire, the deluge valve is manually operated through operation of an electric pull station allowing water flow into the piping network which will discharge through all sprinkler heads protecting the area. | 66

c. Halon Extinguishing Systems

Automatic, total flooding, fixed, Halon extinguishing systems, actuated by ionization detectors, are provided for the cable spreading rooms, the plant computer rooms and the central alarm station.

Halon concentrations for each area are in accordance with NFPA suggested concentration except as described in Section 9.5.1.6.1. Each system is provided with two charges of Halon. | 66 | 65

Each system is also provided with a local alarm that annunicates prior to release of the first charge of Halon. A remote alarm in the Control Room indicates a fire condition in the area. Local halon control cabinets are provided to house all necessary auxiliary relays, timing relays and terminal blocks. Fire dampers, equipped with electro-thermal links are provided to isolate the ventilation systems for these areas. | 50 | 65 | 50

d. Fire Hose Stations

50 | Fire hose stations are located strategically throughout the plant for manual fire fighting operations.

54 | The fire hose stations located on the operating deck of the Turbine Building are equipped with 100 ft of 2-1/2 in.
71 | hose using NFPA 14 as a guideline for Class 1 service except as noted in Reference [19].

50 | All other fire hose stations throughout the plant are equipped with 100 ft of 1-1/2 in. hose and a nozzle
71 | compatible with the type of fire hazard in the area. The respective standpipes which supply water to these hose stations are sized and located throughout the plant using NFPA 14 for class II service as a guideline except as noted in 9.5.1.6.1 and Reference [19].

65 | The Hose stations for the Containment Building, Control Room and the cable spreading rooms are dry pipe with manual charging required.

56 | The hose stations inside the containment are fed from the Demineralized Water System via a transfer pump. This pump is initiated by hand pull stations inside the containment. Should demineralized water not be available or the system malfunctions, additional hand pull stations are provided inside the containment which allows for the normal fire protection water to be used for fire fighting purposes. The use of demineralized water will minimize the possibility of introduction of chlorides inside the containment.

e. Portable Fire Extinguishers

Portable fire extinguishers are provided for fire suppression throughout the plant. The quantity and type of extinguishers located in each fire area are based on the type, quantity, and specific hazard conditions in the respective fire areas. All extinguishers are in accordance with the guidelines of NFPA pamphlet No. 10. | 50 | 66

9.5.1.4.3 System Description

Fixed water suppression systems, fixed Halon systems, hose stations, and portable extinguishers are used as the primary and secondary means of fire suppression. As shown on Figures 9.5-43, 9.5-61 and 9.5-62 water is supplied to the water suppression systems and the hose station standpipes from two atmospheric storage tanks via an underground piping distribution system and three 50 percent-capacity fire pumps, one electric motor driven and two diesel engine driven. When pressure in the main loop drops below a set pressure point, the jockey pump starts automatically; when the system is repressurized, the jockey pump stops automatically. If the jockey pump cannot maintain the system pressure, the lead fire pump (the electric motor-driven fire pump) automatically starts. The diesel engine-driven fire pumps sequentially start automatically if the system pressure cannot be maintained by the other pumps for a preset period of time. The three fire pumps can only be shut down manually at the fire pump house location. The three fire pumps are connected to an approved flow meter to facilitate periodic testing of any fire pump. Pressure switches for the three pumps are located between the pump check valve and pump isolation valve to prevent starting an isolated pump. A siamese fire department connection is provided for emergency fill of the system by | 50 | 66 | 50 | 66

a fire truck or a portable auxiliary pump. This fill is used as a backup to the pumps. As required by NFPA No. 24, a check valve and a ball drip valve are provided at the connection of the siamese to the main loop. The siamese connection is located adjacent to the Service Water Intake Structure.

65 | As shown in Figure 9.5-44, the Turbine Building has an internal loop
| which supplies the standpipes and water spray systems. This internal
50 | loop has connections to the underground loop in Unit 1 and connections
| in Unit 2. A tie-line is provided inside the construction cutoff of
| the Unit 1 to facilitate construction of Unit 2 and to isolate
| sections of the loop. Valves are provided in accordance with NFPA 14
65 | to isolate the system. The water spray systems and automatic
| sprinkler systems are connected to the outside loop via isolation
| valves located in the fire protection valve rooms in the basement of
| the Turbine Building. The valve rooms are accessible from inside and
| outside the Turbine Building, as required, to control the water flow
| to the suppression systems.

50 | As shown on Figure 9.5-46, the water suppression systems protecting
| the diesel generators are independently supplied from the main yard
| loop. Actuation of the wet-pipe sprinkler system protecting one of
| the diesel generators will not affect the operation of the other
65 | diesel generator. Each diesel generator compartment is provided with
| a watertight door to prevent flooding of the adjacent areas.
66 |
66 | The fire pump house structure is divided into five rooms with three
| hour rated fire barriers. The structure is protected by an automatic
66 | wet-pipe sprinkler system. Water flow and valve tamper alarms are
| provided at the pump house location and in the Control Room. Each
| room in the fire pump house is provided with detection which
| annunciates locally and in the Control Room.

The automatic wet pipe, manual preaction, manual deluge, hose stand | 66
pipe and water spray systems are supplied by the respective safety |
related building interior supply loop. |
| 71

Yard post indicator valves are located in supply lines to permanent | 54
plant auxiliary buildings in accordance with NFPA 24 to shut off the |
water supply to these buildings. The hose stations are wet up to the |
shutoff valves at each station. A fire extinguisher is located | 50
adjacent to each hose station in these buildings. |

Each Halon system consists of a detection system, main and reserve | 65
storage cylinders, manifold and header assembly, control valves, |
piping, nozzles, and local control panels. The main Halon charge is |
released automatically after receipt of a fire signal from cross zoned |
ionization detectors located in the respective area. Each system |
incorporates a time delay which provides a warning for personnel
evacuation of the area. The reserve charge of Halon is provided for | 65
automatic protection of the areas during the time the main cylinders |
are being refilled following a discharge. Halon can also be released |
manually. |

A Fire Detection System is provided throughout the plant. When a fire is detected, it is annunciated and indicated by zone on the fire
65 | detection panel in the Control Room. An alarm-indicating lamp
| illuminates the base of the ionization detector showing the actuated
| detector. The majority of detectors are placed overhead in the
50 | monitored areas. Detectors serve a dual purpose: 1) they sound an
| alarm via the Control Room main fire detection panel and 2) where
| applicable, they actuate the automatic suppression systems.

66 | 9.5.1.4.4 Administrative Controls

66 | The administrative controls related to fire protection at CPSES are
| contained in the CPSES Fire Protection Report and augmented by station
| procedures as required for effective implementation. These include
| the limiting conditions for operation required for the fire
| suppression systems and fire detection instrumentation, the
| corresponding compensatory measures, and the required surveillance
| test requirements to assure operability of the systems which were
| previously contained in the technical specifications. Changes to the
| CPSES Fire Protection Report are subject to safety evaluations
| completed under the provisions of 10CFR50.59 per section 6.0 of the
| Technical Specifications.

9.5.1.5 Plant Fire Protection Design Requirements

9.5.1.5.1 General Plant Arrangement

The various buildings of CPSES are divided into a series of fire
65 | areas. The primary consideration in this division was the separation
| of fire safe shutdown systems and components from their redundant
| counterparts and the isolation and separation of fire hazards from
| fire safe shutdown systems. Consideration was also given to the
| isolating of combustibles not located in, or exposed to, areas
| containing fire safe shutdown components and to provide access and
| egress routes to fire areas for plant personnel and the fire brigade.

Interior finishes such as gypsum plaster, ceramic tile, and acoustical ceiling materials are noncombustible. The acoustical tiles are mineral fiber board with a flame spread rating of less than 25 in accordance with ASTM E-84, Surface Burning Characteristics of Building Materials. Protective coatings used throughout the primary plant are in accordance with the requirements of ANSI N101.2, Protective Coatings for Light Water Nuclear Reactor Containment Facilities, and ANSI N512, Protective Coatings for the Nuclear Industry. All other paints (such as enamel undercoat, alkyd gloss enamel, latex emulsion, and alkyd enamel) conform to the requirements of Factory Mutual, Occupational Safety and Health Act (OSHA) and Steel Structures Painting Council (SSPC) for the service intended. Vinyl asbestos floor tiles, located in the Control Room, various corridors, and in the office areas in the Turbine Building, have a flame propagation index of less than four. The flame | 52
propagation index is in accordance with UL 992, Test Method for |
Measuring the Flame Propagating Characteristics of Flooring and |
Floor Covering Materials. Carpeting installed in the Control |
Room is discussed in Section 9.5.1.6.2. |
| 53

Steel checker plate hatch covers and removeable concrete hatches | 66
are provided in floor openings required for equipment removal. |
In floors designated as fire barriers, the steel checker plate | 71
hatch covers are coated with an approved fire-resistant |
coating. Protection provided by steel hatch covers has been |
demonstrated through analysis, in lieu of providing a tested |
configuration, as described in 9.5.1.6.2. Concrete hatches are |
constructed such that the designated fire rating of the barrier |
is maintained. |
| 53

The reflective piping insulation is composed of stainless steel | 42
sheets and foil and the thermal piping insulation is composed of |
hydrous calcium silicate. Both are 100-percent inorganic and |
will not burn or support combustion. Anti sweat piping |
insulation is composed of fiberglass and has been tested by UL |
to the requirements of ASTM E-84 with a flame spread of 25, a |
fuel contribution of 25, and a smoke development of 50. |

2. Penetration Seals

50 | Penetrations in designated fire barriers are sealed with an approved fire stop material except as noted in Subsection 9.5.1.6.2. The penetration seals have fire resistance ratings
66 | that meet or exceed the rating designated for the barrier. The majority of the penetrations are sealed with approved silicone materials tested in accordance with the requirements of ASTM E 119 and, in the case of electrical seals, tested in accordance with IEEE 634.

3. Fire Door Assemblies

50 | Door openings in designated fire barriers are provided with approved labeled fire door assemblies except as noted in Subsection 9.5.1.6.2.

71 |

9.5.1.5.4 Ventilation System Characteristics

1. Fire Dampers

66 | All ductwork that penetrates a designated fire barrier of two hours or greater is equipped with an approved damper with a rating at least equivalent to that designated for the barrier.
50 | Most fire dampers are equipped with heat-responsive elements which automatically release the fire damper blade when the air temperature in the ductwork exceeds the predetermined element operating temperature. Where appropriate, fire dampers are equipped with electro-thermal links. Fire dampers are normally open, but they close during a fire condition. Where applicable, fire dampers located in ductwork are seismically qualified to ensure that the dampers will not close during a seismic event (see Section 9.4.5).

2. Smoke Removal | 52

Smoke will be removed by portable smoke ejectors. Directions | 41
for approaching the fire area, placing of the smoke ejectors and |
routing of the ejector trunk for each fire area will be provided |
to the fire brigade. This information will be based on the |
smoke removal study. |

The radiation level of the smoke in the subject fire area will | 27
be measured. If it is within the allowable limits as outlined |
in 10 CFR-20, smoke ejection can proceed. However, if the |
radiation is above the acceptable limits one of the below |
procedures must be followed: |

a) The radiation level will be allowed to decay until it is | 27
below the acceptable limit, the smoke then will be |
released, directly to the atmosphere. |

b) The radioactive smoke will be passed through the | 27
atmospheric clean-up units, before being released to the |
atmosphere. |

The primary method of smoke removal is via the use of | 50
electrically powered portable smoke ejectors. In addition, a | 65
sufficient number of gasoline engine powered portable smoke |
ejectors are provided as a back-up. |

Smoke control and heat venting in the Turbine Building will be | 50
accomplished by power venting of the mezzanine level using the |
exhaust fans. Venting of the basement level will be |
accomplished by natural draft through grating and equipment |
hatches and openings in the mezzanine floor. |

9.5.1.5.5 Electrical Cable and Cable Tray Design - Characteristics

50 | Generally, electrical cables are flame-retardent, noncombustible, and
| nonpropagating in nature and conform to the criterion of IEEE 383-
| 1974. They will not support combustion in the absence of a sustained ignition source. The cable construction will allow wetting down without structural damage or electrical faulting. All cable trays, conduits, and their supports are constructed of noncombustible materials.

71 | Outside the Containment buildings, where cable trays containing
| cabling related to both redundant trains of equipment required to
| bring the plant to a hot standby condition, and where both trains are
| located in the same fire area, and are not separated by a negligible
| combustible horizontal distance of greater than or equal to 20 feet,
| one train of cabling will be protected by at least a one hour rated
| fire barrier. Where this situation exists, automatic sprinklers are
| arranged to provide coverage adequate for the hazards in the area.
66 | Sprinklers are also provided for cabling where there is a congestion
| of cable trays see Section 9.5.1.6.1d. Fire stops are provided within the cable trays whenever the cables penetrate walls or floors designated as fire barriers. Fire stops are not provided at intermediate points in vertical or horizontal cable runs, except in long vertical runs. In such instances, fire stops are located at
65 | intervals equivalent to floor spacings. It is a general installation
| practice that vertical tray runs are provided with solid, sheet steel
| covers for a minimum distance of 4 feet above the floor where
| necessary for physical protection of the cable. Fire stops are not provided in cable trays inside the Containment Buildings. Conduit fire stops are provided when the conduit penetrates a designated fire barrier and is not run continuously through the fire area.

9.5.1.5.6 Transformers

All interior transformers are of the air-cooled dry type and do not contain any insulating oil. The main, unit auxiliary, and startup

transformers are oil-cooled and are located outdoors adjacent to the Turbine Buildings. The main transformers are separated from each other, as well as from the Turbine Buildings, by a blank three-hr rated fire wall. The unit auxiliary transformer and the Unit 1 startup transformer are separated from the Turbine Buildings by a three-hr rated fire wall. Penetrations in this wall within 50 ft from each side of the center line of the transformer are protected in order to maintain the fire-resistant integrity of the wall. The Unit 2 startup transformer is also separated from the Turbine Building by a three-hr rated fire wall. Additional walls are provided extending out from the Turbine Building wall to protect the ventilation openings located in the exterior Turbine Building wall.

9.5.1.5.7 Flammable Liquid and Gas Storage

1. Flammable Liquid Storage

All significant amounts of flammable liquids are stored in separate fire areas that are isolated from the adjacent plant areas by three-hr fire rated barriers. As a minimum, fire detectors are provided in each area, and dependent upon the hazard, a fixed fire extinguishment system is provided. In all instances, such areas do not present a potential hazard for equipment located in the adjacent areas.

2. Flammable Gas Storage

Bulk storage of all flammable explosive gases is located outside the primary, secondary and turbine plant buildings. The storage facility is an open structure located outdoors in the yard adjacent to the security fence. An explosion or fire in this area will not affect any of the primary plant buildings.

### 9.5.1.6 Conclusions

#### 9.5.1.6.1 Comparison with Appendix A of Branch Technical Position APCSB 9.5-1 of Standard Review Plan 9.5.1

As requested by the NRC in their September 30, 1976, letter, the following is a comparison of the CPSES fire protection program with the guidelines in Appendix A to the above branch technical position.

CPSES Fire Protection Program

(1) All buildings of the plant are divided into fire areas. The criteria used to develop this arrangement are discussed in Subsection 9.5.1.2.2, 9.5.1.2.3 and 9.5.1.5.1. | 50

APCSB 9.5-1 Appendix A

(2) Separate redundant safety related systems from each other so that both are not subject to damage from a single fire hazard.

(2) Alternatives:

(a) Redundant safety-related systems that are subject to damage from a single fire hazard should be protected by a combination of fire retardant coatings and fire detection and suppression systems, or

(b) a separate system to perform the safety function should be provided.

CPSES Fire Protection Program

(2) (a): Where redundant fire safe shutdown systems, required to bring the plant to a hot standby condition, are located within the same fire area and are subject to damage from a single fire hazard a Fire Hazards Analysis Evaluation demonstrates and documents compliance to that recommended in the guideline by protecting the function with one of the following: | 71

65 | For systems located outside the Containment Building the following is provided:

71 | 1) A one-hour fire barrier on one set of required fire safe shutdown cabling and, based on the fire hazards of the area, automatic fire suppression and fire detection are provided.

2) Alternate shutdown capability

71 | 3) Fire detection and suppression, adequate for the hazards of the area, accompanied by 20 feet of horizontal separation with negligible intervening combustibles or fire hazards, unless justified per Reference [19].

71 | 4) Separation of redundant required sets of fire safe shutdown systems and components by a fire barrier having a 3 hour rating, unless justified per Reference [19].

65 | For systems located inside the Containment Building the following is provided:

71 | 1) Fire detection in combination with radiant energy shields protecting one set of required fire safe shutdown systems and components unless justified per Reference [19].

71 | 2) Fire detection accompanied by 20 feet of horizontal separation with negligible intervening combustibles or fire hazards, unless justified per Reference [19].

(b) Where a redundant system required to bring the plant to a cold shutdown condition is subject to damage from a single fire hazard, the following will be provided:

1) Fire detection system

2) procedure to repair at least one train of the damaged system within 72 hours.

APCSB 9.5-1 Appendix A

D.1.b In order to accomplish 1.(a) above, safety related systems and fire hazards should be identified throughout the plant. Therefore, a detailed fire hazards analysis should be made. The fire hazards analysis should be reviewed and updated as necessary.

CPSES Fire Protection Program

The CPSES Fire Protection Program is based on detailed fire hazard evaluations which satisfy this guideline. | 50

APCSB 9.5-1 Appendix A

D.1.c For multiple reactor sites, cable spreading rooms should not be shared between reactors. Each cable spreading room should be separated from other areas of the plant by barriers (walls and floors) having a minimum fire resistance of three hours. Cabling for redundant safety divisions should be separated by walls having three hour fire barriers.

Alternative guidance for constructed plants is shown in Section F.3, "Cable Spreading Room".

CPSES Fire Protection Program

Two cable spreading rooms are included in the design of CPSES, one for each unit. These rooms are separated by three hour rated fire barriers except as noted in Reference [19]. See Section F.3 for the design description. | 66

APCSB 9.5-1 Appendix A

D.1.d Interior wall and structural components, thermal insulation materials and radiation shielding materials and sound-proofing should be non-combustible. Interior finishes should be non-combustible or listed by a nationally recognized testing laboratory, such as Factory Mutual or Underwriters' Laboratory, Inc. for flame spread, smoke and fuel contribution of 25 or less in its use configuration (ASTM E-84 Test "Surface Burning Characteristics of Building Materials").

CPSES Fire Protection Program

50 | The Fire Protection Program is in compliance with the guideline except
| as noted in section 9.5.1.6.2. Specific criteria of the structural and interior construction materials are described in Subsection 9.5.1.5.1, 9.5.1.5.2, and 9.5.1.5.3.

APCSB 9.5-1 Appendix A

D.1.e Metal deck roof construction should be non-combustible (see the building materials directory of the Underwriters' Laboratory, Inc.) or listed as Class I by Factory Mutual System Approval Guide.

CPSES Fire Protection Program

65 | Metal roof deck construction is not used at CPSES for power block or
| other safety-related buildings.

construction capable of withstanding and containing a fire that consumes all combustibles present. Examples of such combustible materials that may not be separable from the remainder of its system are:

(1) Emergency diesel generator fuel oil day tanks

(2) Turbine-generator oil and hydraulic control fluid systems

(3) Reactor coolant pump lube oil system.

CPSES Fire Protection Program

The Fire Protection Program is in compliance with the guideline. | 52
Separation and protection of required fire safe shutdown systems are | 71
discussed for each fire area in the Fire Protection Report. |

APCSB 9.5-1 Appendix A

D.2.b Bulk gas storage (either compressed or cryogenic), should not be permitted inside structures housing safety related equipment. Storage of flammable gas such as hydrogen, should be located outdoors or in separate detached buildings so that a fire or explosion will not adversely affect any safety related systems or equipment.

Care should be taken to locate high pressure gas storage containers with the long axis parallel to building walls. This will minimize the possibility of wall penetration in the event of a container failure. Use of compressed gases (especially flammable and fuel gases) inside buildings should be controlled. (Refer to NFPA 6, "Industrial Fire Loss Prevention.")

CPSES Fire Protection Program

50 | The Fire Protection Program is in compliance with the guideline except
| as noted in Section 9.5.1.6.2. Bulk gas storage is discussed in
Section 9.5.1.5.7.

APCSB 9.5-1 Appendix A

D.2.c The use of plastic materials should be minimized. In particular, halogenated plastics such as polyvinyl chloride (PVC) and neoprene should be used only when substitute non-combustible materials are not available. All plastic materials, including flame and fire retardant materials, will burn with a[illegible] tensity and BTU production in a range similar to th[illegible] of ordinary hydrocarbons. When burning, they produce heavy smoke that obscures visibility and can plug air filters, especially charcoal and HEPA. The halogenated plastics also release free chlorine and hydrogen chloride when burning which are toxic to humans and corrosive to equipment.

CPSES Fire Protection Program

The Fire Protection Program is in compliance with the guideline.
50 | Plastic material is used when required for radiation resistance
| reasons. Halongenated plastics such as polyvinyl chloride (PVC) are
| not used as an exposed cable insulation or jacketing material at CPSES
| except as discussed in Subsection D.3.f.

APCSB 9.5-1 Appendix A

D.2.d Storage of flammable liquids should, as a minimum, comply with the requirements of NFPA 30, "Flammable and Combustible Liquids Code."

Alternate criteria: Where installed penetration seals are deficient with respect to fire resistance, these seals may be protected by covering both sides with an approved fire retardant material. The adequacy of using such material should be demonstrated by suitable testing.

CPSES Fire Protection Program

For conduits which are greater than four (4) inches nominal size, internal seals are installed either at the barrier or on both sides of the barrier at the first opening in the direction of the barrier. These internal seals have a fire rating equal to or greater than that of the fire barrier rating. | 71

For conduits which are less than or equal to four (4) inches nominal size, and automatic suppression and detection are provided on both sides of the barrier, internal seals are installed in the barrier, or at the first opening on either side of the barrier with a fire rating equivalent to that of the barrier, unless individually evaluated and documented in Section 9.5.1.6.2. For conduits which are less than or equal to four (4) inches nominal size, and automatic suppression and detection are not provided on both sides of the barrier, internal seals are installed at the barrier with a fire rating equivalent to that of the barrier, or gas and smoke seals are installed at the first opening on both sides of the barrier, except as described in 9.5.1.6.2. | 71

APCSB 9.5-1 Appendix A

D.3.e Fire breaks should be provided as deemed necessary by the fire hazards analysis. Flame or flame retardant coatings may be used as a fire break for grouped electrical cables to limit spread of fire in cable ventings. (Possible cable derating owing to use of such coating materials must be considered during design.)

CPSES Fire Protection Program

The Fire Protection Program complies with the guideline. Fire breaks are provided as described in Subsection 9.5.1.5.5.

APCSB 9.5-1 Appendix A

D.3.f Electric cable constructions should as a minimum pass the current IEEE No. 383 flame test. (This does not imply that cables passing this test will not require additional fire protection).

CPSES Fire Protection Program

50 | The Fire Protection Program is in compliance with this guideline
| except as noted in section 9.5.1.6.2. Electrical cable construction is described in Section 9.5.1.5.5.

APCSB 9.5-1 Appendix A

D.3.g To the extent practical, cable construction that does not give off corrosive gases while burning should be used.

CPSES Fire Protection Program

The Fire Protection Program is in compliance with the guidelines to the extent practical with present day cable insulation and jacket material.

APCSB 9.5-1 Appendix A

D.3.h Cable trays, raceways, conduit, trenches, or culverts should be used only for cables. Miscellaneous storage should not be permitted, nor should piping for flammable or combustible liquids or gases be installed in these areas.

CPSES Fire Protection Program

The Fire Protection Program complies with the guideline.

APCSB 9.5-1 Appendix A

D.3.i The design cable tunnels, culverts and spreading rooms should provide for automatic or manual smoke venting as required to facilitate manual fire fighting capability.

CPSES Fire Protection Program

The Fire Protection Program provides for manual smoke venting to enable manual fire fighting. See Subsection 9.5.1.5.4 for criteria on smoke venting.

APCSB 9.5-1 Appendix A

D.3.j Cables in the control room should be kept to the minimum necessary for operation of the control room. All cables entering the control room should terminate there. Cables should not be installed in floor trenches or culverts in the control room.

CPSES Fire Protection Program

The cables in the Control Room are the minimum necessary for operation of the plant. There are no cables routed in floor trenches in the Control Room. There is, however, a small amount of cabling enclosed in steel conduit, routed above the suspended ceiling in the Control Room. Fire detection is provided for this concealed area.

APCSB 9.5-1 Appendix A

D.4 Ventilation

D.4.a The products of combustion that need to be removed from a specific fire area should be evaluated to determine how they will be controlled. Smoke and corrosive gases should generally be automatically discharged directly outside to a safe location. Smoke and gases containing radioactive materials should be monitored in the fire area to determine if release to the environment is within the permissible limits of the plant Technical Specifications.

CPSES Fire Protection Program

The Fire Protection Program is in compliance with the guideline. See Section 9.5.1.5.4 for further information.

APCSB 9.5-1 Appendix A

D.4.b Any ventilation system designed to exhaust smoke or corrosive gases should be evaluated to ensure that inadvertent operation or single failures will not violate the controlled areas of the plant design. This requirement includes containment functions for protection of the public and maintaining habitability for operations personnel.

CPSES Fire Protection Program

Ventilation of smoke or corrosive gases, resulting from a fire will be accomplished manually as required, and subsequent to monitoring for radioactivity and evaluating the products of combustion.

APCSB 9.5-1 Appendix A

D.4.c The power supply and controls for mechanical ventilation systems should be run outside the fire area served by the system.

APCSB 9.5-1 Appendix A

D.4.h Self-contained breathing apparatus, using full face positive pressure masks, approved by NIOSH (National Institute for Occupational Safety and Health - approval formerly given by the U.S. Bureau of Mines) should be provided for fire brigade, damage control and control room personnel. Control room personnel may be furnished breathing air by a manifold system piped from a storage reservoir if practical. Service of operating life should be a minimum of one-half hour for the self-contained units.

CPSES Fire Protection Program

Self-contained breathing apparatus are provided for fire brigade, damage control, and control room personnel. Service life for the self contained units exceed one-half hour. | 50

APCSB 9.5-1 Appendix A

D.4.h At least two extra air bottles should be located onsite for each self-contained breathing unit. In addition, an onsite 6-hour supply of reserve air should be provided and arranged to permit quick and complete replenishment of exhausted supply air bottles as they are returned. If compressors are used as a source of breathing air, only units approved for breathing air should be used. Special care must be taken to locate the compressor in areas free of dust and contaminants.

CPSES Fire Protection Program

The Fire Protection Program complies with this guideline. | 27

APCSB 9.5-1 Appendix A

D.4.i Where total flooding gas extinguishing systems are used, area intake and exhaust ventilation dampers should close upon initiation of gas flow to maintain necessary gas concentration. (See NFPA 12, "Carbon Dioxide Systems", and 12A, "Halon 1301 Systems.")

CPSES Fire Protection Program

The Fire Protection Program complies with the guideline. See Subsection 9.5.1.5.4 for description of fire dampers.

APCSB 9.5-1 Appendix A

D.5 Lighting and Communication

Lighting and two way voice communication are vital to safe shutdown and emergency response in the event of fire. Suitable fixed and portable emergency lighting and communication devices should be provided to satisfy the following requirements:

(a) Fixed emergency lighting should consist of sealed beam units with individual 8-hour minimum battery power supplies.

(b) Suitable sealed beam battery powered portable hand lights should be provided for emergency use.

CPSES Fire Protection Program

71 | Areas containing fire safe shutdown equipment required to achieve hot
| standby, and primary interior egress and access routes between these
| areas, are provided with

DC Emergency Lighting supplied by 8 hour sealed beam or fluorescent | 71
lamp battery power pack units (except in the Control Room). DC |
Emergency Lighting in the Control Room is supplied power from the non- | 66
class 1E dedicated 8-hour batteries. (See FSAR Section 9.5.3.2.1 and |
9.5.1.6.2). Supplemental lighting is provided from battery-powered | 71
hand held portable lights. |

APCSB 9.5-1 Appendix A

D.5 (c) Fixed emergency communication should use voice powered head sets at pre-selected stations.

CPSES Fire Protection Program

The Fire Protection Program provides intra plant portable radio with | 66
page-party/public address system backup for use in emergency |
conditions instead of voice powered head sets. For additional |
description of the communication systems, see Subsection 9.5.2.2.

APCSB 9.5-1 Appendix A

D.5 (d) Fixed repeater installed to permit use of portable radio communication units should be protected from exposure to fire damage.

CPSES Fire Protection Program

The Fire Protection Program is in compliance with this guideline by | 66
providing radio to radio "talkaround" and plant page party/public |
address system capability in the event of fire damage to the |
repeater. |

APCSB 9.5-1 Appendix A

E. Fire Detection and Suppression

E.1 Fire Detection

E.1.a Fire detection systems should as a minimum comply with NFPA 72D, "Standard for the Installation, Maintenance and Use of Proprietary Protective Signaling Systems."

CPSES Fire Protection Program

55 | The Fire Protection Program complies with this guideline set forth by
| the NRC, except for ground fault supervision of fire detection panels
| containing thermistor-line detection. Fire detection system design
53 | parameters are described in Subsection 9.5.1.4.2. Location and
| placement of detectors are in accordance with the guidelines of NFPA
66 | 72E except where special conditions did not permit. In such cases a
| Fire Protection Engineer located the detector based on engineering
| judgement as permitted by NFPA 72E.

APCSB 9.5-1 Appendix A

E.1.b Fire detection system should give audible and visual alarm and annunciation in the control room. Local audible alarms should also sound at the location of the fire.

CPSES Fire Protection Program

53 | Fire detection systems give audible and visual alarms and annunciation
| in the Control Room. Local audible alarms sound at the local
66 | detector control panel. Fire protection procedures provide for the
| use of the Public Address System (Gaitronics) for audible annunciation
| of the fire alarm location throughout the plant upon receipt of an

Threads compatible with those used by local fire departments should be provided on all hydrants, hose couplings and standpipe risers.

CPSES Fire Protection Program

The Fire Protection Program is in compliance with the guideline. | 52
Auxiliary gate valves (curb box valves) are provided adjacent to each hydrant in accordance with ANI criteria. A description of the outside hose station layout, auxiliary equipment contained in each cabinet and the type of threads on all fire fighting equipment is provided in Subsection 9.5.1.4.

APCSB 9.5-1 Appendix A

E.3 Water Sprinklers and Hose Standpipe Systems

E.3.a Each Automatic sprinkler system and manual hose station standpipe should have an independent connection to the plant underground water main. Headers fed from each end are permitted inside buildings to supply multiple sprinkler and standpipe systems. When provided, such headers are considered an extension of the yard main system. The header arrangement should be such that no single failure can impair both the primary and backup fire protection systems.

Each sprinkler and standpipe system should be equipped with OS&Y (outside screw and yoke) gate valve, or other approved shut off valve, and water flow alarm. Safety related equipment that does not itself require sprinkler water fire protection, but is subject to unacceptable damage if wetted by sprinkler water discharge should be protected by water shields or baffles.

CPSES Fire Protection Program

71 | The Fire Protection Program is in compliance with the guideline except
| as noted in Section 9.5.1.6.2. The connection of each automatic sprinkler system and hose station is described in Subsection 9.5.1.4.

50 | Also see guideline D.3.c.

APCSB 9.5-1 Appendix A

E.3.b All valves in the fire water systems should be electrically supervised. The electrical supervision signal should indicate in the control room and other appropriate command locations in the plant (See NFPA 26, "Supervision of Valves").

Alternate Criteria: When electrical supervision of fire protection valves is not practicable, an adequate management supervision program should be provided. Such a program should include locking valves open with strict key control; tamper proof seals; and periodic, visual check of all valves.

CPSES Fire Protection Program

The Fire Protection Program is in compliance with the criteria. All isolation or sectional control valves are electrically supervised or locked in the appropriate position. Appropriate procedures will be developed for key control and for periodic visual inspection of valves. | 53

APCSB 9.5-1 Appendix A

E.3.c Automatic sprinkler systems should as a minimum conform to requirements of appropriate standards such as NFPA 13, "Standard for the Installation of Sprinkler Systems", and NFPA 15, "Standard for Water Spray Fixed Systems."

CPSES Fire Protection Program

53 | Automatic sprinkler systems comply with requirements of NFPA 13 and
66 | NFPA 15. Water spray systems for the charcoal filters are designed
71 | to the requirements of Regulatory Guide 1.52. Design densities for
| cable tray suppression systems located in congested cable areas meet
| the applicable NFPA Standards (Reference 24). Specific differences
| with the applicable NFPA standards are identified and justified in
| Reference [19].

APCSB 9.5-1 Appendix A

E.3.d Interior manual hose installation should be able to reach any location with at least one effective hose stream. To accomplish this, standpipes with hose connections, equipped with a maximum of 75 feet of 1-1/2 inch woven jacket lined fire hose and suitable nozzles should be provided in all buildings, including containment, on all floors and should be spaced at not more than 100 foot intervals. Individual standpipes should be of at least 4-inch diameter for multiple hose connections and 2-1/2-inch diameter for single hose connections. These systems should follow the requirements of NFPA 14 for sizing, spacing and pipe support requirements (NELPIA).

Hose stations should be located outside entrances to normally unoccupied areas and inside normally occupied areas. Standpipes serving hose stations in areas housing safety related equipment should have shut off valves and pressure reducing devices (if applicable) outside the area.

CPSES Fire Protection Program

NFPA 14 was used as guidance for installation of Class 'I service interior manual hose stations. Each hose station is equipped with 100 feet of 1-1/2 inch woven jacket lined fire hose and a nozzle compatible with the type of fire postulated. The spacing of the hose | 71
stations ensures that at least one effective hose stream can reach any |
location in safety-related areas of the plant except where identified |
and justified in the Fire Protection Report, Reference [19]. NFPA 14 |
was used as guidance for sizing of Class II type standpipes and hose | 66
systems. For a further description of the interior hose stations see |
Subsection 9.5.1.4.

APCSB 9.5-1 Appendix A

E.3.e The proper type of hose nozzles to be supplied to each area should be based on the fire hazard analysis. The usual combination spray/straight-stream nozzle may cause unacceptable mechanical damage (for example, the delicate electronic equipment in the control room) and be unsuitable. Electrically safe nozzles should be provided at locations where electrical equipment or cabling is located.

CPSES Fire Protection Program

FOG type nozzles are provided in hose cabinets inside plant | 50
buildings. Outside hose houses are provided with combination |
nozzles. |

APCSB 9.5-1 Appendix A

E.3.f Certain fires such as those involving flammable liquids respond well to foam suppression. Consideration should be given to use of any of the available foams for such specialized protection application. These include the

more common chemical and mechanical low expansion foams, high expansion foam and the relatively new Aqueous Film Forming Foam (AFFF).

CPSES Fire Protection Program

50 | No fixed foam systems are used at the plant but manual foam-based fire
| fighting equipment and training is provided.

APCSB 9.5-1 Appendix A

E.4 Halon Suppression Systems

The use of Halon fire extinguishing agents should as a minimum comply with the requirements of NFPA 12A and 12B, "Halogenated Fire Extinguishing Agent Systems - Halon 1301 and Halon 1211." Only UL or FM approved agents should be used.

In addition to the guidelines of NFPA 12A and 12B, preventative maintenance and testing of the systems, including check weighing of the Halon cylinders should be done at least quarterly.

Particular consideration should also be given to:

(a) minimum required Halon concentration and soak time;

(b) toxicity of Halon;

(c) toxicity and corrosive characteristics of thermal decomposition products of Halon.

CPSES Fire Protection Program

The CPSES Fire Protection Program uses NFPA 12A and 12B, "Halogenated Fire Extinguishing Agent Systems - Halon 1301 and 1211," as a guideline for the halon suppression system design and installation. Design parameters and a system description are stated in Subsection 9.5.1.4.2. Maintenance procedures are in accordance with CPSES Technical Specifications. | 50 | 52

APCSB 9.5-1 Appendix A

E.5 Carbon Dioxide Suppression Systems

The use of carbon dioxide extinguishing systems should as a minimum comply with the requirements of NFPA 12, "Carbon Dioxide Extinguishing Systems."

Particular consideration should also be given to:

(a) minimum required $CO_2$ concentration and soak time;

(b) toxicity of $CO_2$;

(c) possibility of secondary thermal shock (cooling) damage;

(d) offsetting requirements for venting during $CO_2$ injection to prevent overpressurization versus sealing to prevent loss of agent;

(e) design requirements from overpressurization; and

(f) possibility and probability of $CO_2$ systems being out of service because of personnel safety consideration. $CO_2$ systems are disarmed whenever

people are present in an area so protected. Areas entered frequently (even though duration time for any visit is short) have often been found with $CO_2$ systems shut off.

CPSES Fire Protection Program

The Fire Protection Program does not use fixed carbon dioxide suppression systems.

APCSB 9.5-1 Appendix A

E.6 Portable Extinguishers

Fire extinguishers should be provided in accordance with guidelines of NFPA 10 and 10A, "Portable Fire Extinguishers Installation, Maintenance and Use." Dry chemical extinguishers should be installed with due consideration given to cleanup problems after use and possible adverse effects on equipment installed in the area.

CPSES Fire Protection Program

71 | The Fire Protection Program is in compliance with the guideline. See Subsection 9.5.1.4.2 for description of portable fire extinguishers.

APCSB 9.5-1 Appendix A

F. Guidelines for Specifics Plant Areas

F.1 Primary and Secondary Containment

F.1.a Normal Operation

Fire protection requirements for the primary and secondary containment areas should be provided on the basis of specific identified hazards. For example:

- Lubricating oil or hydraulic fluid system for the primary coolant pumps
- Cable tray arrangements and cable penetrations
- Charcoal filters

CPSES Fire Protection Program

The Fire Protection Program is in compliance with this guideline | 50
except as noted in Section 9.5.1.6.2. The Fire Protection Report | 71
identifies specific hazards inside containment. Fire detection and |
suppression are provided accordingly.

APCSB 9.5-1 Appendix A

F.1.a Fire suppression systems should be provided based on the fire hazards analysis.

Fixed fire suppression capability should be provided for hazards that could jeopardize safe plant shutdown. Automatic sprinklers are preferred. An acceptable alternate is automatic gas (Halon or $CO_2$) for hazards identified as requiring fixed suppression protection.

An enclosure may be required to confine the agent if a gas system is used. Such enclosures should not adversely affect safe shutdown, or other operating equipment in containment.

CPSES Fire Protection Program

66 | Automatic water spray systems are provided for the carbon absorber
| beds of the pre-access filter units located inside the Containment.
See Section 9.5.1.4.2 for description of these systems. The reactor
50 | coolant pumps are equipped with an oil collection system. This system
| is designed to collect and drain, to a safe place, any oil which may
| be discharged from the reactor coolant pump lubrication system.

APCSB 9.5-1 Appendix A

F.1.a Operation of the fire protection systems should not compromise integrity of the containment or the other safety related systems. Fire protection activities in the containment areas should function in conjunction with total containment requirements such as control of contaminated liquid and gaseous release and ventilation.

CPSES Fire Protection Program

50 | Operation of the fire protection system does not compromise the
| integrity of the Containment.

APCSB 9.5-1 Appendix A

F.1.a Fire detection systems should alarm and annunciate in the control room. The type of detection used and the location of the detectors should be most suitable to the particular type of fire that could be expected from the identified hazard. A primary containment general area fire detection

capability should be provided as backup for the above described hazard detection. To accomplish this, suitable smoke detection (e.g., visual obscuration, light scattering and particle counting) should be installed in the air recirculation system ahead of any filters.

Automatic fire suppression capability need not be provided in the primary containment atmospheres that are inserted during normal operation. However, special fire protection requirements during refueling and maintenance operations should be satisfied as provided below.

CPSES Fire Protection Program

Fire detection is provided throughout the Containment in accordance | 71
with the results of Fire Hazard Analysis Evaluations, which are |
summarized in the Fire Protection Report. The type, quantity, and |
general location of each detector are shown on the FHA drawings. | 50
Alarms are provided in the Control Room to annunciate a fire condition via the plant public address (PA) system.

APCSB 9.5-1 Appendix A

F.1.b Refueling and Maintenance

Refueling and maintenance operations in containment may introduce additional hazards such as contamination control materials, decontamination supplies, wood planking, temporary wiring, welding and flame cutting (with portable compressed fuel gas supply). Possible fires would not necessarily be in the vicinity of fixed detection and suppression systems.

Management procedures and controls necessary to assure adequate fire protection are discussed in Section 3a.

In addition, manual fire fighting capability should be permanently installed in containment. Standpipes with hose stations, and portable fire extinguishers, should be installed at strategic locations throughout containment for any required manual fire fighting operations.

CPSES Fire Protection Program

The Fire Protection Program is in compliance with the guideline. Standpipes and hose stations are located on each elevation in the Containment Building such that an effective hose stream can reach any location. Portable extinguishers are provided for the Containment
66 | Building. To reduce radiation related deterioration, portable
| extinguishers and hoses are removed from the containment during normal
| operation and installed or stored adjacent to the containment
| entrance. Whenever the containment is to be occupied for longer than 48 hours, the portable extinguishers and hoses are returned to their
| designated locations in containment.

APCSB 9.5-1 Appendix A

F.1.b. Adequate self-contained breathing apparatus should be provided near the containment entrances for fire fighting and damage control personnel. These units should be independent of any breathing apparatus or air supply systems provided for general plant activities.

CPSES Fire Protection Program

52 | Adequate, self-contained breathing apparatus are provided at the fire
| brigade staging area located in the turbine building. By procedure
| the fire brigade gathers all required equipment from this location for
| any fire in the plant including containment fires. This location is
| sufficiently near the containment to provide for prompt action.
| Additional air cylinders are located at the containment entrance.

APCSB 9.5-1 Appendix A

F.2 Control Room

The Control Room is essential to safe reactor operation. It must be protected against disabling fire damage and should be separated from other areas of the plant by floors, walls and roofs having minimum fire resistance ratings of three hours.

(b) Exposure fire involving combustibles in the general room area.

CPSES Fire Protection Program

The Fire Protection Program is in general compliance with the guideline, except as noted in FSAR Section 9.5.1.6.2. The Control Room is separated from other areas of the plant by three hour rated fire barriers, except as noted in Reference [19]. | 50 | 71

APCSB 9.5-1 Appendix A

F.2 Control Room cabinets and consoles are subject to damage from two distinct fire hazards:

(a) Fire originating within a cabinet or console; and

(b) Exposure fire involving combustibles in the general room area.

Manual fire fighting capability should be provided for both hazards.

CPSES Fire Protection Program

50 | Manual fire fighting capability employing portable water and Halon
| extinguishers and hose stations are provided inside the Control Room.

APCSB 9.5-1 Appendix A

F.2 Hose stations and portable water and Halon extinguishers should be located in the control room to eliminate the need for operators to leave the control room. An additional hose piping shut off valve and pressure reducing device should be installed outside the control room.

Hose stations adjacent to the control room with portable extinguishers in the control room are acceptable.

Nozzles that are compatible with the hazards and equipment in the control room should be provided for the manual hose station. The nozzles chosen should satisfy actual fire fighting needs, satisfy electrical safety and minimize physical damage to electrical equipment from hose stream impingement.

Fire detection in the control room cabinets, and consoles should be provided by smoke and heat detectors in each fire area. Alarm and annunciation should be provided in the control room. Fire alarms in other parts of the plant should also be alarmed and annunciated in the control room.

CPSES Fire Protection Program

66 | Manual fire fighting capability employing portable water and Halon
| extinguishers, as well as hose stations, is provided in the Control
| Room.

provided to alarm and annunciate in the control room and alarm locally. Manual hose stations and portable water and halon fire extinguishers should be provided.

CPSES Fire Protection Program

The plant computers are not safety-related. | 66

APCSB 9.5-1 Appendix A

F.5 Switchgear Rooms

Switchgear rooms should be separated from the remainder of the plant by minimum three hour rated fire barriers to the extent practicable. Automatic fire detection should alarm and annunciate in the control room and alarm locally. Fire hose stations and portable extinguishers should be readily available.

Acceptable protection for cables that pass through the switchgear room is automatic water or gas agent suppression. Such automatic suppression must consider preventing unacceptable damage to electrical equipment and possible necessary containment of agent following discharge.

CPSES Fire Protection Program

There are two safety related switchgear rooms in each unit: Train A | 52
and Train B. Each switchgear room is in a separate fire area. |
Manual pre-action water sprinklers are provided for direct water spray | 50
on cable trays wherever there is a concentration of cable trays. |
Manual hose stations and portable extinguishers are also provided in |
these areas. |

52 | A fire detection system which alarms at the local detection panel and
| in the control room is provided for both safety-related switchgear
| areas. Electrical equipment which could be damaged by direct water
spray was considered. See Guideline D.3.c.

APCSB 9.5-1 Appendix A

F.6 Remote Safety Related Panels

The general area housing remote safety related panels should be provided with automatic fire detectors that alarm locally and alarm and annunciate in the control room. Combustible materials should be controlled and limited to those required for operation. Portable extinguishers and manual hose stations should be provided.

CPSES Fire Protection Program

71 | The general area, housing safety related equipment, is provided with
| automatic detectors that alarm at the local control panel and
| annunciate in the Control Room as determined in the Fire Protection
| Report. Administrative procedures have been developed to control
52 | combustible materials. Portable extinguishers and manual hose
| stations are provided.

APCSB 9.5-1 Appendix A

F.7 Station Battery Rooms

Battery rooms should be protected against fire explosions. Battery rooms should be separated from each other and other areas of the plant by barriers having a minimum fire rating of three hours inclusive of all penetrations and openings. (See NFPA 69, "Standard on Explosion Prevention

Systems.") Ventilation systems in the battery rooms should be capable of maintaining the hydrogen concentration well below 2 percent volume hydrogen concentration.

Standpipe and hose and portable extinguishers should be provided.

CPSES Fire Protection Program

The Fire Protection Program is in compliance with the guideline. Safety related battery rooms are separated from each other and other | 71
areas of the plant by three hour fire barriers. The ventilation |
system is capable of maintaining the hydrogen concentration well below two percent by volume.

Hose stations and portable extinguishers are located in the corridors serving the battery rooms.

APCSB 9.5-1 Appendix A

F.8 Turbine Lubrication and Control Oil Storage and Use Areas

A blank fire wall having a minimum resistance rating of three hours should separate all areas containing safety related systems and equipment from the turbine oil system.

CPSES Fire Protection Program

Walls separating safety related areas from the Turbine Building have a | 52
minimum fire rating of three hours. All penetrations in these walls | 71
also have three hour ratings, except for bus duct penetrations which |
are discussed in D.1.j of Section 9.5.1.6.2. |

APCSB 9.5-1 Appendix A

F.9 Diesel Generator Areas

Diesel generators should be separated from each other and other areas of the plant by fire barriers having a minimum fire resistance rating of three hours.

Automatic fire suppression such as AFFF foam, or sprinklers should be installed to combat any diesel generator or lubricating oil fires. Automatic fire detection should be provided to alarm and annunciate in the control room and alarm locally. Drainage for fire fighting water and means for local manual venting of smoke should be provided.

Day tanks with total capacity up to 1100 gallons are permitted in the diesel generator area under the following conditions:

a. The day tank is located in a separate enclosure, with a minimum fire resistance rating of three hours, including doors or penetrations. These enclosures should be capable of containing the entire contents of the day tanks. The enclosure should be ventilated to avoid accumulation of oil fumes.

b. The enclosure should be protected by automatic fire suppression systems such as AFFF or sprinklers.

CPSES Fire Protection Program

50 | The Fire Protection Program is in compliance with the guideline except
53 | as noted in Section 9.5.1.6.2. The day tanks are located in separate
66 | fire areas located above their respective diesel generator. The day
| tank area is protected by an automatic water spray system actuated by
| Class "B" detector loop circuitry.

APCSB 9.5-1 Appendix A

F.10 Diesel Fuel Oil Storage Areas

Diesel fuel oil tanks with a capacity greater than 1100 gallons should not be located inside the buildings containing safety related equipment. They should be located at least 50 feet from any building containing safety related equipment, or if located within 50 feet, they should be housed in a separate building with construction having a minimum fire resistance rating of three hours. Buried tanks are considered as meeting the three hour fire resistance requirements. See NFPA 30, "Flammable and Combustible Liquids Code," for additional guidance.

When located in a separate building, the tank should be protected by an automatic fire suppression system such as AFFF or sprinklers.

Tanks, unless buried, should not be located directly above or below safety related systems or equipment regardless of the fire rating of separating floors or ceilings.

CPSES Fire Protection Program

The diesel fuel oil storage tanks are located outside and adjacent to the Safeguards Buildings. These tanks are buried. The alternate guideline criteria are not applicable to the CPSES design criteria.

APCSB 9.5-1 Appendix A

F.11 Safety Related Pumps

Pump houses and rooms housing safety related pumps or other safety related equipment should be separated from

other areas of the plant by fire barriers having at least three hour ratings. These rooms should be protected by automatic sprinkler protection unless a fire hazards analysis can demonstrate that a fire will not endanger other safety related equipment required for safe plant shutdown. Early warning fire detection should be installed with alarm and annunciation locally and in the control room. Local hose stations and portable extinguishers should also be provided.

Equipment pedestals or curbs and drains should be provided to remove and direct water away from safety related equipment.

Provisions should be made for manual control of the ventilation system to facilitate smoke removal if required for manual fire fighting operation.

CPSES Fire Protection Program

71 | The Fire protection Program provides protection in accordance with the
| guideline for fire safe shutdown components, for required separation
| criteria see D.1.a of Section 9.5.1.6.1.

66 | Fire areas containing required fire safe shutdown pumps are separated
| from other fire areas of the plant by three hour fire rated barriers.

71 | The Fire Protection Report demonstrates that an adequate level of fire
| protection is provided to separate redundant equipment used for safe
| plant shutdown in the event of a fire. Automatic detection is
| provided in these areas except where a Fire Hazards Analysis
| Evaluation has concluded that an equivalent level of protection is
| provided.

APCSB 9.5-1 Appendix A

G. Special Protection Guidelines

G.1 Welding and Cutting, Acetylene-Oxygen Fuel Gas Systems

This equipment is used in various areas throughout the plant. Storage locations should be chosen to permit fire protection by automatic sprinkler systems. Local hose stations and portable equipment should be provided as backup. The requirements of NFPA 51 and 51B are applicable to these hazards. A permit system should be required to utilize this equipment.

CPSES Fire Protection Program

Storage of this equipment is located outside of areas containing safety-related equipment. The use of such equipment is addressed in Section B of this comparison. Additional portable extinguishers are provided in the areas whenever such equipment is brought into and used in the plant.

APCSB 9.5-1 Appendix A

G.2 Storage Areas for Dry Ion Exchange Resins

Dry ion exchange resins should not be stored near essential safety related systems. Dry unused resins should be protected by automatic wet pipe sprinkler installations. Detection by smoke and heat detectors should alarm and annunciate in the control room and alarm locally. Local hose stations and portable extinguishers should provide backup for these areas. Storage areas of dry resin should have curbs and drains. (Refer to NFPA 92M, "Water-proofing and Draining of Floors.")

CPSES Fire Protection Program

50 | The Fire Protection Program complies with this guideline except as
| noted in section 9.5.1.6.2. Dry ion exchange resins are not stored
50 | in or adjacent to areas containing safety-related systems. Storage
| areas for dry ion exchange resins are protected by fire detectors,
| portable extinguishers, and manual hose stations.

APCSB 9.5-1 Appendix A

G.3 Hazardous Chemicals

Hazardous chemicals should be stored and protected in accordance with the recommendations of NFPA 49, "Hazardous Chemicals Data." Chemical storage areas should be well ventilated and protected against flooding conditions since some chemicals may react with water to produce ignition.

CPSES Fire Protection Program

65 | The Fire Protection Program is in compliance with the guideline except
| as noted below. Hazardous chemicals are stored in tanks approved for
50 | such service and in areas not containing safety-related components and
| systems, with the exception of the chemical additive tank in the
71 | Safeguards Building. The chemical additive tanks are located in
| partially enclosed alcoves in fire area SB[illegible]. These tanks are not
50 | open the atmosphere and are inerted with nitrogen. The locations of
| the tanks are not considered hazardous.

APCSB 9.5-1 Appendix A

G.4 Materials Containing Radioactivity

Materials that collect and contain radioactivity such as spent ion exchange resins, charcoal filters, and HEPA

filters should be stored in closed metal tanks or containers that are located in areas free from ignition sources or combustibles. These materials should be protected from exposure to fires in adjacent areas as well. Consideration should be given to requirements for removal of isotopic decay heat from entrained radioactive materials.

CPSES Fire Protection Program

The fire protection program is in compliance with the guideline.

9.5.1.6.2 Justification for Items of Noncompliance to Appendix A to Branch Technical Position APCSB 9.5-1

The following statements are justification for items of noncompliance to Appendix A to Branch Technical Position APCSB 9.5-1 of Standard Review Plan 9.5.1, Revision 1, as stated in the applicable items of Subsection 9.5.1.6.1. Any additional deviations have been included in | 71
Appendix C of Reference [19].

Guideline D.1.d

Guideline D.1.d limits the flame spread, smoke and fuel contribution | 50
to a maximum of 25 for interior wall and structural components,
thermal insulation materials and sound proofing.

Owens Corning fiberglass pipe insulation is used in various areas of | 50
the plant. This insulation is rated as Flame Spread-25, Fuel
Contribution-25, and Smoke Development-50.

Carpet, installed in the Control Room as soundproofing, was tested to | 53
ASTM E 84 yielding flame spread 30, fuel contribution 30 and smoke
developed 100.

Thermal insulation for ducts have ASTM E 84 rating of 25, 50, 50. | 52

53 | Thermal insulation for chiller unit heat exchangers and piping have
| ASTM E 84 rating less than flame spread 25, fuel contribution 30 and
| smoke developed 150.

65 |

50 | Guideline D.1.j

50 | Guideline D.1.j address 3-hour rated floors, walls and ceilings
71 | separating fire areas. The following justifications are provided
| where installations are shown to be adequate through analysis in lieu
| of providing a tested configuration.

50 | 1. Floors, walls and ceilings

50 | Stair tower walls are constructed of two hour rated of design.
| Justification is provided in subsection 9.5.1.6.2, guideline
| D.4.f.

Removable concrete block walls are not fire tested design.
50 | Justification is provided in reference [19]. This
| justification applies to all applications.

71 | Protection provided by metal hatch covers installed in three (3)
| hour rated floors has been demonstrated through analysis in lieu
| of providing a tested configuration. The combustible loading
| below the hatches is less than 15 minutes with automatic
| suppression and detection above and below the hatches. The
| hatches are coated with a layer of fire resistive material to
| provide a three (3) hour structural steel resistance. Based on
| the combustible loading, automatic suppression and detection,
| and fire resistive coating, a one hour fire could occur without
| breaching the fire barrier through the metal hatches.

50 | 2. Penetration Seals

Containment electrical seals are not a fire tested
50 | configuration. Justification is provided in reference [19].

65 | Containment mechanical seals are not a fire tested

configuration. Justification is provided in reference [19]. | 65

Protection provided by the penetration seals installed in bus duct penetrations installed in three (3) hour rated barriers has been demonstrated through analysis in lieu of providing a tested configuration. The penetration seal design is similar to one currently used in the plant which has a three (3) hour fire rating. The seal maintains the thickness and continuity of the barrier. The barrier's purpose is unchanged by the bus duct penetration. The fire protection features in the vicinity of bus duct penetrations are adequate for the hazards of the area. Based on the fire protection features and a review by a Fire Protection Engineer, bus duct penetrations are expected to survive a fire severity of three (3) hours without breaching the barrier. | 71

3. Non-Rated Fire Doors

Missile resistant doors are not fire tested assemblies. Justification is provided per reference [19]. | 65

Watertight doors are not fire tested assemblies. Justification is provided per reference [19] for redundant safe shutdown related separation barriers. The justifications are also applicable for doors in fire barriers that do not separate redundant safe shutdown systems. | 50

Bullet resistant and penetration resistant doors are not fire rated assemblies. The door assemblies are of a construction similar to units tested and listed by Underwriters' Laboratory subsequent to procurement and installation of the CPSES assemblies except for the Cable Spreading Room (BR/PR) door. This door is justified per reference [19]. | 65

Containment Air-Locks for personnel and emergency escape use are not fire tested assemblies. Justification is provided per reference [19]. | 50 | 65

71 | Protection provided by the tornado vent/fire dampers installed in fire rated barriers with frames mounted outside the concrete walls on steel angles has been demonstrated through analysis in lieu of providing a tested configurations. The support frames of the assemblies are protected with an approved coating to yield a fire resistance equal to that of the barrier.

71 | Fire damper support frames are more substantial than those used in standard sleeve installations. UL 555 gives the acceptance criteria which specifies that a damper assembly must remain in the opening during the fire, and during hose stream application and that no through openings be created. Based on the substantial support frames, the high probability of the dampers remaining in the opening, and the UL test acceptance criteria, the dampers are expected to provide a tortuous path for fire propagation and meet the conditions of acceptance in a fire test.

71 | Fire door frames are mounted in a frame of steel angles. These angles are then coated with Thermo-lag fire proofing material in accordance with U.L. Design No. X-611. These fire door assemblies are not be expected to compromise the integrity of their host 3 hour fire barriers when exposed to a postulated fire.

Guideline D.2.b

50 | Guideline D.2.b addresses bulk gas storage and tank orientation with relations to building walls.

50 | The CPSES bulk gas storage tanks are located 350 feet from the nearest safety-related building (Electrical and Control Building). The spacial separation between the tanks and nearest primary plant building is well in excess of the NFPA requirements and therefore the tank orientation is considered acceptable.

Guideline D.3.d: | 66

Protection provided by the penetration seals installed in flexible | 71
conduit penetrations installed in fire rated barriers which separate |
buildings has been demonstrated through analysis in lieu of providing |
a tested configuration. Flexible conduits are sealed on both sides |
of a barrier, which is similar to a tested configuration. The |
combustible loading is low in the areas of flexible conduit |
penetrations, and fire protection features adequate for the hazards in |
the area have been provided. Based on the similarity of the |
configurations to tested configurations, detection, automatic |
suppression, and manual fire fighting capability, any fire zone which |
has a flexible conduit could have a fire severity of 3 hours without |
breaching the barrier through any of the flexible conduit |
penetrations. |

Guideline D.3.f

Guideline D.3.f requires electric cable construction to meet as a | 50
minimum the current IEEE-383 Flame Test. |

A small portion of low capacitance non IEEE-383 cable is installed in | 65
the Control Room cable spreading room and computer room for Unit 1. |
This cable is associated with the ERF computer system. Justification | 65
is provided in item 5a of reference [19]. |

Another small amount of cable is used in association with the | 52
radiation monitoring and security systems. These cables are all |
routed in conduit (except for short flexible connectors to the |
detectors) and are designed for low power service. They do not |
present a fire hazard in the areas where they are installed. | 50

Guideline D.4.f | 50

Guideline D.4.f addresses the fire rating of elevator towers and | 65
stairwells outside containment. Barriers enclosing the elevator |

65 | shafts are rated at two hours with 1 1/2 hour UL labeled fire door
| assemblies at openings to the elevator shaft. The elevators are not
| used during fire emergencies. Stairwells used for egress routes have
| a two-hour fire resistance rated walls with 1-1/2 hour UL labeled fire
| door assemblies at all openings into the stairwell. Based on the
intended use of the stairwells, it is determined that the two-hour
50 | rating is adequate. The presence of a stairwell or elevator tower in
| a fire area will not degrade the 3-hour fire rating of that area's
| fire barrier. This is based on the tower creating two 2-hour rated
| fire barriers in series between fire areas joined by the common
| tower.

31 | Guideline D.5.a

31 | Guideline D.5.a addresses fixed emergency lighting requirements in the
| event of a fire.

66 | The control room is provided with AC Essential Lighting and DC
| Emergency Lighting. The AC Essential Lighting is powered from the
| onsite Standby Diesel Generators. The DC Emergency Lighting is
| powered from the dedicated non-Class 1E batteries which are sized to
| supply DC power requirements for a minimum of 8-hours. Fires in
| areas outside of the control room and cable spreading room will not
| preclude the availability of AC Essential or DC Emergency Lighting for
| the control room.

Guideline E.2.a

50 | Guideline E.2.a addresses the independence of the fire main system
| piping from service or sanitary water system piping. One inter-tie
| exists in the fire main system. Water is supplied from the fire main
| system for use in circulating water pump bearing seals during
| coastdown when offsite power causes the pumps to trip. This does not
| degrade the performance of the fire main system for the following
| reasons:

1. Isolation valves are normally closed fire main system valves and
50 | are controlled by U. L. listed devices.

50 | 2. The control valves are closed automatically if the circulating water pump system demand occurs concurrently with a fire main system demand, resulting in low fire main system pressure.

50 | 3. The total demand when the system operates is small, and operation occurs infrequently only when the circulating water pumps are operating and all offsite power is unavailable.

66 | 4. Two fire pumps can supply the most limiting single suppression system actuation, a 500 gpm hose stream and the 75 gpm required by the inter-tie with a significant reserve margin.

66 |

Guideline E.2.e

50 | Guideline E.2.e requires that the water supply be sized assuming all sprinkler heads in the largest designed fire area operating, plus a 1000 GPM hose station allowance. This guideline is overconservative.
71 | The CPSES water supply is sized following the requirements of NFPA Code 13 with 1000 GPM hose stations allowance.

50 | Guideline E.3.a

50 | Guideline E.3.a requires water flow alarms for standpipe systems. This guideline is not justified because standpipe systems are manual systems requiring plant personnel to be aware of the fire condition prior to the operation of hose stations.

53 |

50 | Guideline F.1.a

71 | Guideline F.1.a addresses fixed fire protection for hazards that could jeopardize safe plant shutdown due to a fire inside the Containment Building. An analysis was performed to demonstrate that sufficient equipment is available in at least one shutdown path to safely shutdown CPSES in the event of an exposure fire in the Containment Building. Radiant Energy Shields were added to resolve interactions
65 | as a result of this analysis, and justifications for other interactions present were provided in References [19].

50 | Guideline F.2

50 | Guideline F.2 requires the installation of smoke detectors in the
| control room cabinets. CPSES has provided detectors inside control
| room consoles and equivalent detection for all other control room
| cabinets.

50 | a. The area immediately adjacent to the cabinets is monitored by
| ionization type smoke detectors.

50 | b. The Alternate Shutdown System provides safe shutdown of the
| plant independently of the control room.

50 | c. The area is continuously manned, thus ensuring prompt fire
| detection.

50 | d. The cabinets were constructed with non-flammable materials
| containing only low power circuits.

Guideline F.3.b.2

50 | Guideline F.3.b.2 addresses installation of fire retardant coatings on
| cables in the cable spreading rooms of redundant divisions that are
| not separated by fire barriers rated at 3 hours fire resistance.

50 | In lieu of installation of 3 hour fire barriers between cable
| divisions or coating all cables in the area, alternate safe shutdown
| capability independent of the cable spreading rooms is provided.

Guideline F.9

50 | Guideline F.9 addresses the separation criteria, fire protection
| criteria, and capability of the diesel generator fuel oil day tanks.
| The day tanks for each of the four diesel generators are separated and
| protected in accordance with the criteria of the subject guideline.

3. Emergency illumination levels provided by AC essential lighting for personnel safety, evacuation, and operation of safe shutdown work stations will meet or exceed the requirements as described under DC Emergency Lighting System in this section. | 66

| Q040.14

Outside of the Containment and Fuel Building, AC Essential Lighting is provided in primary plant areas required for safe shutdown and in major interior access/egress routes between these areas. Inside the Containment, AC lighting is provided for emergency egress. This AC lighting is supplied power from the standby diesel generators during a loss of off-site power but is shed during a LOCA. AC Essential Lighting is not provided in the Fuel Building, Service Water Intake Structure or Turbine Building. | 41

| Q040.14

The non-Class 1E DC Emergency Lighting System consists of lights connected to the dedicated batteries or individual battery packs. DC Emergency Lighting is provided in all areas needed for the operation of fire safe shutdown equipment necessary to achieve hot standby and in the primary interior access/egress routes between these areas. This lighting is provided by 8-hour rated battery packs except in the control room where the lighting is provided by dedicated 8-hour batteries. DC Emergency Lighting is also provided for safe egress in other areas of the plant which include the Containment, Fuel Building, Service Water Intake Structure, Turbine Building, and non-safety related areas of the Auxiliary Building. Power is supplied from the station batteries or individual battery packs. The battery pack rating is 8 hours except for the Turbine Building which has at least 4 hour rated battery packs. Battery pack lights are fluorescent or sealed beam type. | 66 | 71 | 66 | 41 | 71 | 66

| Q040.14

The DC Emergency Lights in the Control Room are normally deenergized. The contactor in the DC Emergency Lighting panels is normally held open by a feed from the AC Lighting System. DC Emergency Lights are activated by the loss of power to the AC Lighting Systems. | 66 | 41

Q040.14 |
41 | Individual battery packs are normally under a float charge from the AC lighting power supplies for their respective areas. . If an AC
41 | lighting power supply is lost, the respective DC lights are activated from their individual battery packs by their respective relays.

Q040.14 |
41 | The lighting (AC and DC) in the Control Room, the primary plant (non-containment) essential control areas and the primary interior access routes between them is arranged in a staggered pattern and alternately fed from the redundant trains and/or from self contained battery packs energized from either Train A, Train B or Normal AC sources. As an alternate, where the engineered safety features (ESF) equipment is energized from a particular train, AC essential and DC emergency lighting from the same train is provided in that area and in the primary access route to it. These practices ensure adequate lighting in these areas under any possible electrical single-failure condition.

66 | The DC Emergency Lighting System provides the following illuminance levels:

66 | 1. 0.5 footcandles (fc) average maintained, horizontally, along the center line of fire protection access/egress routes at floor level, with a maximum/minimum uniformity ratio less than 40:1;

66 | 2. 0.5 fc minimum maintained at the center point of a slight hazard within the fire protection access/egress route, with 3 fc average maintained along the hazard. Slight hazards are defined, for safety lighting purposes only, as abrupt changes in direction, intersections of two or more corridors or access/egress routes, changes of floor level, at each door, along stairs, and at weather-stripping door sills;

12. NRC Regulatory Guide 1.29, Seismic Design Classification Revision 2, 1976, U. S. Nuclear Regulatory Commission.

13. Branch Technical Position APCSB 3-1, Protection Against Postulated Piping Failures in Fluid Systems Outside Containment, attached to Standard Review Plan 3.6.1.

14. Branch Technical Position MEB 3-1, Postulated Break and Leakage Locations in Fluid System Piping Outside Containment, attached to Standard Review Plan 3.6.2.

15. ANSI N18.2-1973, Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants, 1973.

16. IEEE 387-1977, Criteria for Diesel Generator Units Applied as Standby Power Supplies for Nuclear Power Generating Stations.

17. Illuminating Engineering Society (IES) Lighting Handbook, Application Volume, 1981. | 66

18. Branch Technical Position EICSB-17, Diesel Generator Protective Trip Circuit Bypasses, attached to Standard Review Plan Appendix 7-A.

19. Comanche Peak Steam Electric Station Unit 1 "Fire Protection Report" | 71

20. NFPA 10-1981, "Portable Fire Extinguishers" | 65

21. NFPA 12A-1980, "Halon 1301 Fire Extinguishing Systems" | 66

22. NFPA 13-1978 and 1985, "Automatic Sprinkler Systems" | 65

23. NFPA 14-1973, "Standpipe and Hose Systems" | 65

66 | 24. NFPA 15-1979, "Water Spray Fixed Systems"

65 | 25. NFPA 20-1974, "Centrifugal Fire Pumps"

65 | 26. NFPA 24-1973, "Outside Protection"

65 | 27. NFPA 49-1975, "Hazardous Chemical Data"

65 | 28. NFPA 72D-1975, "Proprietary Protection and Signaling System"

65 | 29. NFPA 72E-1978, "Fire Detection Systems"

65 | 30. NFPA 80-1977, "Fire Doors and Windows"

65 | 31. NFPA 6-1974, "Industrial Fire Loss Prevention"

65 | 32. NFPA 26-1976, "Supervision of Valves"

65 | 33. NFPA 30-1984, "Flammable Combustible Liquid Code"

65 | 34. NFPA 69-1973, "Explosion Prevention Systems"

65 | 35. IEEE 383-1974, "IEEE Standard for Type Test of IE Electric
| Cables, Field Splices, and Connections"

65 | 36. IEEE 634-1978, "IEEE Standard Cable Penetration Fire Stop
| Qualification Test"

65 | 37. UL Subject 992, "Test Method for Measuring the Flame Propagating
| Characteristics of Floor and Floor Covering Materials"

65 | 38. ASTM E 84-1976, "Surface Burning Characteristics of Building
| Materials"

valves, feedwater control bypass valves, feedwater split flow | 71
bypass valves, and steam generator preheater bypass valves are |
all tripped closed by separate, redundant control circuits and |
solenoids and are powered from two Class 1E-125 VDC power |
systems, maintaining the proper train separation. The |
independence and redundance of these two Class 1E-125 VDC power systems is described in Section 8.3.2.

The rest of the valves and equipment in the condensate and feedwater systems are powered from non-Class 1E systems.

10.4.7.3 Safety Evaluation

The requirements of 10 CFR Part 50, GDC 57, for Containment isolation are satisfied by one stop valve on each feedwater line outside the Containment (see Section 6.2.4.). With loss of flow in the normal direction, the check valve upstream of the stop valve closes and is held closed by back pressure. In addition, the stop valve can be closed and secured by remote operation.

The Feedwater System from the steam generators, back to and including | 66
the moment restraint upstream of the feedwater isolation valve, is |
designated as Safety Class 2 and is designed to the requirements of |
seismic Category I systems (see Section 3.2.1). For an analysis of |
the effects of a break in the Safety Class portion of the Feedwater
System, see Section 10.4.9. The remaining portion of the Feedwater | 66
System piping inside the Safeguards Building is designated non-nuclear |
safety seismic Category II. The portion of the system in the turbine |
building and the Condensate System is non-seismic except for the |
Condensate Storage Tank which is designated Safety Class 3, seismic |
Category I. |

The Condensate and Feedwater Systems are designed to the requirements of the codes listed in Subsection 10.4.7.1. The potential for pipe rupture caused by internal pressure and temperature is as discussed in Section 3.6. Short lengths of pipe are installed above the turbine operating floor and could be fractured by a heavy object carried by

the gantry crane or by a turbine-generated missile; but such an occurrence is extremely unlikely. A rupture of the condensate piping anywhere in the Turbine Building does not cause failure of safety-related equipment as a result of flooding, as no such equipment is installed therein.

In the Safeguards Building the feedwater pipes are, for most of their length, enclosed in separate, reinforced concrete ducts fitted with individual drains. Elsewhere, floor drains are designed to collect any discharge from the pipe, preventing damage to safety-related equipment resulting from flooding.

Any failure in the non-safety-class portion of the Condensate and Feedwater Systems has no effect on the safety of the reactor, which can be shutdown in an orderly manner. (See Section 3.6 for a further discussion of postulated pipe rupture.) A source of feedwater supply to the steam generators is required for decay heat removal from the reactor following a unit shutdown. In the event that the Condensate and Feedwater Systems are not available, the Auxiliary Feedwater System (see Section 10.4.9) provides the required emergency supply of feedwater.

Condensate available for emergency purposes is stored in the Condensate Storage Tank (see Section 9.2.6), which is a seismic Category I structure (see Section 3.2.1).

Although unlikely, a small amount of radioactivity may be present in the Condensate and Feedwater Systems in the event of a steam generator tube leak. Water from a pipe leak or break in the Condensate and Feedwater Systems is collected by the Equipment and Floor Drainage System. These drains are monitored for radioactive releases and are handled as described in Section 9.3.3.

b. Steam Generator Pressure

Steam generator pressure in the loop associated with the FIV must be above a low-level set-point (605 psig). Two-out-of three coincident logic from the Westinghouse supplied steam generator pressure transmitters is used for this signal. | 59 | 10

c. Feedwater Flow | 59

Feedwater flow must be above a low-flow set-point, as measured by a flow switch at the feedwater flow venturi meters. FS-2189, -2190, -2191, and -2192 are provided for loops 1, 2, 3 and 4 respectively. The set-point for these flow switches corresponds to approximately 12 to 15 percent of full feedwater full. | 59

d. Feedwater Temperature | 10

The feedwater temperature must be above approximately 250°F (as measured by resistance temperature detectors on the main feedwater lines). In addition, the difference in temperature between the RTDs installed outside containment, downstream of the FIVs and RTDs mounted at a piping low point on the feedwater lines inside containment, near the main feedwater nozzle must be within about 5°F of each other. This arrangement of temperature sensors is used to preclude pocketing of cold water at the piping low point during startups and, also, to avoid the possibility of a single RTD open circuit failure causing a false temperature permissive signal to open the FIVs. | 59 | 71 | 10

Once the temperature permissives have been cleared allowing the FIV to open, the FIV can remain open irrespective of temperature, providing the FW flow remains high (above | 10

10 | the low flow set point as described in item (c) above).
| Interlocks are provided for this condition.

10 | 2. FEEDWATER PREHEATER BYPASS VALVE (FPBV)

10 | The FPBV bypasses feedwater from the main feedwater line to the
| upper auxiliary nozzle. It also serves as a containment
| isolation valve and is redundantly interlocked with the feedwater
| isolation signals provided by Westinghouse.
Q032.90 |
13 | The FPBV is automatically opened whenever the FIV is closed due
| to the absence of water hammer permissive signals as described
| above for the FIV. Likewise, it is automatically closed
| whenever the water hammer permissives are cleared and the FIV is
| opened. It is also automatically closed on Feedwater isolation
| actuation signal. The FPBVs are provided with three position
| close-auto-open control switches on the main board. The switch
| spring returns to auto; the valves fail closed on loss of control
| power or air.

66 | 3. FEEDWATER SPLIT FLOW BYPASS VALVE (FSBV)

59 | The FSBV is provided to maintain a split bypass flow from the
| main feedwater line to the upper auxiliary feedwater nozzle.
| This bypass valve is open whenever feedwater is admitted to the
| steam generators through the main feedwater nozzle, and is used
| to minimize flow induced tube vibration in the preheater section
| as well as thermal transients at the auxiliary feedwater nozzle.

59 | The FSBV is automatically opened whenever the water hammer
| permissive signals allow the FIV to be opened. Likewise, the
| FSBV is closed when the water hammer permissive signals described
71 | above cause the FIV to close. The FSBV is also automatically
| closed on an AFW initiation signal to direct AFW to the auxiliary
| feedwater nozzle, to minimize delays in admitting AFW to the
| steam generator, and to prevent steam generator blowdown through
| the auxiliary nozzle during a main feedwater line break.

Manager, Safeteam - The responsibilities of the Manager, Safeteam are: | 60

- Manage the Safeteam Program for the review and investigation of employee safety concerns. | 60

- Ensure both departing employees and employees with concerns are interviewed. | 60

- Maintain the independence and credibility of the Program. | 60

- Ensure adequate responses are provided to employees with concerns. | 60

13.1.1.2.1 Organization - Nuclear Operations | 62

Vice President, Nuclear Operations - The responsibilities of the Vice President, Nuclear Operations are: | 60

- Ensure CPSES operation and maintenance activities are conducted in compliance with federal, state, and local laws, regulations, licenses, codes, and within established corporate and NEO policies, plans, and procedures. | 62

- Provide direction and guidance to the Manager, Plant Operations; the Director, Nuclear Training; the Manager, Technical Support; the Manager, Plant Support; the Manager, Administrative Support; the Plant Evaluation Manager; and the Manager, Start-up and Test. | 68

The CPSES operating organization is discussed in Section 13.1.2 and illustrated in Figure 13.1-3. Organizations which support plant operations are discussed below. | 62

60 | Manager, Plant Operations - The responsibilities of the Manager, Plant
| Operations are:

- Direct CPSES operation and maintenance activities in accordance with applicable federal, state, and local laws, regulations, licenses, codes and within established corporate and Nuclear Engineering and Operations policies, plans and procedures.

60 | Director, Nuclear Training - The responsibilities of the Director,
| Nuclear Training are:

60 | - Direct the analysis, design, development, implementation,
| evaluation, and revision of nuclear training programs in order to
| provide personnel with the requisite skills and knowledge for
| effectively performing functions important to the operation and
| maintenance of CPSES.

62 | Manager, Administrative Support - The responsibilities of the Manager,
| Administrative Support are:

64 | - Provide administrative support services for Nuclear Operations
| including: onsite and offsite emergency planning, local public
| information and relations, the records center, operations document
| control and reference libraries, clerical assistance, site
| transportation and office building services.

62 | Plant Evaluation Manager - The responsibilities of the Plant
| Evaluation Manager are:

62 | - Provide administrative and technical direction to the Independent
| Safety Engineering Group (ISEG).

62 | - Provide for the systematic monitoring and assessment of plant
| operations and maintenance activities.

## 13.2 TRAINING

### 13.2.1 PLANT STAFF TRAINING PROGRAM

Selected Personnel, as indicated on Figure 13.2-1, have attended the Westinghouse Nuclear Training Program as described in Sections 13.2.1.1.1 (items 2, 3 and 4) and have satisfactorily completed the requirements for Senior Reactor Operator or Reactor Operator Certification. | 3

| Q441.2

The number of candidates for whom cold licensing examinations are planned is shown on Figure 13.2-1 for each appropriate job title. The number of candidates exceeds the requirements of CPSES Technical Specifications and will ensure that an adequate number of licensed candidates are available at the time of initial core loading. Additional qualified candidates for cold licensing may be added prior to the USNRC cold license examination date. | 15

The position titles for which training programs have been or will be conducted are shown in Figure 13.2-1.

#### 13.2.1.1 Program Description

##### 13.2.1.1.1 Training Program for Licensed Personnel

The licensed personnel training program for the initial CPSES Unit 1 staff consists of a pretraining program and the five phase Westinghouse nuclear training program. This program is designed to utilize experienced fossil power plant personnel with no nuclear experience. Parts of the program may be eliminated for those personnel with previous nuclear training and/or experience.

| Q440.1

Personnel that have been licensed by the USNRC as Reactor Operator or Senior Reactor Operator on CPSES Unit 1, through the training programs | 1

Q440.1 |
71 | described in Section 13.2.1.1.1 or Section 13.2.2.3.1, may also be
| licensed on CPSES Unit 2 prior to the initial operation of that Unit.
1 | These personnel will complete a training program that will present
| specific differences between CPSES Unit 1 and CPSES Unit 2.

All Unit 1 cold license candidates will meet the requirements of ANSI N18.1-1971, Section 5.2.1.

27 | A description of each of the parts of the training program for
| licensed personnel follows:

1. Pretraining Program

An initial group of supervisors and reactor operators has participated in a refresher course in mathematics and physical science with an introduction to nuclear power plants. The course was conducted by General Physics Corporation and was an eight-week full-time program. Progress was monitored through frequent
3 | quizzes and examinations. A second group of Reactor Operators
| has completed a similar five week full-time program.

27 | Two groups of Auxiliary Operators have received a refresher
| course in mathematics and physics and an introduction to nuclear
| power plant systems conducted by the CPSES training staff. The
| first group received nine weeks of Auxiliary Operator training.
| The second group of Auxiliary Operators received 11 weeks of
| training. A third group of Auxiliary Operators will receive
| pretraining consistent with their background and prior experience
| before cold license certification training.

27 | 2. Fundamental Nuclear Reactor Training - Phase I

This eleven-week course, conducted by the Westinghouse Nuclear Training Center (WNTC), presents a thorough and comprehensive

TABLE 13.5-2
(Sheet 1 of 4)

SYSTEM OPERATING PROCEDURES

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| - | Boron Thermal Regeneration System | \| 38 |
| | | \| 71 |
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| - | Condensate System | \| 38 |
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| - | Water Fire Protection System | 38 |
| - | Plant Lighting Systems | 38 |
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TABLE 13.5-5

RADWASTE SYSTEMS PROCEDURES

Gaseous Waste System - Collection, Storage and Disposal

Liquid Waste System - Collection, Storage, Processing and Disposal

Solid Waste System - Processing, Storage and Disposal

Boron Recycle System | 71

## 13.6 SECURITY | 57

The security program was developed under the guidance specified in | 71
1A(B) (Reference Guide 1.17). In accordance with 10 CFR Part |
2.790(d), the plant security plans contain confidential and safeguards | 65
information that is exempt from public disclosure under the provisions |
of 10CFR 9.5(a)4 and 10CFR 73.21. These plans are described in a |
separate submittal.

### 13.6.1 ORGANIZATION AND PERSONNEL

#### 13.6.1.1 Management Organization and Responsibilities

The Vice President, Nuclear Operations is responsible for the safe and | 65
reliable operation of the plant and has overall responsibility for |
security of the plant. The Vice President, Nuclear Operations |
reports to the Executive Vice-President, Nuclear Engineering and |
Operations. The Executive Vice President, Nuclear Engineering and |
Operations has responsibility for all aspects of the CPSES operation. | 57

#### 13.6.1.2 Security Organization | 57

The security organization will consist of a plant security group (to | 57
maintain security inside the protected area) and an industrial |
security group (to maintain security outside the protected area) with |
a licensee supervisor responsible for the activities of each group. |
The Plant Security Supervisor and the Industrial Security Supervisor | 71

71 | will report to the Security Manager who is responsible for the program
| outlined in the CPSES security plans and procedures. The Security
65 | Manager reports security management matters directly to the Manager,
| Plant Support. A contract security force, under CPSES management,
57 | will perform the day-to-day security duties.
15 |

Applicants for employment in the security organization will be subjected to appropriate background investigations, and all guards will be properly trained and qualified. As a result of training, each member of the security force will demonstrate an understanding of CPSES security procedures and the ability to execute all duties required by the procedures.

13.6.1.3 Plant Employee Selection and Reliability

15 | Employees will be selected only after screening for the purposes of
| determining physical condition and emotional stability. The extent
| of the screening will be dependent on the job duties of the particular
| employee. Supervisory personnel will be responsible for observation of all personnel in the course of their employment for indications of aberrant behavior and for initiation of appropriate corrective measures as necessary.

13.6.1.4 Security Training

Each plant employee will receive an appropriate security orientation and refresher training, with emphasis on those security matters for which he has a responsibility.

13.6.1.5 Security Emergency Procedures

Security plans and procedures will be developed to include, but not necessarily limited to, the following contingencies:

1. Guard strike or other unavailability of the security force.

2. Fire or explosion.

3. Site evacuation.

4. Personnel disturbance.

5. Bomb threat or other stated or perceived threat of sabotage.

6. Civil disturbance.

7. Suspected or confirmed intrusions or sabotage attempts.

Plant employees will receive training in their responsibilities during applicable contingencies, with emphasis on alertness to the presence of unauthorized persons and evidence of forced entry into the plant.

13.6.2 PLANT DESIGN AND PHYSICAL SECURITY FEATURES

13.6.2.1 Plant Design

The plant design accommodates the security criteria established by 10 CFR Part 73.55. These basic physical security design criteria will:

1. Control entry into protected and vital areas.

2. Deter or preclude penetration by unauthorized persons into protected and vital areas.

3. Detect actual unauthorized penetrations.

4. Aid security response personnel in timely apprehension of unauthorized persons or other personnel acting in a manner constituting a sabotage threat.

13.6.2.2 Physical Security Features

Physical security measures that will protect against or limit the effects of possible sabotage efforts include:

1. A protected area boundary enclosed by a perimeter barrier supplemented with an intrusion detection system and closed circuit television systems or controlled by security personnel.

2. Employee and visitor parking located outside the protected area boundary.

3. An isolation zone on both the outside and inside of the perimeter barrier.

71 | 4. A perimeter patrol road within the protected area.

5. A well-lighted, protected area utilizing a protective lighting system having emergency power.

6. A minimum number of access points into the protected area.

7. A minimum number of exterior plant doors used for normal access into the complex that contains vital equipment, with all other exterior doors locked and secured from the inside when not in use.

8. A key card access control system for entrance into the vital complex and at selected points within the vital area complex.

9. Use of a trained, uniformed, and armed guard force employed continuously 24 hours a day to protect the property and provide access control.

10. Positive identification and search of all personnel prior to entry into the protected area. At the primary and alternate access points into the protected area, guards will inspect for appropriate identification and will conduct searches of personnel and vehicles for firearms, explosives, incendiary devices, and contraband. | 71

11. Communications systems providing direct links to area law enforcement agencies.

### 13.6.3 ADMINISTRATIVE P DURES IN THE EVENT OF AN INCIDENT

In the event of any incident in which an attempt has been made, or is believed to have been made, to commit an act of radiological sabotage or other act which threatens the security of the plant, TU Electric personnel and the Nuclear Regulatory Commission shall be notified as appropriate in accordance with station procedures; simultaneously, a counteraction will be initiated and a thorough investigation of the incident will be conducted. | 71

### 13.6.4 AUDITS

An annual audit will be conducted of the CPSES security program by
65 | designated individuals independent of CPSES plant management. A
| formal report of findings will be submitted to the Vice-President,
| Nuclear Operations for appropriate action.

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2. Review and approval of design change requests originated during the course of the startup program.

3. Management of Contractors ( e.g. Gibbs & Hill, Brown & Root, Westinghouse). | 15

4. Technical review and comments of Unit 2 preoperational test procedures objectives and acceptance criteria, prior to approval. | 46

14.2.2.4.2 Brown & Root, Inc. (B&R) | 68

B&R, as the constructor for CPSES, is responsible for the construction completion, performance of associated constructions tests, and orderly release of components and systems to TU Electric consistent with the startup program schedules. This responsibility includes:

1. Completion of construction and construction testing activities;

2. Provision of craft technical manpower support as required for performance of the startup program. | 11

14.2.2.4.3 Westinghouse Electric Corporation | 68

Westinghouse, as the Nuclear Steam Supply System (NSSS) supplier, is responsible for providing technical direction to TU Electric during preoperational and initial startup testing performed on the NSSS and associated auxiliary equipment. Technical direction is defined as technical guidance, advice and counsel based on current engineering, installation, and testing practices. This responsibility includes: | 60

1. Assignment of personnel to provide advice and assistance to TU Electric for test and operation of all equipment and systems in the Westinghouse area of responsibility.

2. Assignment of an operational physicist to the site organization during fuel loading and power testing; and

3. Provision of test procedure outlines and technical assistance for tests of Westinghouse furnished components and systems.

68 | 14.2.2.4.4 Allis-Chalmers Power Systems, Inc. (ACPSI)

ACPSI, as supplier of the main turbine generator set, is responsible for providing technical direction to TU Electric during preoperational and initial startup testing performed on the turbine generator and related auxiliary equipment.

37 |

14.2.2.5 Joint Test Group (JTG)

68 | The Joint Test Group (JTG) is comprised of certain station supervisory
| and technical personnel as described in Section 14.2.2.5.1. The JTG
| functions as a subcommittee of the Station Operations Review Committee
71 | (SORC) for testing matters. The JTG is charged with reviewing
| testing activities and advising the SORC on the disposition of those
| items reviewed.

CONTROL ROOM VENTILATION SYSTEM
TEST SUMMARY

OBJECTIVE

To demonstrate the capability of the Control Room Ventilation System to maintain suitable and safe ambient conditions for operating equipment and personnel in the Control Room and associated areas.

PREREQUISITES

1. A cooling water supply is available for the Control Room condensing air compressor units.

2. Compressed air is available for system valve and damper operators.

TEST METHOD

1. Demonstrate proper functioning of the Control Room Ventilation System in the normal emergency recirculation and emergency ventilation modes of operation.

2. Verify that the system responds properly to safeguards actuation signals.

3. Verify proper pressure differentials.

4. Demonstrate proper operation of chlorine gas detectors, fans, valves, dampers, and filters. | 71

5. Check operation of system instrumentation, interlocks, and alarms.

## 15.0.6 TRIP POINTS AND TIME DELAYS TO TRIP ASSUMED IN ACCIDENT ANALYSES

A reactor trip signal acts to open two trip breakers connected in series feeding power to the control rod drive mechanisms. The loss of power to the mechanism coils causes the mechanisms to release the rod cluster control assemblies which then fall by gravity into the core. There are various instrumentation delays associated with each trip | 71
function, including delays in signal actuation, in opening the trip |
breakers, and in the release of the rods by the mechanisms. Limiting |
trip setpoints assumed in accident analyses and the time delay which |
occurs between generation of the reactor trip signal and the point at |
which the rods are free to fall for each trip function are given in |
Table 15.0-4. Reference is made in that table to Overtemperature and |
Overpower N-16 trip shown in Figure 15.0-1. | 5

The difference between the limiting trip point assumed for the analysis and the nominal trip point represents an allowance for instrumentation channel error and setpoint error. Nominal trip setpoints are specified in the plant Technical Specifications. During plant startup tests it will be demonstrated that actual instrument time delays are equal to or less than the assumed values. Additionally, protection system channels are calibrated and instrument response times determined periodically in accordance with the plant Technical Specifications.

## 15.0.7 INSTRUMENTATION DRIFT AND CALORIMETRIC ERRORS - POWER RANGE NEUTRON FLUX

The instrumentation drift and calorimetric errors used in establishing the power range high neutron flux setpoint are presented in Table 15.0-5.

The calorimetric error is the error assumed in the determination of core thermal power as obtained from secondary plant measurements. The total ion chamber current (sum of the top and bottom sections) is calibrated (set equal) to this measured power on a periodic basis.

The secondary power is obtained from measurement of feedwater flow, feedwater inlet temperature to the steam generators and steam pressure. High accuracy instrumentation is provided for these measurements with accuracy tolerances much tighter than those which would be required to control feedwater flow.

## 15.0.8 PLANT SYSTEMS AND COMPONENTS AVAILABLE FOR MITIGATION OF ACCIDENT EFFECTS

The NSSS is designed to afford proper protection against the possible effects of natural phenomena, postulated environmental conditions and dynamic effects of the postulated accidents. In addition, the design incorporates features which minimize the probability and effects of fires and explosions. Chapter 17 discusses the quality assurance program which has been implemented to assure that the NSSS will satisfactorily perform its assigned safety functions. The incorporation of these features in the NSSS, coupled with the reliability of the design, ensures that the normally operating systems and components listed in Table 15.0-6 will be available for mitigation of the events discussed in Chapter 15. In determining which systems are necessary to mitigate the effects of these postulated events, the classification system of ANSI-N18.2-1973 is utilized. The design of "systems important to safety" (including protection systems) is consistent with IEEE Standard 379-1972 and Regulatory Guide 1.53 in the application of the single failure criterion.

3. No credit is taken for the pressurizer power operated relief valves or pressurizer spray.

4. Initial pressurizer level is at the nominal programmed value plus 5 percent (error); initial steam generator water level is at the nominal value, plus 5 percent in the faulted steam generator and at the nominal value minus 5 percent in the intact steam generators. | 57

5. No credit is taken for the high pressurizer pressure reactor trip.

6. Main feedwater flow to all steam generators is assumed to be lost at the time the break occurs (all main feedwater spills out through the break).

7. The worst possible break area is assumed. This maximizes the blowdown discharge rate following the time of trip, which maximizes the resultant heatup of the reactor coolant.

8. A conservative feedline break discharge quality is assumed prior to the time the reactor trip occurs, thereby maximizing the time the trip setpoint is reached. After the trip occurs, a saturated liquid discharge is assumed until all the water inventory is discharged from the affected steam generator. This minimizes the heat removal capability of the affected steam generator.

9. Reactor trip occurs on steam generator low-low level. | 57

10. The Auxiliary Feedwater System is actuated by the low-low steam generator water level signal. The Auxiliary Feedwater System is assumed to supply a total of 430 gallons per minute (gpm) to three unaffected steam generators, including allowance for possible spillage through the main feedwater line break. A 60 second delay was assumed following the low-low level signal to allow time for startup of the emergency diesel generators and the auxiliary feedwater pumps. | 57

57 | Approximately 118 seconds was assumed before the feedwater lines were purged and the relatively cold (120°F) auxiliary feedwater entered the unaffected steam generators.

11. Thirty minutes after the reactor trip, an additional 430 gpm is assumed to be supplied to the intact steam generators.

12. No credit is taken for heat energy deposited in RCS metal during the RCS heatup.

13. No credit is taken for charging or letdown.

14. Steam generator heat transfer area is assumed to decrease as the shell side liquid inventory decreases.

57 | 15. Conservative core residual heat generation is based upon the American National Standard For Decay Heat Power In Light Water Reactors, ANSI/ANS-5.1-1979 and assumes an infinite irradiation time and a two sigma uncertainty allowance.

16. No credit is taken for the following potential protection logic signals to mitigate the consequences of the accident:

5 | a. High pressurizer pressure.
5 | b. Overtemperature N-16.
5 | c. High pressurizer level.
d. High Containment pressure.

Receipt of a low-low steam generator water level signal in at least one steam generator starts the motor driven auxiliary feedwater pumps, which then deliver auxiliary feedwater flow to the steam generators. The turbine driven auxiliary feedwater pump is initiated if the low-low steam generator water level signal is reached in at least two steam generators. Similarly, receipt of a low steam line pressure

signal in at least one steam line initiates a steam line isolation signal which closes the main steam line isolation valves in all steam lines. This signal also gives a safety injection signal which initiates flow of borated water into the RCS. The amount of safety injection flow is a function of RCS pressure.

Emergency operating procedures following a secondary system line rupture will call for the following actions to be taken by the reactor operator:

1. Isolate feedwater flow spilling out the break of ruptured steam generator and align system so level in intact steam generators recovers.

2. Turn off all reactor coolant pumps (if offsite power is still available).

3. Stop high head safety injection pumps if water level in the pressurizer is recovering, and the intact steam generators are at the safety valve setpoint, and water level in intact steam generators is above the top of the narrow range span.

Shutting off the reactor coolant pumps (action 2, above) serves to decrease the addition of energy (approximately 3.5 megawatts (MW) per pump) to the RCS. Isolating feedwater flow through the break allows additional auxiliary feedwater flow to be diverted to the intact steam generators (see assumption 11, above).

Subsequent to recovery of level in the intact steam generators, the high head safety injection pumps will be turned off and plant operating procedures will be followed in cooling the plant to hot shutdown conditions.

Plant characteristics and initial conditions are further discussed in Section 15.0.3.

No reactor control systems are assumed to function. The Reactor Protection System is required to function following a feedwater line rupture as analyzed here. No single active failure will prevent operation of this system.

The engineered safety systems assumed to function are the Auxiliary
57 | Feedwater System and the Safety Injection System. For the Auxiliary
| Feedwater System, the worst case has been used, i.e., three intact
| steam generators receive auxiliary feedwater following the break.
| The motor driven auxiliary feedwater pump on the intact loops has been
| assumed to fail; flow from the turbine driven pump delivers 430 gpm to
| the three steam generators.

Following the trip of the reactor coolant pumps, there will be a flow coastdown until flow in the loops reaches the natural circulation value. The natural circulation capability of the RCS has been shown in Section 15.2.6, for the loss of AC power transient, to be sufficient to remove core decay heat following reactor trip. Pump coastdown characteristics are demonstrated in Sections 15.3.1 and 15.3.2 for single and multiple reactor coolant pump trips, respectively.

A detailed description and analysis of the Safety Injection System is provided in Section 6.3. The Auxiliary Feedwater System is described in Section 10.4.9.

Results

Calculated plant parameters following a major feedwater line rupture are shown in Figures 15.2-13 through 15.2-26. Results for the case with offsite power available are presented in Figures 15.2-13 through 15.2-19. Results for the case where offsite power is lost are presented in Figures 15.2-20 through 15.2-26. The calculated sequence of events for both cases analyzed are listed in Table 15.2-1.

The system response following the feedwater line rupture is similar for both cases analyzed. Results presented in Figures 15.2-14 and 15.2-19 (with offsite power available) and Figures 15.2-21 and 15.2-26 (without off-site power) show that pressures in the RCS and main steam system remain below 110 percent of the respective design pressures. Pressurizer pressure increases until reactor trip occurs on low-low steam generator water level. Pressure then decreases, due to the loss of heat input, until the Safety Injection System is actuated on low steam line pressure in the ruptured loop. Coolant expansion occurs due to reduced heat transfer capability in the steam generators; the pressurizer safety valves open to maintain primary pressure at an acceptable value. Addition of the safety injection flow aids in cooling down the primary and helps to ensure that sufficient fluid exists to keep the core covered with water.

Figures 15.2-13 and 15.2-20 show that following reactor trip the plant | 66
remains subcritical. |

RCS pressure will be maintained at the safety valve setpoint until | 57
safety injection flow is terminated by the operator or until AFW flow |
is increased to the intact steam generators as mentioned in Section |
15.2.8.2. The reactor core remains covered with water throughout the | 71
transient, and water relief due to thermal expansion is prevented by |
the heat removal capability of the Auxiliary Feedwater System. |

The major difference between the two cases analyzed can be seen in the plots of hot and cold leg temperatures, Figures 15.2-16 through 15.2-18 (with offsite power available) and Figures 15.2-23 through 15.2-25 (without offsite power). It is apparent from the initial poriton of the transient ( 300 seconds) that the case without offsite power results in higher temperatures in the hot leg. For longer times, however, the case with offsite power results in a more severe rise in temperature until the coolant pumps are turned off and the Auxiliary Feedwater System is realigned. The pressurizer fills more rapidly for the case with power due to the increased coolant expansion resulting from the pump heat addition; however, no water is relieved for either

57 | case. As previously stated, the core remains covered with water for
| both cases.

15.2.8.3 Conclusions

Results of the analyses show that for the postulated feedwater line rupture, the assumed Auxiliary Feedwater System capacity is adequate to remove decay heat, to prevent overpressurizing the RCS, and to prevent uncovering the reactor core.

15.2.8.4 Analysis of Radiological Effects and Consequences

Radioactivity doses from the postulated feedwater line rupture are less than those previously presented for the postulated steam line
57 | break. All applicable acceptance criteria are therefore met.

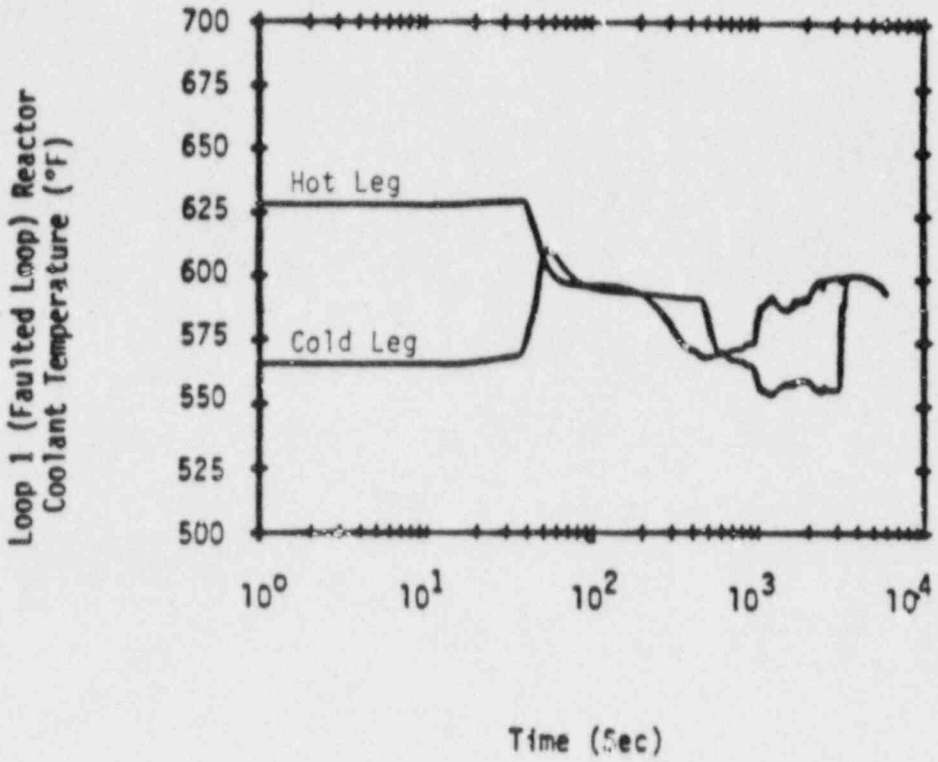
REFERENCES

1. Mangan, M. A., "Overpressure Protection for Westinghouse Pressurized Water Reactors", WCAP-7769, October 1971.

2. "Westinghouse Anticipated Transients Without Trip Analysis", WCAP-8330, August 1974.

3. Burnett, T. W. T., et. al., "LOFTRAN Code Description", WCAP-7907-P-A (Proprietary), WCAP-7907-A (non-Proprietary), April 1984. | 66

4. Hargrove, H. G., "FACTRAN-A Fortran-IV Code for Thermal Transients in a UO2 Fuel Rod", WCAP-7908, June 1972.

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UNITS 1 and 2

MAIN FEEDLINE RUPTURE WITHOUT OFFSITE POWER

FIGURE 15.2-23

May 27, 1988

Evaluation of this case at the power and coolant conditions | 42
at which the overtemperature N-16 trip would be expected to |
trip the plant shows that an upper limit for the number of |
rods with a DNBR less than the limit value is 5 percent. |

b. If the reactor is in the automatic control mode, the | 42
multiple failures that result in the withdrawal of a single |
RCCA will result in the immobility of the other RCCAs in |
the controlling bank. The transient will then proceed in |
the same manner as Case a described above. |

For such cases as above, a reactor trip will ultimately ensue, | 42
although not sufficiently fast in all cases to prevent a minimum DNBR |
in the core of less than the limit value. Following reactor trip, |
normal shutdown procedures are followed. |

15.4.3.3 Conclusions | 42

For cases of dropped RCCAs or dropped banks, for which the reactor is | 42
tripped by the power range negative neutron flux rate trip, there is |
no reduction in the margin to core thermal limits, and consequently |
the DNB design basis is met. It is shown for all cases which do not |
result in reactor trip that the DNBR remains greater than the limit |
value and, therefore, the DNB design is met. |

For all cases of any RCCA fully inserted, or bank D inserted to its | 42
rod insertion limits with any single RCCA in that bank fully withdrawn |
(static misalignment), the DNBR remains greater than the limit value. |

For the case of the accidental withdrawal of a single RCCA, with the | 42
reactor in the automatic or manual control mode and initially |
operating at full power with bank D at the insertion limit, an upper |
bound of the number of fuel rods experiencing DNB is 5 percent of the |
total fuel rods in the core. |

## 15.4.4 STARTUP OF AN INACTIVE REACTOR COOLANT PUMP AT AN INCORRECT TEMPERATURE

### 15.4.4.1 Identification of Causes and Accident Description

If the plant is operating with one pump out of service, there is reverse flow through the inactive loop due to the pressure difference across the reactor vessel. The cold leg temperature in an inactive loop is identical to the cold leg temperature of the active loops (the reactor core inlet temperature). If the reactor is operated at power, and assuming the secondary side of the steam generator in the inactive loop is not isolated, there is a temperature drop across the steam generator in the inactive loop and, with the reverse flow, the hot leg temperature of the inactive loop is lower than the reactor core inlet temperature.

Administrative procedures require that the unit be brought to a load of less than 25 percent of full power prior to starting the pump in an inactive loop in order to bring the inactive loop hot leg temperature closer to the core inlet temperature. Starting of an idle reactor coolant pump without bringing the inactive loop hot leg temperature close to the core inlet temperature would result in the injection of cold water into the core, which would cause a reactivity insertion and subsequent power increase.

| Q212.78
| Q212.136

f) Power Range Neutron Flux - High, both high and low setpoint Reactor Trips. | 14

This event is classified as an ANS Condition II incident (a fault of moderate frequency) as defined in Section 15.0.1. | 14
| Q212.78
| Q212.136

15.4.6.2 Analysis of Effects and Consequences

To cover all phases of plant operation, boron dilution during Refueling, Cold Shutdown, Hot Shutdown, Hot Standby, Startup, and Power modes of operation are considered in this analysis. Conservative values for necessary parameters were used, i.e., high RCS critical boron concentrations, high boron worths, minimum shutdown margins, and lower than actual RCS volumes. These assumptions result in conservative determinations of the time available for operator or system response after detection of a dilution transient in progress. | 14
| Q212.78
| Q212.136

Dilution During Refueling | 14

An uncontrolled boron dilution transient cannot occur during this mode of operation. Inadvertent dilution is prevented by administrative controls which isolate the RCS from the potential source of unborated water. Either valve ICS-8455 or valves ICS-8560, FCV-111B, ICS-8441, ICS-8453 and ICS-8439 in the CVCS will be locked closed during refueling operations. These valves block all flow paths that could allow significant rates of unborated makeup water to reach the RCS. Any makeup which is required during refueling will be borated water supplied from the RWST by the low head safety injection pumps. | 14 | 71 | 14

Q212.78 |
Q212.136 |
14 | Dilution During Cold Shutdown

14 | The Technical Specifications require the reactor to be shutdown by at
| least 1% $\Delta K/K$ when in this mode. The following conditions are
| assumed for inadvertent boron dilution while in this operating mode:

parameters are discussed below. Table 15.4-3 presents the parameters used in this analysis.

Ejected Rod Worths and Hot Channel Factors

The values for ejected rod worths and hot channel factors are calculated using either three dimensional static methods or by a synthesis method employing one dimensional and two dimensional calculations. Standard nuclear design codes are used in the analysis. No credit is taken for the flux flattening effects of reactivity feedback. The calculation is performed for the maximum allowed bank insertion at a given power level, as determined by the rod insertion limits. Adverse xenon distributions are considered in the calculation.

Appropriate margins are added to the ejected rod worth and hot channel factors to account for any calculational uncertainties, including an allowance for nuclear power peaking due to densification.

Power distributions before and after ejection for a "worst case" can be found in Reference [7]. It has been found that the ejected rod worth and power peaking factors are consistently overpredicted in the analysis. | 71

Reactivity Feedback Weighting Factors

The largest temperature rises, and hence the largest reactivity feedbacks occur in channels where the power is higher than average. Since the weight of a region is dependent on flux, these regions have high weights. This means that the reactivity feedback is larger than that indicated by a simple channel analysis. Physics calculations have been carried out for temperature changes with a flat temperature distribution, and with a large number of axial and radial temperature distributions.

Reactivity changes were compared and effective weighting factors determined. These weighting factors take the form of multipliers which when applied to single channel feedbacks correct them to effective whole core feedbacks for the appropriate flux shape. In this analysis, since a one dimensional (axial) spatial kinetics method is employed, axial weighting is not necessary if the initial condition is made to match the ejected rod configuration. In addition, no weighting is applied to the moderator feedback. A conservative radial weighting factor is applied to the transient fuel temperature to obtain an effective fuel temperature as a function of time accounting for the missing spatial dimension. These weighting factors have also been shown to be conservative compared to three dimensional analysis [7].

Moderator and Doppler Coefficient

The critical boron concentrations at the beginning-of-life and end-of-life are adjusted in the nuclear code in order to obtain moderator density coefficient curves which are conservative compared to actual design conditions for the plant. As discussed above, no weighting factor is applied to these results.

The Doppler reactivity defect is determined as a function of power level using a one dimensional steady state computer code with a Doppler weighting factor of 1.0. The Doppler defect used is given in Section 15.0.4. The Doppler weighting factor will increase under accident conditions, as discussed above.

Delayed Neutron Fraction

Calculations of the effective delayed neutron fraction ($\beta_{eff}$) typically yield values no less than 0.70 percent at beginning of-life and 0.50 percent at end-of-life for the first cycle. The accident is sensitive to $\beta$ if the ejected rod worth is equal to or greater than as in zero power transients. In order to allow for future cycles, pessimistic

from the coolant through the rupture in the reactor vessel head, 100 percent is assumed to be mixed instantaneously throughout the Containment. Fifty (50) percent of the iodine activity released from | 66
the melted fuel is assumed to immediately plate out on Containment |
surfaces. The remaining activity is available for leakage from the | 71
Containment at the design leak rate of 0.10 percent of Containment |
volume per day for the first 24 hours, and at a rate of 0.05 percent |
of Containment volume per day for the duration of the accident. The |
only removal processes considered in the Containment are radioactive decay and leakage from the Containment.

The model for the activity available for release to the atmosphere from the relief valves assumes that the release consists of the activity in the secondary coolant prior to the accident plus that fraction of the activity leaking from the primary coolant through the steam generator tubes following the accident. The leakage of primary coolant to the secondary side of the steam generator is assumed to continue at its initial rate, which is assumed to be the same rate as the leakage prior to the accident, until the pressures in the primary system and the secondary system are equalized. No mass transfer from the primary system to the secondary system through steam generator tube leakage is assumed thereafter. With the assumption of coincident | 66
loss of offsite power, activity is assumed to be released to the |
atmosphere from a steam dump through the relief valves for 400 |
seconds. |

A summary of parameters used in the analysis is given in Table | 66
15.4-4. |

Fuel melting, limited to less than the innermost 10 percent of the fuel pellet at the hotspot, is included in the design criteria to ensure that fuel dispersion into the coolant does not occur [1].

66 | Even though centerline melting in a small fraction of the core is not
| expected, a conservative upper limit of fission product release from
| the core as a result of a rod ejection accident can be estimated.

The Regulatory Guide 1.77 limit of fission product release from the core for this very conservative case is determined using the following assumptions:

1. 100 percent of the noble gases and iodines in the clad gaps of the fuel rod experiencing clad damage (assumed to be 10 percent of the rods in the core) are released to the reactor coolant.
66 | The gap activities are presented in Table 15.6-8.

66 | 2. 50 percent of the iodines and 100 percent of the noble gases in
| the fuel that melts is assumed to be released to the reactor
| coolant.

3. The fraction of fuel melting is conservatively assumed to be 0.25 percent of the core, as determined by the following method [1]:

   a. A conservative upper limit of 50 percent of the rods experiencing clad damage also may experience centerline melting (a total of 5 percent of the core).

   b. Of rods experiencing centerline melting, only a conservative maximum of the innermost 10 percent of the volume actually melts (equivalent to 0.5 percent of the core that could experience melting).

WREFLOOD is also linked to the LOCTA-IV code in that thermal-hydraulic parameters from WREFLOOD are used by LOCTA-IV in its calculation of the fuel temperature. LOCTA-IV is used throughout the analysis of the LOCA transient to calculate the fuel clad temperature and metal-water reaction of the hottest rod in the core.

The analysis presented here was performed with the February 1978 version of the evaluation model which includes modifications delineated in References [15], [16], [17] and [17a]. | 6

The analysis in this section was performed with the upper head fluid temperature equal to the reactor coolant system cold leg fluid temperature. | 6

The upper head fluid temperature has been made equal to the cold leg temperature by increasing the upper head cooling flow [20]. | 6

Small Break LOCA Evaluation Model

The WFLASH program used in the analysis of the small break LOCA is an extension of the FLASH-4 code [13] developed at the Westinghouse Bettis Atomic Power Laboratory. The WFLASH program permits a detailed spatial representation of the RCS.

The RCS is nodalized into volumes interconnected by flowpaths. The broken loop is modeled explicitly with the intact loops lumped into a second loop. The transient behavior of the system is determined from the governing conservation equations of mass, energy and momentum applied throughout the system. A detailed description of WFLASH is given in Reference [14].

The use of WFLASH in the analysis involves, among other things, the representation of the reactor core as a heated control volume with the associated bubble rise model to permit a transient mixture height

calculation. The multi-node capability of the program enables an explicit and detailed spatial representation of various system components. In particular it enables a proper calculation of the behavior of the loop seal during a loss of coolant transient.

Clad thermal analyses are performed with the LOCTA-IV code [9] which uses the RCS pressure, fuel rod power history, steam flow past the uncovered part of the core and mixture height history from the WFLASH hydraulic calculations as input.

Schematic representations of the computer code interfaces are given in Figures 15.6-5 and 15.6-6.

6 | The small break analysis was performed with the October, 1975 version
| of the Westinghouse ECCS Evaluation Model (refer to References [9],
| [14], [14a] and [14b]).

15.6.5.3.2 Input Parameters and Initial Conditions

Table 15.6-5 lists important input parameters and initial conditions used in the analysis.

6 | The analysis presented in this section was performed with a reactor
| vessel upper head temperature equal to the RCS cold leg temperature.
| The effect of using the cold leg temperature in the reactor vessel
36 | upper head is described in Reference [20]. In addition, the large
| break analysis in this section utilized the upflow barrel-baffle
| methodology described in Reference [25].

TABLE 15.6-9

(Sheet 4 of 4)

PARAMETERS FOR POSTULATED LOCA ANALYSIS[a]

| | | |
|---|---|---|
| b. x/Q's (for time intervals of 2 hours, 8 hours, 24 hours, 4 days, 30 days) | @ EAB, onsite | 66 |
| | 5 percentile data | 66 |
| | $2.6 \times 10^{-4}$ sec/m$^3$ | 66 |
| | (0-2 hrs) | 66 |
| | @LPZ, onsite | 66 |
| | 5 percentile data | 66 |
| | $2.3 \times 10^{-5}$ sec/m$^3$ | 66 |
| | (0-8 hrs) | 66 |
| | $2.2 \times 10^{-6}$ sec/m$^3$ | 66 |
| | (8-24 hrs) | 66 |
| | $1.1 \times 10^{-6}$ sec/m$^3$ | 66 |
| | (1-4 days) | 66 |
| | $6.6 \times 10^{-7}$ sec/m$^3$ | 66 |
| | (4-30 days) | 66 |
| 4. Dose due to containment and ESF equipment leakage | | 66 |
| | | 66 |
| a. Method of dose calculation | See Appendix 15B | 66 |
| | | 66 |
| b. Dose conversion assumptions | See Appendix 15B | 66 |
| | | 66 |
| c. Doses | @EAB, (0-2 hrs) | 66 |
| | thyroid = 145 rem | 66 |
| | whole body gamma | 66 |
| | =2.2 rem | 66 |
| | | 66 |
| | @LPZ (0-30 days) | 66 |
| | thyroid=36.0 rem | 66 |
| | whole body gamma | 66 |
| | =1.1 rem | 66 |

TABLE 15.6-11

This table has been revised and renumbered 15.6-10. | 71

of the tank are assumed to be released to the atmosphere at ground level over a 2 hr period. Other conservative assumptions are detailed in Table 15.7-4.

Based on the foregoing model, the thyroid and whole body doses at the EAB are conservatively calculated to be 5.14 rem and $1.82 \times 10^{-1}$ rem, respectively. The doses from this accident are well within the limits defined in 10CFR100 . | 66

15.7.3 POSTULATED RADIOACTIVE RELEASES DUE TO LIQUID TANK FAILURES

The analysis is presented in Section 2.4.12 and 2.4.13.3. | 66

15.7.4 DESIGN BASIS FUEL HANDLING ACCIDENTS

15.7.4.1 Identification of Causes and Accident Description

The accident is defined as dropping of a spent fuel assembly in the Containment Building or spent fuel pool fuel storage area floor resulting in the rupture of the cladding of all the fuel rods in the assembly despite many administrative controls and physical limitations imposed on fuel handling operations. All refueling operations are conducted in accordance with prescribed procedures under direct surveillance of a supervisor. | 66

15.7.4.2 Analysis of Effects and Consequences

Method of Analysis

The method of analysis used for evaluating the potential radiological consequences of a fuel handling accident is in compliance with Regulatory Guide 1.25 except for those provisions listed in Appendix 1A(B). A two hour, ground level release is assumed for the analysis. | 66

The following assumptions are postulated in the calculation of the radiological consequences of a fuel handling accident:

66 | 1. The accident occurs at 100 hr following the reactor shutdown, the minimum time at which spent fuel could be first moved into the fuel storage area.

66 | 2. The accident results in the rupture of the cladding of all fuel rods in a single assembly.

3. The damaged assembly is, coincidentally, the one operating at the highest power level in the core region to be discharged.

4. The power in this assembly, and corresponding fuel temperatures establish the total fission product inventory and the fraction of this inventory which is present in the fuel pellet-cladding gap at the time of reactor shutdown.

66 | 5. The fuel pellet-cladding gap inventory of fission products is released to the refueling cavity or spent fuel pool at the time of the accident.

66 | 6. The refueling cavity or spent fuel pool retains a large fraction of the gap activity of halogens by virtue of their solubility and hydrolysis. Noble gases are not retained by the water as they are not subject to hydrolysis reactions.

Fission Product Inventories

Q312.26 |
13 | The actual fission product gap inventory in the fuel assembly is dependent on the linear heat generation rate of the assembly and the temperature of the fuel. However, the gap inventories assumed in fuel handling accident analyses were based on the conservative
66 | guidance contained in Regulatory Guide 1.25. Table 15.7-6 lists fuel assembly fission product activities at the time of the fuel handling accident. These activities are consistent with the description of
13 | the assumptions used in analyzing the environmental consequences of postulated fuel handling accidents detailed in Section 15.7.4.3.

TABLE 15.7-1

(Sheet 2)

| | | | |
|---|---|---|---|
| 3. | Dispersion data | | |
| | a. Exclusion area boundary (EAB) and low population zone (LPZ) distances | 1544 m and 4 miles | \| 66<br>\| 66<br>\| 66<br>\| 66 |
| | b. x/Q | $2.6 \times 10^{-4}$ sec/$m^3$<br>(0 - 2 hr) | \| 66<br>\| 66 |
| 4. | Dose data | | |
| | a. Method of dose calculations | Regulatory Guide 1.24 | \| 66<br>\| 66 |
| | b. Doses | @EAB, whole body dose = $7.3 \times 10^{-2}$ rem (gamma dose) | \| 66 |

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## 17.0 QUALITY ASSURANCE (QA)

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# 17.0 QUALITY ASSURANCE (QA)

Texas Utilities Electric Company (TU Electric) is submitting this application as Licensee for Comanche Peak Steam Electric Station (CPSES). TU Electric acts as owners agent for construction and operation of CPSES and is therefore responsible for the design, engineering, procurement, fabrication, and construction technical support of CPSES. This delegation of authority has been formally established among the Owners. Texas Utilities Company (TUCO) is the parent company of TU Electric. | 60 | 50

To establish and maintain the high quality level required for all quality-related activities for CPSES, TU Electric has developed a comprehensive Quality Assurance Program (QA Program) as documented in this chapter of the FSAR. TU Electric has implemented those portions of the Quality Assurance Program that are commensurate with the quality activities currently being performed. The program requires, as a minimum, that the quality activities performed by TU Electric and its contractors/vendors comply with the NRC criteria established in 10 CFR Part 50, Appendix B, Licensing of Production and Utilization Facilities, "Quality Assurance Criteria for Nuclear Power Plants". Where appropriate, the requirements of regulatory or safety guides have been incorporated into the program. | 71 | 60

The TU Electric Quality Assurance Program requires that a Quality Assurance Manual be established to provide references to the written policies, procedures and instructions used to implement the QA Program for each nuclear power plant project for which it provides service. The combination of the requirements documented in the Quality Assurance Program and the Quality Assurance Manual provides TU Electric with the means of fully executing its assignment. | 71

Appendix 17A identifies all safety-related items for CPSES within the scope of the Quality Assurance Program.

## 17.1 QUALITY ASSURANCE DURING DESIGN AND CONSTRUCTION

### 17.1.1 ORGANIZATION

The major organizations involved in the Comanche Peak Steam Electric Station (CPSES) project are:

60 | Texas Utilities Electric Company (TU Electric) - as the Applicant, TU
| Electric has delegated to the Nuclear Engineering and Operations (NEO)
| Group within TU Electric the management and the authority for the
| engineering, design, procurement, construction, operation, and quality
| assurance activities of CPSES.

60 | The NEO Group has been designated by TU Electric to have the authority
| for all engineering, design, procurement and construction activities
| for CPSES. The NEO Group provides the QA program for quality-related
| activities within its scope of work. The NEO Group may contract with
| others for specific work tasks.

71 | Engineering Services Contractors - Architect-Engineers such as Stone
| and Webster, Ebasco and other engineering services contractors, are
| assigned specific scopes of work for design engineering in accordance
| with the requirements of the Nuclear Engineering and Operation (NEO)
| organization and conduct this work in accordance with their TU
| Electric approved Quality Assurance Programs.

60 | Westinghouse - as the nuclear steam supply system supplier,
| Westinghouse provides TU Electric with the nuclear steam supply system
| by conducting engineering, design, procurement, and fabrication
| services for the NSSS and by providing the initial supply of nuclear
| fuel. Westinghouse provides the QA program on the NSSS structures,
systems and components.

Brown & Root (B&R) - as the Constructor, B&R provides TU Electric with
71 | construction services at the site. As the ASME NA certificate holder,
| Brown & Root provides the QA program for ASME Code Section III work.

B&R also provides QA functions as requested by the TU Electric Director, Quality Assurance. | 60

Organization charts for TUCO, Westinghouse QA, B&R QA and NEO Group are presented as Figures 17.1-1, 17.1-4, 17.1-5 and 17.1-6, respectively. | 60

17.1.1.1 TU Electric

The TU Electric Quality Assurance Organization was established to provide effective control of quality activities related to its nuclear plants. For CPSES, the provision of this control applies to all organizations performing quality related services during the engineering, design, procurement, and construction phases. The NEO organizations participating in the design and construction phase of CPSES are shown in Figure 17.1-6. This chart illustrates the organizational structure and lines of reporting for each organization. | 60 | 50 | 60

17.1.1.1.1 Quality Assurance Department | 60

The Quality Assurance Department is responsible for the development, implementation, and evaluation of the TU Electric Quality Assurance Program for design and construction. This responsibility extends into all project activities including engineering, design, procurement, and construction. The Quality Assurance Department is headed by the Director, Quality Assurance. | 60 | 25 | 60

The Director, Quality Assurance reports on all technical and administrative matters to the Vice President, Nuclear Engineering. This reporting arrangement provides isolation of cost and scheduling influences from activities performed by the Director, Quality Assurance. | 55 | 60

55 | The Director, Quality Assurance has the duty and authority to identify
| quality-related problems; to initiate, recommend or provide solutions;
60 | and to verify the implementation and effectiveness of solutions. He
| has authority to "Stop Work" in the engineering, design, procurement
| and construction phases. His principal duties and responsibilities
include the following:

71 | 1. Develops an overall TU Electric Quality Assurance Program and
| Quality Assurance Manual.

71 | 2. Establishes means for implementing the QA Program and Manual
| including personnel indoctrination and training, definition of
| individual's quality assurance responsibilities, and evaluation
| of modifications to the QA Program and Manual.

59 | 3. Performs audits and surveillances of quality assurance activities
| conducted by TU Electric.

60 | 4. Performs audits and surveillances of quality assurance activities
| conducted by contractors/vendors.

60 | 5. Manages the Quality Assurance Department.

50 | 6. Maintains liaison on quality assurance matters with TU Electric
| senior management.

7. Establishes means to assure that individuals or groups assigned responsibility for checking, inspecting, auditing, or otherwise verifying correct performance of an activity are independent of the group responsible for the performance of that specific activity.

60 | 8. Reviews the performance of the Quality Assurance Program on a
| regular basis (not less than quarterly) with TU Electric senior
| management during meetings of the Senior Management QA Overview
| Committee.

9. Reviews selected engineering and design documents, e.g., procurement specifications, purchase orders, and Chapter 17 of the Final Safety Analysis Report, for conformance to TU Electric quality assurance standards. | 60

In addition, the Director, Quality Assurance supervises the Manager, QC, the Manager, Operations QA and the Manager, QA. The Manager, Quality Control is responsible for implementation of portions of the CPSES QA Program and technical supervision of site QC efforts in construction areas excluding ASME Section III Code work. The Manager, Operations QA is responsible for implementation of portions of the CPSES QA Program and technical supervision of the training, trending and corrective action reporting efforts. The Manager, QA is responsible for verification of overall conformance to the QA Program and Manual. | 65 | 71

The qualification requirements of the TU Electric Director, Quality Assurance are: | 55

1. Minimum of 10 years experience in design, construction, and/or operations of power plants. A maximum of four years of this ten years experience may be fulfilled by related technical or academic training. | 59

2. A bachelors degree from an accredited college, university or other institution. | 59

3. Demonstrated ability to manage people and projects. | 9

4. Knowledge of quality assurance requirements for nuclear plants including a minimum of one year related experience in the implementation of a nuclear quality assurance program. | 59

17.1.1.1.2 Project Management | 37

The Vice President, Engineering and Construction reports to the Executive Vice President, Nuclear Engineering and Operations | 60

60 | and is responsible for the design and construction of CPSES. He has
| delegated design engineering and technical review of procurement
| activities for the CPSES project to the Director of Engineering.
| These activities may be delegated by the Director of Engineering to TU
| Electric approved engineering contractors/vendors. However, TU
| Electric retains overall responsibility for these activities. The
| Vice President, Engineering and Construction retains responsibility
| for cost and schedule and is charged with ensuring that quality
| requirements are met during design and construction.

60 | 17.1.1.2 Engineering Services Contractors

60 | Engineering Services Contractors are assigned specific scopes of work
| by the Vice President, Engineering and Construction through
| procurement documentation or other procedurally established
| administrative controls. Prior to award of contract for these
| services, the contractor's QA Manual will be approved and a pre-award
| evaluation will be performed by TU Electric Quality Assurance. This
| review and evaluation is designed to verify the conformance of the
| Contractor's QA Program to 10CFR50, Appendix B and any additional
| quality requirements, as specified by the Director of Engineering or
| the Director, Quality Assurance. Implementation audits are conducted
| beginning early in the life of the activities to assure adequate
| implementation of the contractors QA program.

60 | TU Electric, through the Vice President, Engineering and Construction
| may revoke the delegation and reassume design responsibility or may
| reassign this responsibility to other organizations. The Director of
| Engineering is responsible for the technical management of each
| engineering services contractor. This includes the responsibility to
| establish an adequate design interface among the various
| organizations. The Director, Quality Assurance is responsible for
| assuring that an adequate interface exists through the audit and
| surveillance programs.

17.1.1.3 Brown & Root

Brown & Root provides the QA program for ASME Section III Code construction and other QA functions as requested by the TU Electric Director, QA. B&R has an organization such that those performing the quality assurance functions have the freedom to identify quality problems, to provide means for obtaining solutions to problems, and to verify that solutions have been implemented. This organization has sufficient independence, authority, and technical expertise to carry out the program in an orderly, routine manner. It employs a documentation system which provides necessary record retention and access capability. | 71

Figure 17.1-5 presents the B&R QA Organization for Houston's office and for site activities. | 60

The B&R Quality Assurance (QA) Manager has the following qualifications:

1. College degree in an engineering discipline from an accredited university.

2. Ten years engineering or Quality Control experience.

3. Technical, supervisory and management experience in the field of Quality Assurance and Quality Control.

4. Administrative and managerial effectiveness in implementing a quality assurance program.

Technical support and auditing functions are accomplished under the QA Manager's direction through the B&R QA Department Section Managers. | 12

60 | B&R has been delegated responsibility for site construction
| activities, such as erection and installation, as well as the
| formulation, preparation, and issuance of construction procedures and
| documents necessary to accomplish these activities. The B&R
Construction Project Manager is also responsible for compliance with
the B&R QA Manual in the fabrication and installation of ASME Code,
Section III components.

71 | Technical direction of construction site QC activities other than ASME
| Section III Code work is provided by the TU Electric Manager, QC.
60 | Assisting him is the B&R Site QA Manager. Differences of opinion
50 | between the B&R Site QA Manager and the TU Electric Manager, QC are
71 | resolved by the TU Electric Director, QA. For technical and
| administrative supervision of ASME Section III Code work and for
| administrative supervision in all other areas, the B&R Site QA Manager
| reports to the B&R QA Manager. These interfaces are defined in
60 | Figures 17.1-5 and Figure 17.1-6.

60 | QC engineers and inspectors performing ASME Section III, Division 1,
| activities are responsible to the B&R Site QA Manager and are
| authorized to: (1) approve the start of various phases of work after
| inspection has been provided, (2) prohibit the use of materials,
| equipment, or workmanship which do not conform to specifications or
| which will cause improper construction relative to specification, (3)
| stop any work which is not being done in accordance with plans or
| specifications by initiating a nonconformance report and (4) with
| prior approval from the B&R Site QA Manager, require the removal or
| repair of faulty construction or of construction performed without
| inspection and which cannot be inspected in place.

17.1.1.4 Consultants

50 | TU Electric utilizes the services of qualified consultants to assist
| in the performance of quality-related tasks such as audits,
| inspections, interpretations of test results, and review.

17.1.1.5 Organizational Interfaces

TU Electric establishes with each of its principal contractors a division of responsibility covering all phases of the project. This division of responsibility becomes the basis for identifying specific external interfaces to the system, structure, and component level which TU Electric must control. For CPSES, the interrelationships of the participating organizations in the QA Program are summarized as follows: | 50

1. B&R Site QA Manager reports to the B&R QA Manager for technical and administrative supervision of ASME Section III Code work, and for administrative supervision in all other areas. Technical direction of the B&R Site QA Manager in areas other than ASME is provided by the TU Electric Manager, QC. | 71 | 55

2. Construction site inspection is performed under the direction of TU Electric Site QC and B&R Site QC (ASME Section III Code work). | 71

3. Periodic audits and surveillances of site QC and construction activities are performed by TU Electric QA to verify conformance. | 60

4. Vendors are required to provide internal, independent QA Programs to check safety-related design and fabrication work unless working under the TU Electric QA Program. | 60

5. TU Electric QA and/or its consultants or agents perform vendor audits and surveillances to verify vendor performance. | 60

6. Westinghouse is required to provide an internal QA Program for NSSS components. | 6

60 | 7. TU Electric and its design contractors/vendors provide a Design Control Program for design and engineering. TU Electric is responsible for assuring design interfaces.

60 | 8. TU Electric QA periodically audits contractors/vendors, Brown and Root and internal TU Electric safety-related activities.

71 | 9. B&R QA periodically audits the B&R ASME Section III Code Program onsite, as required to maintain the B&R ASME Certificate of Authorization.

### 17.1.2 QUALITY ASSURANCE PROGRAM

71 | TU Electric's Quality Assurance Program and CPSES Quality Assurance Manual are the primary documents by which TU Electric assures effective control of all project quality-related activities. The other major participating organizations and their functions are identified in Section 17.1.1.

71 | In the development of the CPSES QA Program and Manual, TU Electric has utilized the provisions of Appendix B, 10 CFR Part 50, and certain of the ANSI N45.2 series standards, including N45.2.12, Draft 3, Rev. 0.
71 | Table 17.1-2 is a matrix which shows 10 CFR Part 50, Appendix B criteria versus appropriate sections of the Quality Assurance Manual. This matrix illustrates how the Manual satisfies the 18 criteria. Revisions to the Program and Manual incorporate the intended objectives of the ANSI standards and draft standards as presented in the NRC text "Guidance on Quality Assurance Requirements During Design and Procurement Phase of Nuclear Plants," dated June 7, 1973. Subsequent comments by the Nuclear Regulatory Commission staff have also been considered in latest revisions to the CPSES QA Program and Manual.

Procedures define the organizational structures within which the programs are implemented and delineates the authority and responsibility of the persons and organizations involved performing

design, engineering, procurement, and construction activities affecting the quality of design. These procedures identify the organization interfaces, both internal and external, between the contributing organizations.

The CPSES QA program is effectively administered and controlled by TU Electric through close association with, and supervision and audit of, the contractors who perform the requirements outlined herein. The QA programs of the contractors are reviewed by TU Electric QA and/or its agents to assure that they contain adequate requirements and procedures to control the quality level. | 60

Authority to implement certain nuclear QA activities included in the TU Electric QA Program during design, procurement and construction has been delegated to approved contractors/vendors. These activities are conducted in accordance with the current revisions of the approved contractors/vendors QA Topicals or QA Plans and Procedures. B&R is delegated the authority for QA functions relating to ASME Section III Code work. Primary authority for the construction site QA and QC programs lies with the TU Electric Director, Quality Assurance. This QA Program is organized to provide an integrated plan under the direct control of the TU Electric Director, QA. | 60 | 71 | 60

### 17.1.3 DESIGN CONTROL

The TU Electric Quality Assurance Program provides for several levels of design control. These levels include the design control measures of TU Electric and its approved contractors/vendors. TU Electric is the engineering organization ultimately responsible for plant design. TU Electric has contracted with Westinghouse for the Nuclear Steam Supply System design. TU Electric may contract with approved Architect-Engineers for specific design work tasks. | 71 | 60

60 | TU Electric Regulatory Guide commitments for design activities are
| discussed in, FSAR sections 1A(N) and 1A(B). The TU Electric QA
| Program requires that the engineering services contractors meet
| applicable NRC Regulatory Guides for technical design requirements as
| specified by the Director of Engineering for all safety-related
| activities.

71 | The CPSES QA Program requires verification that applicable NRC
| Regulatory Guides for technical design requirements have been
| incorporated in activities affecting quality by design review, audit,
| and surveillance of engineering services contractors.

This verification assures that applicable regulatory requirements and the design bases as specified in the license application for safety-related structures, systems, and components for CPSES are correctly translated into specifications, drawings, procedures, and
60 | instructions. Audits by TU Electric assures that the engineering
| services contractor organizations' design control measures include a
| clear definition of design interfaces, review and approval of initial
| design, including changes or revisions, and that personnel performing
| design reviews are thoroughly familiar with the regulatory
| requirements and design bases described in the PSAR/FSAR and are
| independent of those originating the design.

17.1.3.1 Design Control for Preparation of Drawings

6 | Design drawings are prepared, reviewed, and controlled per applicable
| project procedures. These procedures ensure that design drawings are
| reviewed independently for completeness, accuracy, agreement with
| design concepts, and possible interferences. Further review is
| provided by engineers of related disciplines who review for
| consistency and compatibility with related systems and design
| requirements. Procedures also call for supervisory review for content
| and compliance. Changes to drawings or drawing input are subject to
| the same controls as were applicable to the original.

17.1.3.2 Engineering Specifications

The TU Electric Quality Assurance Program requires that measures be | 60
documented for the translation of applicable regulatory requirements |
and design bases into specifications. Written procedures require |
that the specification be independently reviewed for technical | 6
accuracy, completeness, conformance with applicable regulatory |
requirements, and overall acceptability. Additional review is |
provided by related disciplines to ensure coordination and by project |
management for overall project requirements. Changes to engineering | 71
specifications are subject to the same controls as were applicable to |
the original. Written procedures further require documentation of |
the reviews. | 9

17.1.3.3 Review of Vendor Equipment Drawings, Specifications, and | 6
Procedures | 6

Upon receipt from a manufacturer, these documents are routed through | 6
the applicable engineering disciplines to check compliance with |
engineering drawings, and specifications. A controlled interface is |
maintained with the manufacturer to assure resolution of |
discrepancies. Interdiscipline and supervisory reviews of this | 9
process are performed and documented as well. |

17.1.3.4 Engineering Calculations

Measures have been established that control the preparation of | 9
calculations. Written procedures outline the method of preparation |
to ensure uniformity, validity of assumptions and input, as well as |
accuracy of results. Procedures also require review of calculations |
by an independent checker. Each review is documented. |

17.1.3.5 Design Review and Verification | 6

Safety related design activity is reviewed in accordance with a | 6
formalized and documented system. The types of review used are: |

6 | 1. Checks to compare information presented on a drawing or other document with a definite figure, criterion, or design base.

6 | 2. Supervisory reviews of design work, conducted by a superior in a given discipline, of work by a project team member in that discipline.

6 | 3. Interface reviews, by personnel of one discipline, of work performed by another discipline to determine that the reviewer's discipline requirements and commitments are satisfied.

6 | 4. Review by QA to determine that QA requirements are included as appropriate for the item being reviewed.

6 | Design verification to review, confirm or substantiate the design is performed to provide assurance that the design meets the specified inputs. Methods of verification include, but are not limited to, design review, alternate calculations, and qualification testing. Procedures will define the actions necessary to report and resolve deficiences identified during design verification.

50 | Written procedures define the actions necessary to report and resolve deficiencies identified during design verification.

17.1.3.6 Design and Engineering Surveillance

6 | In order to verify that engineering and design of nuclear safety related structures systems, and components are performed in accordance with applicable procedures these efforts are reviewed by Quality Assurance through surveillance or audit. The scope and frequency of these reviews is commensurate with the complexity of the design and past performance.

The surveillance and audit functions are documented in written procedures.

17.1.3.7 Record Accumulation & Control

Records associated with the design activity are maintained and copies of these records stored as required. These records are audited by TU Electric QA and/or its agents. | 6

17.1.4 PROCUREMENT DOCUMENT CONTROL

Appropriate requirements have been established by the TU Electric Quality Assurance Program to assure that procurement documentation is controlled and accurately reflects applicable regulatory requirements, design bases, and other appropriate requirements, such as industry codes and standards. These requirements are consistent with the provisions of Regulatory Guide 1.28 and Regulatory Guide 1.123 as discussed in Appendix 1A(B) and apply to procurement documents prepared by TU Electric, or their designated agents. | 60 | 59

TU Electric has satisfied these requirements as follows: | 50

Selected review of procurement documentation for materials, equipment, and services listed in Table 17A-1 of FSAR Section 17A is performed. This review is described in 17.1.1.1.1. | 57

Planned, periodic, and documented audits are performed by TU Electric QA personnel or its agents to provide assurance that the procurement activities of TU Electric and contractors/vendors are being carried out in accordance with approved procedures. These audits will be conducted as described in paragraph 17.1.18. | 60

All procurement documents that are prepared by contractors/vendors on behalf of TU Electric are subject to reviews and controls similar to those described in this section. Contracts involving equipment, material, or services that are concerned with nuclear or | 71 | 60

60 | nuclear safety equipment, systems, or structures require appropriate
| Quality Assurance and Quality Control by the vendor. QA defines the
| requirements of the Vendors' QA Program contents and changes thereto,
| and those requirements will be enumerated in each procurement
| specification.

71 | TU Electric or Brown and Root (ASME Section III Code Purchases)
| Quality Assurance also reviews purchase orders or contracts to assure
| that all required quality assurance and quality control information of
| the procurement document, including requirements for control,
| maintenance, and submittal of quality records, is reflected in the
| purchase order and contract.

60 | When required, contracts or purchase orders issued by TU Electric or
| its agents for any component, system, structure, or service,
| classified as being nuclear or nuclear safety-related is referenced to
| the applicable criterion of Appendix B to 10 CFR Part 50 or ASME code
| requirements.

60 | TU Electric and their contractors evaluate vendor Quality Assurance
| Programs prior to award of contracts or issuance of purchase orders as
| discussed in Section 17.1.7.

### 17.1.5 INSTRUCTIONS, PROCEDURES, AND DRAWINGS

60 | Appropriate requirements have been established by the TU Electric
| Quality Assurance Program to assure that quality-related activities
| for CPSES are prescribed by documented instructions, procedures, or
| drawings; accomplished in accordance with such documents; and that
| approved acceptance criteria are met. The authority for the
| development of the methods that assure this is delegated to the
| various participating organizations; however, the developed methods
71 | are subject to TU Electric audit. The TU Electric QA Program
| requires that measures be established by TU Electric and its

contractors/vendors to assure that approved changes are promptly included into instructions, procedures, and drawings where applicable. | 60

The CPSES QA Program requires that changes be reviewed for their effect on present instructions, procedures and/or drawings. | 71

The TU Electric QA Program requires that an inspection procedure include flow charts, shop travelers or narrative description of the sequence of activities or operation for fabrication, processing, assembly, inspection, and test. Instructions shall indicate the operations or processes to be performed, type of characteristics to be measured or observed, the methods of examination, the applicable acceptance criteria and documentation requirements. The program also requires establishment of those inspection, test, and hold points from raw material through fabrication, processing, and assembly at which conformance of parts, components, and subsystems to requirements are verified. Hold points identify those inspections which are rendered impossible to perform by subsequent operations, and those inspections must be certified as completed before start of the next operation by the use of process sheets (e.g. travelers). Each process sheet shall include the date of completion of operation or test and the signature or stamp of the operator or inspector. TU Electric QA reviews applicable documentation to assure that it adequately reflects applicable quality requirements. In its review activities, TU Electric QA assures that instructions, procedures, and drawings contain appropriate quantitative (such as, dimensions, tolerances, and operating limits) or qualitative (such as workmanship samples) acceptance criteria for determining that important activities have been satisfactorily accomplished. | 60 | 4 | 50 | 57

Through its auditing procedures, as described in 17.1.18, TU Electric determines that quality related activities are accomplished in accordance with those approved instructions, procedures, and drawings.

## 17.1.6 DOCUMENT CONTROL

50 | TU Electric has established requirements to assure that documents, including changes, are reviewed for adequacy and approved for release
60 | by authorized personnel. These requirements provide that contractors/vendors include in their internal programs measures to assure that changes to documents will be reviewed and approved by the same organizations that performed the original review and approval or others as designated by TU Electric. TU Electric will verify implementation of these requirements through audits of
71 | contractors/vendors. The CPSES QA Program requires that changes to documents that have been reviewed and approved by TU Electric organizations will be reviewed and approved by those same TU Electric organizations that performed the original review and approval unless TU Electric designates another organization. These requirements also
60 | provide that the documents are distributed to and used at the location where the prescribed activity is performed. The scope of these requirements applies to TU Electric as well as to contractors/vendors.

50 | TU Electric employs within its own internal organization a control system that utilizes registering of documents requiring control, distribution, and review and approval procedures. The TU Electric Quality Assurance Program requires design engineering and procurement documentation for all safety-related equipment which consists of specifications, drawings, PSAR/FSAR material and related licensing questions and answers, instructions, procedures, reports and changes thereto, and manufacturing and construction documents and records required for traceability, evidence of quality, and substantiation of
55 | the "as built" configuration, be controlled. Procedures identify those individuals or groups responsible for reviewing, approving and issuing documents and revisions thereto. Where deemed necessary, TU Electric will require that periodic in-place document summary lists including revision level be submitted by an organization to verify the use of the proper document or change.

Uncontrolled installation or use of delivered components does not occur until receipt of objective evidence of the quality verification package. The quality verification package is required to be on-site prior to relying on the related equipment to perform a safety function. | 25

## 17.1.8 IDENTIFICATION AND CONTROL OF MATERIALS, PARTS AND COMPONENTS

Appropriate requirements have been established to assure continuous and accurate identification and control of materials, parts, and components so that the use of incorrect or defective materials, parts, or components is prevented.

| Q421.82

TU Electric and its contractors/vendors are required to utilize procedures which establish and document a system or method for identifying the material (e.g., physical marking, tagging, labeling, color code). Upon receipt of Q material, equipment receipt inspections are performed and documented. Items are then entered into the program established by site procedures and instructions for the storage and handling of Q material and equipment. Procedures and instructions require the status of nonconforming items to be maintained as required by Section 17.1.14. Upon request for material and equipment, the status of the item requested is checked, and QC concurrence is required prior to release to construction. Provisions are made for the conditional release of the status of nonconforming items under certain conditions. Procedures outline the required identification, traceability, and controls, including TU Electric QA approval that must be met before a conditional release request can be issued. If granted, the approval provides for further processing on a removal risk basis while the conditional release is in effect. This system provides assurance that only acceptable items are ultimately used. Material traceability is provided as specifically required by

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50 | applicable codes and procedures. Material identification either on
| the item, or on records uniquely traceable to the item, will be
| provided for other components except where specific categories of
| material are exempted. Where identification marking of an item is
| employed, the marking is clear, understandable and legible, and
| applied in such a manner as not to affect the function of the item.
The identification and control measures provide for relating the item of production (batch, lot, components, part) at any stage, from materials receipt through fabrication, shipment, and installation, to an applicable drawing, specification, or other technical document.

71 | TU Electric and its contractors/vendors are required to establish and
| implement a documented program for inspecting, marking, identifying,
| and documenting the status of material prior to use or storage.

25 | Hold points are required where inspections must be made and certified
| complete before start of next operation. Inspection of materials
| includes the following; as applicable:

1. Verification that identification and markings are in accordance with applicable codes, standards, specifications, drawings, and purchase orders.

2. Visual examination of materials and components for physical damage or contamination.

3. Examination of quality verification records to assure that the material received was manufactured, tested and inspected prior to shipment in accordance with applicable requirements.

4. Actual inspection as required of workmanship, configuration, and other characteristics.

These inspections are documented and verified as appropriate by vendor and TU Electric QA/QC organizations. TU Electric performs surveillance of vendor facilities to assure implementation of the program. | 25

Items shipped to the site are normally identified by nameplate or other identification marking on the item. In those instances when it is not practical to provide identification markings on the individual items, identification information is provided in shipping paperwork that is transmitted with each shipment.

TU Electric and its contractors/vendors are required to establish specific measures to assure compliance with approved procedures for identification and control of materials, parts, and components, including partially fabricated assemblies. TU Electric QA verifies conformance by three methods: | 71 | 60

1. Review and approval of contractors'/vendors' quality assurance programs. | 60

2. Surveillance of selected manufacturing, fabrication, construction, and installation activities by quality assurance personnel.

3. Auditing of TU Electric and contractors/vendors implementation of the approved Quality Assurance Program. | 60

17.1.9 CONTROL OF SPECIAL PROCESS

TU Electric and its contractors/vendors are required to establish written procedures and controls to assure that special processes including welding, heat treating, casting, coating applications, nondestructive testing, and concrete batching | 71

60 | are accomplished by qualified personnel, using qualified procedures,
| in accordance with applicable codes, standards, specifications,
| criteria, and other special requirements. These procedures describe the operations performed, the sequence of operations, the characteristics involved (e.g., flow, temperature, fit-up, finish, hardness, and dimensions), the limits of these characteristics, process controls, measuring and testing equipment utilized, and documentation requirements.

56 | Alternative requirements, as provided by ASME Code Cases, are utilized
60 | at CPSES in accordance with 10 CFR Part 50, Section 55a(a)(3). By
| reference to ASME Section III requirements in the procurement
| specifications, the use of code cases by mechanical equipment vendors
| requires mutual consent of TU Electric or his agent and the
| manufacturer. The ASME Code Cases which are used for design and
56 | erection at CPSES are identified in the appropriate mechanical design
| and erection specifications or the Brown & Root QA Manual;
| conditionally-approved Code Cases will show justification for their
| use, as required by NRC, in these documents. The application of ASME
60 | Code Cases is documented on the ASME Data Report Forms. For further
| discussion, see the text concerning Regulatory Guides 1.84 and 1.85 in
| FSAR sections 1A(N) and 1A(B).

Examinations, tests, and inspections are conducted to verify conformance to the specified requirements.

Written procedures also are required to cover training, examination, qualification, certification, and verification of personnel as well as the maintenance of all required personnel records.

71 | Compliance with these procedures is required for TU Electric and its
| contractors/vendors. Procedures for control of special processes are
60 | subject to review and approval by TU Electric on a case basis.

55 | TU Electric assures conformance with these requirements by:

1. Review of procedures for inclusion of control of special processes where required; proper definition of requirements for operator training, qualification, and certification; conformance to applicable codes, standards, drawing, specifications, or other criteria. | 50

2. Audits to verify the adequacy of selected site and vendor shop activities and the effectiveness of the special process control procedures being implemented. | 60

17.1.10 INSPECTION

TU Electric audits contractors/vendors are required to establish a division of authority which determine the services, structures, systems, components and materials for which each has inspection authority. TU Electric however, reserves the right to review, disapprove and perform surveillance or audits of the inspection procedures utilized by these organizations. | 71 | 50

The review and approval of contractor's/vendor's inspection procedures is accomplished as an integral part of TU Electric's review of the organization's Quality Assurance/Quality Control Programs. TU Electric Quality Assurance uses the following criteria in establishing an inspection program and in evaluating inspection methods proposed by organizations under contract: | 60 | 71

1. Inspection procedures for functional groups such as procurement, project management, construction, and shop inspection are described, including measures to identify inspection and test status.

2. Duties and responsibilities of personnel performing inspection are clearly established.

3. Qualifications of personnel performing inspections are commensurate with their duties and responsibilities.

4. Documentation methods for inspection activities of each group are established (e.g., inspection forms, reports).

50 | 5. Documentation control systems for identifying, distributing, and
| retaining requisite inspection documents are defined.

6. Review and approval procedures for inspection documentation are provided.

7. Surveillance methods are established to assure proper implementation of inspection procedures.

71 | 8. Planning of inspection sequence activities include the type of
| characteristics to be measured, the methods of examination, and
| the criteria.

Inspection planning is utilized to assure conformance to procedures, drawings, specifications, codes, standards and other documented instructions. Inspections are performed by individuals not responsible for the activity being inspected. Sufficient inspections are conducted to verify conformance particularly in areas rendered inaccessible by further processing. Process monitoring is utilized in lieu of inspection in those cases where inspection is impossible, disadvantageous or destructive. When required for adequate control, a combination of inspection and process monitoring is employed. Hold points are established and enforced as required by the supplier and the purchaser. TU Electric and/or its representatives verifies by review of inspection reports, visits to vendor shops, and onsite surveillance, that inspections are being performed and documented by personnel in conformance with approved procedures.

## 17.1.11 TEST CONTROL

The TU Electric Quality Assurance Program requires that TU Electric and its contractors/vendors designate appropriate tests to be performed at specific stages of manufacturing, fabrication, and construction. Conduct of test is governed by written procedures which incorporate requirements and acceptance limits to assure that the structures, systems, and components tested perform satisfactorily in service. Tests are conducted in accordance with these procedures and are properly documented. | 71

TU Electric and its contractors/vendors are required to assure that all necessary tests are conducted. Such testing is performed in accordance with quality assurance and engineering test procedures which incorporate or reference the test requirements and acceptance limits contained in applicable design documents. Test requirements and acceptance criteria are provided by the organization responsible for the specification of the item under test, unless otherwise designated. The entire test program covers all required testing, including, as appropriate, development testing, prototype qualification testing, performance testing of production equipment, calibration testing of instruments, and hydrostatic testing of pressure boundary components. | 71

Test procedures include:

1. Requirements that prerequisites for the test have been met. Test prerequisites include but are not limited to the following:

    a. Calibrated instrumentation
    b. Adequate and appropriate equipment
    c. Trained, qualified, and, as appropriate, licensed and/or certified personnel

d. Preparation, conditions, and completeness of item to be tested

e. Suitable and, if required, controlled environmental conditions

f. Mandatory inspection hold points where applicable for witness by owner, contractor, or authorized inspector

g. Provisions for data collection and storage

h. Acceptance and rejection criteria

i. Methods of documenting or recording test data results

2. Designation of specific test methods to adequately assess appropriate parameters.

3. Designation of measuring and test equipment to be used.

4. Specific environmental considerations.

5. Measures to prevent damage to the item or system under test.

6. Safety considerations.

7. Documentation requirements.

Test results are evaluated to verify:

1. Proper functioning of the system, structure, or component.

2. Conformance to design specifications.

3. Compliance with stated test requirements.

50 | 4. That test results are within acceptance limits.

5. That recording and documentation is complete and accurate.

## 17.1.14 INSPECTION, TEST, AND OPERATING STATUS

TU Electric and its construction contractor/vendors have established procedures to identify the inspection, test, and operating status of safety-related structures, systems, and components. The inspection and test status of items are required to be maintained through the use of status indicators such as physical location, tags, markings, shop travelers, stamps, or inspection records. These measures provide for assuring that only items that have received and satisfactorily passed the required inspections and tests are used in manufacturing or are released for shipment. The procedures for control of status indicators, including the authority for application and removal of tags, markings, labels, or stamps, are documented in approved manufacturing or quality assurance procedures. | 60 | 50

System completeness and acceptance prior to fuel load will be determined by: | 33

1. Reviewing quality verification records for adequacy, completeness, and conformance to quality assurance requirements for each system or component being accepted.

2. Visually examining the systems or components in order to verify that they have been correctly installed. | 33

Systems are transferred to TU Electric through procedures that require inspections and signoffs by TU Electric. Upon completion of the transfer, the Manager, Plant Operations assumes operational and maintenance responsibility for each system. Prerequisite testing and preoperational testing will be conducted. TU Electric QA/QC personnel will assure that outstanding construction, document and test deficiencies will be controlled. Prior to fuel load, all remaining outstanding identified deficiencies will be reviewed to verify that they have no adverse impact on safety. | 71 | 50 | 55 | 50

The methods of identifying the status of these systems is through the use of status indicators such as tags, stickers, markings, or status
60 | cards. These indicators are used on valves, switches, meters, or
| equipment to indicate their test or operating status. TU Electric QA Site personnel monitor the use of these indicators to assure their proper and effective implementation.

### 17.1.15 NONCONFORMING MATERIALS, PARTS, OR COMPONENTS

60 | The TU Electric Quality Assurance Program requires that measures be
| documented by TU Electric and its contractors/vendors to control the
| identification, documentation, segregation, and disposition of
| nonconforming material, parts, or components. These measures prevent
| their inadvertent use or installation and are subject to review by TU
| Electric QA.

Written procedures require investigation of the nonconforming item, decisions on their disposition, and preparation of adequate reports. Procedures also control further processing, fabrication, delivery, or
60 | installation of items for which disposition is pending. All reports
| documenting actions taken on nonconforming items are available to TU
| Electric for evaluation.

71 | The TU Electric Quality Assurance Program requires that measures be
| established by TU Electric and its construction contractors to assure
| that departures from design specification and drawing requirements
| that cannot be dispositioned "rework" or "scrap" are formally reported
| to and dispositioned by TU Electric Engineering or its contractors.
| TU Electric QA audits to assure compliance. The TU Electric QA
60 | Manager assures that periodic evaluations of these reports are
| forwarded to TU Electric management to show quality trends.

The effectiveness of nonconformance control procedures may be verified by:

1. Contractor quality assurance and manufacturing, fabrication, or construction personnel involved in processing nonconforming reports.

2. TU Electric participation in dispositions and approvals as well as by the contractor responsible for the specification. | 60

3. Document review at final inspection or shipping release.

4. Audits or surveillances performed by the contractor, vendor, and TU Electric. | 60

Conditions which render the quality of an item or activity unacceptable or indeterminate will be identified, resolved and closed out. Such conditions are documented on inspection reports, deficiency reports, or nonconformance reports in accordance with procedures. | 50

An inspection report (IR) is used to document field inspections performed by Quality Control (QC). Each attribute on the IR is verified to be satisfactory or unsatisfactory. | 50

A deficiency report (DR) is a document used for documenting, controlling and correcting a condition or action which departs from procedures or other specific requirements but does not necessarily render the quality or function of a safety-related item unacceptable or indeterminate. | 61

A nonconformance report (NCR) is a document used for documenting, controlling, and correcting a condition or action which departs from | 71

71 | procedures or other specified requirements and renders the quality or
| function of a safety-related item unacceptable or indeterminate.
65 | Nonconformance reports shall be issued for those instances where:

65 | (1) A potentially nonconforming condition is identified and an
| approved method is not provided in the work, inspection, or
| test procedures or program to document the condition; or

65 | (2) A potentially nonconforming condition has been identified
| and documented in accordance with approved procedures or
| programs and the identified condition cannot be corrected
| (reworked or scrapped) to comply with existing engineering
| requirements in accordance with approved procedures.
65 |
71 | Disposition of items of unsatisfactory, unacceptable or indeterminate
| quality identified on IR's, DR's, or NCR's, is determined by
| appropriate personnel and may result in a design change as discussed
| in Section 17.1.3 "Design Control". IR's, DR's, and NCR's remain
50 | open until the deficiency is satisfactorily resolved and identified
| corrective action satisfactorily completed. Upon completion of the
| action required for disposition, repaired or reworked items are
| reinspected to verify compliance with specified actions and
65 | requirements. Independent review of nonconformances, including
| disposition and closeout, is performed by appropriate Quality
| Assurance personnel. The status of these items is maintained in
50 | accordance with Section 17.1.14, "Inspection and Test Status" and
| Section 17.1.13, "Handling, Storage and Shipping".

Procedures require trending of deficiencies reported on inspection | 50
reports, deficiency reports, and nonconformance reports to identify |
trends adverse to quality. Trend reports are reviewed quarterly by |
appropriate levels of management to address areas requiring corrective |
action. |

Nonconformance reports and trend reports are reviewed upon issuance by | 65
the appropriate Quality Assurance personnel for significant conditions |
adverse to quality or chronically repetitive deficiencies. If such |
conditions exist, procedures require additional action, as | 50
appropriate. This may include issuance of corrective action requests |
as discussed in Section 17.1.16, "Corrective Action", or reports to |
the Nuclear Regulatory Commission. |

17.1.16 CORRECTIVE ACTION

TU Electric requires that measures be established to assure that | 50
conditions adverse to quality are promptly identified, reported, and |
corrected. Responsibility for performing corrective action is | 71
assigned to the responsible TU Electric organization or its |
contractors/vendors so that each is alert to those conditions adverse |
to quality within his own area of activity. In the case of |
significant conditions adverse to quality, measures are taken to | 60
assure that the cause of the condition is determined and corrective |
action is implemented to preclude repetition. Corrective action |
procedures placed in effect require thorough investigation and
documentation of significant conditions adverse to quality. The cause | 60
and corrective action is reported in writing to the appropriate levels |
of contractor/vendor management and to TU Electric in accordance with |
the purchase document. |

For CPSES, the Quality Assurance Program requires that procedures and | 71
practices be established and documented which provide assurance |

that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances, are promptly identified, documented, and corrected as soon as practicable, and that appropriate action be taken to correct the cause of the condition. Corrective action documentation and request forms or formal letters are used to document the corrective
71 | action-related requests, responses, and follow up. The QA Program
| requires that measures be established by TU Electric and its
| construction contractors/vendors to assure that the acceptability of
| rework or repairs is verified by reinspecting the item to specified
| requirements and that the reinspection is documented. These measures
60 | are verified by review and approval of the construction
| contractors'/vendors' QA Program and by the subsequent audit for
| conformance to the approved program. Significant conditions adverse to quality are identified (such as those which, if they had remained undetected, would have adversely affected safety-related functions), the cause of the condition is determined, and corrective action is taken to preclude repetition. Such significant conditions, their causes, and the corrective action taken are documented and reported to appropriate levels of management through established communication systems. Corrective action followup and close-out procedures provide that corrective action commitments are implemented in a systematic and timely manner and are effective.

The occurrence and magnitude of deficiencies and nonconformances requiring corrective action are evaluated by the purchaser's inspectors during surveillance and at hold point inspection and witnessing. Additionally, these areas are identified for audit purposes.

The effectiveness of the vendor's corrective action program is
60 | assessed during audits by TU Electric. Stop work authority is
| exercised as required.

## 17.1.17 QUALITY ASSURANCE RECORDS

The TU Electric Quality Assurance Program establishes procedures and practices to assure that TU Electric and its contractors/vendors have a quality records system which provides documentary evidence of the performance of activities affecting quality. Procedures assure or shall require: | 60

1. That records that are required to be maintained show evidence of performance of activities affecting quality. Typical records maintained include quality assurance programs and plans, design data and studies, design review reports, specifications, procurement documents, procedures, inspection and test reports, material certifications, personnel certification and test reports, audit reports, reports of nonconformances and corrective actions, as-built drawings, operating logs, calibration records, maintenance data, and failure and incident reports.

2. That inspection and test records, as a minimum, identify the date of the inspection or test, the inspector or data recorder, the type of observation, the results, the acceptability, and the action taken in connection with any deficiencies noted. | 50

3. That records are protected against deterioration and damage.

4. The criteria for determining the classification of the record as well as the length of the retention period.

5. The method of identification and indexing of records for ease of retrievability.

6. Responsibility for record keeping during design, fabrication, construction, preoperational testing and commercial operation.

7. The method of transfer of records between organizations.

60 | TU Electric verifies conformance to the record requirements by
| reviewing contractors'/vendors' quality assurance methods for record
| keeping, by auditing contractors'/vendors' systems when functional,
| and by selective review of quality records for completeness and
| accuracy.

71 |

71 | Records will be stored in specially constructed storage facilities at
| CPSES to prevent their destruction, deterioration or theft. Access
| to the records facility is controlled so that only authorized
| personnel will have access to the records area. As an alternative to
| the utilization of the storage facility, maintenance of duplicate
| records stored in a remote location is acceptable.

### 17.1.18 AUDITS

TU Electric requires that planned and periodic audits be performed to verify compliance with all aspects of the quality assurance program

60 | and to determine the effectiveness of the program. TU Electric QA
| performs such audits on TU Electric and its contractors/vendors to
| provide an objective evaluation of the effectiveness of their
| programs; to determine that their programs are in compliance with
| established requirement, methods, and procedures; to determine quality
| progress; and to verify implementation of recommended corrective
| action. TU Electric audits, both internal and external, are
conducted primarily by members of the Quality Assurance staff.
Consultants will be utilized by TU Electric on audits as required.

As part of the Quality Assurance program TU Electric QA: | 29

1. Utilizes an audit planning document which defines the organizations and activities to be audited and the frequency of the audits.

2. Requires auditors be familiar with the type of activities to be audited and have no direct responsibilities in the area being audited.

3. Provides auditing checklists or other objective guidelines to identify those activities which will be examined. | 25

4. Requires examination of the essential characteristics of the quality related activity examined. | 50

5. Requires an audit report be prepared and that it notes the extent of examination and deficiencies found. | 55

6. Requires the audit report be sent to management responsible for the area audited for review and corrective action for deficiencies.

7. Requires corrective action taken as result of the audit be reported.

8. Requires reauditing of deficient areas when it is considered necessary to verify implementation of required corrective actions.

Documentation of audits performed by contractors/vendors are made available to TU Electric for evaluation. | 60

71 | TU Electric verifies conformance to the regulatory audit requirements
| by three methods:

60 | 1. Review of contractors'/vendors' quality assurance methods for
| auditing.
71 |
71 | 2. Review of documentation of the audit report performed by those
| contractors/vendors.

71 | 3. Internal and external audits performed by members of the Quality
| Assurance staff.

TABLE 17.1-2

(Sheet 1 of 2)

CPSES QA MANUAL COMPLIANCE MATRIX ; 71

COMANCHE PEAK

QUALITY ASSURANCE

MANUAL ; 71

APPENDIX B

QUALITY ASSURANCE CRITERIA

| MANUAL | I | II | III | IV | V | VI | VII | VIII | IX | X | XI | XII | XIII | XIV | XV | XVI | XVII | XVIII |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1.0 Organization | X | | | | | | | | | | | | | | | | | |
| 2.0 Quality Assurance Plan | | X | | | | | | | | | | | | | | | | |
| 3.0 Design Control | | | X | | | | | | | | | | | | | | | |
| 4.0 Procurement Document Control | | | | X | | | | | | | | | | | | | | |
| 5.0 Instructions, Procedures and Drawings | | | | | X | | | | | | | | | | | | | |
| 6.0 Document Control | | | | | | X | | | | | | | | | | | | |
| 7.0 Control of Purchased Items and Services | | | | | | | X | | | | | | | | | | | |
| 8.0 Identification and Control Items | | | | | | | | X | | | | | | | | | | |
| 9.0 Control of Construction Processes | | | | | | | | | X | | | | | | | | | |
| 10.0 Examinations, Tests and Inspections | | | | | | | | | | X | | | | | | | | |
| 11.0 Test Control | | | | | | | | | | | X | | | | | | | |
| 12.0 Control of Measuring and Test Equipment | | | | | | | | | | | | X | | | | | | |
| 13.0 Handling, Storage, and Preservation | | | | | | | | | | | | | X | | | | | |
| 14.0 Examination or Test Status | | | | | | | | | | | | | | X | | | | |

TABLE 17.1-2

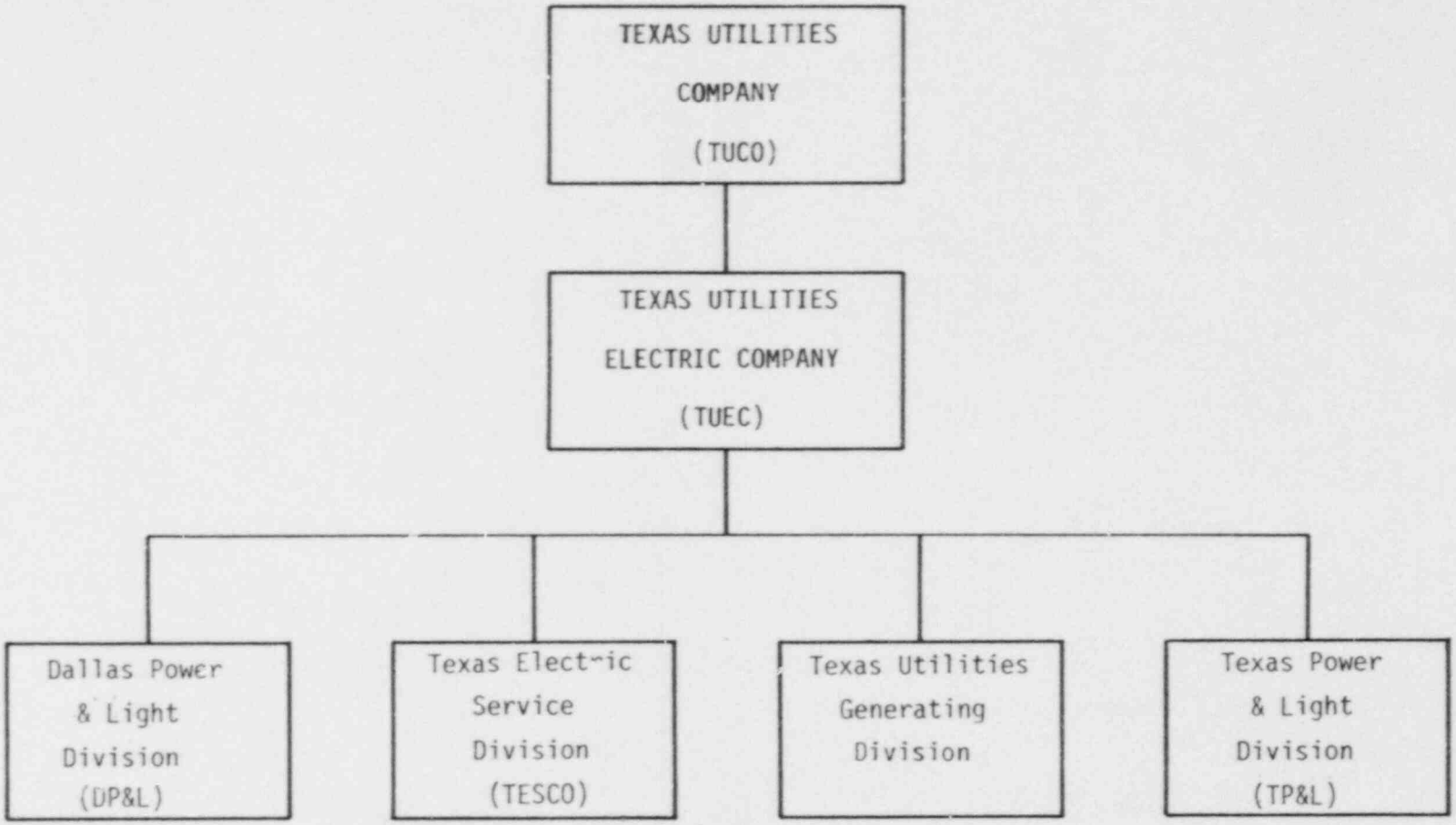
(Sheet 2)

CPSES QA PLAN COMPLIANCE MATRIX

APPENDIX B

QUALITY ASSURANCE CRITERIA

| COMANCHE PEAK QUALITY ASSURANCE MANUAL | I | II | III | IV | V | VI | VII | VIII | IX | X | XI | XII | XIII | XIV | XV | XVI | XVII | XVIII | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 15.0 Nonconforming Items | | | | | | | | | | | | | | | X | | | | ; 71 |
| 16.0 Corrective Action | | | | | | | | | | | | | | | | X | | | |
| 17.0 Quality Assurance Records | | | | | | | | | | | | | | | | | X | | ; 71 |
| 18.0 Audits | | | | | | | | | | | | | | | | | | X | ; 71 |

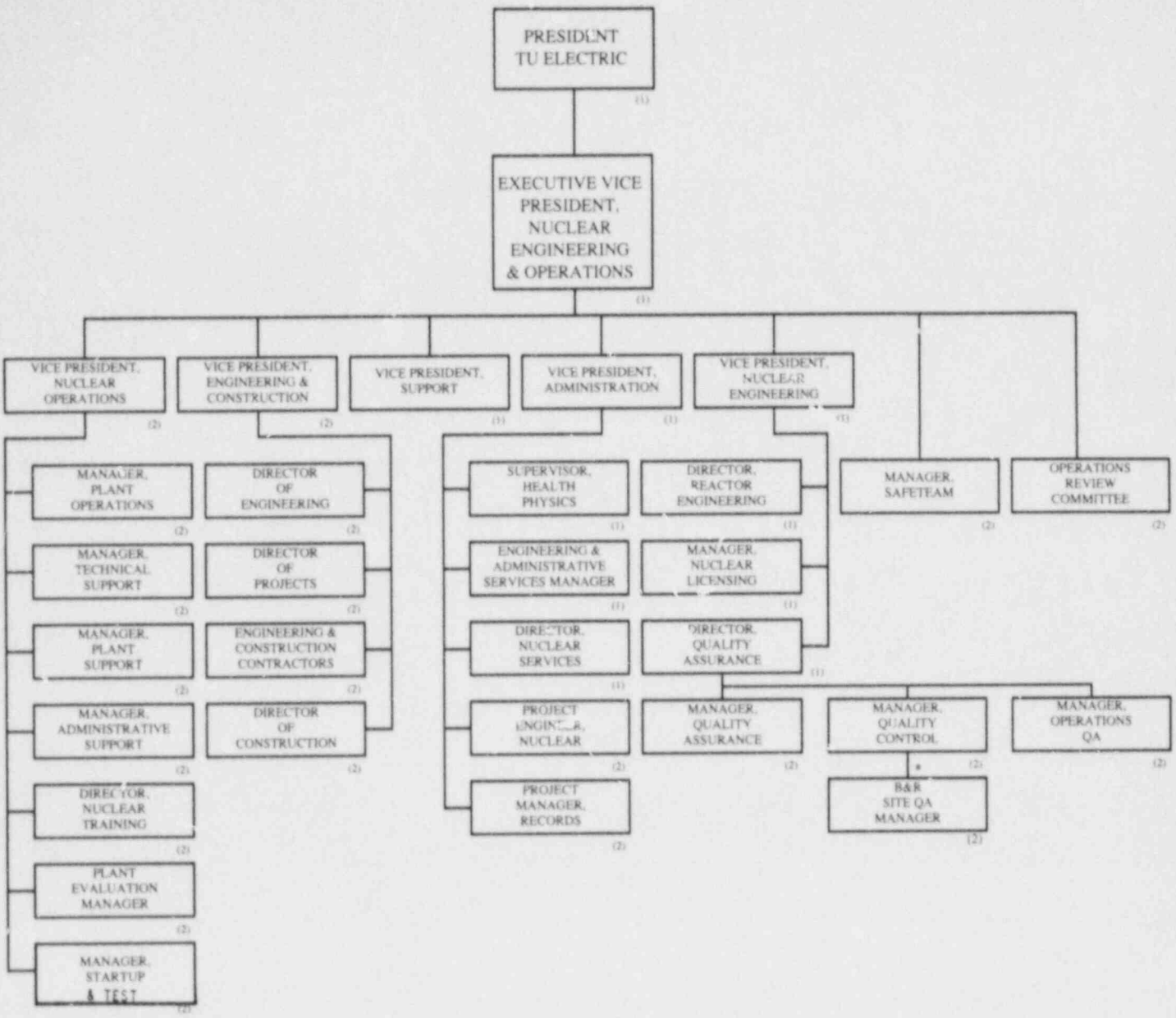



COMANCHE PEAK S.E.S.
FINAL SAFETY ANALYSIS REPORT
UNITS 1 and 2

TEXAS UTILITIES COMPANY ORGANIZATION

FIGURE 17.1-1

Amendment 71
May 27, 1988




PRIMARY LOCATION
(1) Corporate Office
(2) CPSES

* For other than ASME Sec. III, Div. I activities only

COMANCHE PEAK S.E.S.
FINAL SAFETY ANALYSIS REPORT
UNITS 1 and 2

NUCLEAR ENGINEERING AND OPERATIONS (NEO) GROUP

FIGURE 17.1-6

Amendment 71
May 27, 1988

## 17.2 QUALITY ASSURANCE DURING THE OPERATIONS PHASE

### 17.2.1 ORGANIZATION

#### 17.2.1.1 Organizational Structure

Texas Utilities Electric Company (TU Electric), as the licensee, has overall responsibility for the operation of the Comanche Peak Steam Electric Station (CPSES). Nuclear Engineering and Operations (NEO) has been designated by TU Electric to coordinate the design, construction and operation of CPSES. The organizational structure of TU Electric and NEO are described in Section 13.1. | 53

The following paragraphs amplify upon Section 13.1 with regard to establishment and execution of the quality assurance program for the operation of CPSES. Figure 17.2-1 shows the structure and relationships of those elements of NEO which function under the control of the QA program. Figure 17.2-2 shows the CPSES Nuclear Operations organizational structure. | 53 | 62

TU Electric may, from time to time, assign responsibility for executing certain portions of the program to qualified consultants and contractors. However, TU Electric, retains ultimate responsibility for the CPSES operations quality assurance program. | 53

##### 17.2.1.1.1 Executive Vice-President, Nuclear Engineering and Operations | 56

The Executive Vice-President, Nuclear Engineering and Operations is responsible for the overall management of company operations, including operation of CPSES, and for the establishment of company policies. He has the overall responsibility for the establishment and execution of the quality assurance program for the operation of CPSES. | 56

71 | The Executive Vice-President, Nuclear Engineering and Operations has
| assigned to the Vice-President, Nuclear Operations the overall
| responsibility for operation of CPSES and for implementation of the
| quality assurance program for operations at CPSES.

15 | 17.2.1.1.2 Vice President, Nuclear Operations

62 | The Vice President, Nuclear Operations is responsible to the Executive
| Vice President, Nuclear Engineering and Operations for operating
| activities at CPSES.
71 |
53 | Specific duties and responsibilities of the Vice President, Nuclear
| Operations include the following:

62 | 1. Technical and administrative direction of the Manager, Plant
| Operations.
56 |
71 | 2. Technical and administrative direction of the Manager, Startup
| and Test.

62 | 3. Technical and administrative direction of the Manager, Technical
| Support.

62 | 4. Technical and administrative direction of the Manager, Plant
| Support.

5. Technical and administrative direction of the Manager, Administrative Support. | 62

6. Technical and administrative direction of the Plant Evaluation Manager. | 62

7. Technical and administrative direction of the Director, Nuclear Training. | 62

8. Operational and technical support of all Nuclear Plants operated by TU Electric. | 62

9. Technical and administrative direction for the implementation of quality assurance requirements and controls at nuclear plants operated by TU Electric. | 62

10. Overall responsibility for the Initial Startup Test Program at CPSES. | 62 | 71

17.2.1.1.3 Manager, Plant Operations | 62

The Manager, Plant Operations is responsible to the Vice President, Nuclear Operations for Plant operations activities at CPSES. He is the individual who is directly responsible for the safe, reliable, and efficient operation of CPSES. | 62 | 37

Specific duties and responsibilities of the Manager, Plant Operations include the following: | 15

15 | 1. Management of all operations activities at CPSES.

15 | 2. Technical and administrative direction of:

62 | a. Operations Manager
62 | b. Maintenance Manager
62 | c. Instrumentation and Control Manager

3. Chairmanship of the Station Operations Review Committee.

15 | 4. Membership on the Operations Review Committee.
71 |
62 | 17.2.1.1.1 Director, Quality Assurance

71 | The Director, Quality Assurance, reports directly to the Vice-
| President, Nuclear Engineering and is responsible to him for assuring
| effective implementation of the Quality Assurance Program. This
55 | reporting relationship assures that the Director, Quality Assurance
| has sufficient authority, organizational freedom, and independence
| from undue influence from, or responsibility for, costs and schedules
| such that he can effectively assure implementation of and compliance
| with the CPSES operations quality assurance requirements and controls.

71 | The Director, Quality Assurance is responsible for submitting the
| Quality Assurance Manual for concurrence and approval to the Executive
| Vice President, Nuclear Engineering and Operations. He is
62 | responsible for the performance of quality assurance activities in
| support of CPSES operation.

The Director, Quality Assurance communicates directly with NEO supervisory and management personnel and with appropriate management levels in consultant and contractor quality assurance organizations to identify quality problems; initiate, recommend or provide solutions; and to verify implementation of solutions to quality problems. He also has authority to "stop work" during the operations phase. | 55 | 14

Specific duties and responsibilities of the Director, Quality Assurance include the following: | 55

1. Direction of Quality Assurance Department personnel. | 62

2. Technical and administrative direction of: | 62

   a. Manager, Operations QA | 62
   b. Manager, QC | 62
   c. Manager, QA | 62

3. Verification through audit and surveillance that procedures for the control of quality-related activities comply with quality assurance requirements. | 62

4. Verification through audit and surveillance of the implementation of the quality assurance program within NEO and evaluation of its effectiveness. | 62

5. Assurance through audit, surveillance and inspection that consultants, contractors and suppliers providing quality-related items or services have established and implemented an adequate quality assurance program. | 62

6. Membership on, or supervision of a member of the Operations Review Committee. | 55

62 | 17.2.1.1.5 Director, Engineering

62 | The Director, Engineering is responsible for providing engineering
| related technical services in support of CPSES operations.

62 | Specific duties and responsibilities of the Director, Engineering
| includes the following:

53 | 1. Technical support to Nuclear operations.

5 | 2. Technical direction and administrative guidance to his staff.

5 | 3. Assistance, as required, in the procurement of equipment,
| materials, and services for the operation, maintenance or
| modification of CPSES.

62 | 17.2.1.2 Quality Assurance Department

62 | The Quality Assurance Department, under the direction of the Director,
| Quality Assurance functions to assure effective implementation of the
| quality assurance program.

62 | Specific functions performed by the Quality Assurance Department
| include:

62 | 1. Quality assurance auditing of NEO quality-related activities,
| both offsite and onsite.

2. Evaluation of consultants', contractors', and suppliers' quality assurance programs and implementing procedures.

3. Quality assurance auditing of consultants, contractors, and suppliers.

4. Surveillance and inspection conducted at equipment and material suppliers' facilities.

5. Review of procurement documents to assure incorporation of adequate quality assurance requirements for non-routinely procured items and services.

6. Surveillance and review of site quality related activities to assure compliance with the applicable quality requirements. | 65

17.2.1.3 CPSES Operations Quality Assurance Section

| Q421.48

The CPSES Operations Quality Assurance Section, is supervised by the Manager, Operations QA who reports directly to the Director, Quality Assurance. | 62

| 71

| Q421.48

The Manager, Operations QA has sufficient authority and organizational freedom at CPSES to identify quality problems, recommend solutions, verify implementation of solutions, to stop unsatisfactory work and control further processing, delivery or installation of non-conforming material until proper disposition has occurred. | 62

| Q421.48

In addition, the Manager, Operations QA advises the Director, Quality Assurance, of the status of the quality assurance program at CPSES and of any significant conditions which are adverse to quality. | 62

The Operations Quality Assurance Section is responsible for the administration and implementation of an effective quality control inspection program at CPSES. | 65

| 65

11 | 17.2.1.4 Operations Review Committee

Independent reviews of activities affecting plant safety during the operations phase are performed by the Operations Review Committee. The structure and responsibilities of this committee are described in Section 13.4.

17.2.1.5 Delegation of Quality Assurance Functions

53 | NEO periodically retains qualified consultants and contractors to
| provide safety-related services. All consultants and contractors providing safety-related services and suppliers providing safety-related equipment or materials for CPSES are required to establish and implement quality assurance programs appropriate for their scope of
53 | supply. NEO includes specific requirements in procurement documents
| with which consultants', contractors', or suppliers' quality assurance
| programs must comply.

17.2.1.6 Personnel Qualifications

55 | 17.2.1.6.1 Director, Quality Assurance

55 | The following qualification requirements have been established for the
| Director, Quality Assurance.

59 | 1. Minimum of ten years related experience in design, construction,
| and/or operation of power plants. A maximum of four years of
| this ten years experience may be fulfilled by related technical
| or academic training.

59 | 2. A bachelors degree from an accredited college, university or
| other institution.

Q421.47 |

9 | 3. Demonstrated ability to manage people and projects.

| Q421.47
4. Knowledge of quality assurance requirements for nuclear plants | 59
including a minimum of one year related experience in the |
implementation of a nuclear quality assurance program. |

17.2.1.6.2 Manager, Operations QA | 62

The following qualification requirements have been established for the | 62
Manager, Operations QA |
| Q421.7
Six years experience in the field of quality assurance, | 4
preferably at an operating nuclear plant, or operations |
supervisory experience. At least one year of this six years |
experience shall be nuclear power plant experience in the |
overall implementation of the quality assurance program. A |
minimum of one year of this six years experience shall be |
related technical or academic training. A maximum of four |
years of this six years experience may be fulfilled by related |
technical or academic training. |

17.2.1.7 Inspection Functions

| Q421.11
The Manager, Operations QA is responsible for administration and | 62
implementation of an effective quality control inspection program. |
Inspections shall be performed by qualified individuals other than | 11
those who performed or directly supervised the activity being |
inspected. Personnel performing these inspections may be from the |
same department but are not from the same group that performed the |
work. |
| Q421.11
In addition, qualification criteria for inspection personnel are | 71
reviewed for concurrence by the Manager, Operations QA. |

Q421.11 |
71 |

### 17.2.2 QUALITY ASSURANCE PROGRAM

71 | The Quality Assurance Program requires a Quality Assurance Manual be developed for each nuclear power plant, which prescribe specific measures to assure the quality of safety-related activities, structures, systems and components of that facility. The quality assurance requirements and controls implemented during operations of CPSES are established by the portion of the CPSES Quality Assurance Program in this section (17.2) of the FSAR. The quality assurance requirements and controls implemented during design and construction of the CPSES are established by the CPSES Quality Assurance Program (Design and Construction), which is described in Section 17.1.

Q421.15 |
71 | Quality assurance requirements and controls are established implemented throughout the testing and operation phases at CPSES.
9 | This program shall be implemented at least 90 days prior to fuel
71 | loading. Responsibilities and authority, and measures for the control and accomplishment of activities affecting the quality and operation of safety-related structures, systems, and components of CPSES are defined. The structures, systems, and components covered by the quality assurance program are listed in Table 17A-1. These
71 | provisions apply to all activities, such as operating, maintaining, repairing, modifying, and refueling which affect the safety-related functions of those structures, systems, and components.

| 62

A Quality Assurance Program shall be developed and implemented to attain high levels of quality assurance during the operation of CPSES. This program shall comply with the requirements of Title 10, Code of Federal Regulations, Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Processing Plants," and certain NRC Regulatory Guides and ANSI standards as identified in the Final Safety Analysis Report (SAR). | 62

Overall responsibility for the Quality Assurance (QA) Program lies with the Executive Vice President, Nuclear Engineering and Operations. Specific responsibility for development and administration of the program rests with the Director, Quality Assurance. | 62

| Q421.50

The Executive Vice President, Nuclear Engineering and Operations shall, on a regular basis, not to exceed 24 months, perform or authorize independent Management Audits of quality assurance activities as necessary to assess the scope, status, implementation and effectiveness of the QA Program to assure that the program is adequate and complies with 10CFR50, Appendix B criteria. These audits will be conducted in accordance with predetermined schedules, with audit results documented in Audit Reports, and a follow-up system utilized to assure that corrective action is taken and reaudited when it is considered necessary to verify implementation. | 62 | 9

The quality assurance requirements and controls applicable to the operations phase, comply with the requirements of 10 CFR Part 50, Appendix B. Table 17.2-1 provides a matrix showing those sections of the QA Manual which satisfy the requirements of each criterion of 10 CFR Part 50, Appendix B. The quality assurance requirements and controls shall be consistent with the applicable guidance of those Regulatory Guides and industry standards listed in Table 17.2-2 and discussed in Appendix 1A(B). | 71

Q421.51 |
71 | The Director, QA is responsible for controlling the distribution of
| the Quality Assurance Manual and revisions thereto.

The quality assurance requirements and controls are designed to assure that activities affecting the quality and operation of safety-related
71 | items are accomplished in a planned and controlled manner. Activities
| affecting quality are accomplished in accordance with written,
| approved procedures and instructions under suitably controlled
| conditions. Controlled conditions include, as applicable,
appropriate equipment, suitable environmental conditions, and
71 | completion of prerequisites. All procedures prescribing activities
| affecting quality are controlled and distributed in accordance with
| the measures described in Section 17.2.6.

71 | The Director, Quality Assurance, is responsible for assuring, through
| audits and surveillance, implementation of the Quality Assurance
| Program. He is responsible for regularly assessing the status and
| adequacy of the Program, within NEO, and as implemented by
| consultants, contractors, and suppliers. The Director, Quality
62 | Assurance, reports the results of these evaluations to the Vice-
| President, Nuclear Engineering. Unresolved issues between the
| Director, Quality Assurance and others concerning quality are brought
| to the Executive Vice-President, Nuclear Engineering and Operations
| for resolution.

Q421.54 |
71 | The Director, QA has overall responsibility for the identification,
| scheduling, assignment, conduct and reporting of station activities
| assigned to the QA Department. Station activities affecting quality
11 | are subject to quality surveillance by quality assurance site
| personnel.

In addition, the Manager, Operations QA has responsibility for administration and implementation of the CPSES quality control program. | 62

| Q421.54

The Manager, Operations QA reviews for quality assurance requirements all procedures involving operation, maintenance, modification, inspection and testing during the operations phase as a normal function of the Station Operations Review Committee. Implementation of all procedures is periodically reviewed by the QA organization through audits and surveillance activities. | 62

An indoctrination and training program is established for those personnel performing activities affecting quality. The scope, objectives, and methods for implementing the indoctrination and training program are prescribed by written, approved procedures. These procedures also prescribe methods for documenting the accomplishment of training. The indoctrination and training program includes provisions that personnel performing activities affecting quality are: | 71

1. Instructed as to the purpose, scope, and implementation of the Quality Assurance Program and related procedures and instructions as appropriate to their activities. | 71

2. Qualified in the principles and techniques of activities for which they are responsible.

3. Retrained, re-examined or recertified, when appropriate, to maintain necessary proficiency in those activities for which they are responsible.

Schedules have been developed to assure that implementing procedures are prepared prior to commencement of the activities which they are
71 | intended to control. The conduct of the test program and the
| administrative controls to be implemented are described in Section
| 14.2.

Q421.55 | 17.2.3 DESIGN CONTROL
Q421.57 |
71 | Requirements for the control of design activities associated with
| modifications of safety-related structures, systems, and components
| are consistent with the provisions of Regulatory Guide 1.28, and
| Regulatory Guide 1.64 as discussed in Appendix 1A(B).
Q421.55 |
71 | The CPSES Manager, Plant Operations shall have the responsibility for
| approving and controlling the implementation of station design
| modifications. The Vice President, Engineering and Construction has
62 | the overall responsibility for developing procedures to maintain and
| control the design control process.
Q421.57 |
71 | Final approval of all station modifications is the responsibility of
| the SORC. The SORC will submit all proposed station design
44 | modifications which involve a change in CPSES Technical Specifications
| or an unreviewed safety question to the ORC for review and approval
| before proceeding with implementation. Safety evaluations on station
| design modifications which do not involve unreviewed safety questions
| or a change in CPSES Technical Specifications will be reviewed by ORC,
| however, this will not be a prerequisite for implementation. Upon
| recommendation from SORC, the CPSES Manager, Plant Operations approves
| each station design modification for implementation.

| Q421.55

All design modification requests made by station personnel, shall be | 62
submitted to the Manager, Technical Support for coordination of the |
station level engineering review. The actual change of design for | 71
those design modification requests approved by the CPSES Manager, |
Plant Operations shall be done by NEO engineering personnel or |
approved engineering services contractors in areas other than reactor |
engineering for which the Reactor Engineering Department will be |
responsible. The above organizations will have approved design |
procedures and/or instructions before any design modifications are | 53
performed by the respective organization. These procedures and/or |
instructions will assure proper design review and verification. |
These procedures and instructions will also assure that design control |
is commensurate with the original design. The Vice President, | 62
Engineering and Construction will assure that the designer is provided |
with the latest revisions to all drawings, specifications, and other |
design documents which are applicable. |

Design changes, including those originating on site, are subject to the same controls which were applicable to the original design. NEO may designate an organization to make design changes other than the one which prepared the original design. In these cases, NEO will assure that that organization has access to pertinent background information, including an adequate understanding of the requirements and intent of the original design, and has demonstrated competence in applicable design areas.

| Q421.56

The Vice President, Engineering and Construction shall coordinate | 62
necessary revisions to drawings and other design documents. The |
Manager, Plant Operations shall coordinate necessary revisions to |
plant procedures and instructions as a result of design changes. |
Changes are promptly distributed to ensure availability to responsible | 44
plant personnel prior to commencement of work. |

71 | Design changes made to the facility are accomplished in a planned and
| controlled manner in accordance with written, approved procedures. These procedures include provisions, as necessary, to ensure that:

1. Design documents, specifications, drawings, and procedures and instructions reflect applicable regulatory requirements and design bases.

2. Design documents specify quality requirements or reference quality standards as necessary.

62 | 3. There is adequate review of the suitability of materials, parts,
| components, and processes which are essential to the safety-
| related functions of structures, systems, and components.

62 | 4. Materials, parts, and components which are standard commercial
| (off the shelf) or which have been previously approved for a
| different application are evaluated for suitability prior to
| selection.

4 | 5. Design documents are revised to reflect design modifications.

6. Internal and external design interfaces between organizations participating in design modifications are adequately controlled, including the review, approval, release, and distribution of design documents and revisions.

62 | The above controls are applied as necessary to such aspects of design
| as reactor physics; seismic, stress, thermal, hydraulic, radiation,
| and accident analyses; compatibility of materials; and accessability
| for inservice inspection, maintenance, repair and replacement.

The adequacy of design changes be verified by the performance of design reviews, alternate calculations, or qualification testing. The control measures specified in the plan for control of design verification activities are as follows: | 71

1. Personnel responsible for design verification do not include the original designer or the designer's immediate supervisor.

2. Written procedures identify the positions or organizations responsible for design verification and define their authority and responsibility.

3. Qualification tests to verify the adequacy of the design are performed using the most adverse specified design conditions.

Design changes are reviewed to assure that design parameters are defined and that inspection and test criteria are identified.

Any errors or deficiencies found in the design process or the design itself are documented and corrective action taken, as described in Section 17.2.16.

Design documents and revisions thereto are controlled and distributed as described in Section 17.2.6. Records of design activities and design changes are collected, stored, and maintained, as described in Section 17.2.17.

### 17.2.4 PROCUREMENT DOCUMENT CONTROL

Requirements are established for the control of procurement documents prepared by NEO, or their designated agents for safety-related components, materials, and services. These requirements are consistent with the provisions of Regulatory Guide 1.33 and Regulatory Guide 1.123 as discussed in Appendix 1A(B) and apply to procurement documents prepared by NEO, or their designated agents. | 71

71 | Procurement documents, such as purchase specifications, contain or
| reference the following:

1. The design basis technical requirements, including the applicable regulatory requirements, material and component identification requirements, drawings, specifications, codes and industrial standards, and test and inspection requirements

71 | 2. The applicable requirements of 10 CFR Part 50, Appendix B and of
| the QA Program, which must be complied with and described in the
| supplier's QA program.

53 | 3. Identification of the documentation to be prepared, maintained,
| or submitted (as applicable) to NEO for review and approval. These documents may include, as necessary, inspection and test records, qualification records, or code required documentation.

4. Identification of those records to be retained, controlled, and maintained by the supplier, and those delivered to the purchaser prior to use or installation of the hardware.

9 | 5. NEO's right of access to supplier's facilities and records for
| source inspection and audit.

6. Requirements for supplier reporting and dispositioning of nonconformances from procurement requirements.

7. Provisions for extending applicable requirements of the procurement documents to lower-tier suppliers.

Q421.58 |

NEO procurement documents are prepared, reviewed, approved, and controlled in accordance with written procedures which clearly delineate the sequence of actions to be accomplished and which identify the individuals or groups responsible for accomplishing those

actions. These procedures include provisions for review of procurement documents. This review is performed to insure that necessary quality | 9
requirements are incorporated and correct, and that procurement |
requirements for spare or replacement parts are equivalent to or |
better than those used for the original equipment. Documentary |
evidence of that review and approval is retained and available for verification.

NEO evaluates supplier quality assurance programs prior to award of contracts or issuance of purchase orders, as discussed in Section 17.2.7.

### 17.2.5 INSTRUCTIONS, PROCEDURES, AND DRAWINGS

| Q421.53

Activities affecting the quality of safety-related structures, | 71
systems, and components are prescribed by and accomplished in |
accordance with documented instructions, procedures, and drawings. |
The manager or supervisor who has cognizance over a specific | 62
safety-related activity is responsible for the development and |
approval of procedures and instructions for prescribing the |
accomplishment of that activity. Administrative procedures and |
instructions are reviewed and approved prior to performance of the | 55
activity. The cognizant supervisor is responsible for ensuring that |
the activity is performed in accordance with the procedures and | 53
instructions. The development, review, and use of procedures, | 65
instructions, and drawings is reviewed on a periodic basis by the |
Manager, Quality Assurance as part of the station quality surveillance |
program. These requirements are consistent with the provisions of |
Regulatory Guides 1.33, 1.30, and 1.116 as discussed in Appendix | 15
1A(B). |

| Q421.59

71 | Requirements regarding the content of various types of instructions
| and procedures are established which provide for the inclusion, as
| necessary, of items such as prerequisites, precautions, qualitative or
| quantitative acceptance criteria, inspection points, and checklists,
| depending upon the nature of the instruction or procedure.

Administrative procedures clearly delineate the sequence of actions to be accomplished in the preparation, review, approval, and control of those instructions and procedures, and they identify the individuals responsible for those actions.

71 | Confirmation that these instructions and procedures meet requirements
| of the QA Program and are properly implemented is accomplished through
| audit or surveillance activities by the QA Department.

17.2.6 DOCUMENT CONTROL

71 | Requirements are established for the control of documents that
| prescribe activities affecting quality. The documents which are to
be controlled include:

1. Design Specifications

2. Design, manufacturing, construction, and installation drawings

3. Procurement documents

71 | 4. The QA Manual and all station procedures and instructions which
| implement requirements of the QA Program.

53 | 5. Maintenance, modification, and operating procedures and
| instructions

6. Final Safety Analysis Report | 53

7. Inspection and test procedures and instructions | 53

These requirements are consistent with the provisions of Regulatory | 71
Guide 1.33 as discussed in Appendix 1A(B) and include the following |
measures: |
| Q421.69

1. Documents, and changes thereto, are reviewed for adequacy and approved for release by authorized personnel in accordance with written procedures. These procedures identify those individuals or groups responsible for reviewing, approving, and issuing documents and revisions thereto. These individuals or groups | 62
include as appropriate the Manager, Operations QA, the NEO QA |
department or an individual other than the person who generated |
the documents but qualified in quality assurance. |

2. Documents, and changes thereto, are promptly distributed to ensure availability prior to commencement of work.

3. Changes to documents are reviewed and approved by the same organization that performed the original review and approval unless another qualified organization is designated.

4. Master status lists identifying the current revision of documents are periodically updated and utilized to preclude the use of superseded documents.

5. Obsolete or superseded documents are destroyed or identified to prevent their inadvertent use.

Documents generated by NEO are controlled in accordance with written, | 53
approved procedures and instructions. Maintenance, modification and |
inspection procedures and instructions affecting safety related |

53 | equipment are reviewed by a person knowledgeable in QA disciplines to
| determine:

Q421.6 |

9 | A. The need for inspection, identification of inspection
| personnel, and documentation of inspection results.

Q421.6 |

9 | B. That the necessary inspection requirements, methods, and
| acceptance criteria have been identified.

62 | The Manager, Operations QA is responsible for providing the necessary
| reviews of these procedures and instructions.

### 17.2.7 CONTROL OF PURCHASED MATERIAL, EQUIPMENT AND SERVICES

71 | Requirements are established for the control of purchased safety-
| related material, equipment and services, including spare or
| replacement parts. These requirements are consistent with the
54 | provisions of Regulatory Guides 1.33, and 1.123 as discussed in
| Appendix 1A(B).

59 | Measures have been established in procedures which determine the level
| of quality assurance required for the procurement of an item or
| service. As required, contractor and suppliers are evaluated by
| quality assurance personnel prior to award of a purchase order or
| contract to assure the contractor's or supplier's capability to comply
| with procurement document requirements. This evaluation is based on
one or more of the following:

1. A review of the supplier's quality assurance program description provided with the proposal/bid.

2. A review of historical evidence of the supplier's performance in providing similar items or services.

3. A preaward survey of the supplier's facilities and QA program.

| Q421.62

Technical requirements for items and materials to be procured are developed by the design or engineering organization responsible for the modification or maintenance activity. Procurement documents for safety related items and materials are reviewed for inclusion of technical and quality assurance requirements by the Quality Assurance Department prior to initiation of the procurement action by the purchasing organization. The results of the quality assurance review are documented and retained for future reference. | 9 | 62 | 9

Surveillance and audit of suppliers and contractors, are conducted where appropriate, to assure compliance with quality requirements. The Quality Assurance Department is responsible for surveillance and audit of offsite suppliers and contractors. The CPSES Quality Assurance Section is responsible for surveillance of contractors providing services onsite. Surveillance of suppliers and contractors is performed by qualified personnel in accordance with written procedures, instructions and checklists. | 71 | 62 | 53

Surveillance and audit of suppliers are performed to an extent consistent with the importance, complexity, and quantity of the item(s) being purchased and include measures to periodically confirm the validity of suppliers' certificates of conformance. Quality verification records are reviewed by quality assurance personnel to assure their completeness and their compliance with procurement document requirements.

Receipt inspections at CPSES are performed by qualified quality control inspectors in accordance with written procedures and instructions to assure that: | 53

1. Materials, equipment, or components are properly identified and correspond with associated documentation.

2. Inspection records or certificates of conformance attesting to the acceptance of materials, equipment, and components are completed and are available at CPSES prior to installation or use.

3. Materials, equipment, and components are inspected and judged acceptable in accordance with predetermined inspection instructions prior to installation or use.

4. Items accepted or released are identified as to their inspection status prior to forwarding them to a controlled storage area or releasing them for installation or further work.

5. Nonconforming items are clearly identified, controlled, and segregated where practical, until proper disposition is made.

### 17.2.8 IDENTIFICATION AND CONTROL OF MATERIALS, PARTS, AND COMPONENTS

71 | Requirements are established for the identification and control of
| safety-related materials, parts, and components, including spare or
| replacement items. These requirements are consistent with the provisions of Regulatory Guides 1.33 and 1.38 as discussed in Appendix 1A(B).

71 | Materials, parts, and components are identified and controlled to
| prevent the use of incorrect or defective items. Identification of
| items is maintained either on the item in a manner that does not
| affect the function or quality of the item, or on records traceable to
| the item.

Suppliers of safety-related materials, parts, or components are required by procurement documents to establish a system of identification and control which is consistent with the above requirements.

Procedures and instructions implementing these requirements provide for the following: | 53

1. Verification that items received onsite are properly identified and can be traced to the appropriate documentation, such as drawings, specifications, purchase orders, manufacturing and inspection documents, nonconformance reports, or mill test reports.

2. Verification of item identification consistent with the inventory control system and traceable to documentation which identifies the proper uses or applications of the item.

### 17.2.9 CONTROL OF SPECIAL PROCESSES

| Q421.63

Requirements are established for the control of special processes, which are those processes where direct inspection is impossible or disadvantageous such as welding, heat treating, nondestructive testing, and cleaning, which are consistent with the provisions of Regulatory Guides 1.30, 1.33, 1.37, and 1.58 as discussed in Appendix 1A(B). | 71

Special processes are performed by qualified personnel using proper equipment and in accordance with written qualified procedures and instructions. These personnel, procedures and instructions are to be qualified in accordance with applicable codes, standards, and specifications. Qualification records of special process procedures and instructions, and personnel performing special processes are filed, maintained, and available for verification. | 71 | 53

| Q421.64

Qualification of special processes, equipment, and personnel is the responsibility of the cognizant Managers or | 62

62 | Section Supervisors. Qualified test laboratories and consultants may
9 | be used in qualification of special processes. Procedures shall be
| developed which delineate the requirements for special process.
62 | These procedures shall be reviewed by the Manager, Operations QA as
| part of the normal function of the SORC.

17.2.10 INSPECTION

71 | Requirements are established for an inspection program to verify
| conformance of activities affecting quality with requirements
| specified for those activities. These requirements are consistent
| with the provisions of Regulatory Guides 1.30, 1.33, 1.58, and 1.116
| as discussed in Appendix 1A(B).
Q421.48 |
62 | The Manager, Operations QA is responsible for administering and
| implementing the CPSES quality control inspection program.
18 | Inspections are performed by quality control inspectors who are
| qualified and certified in accordance with ANSI N45.2.6-1978 and who
| are independent of the individuals performing the activity being
62 | inspected. The quality control inspectors may be selected from among
| any of the NEO departments, including contract personnel, and will
| report directly to the Manager, Operations QA when acting in the
| capacity of quality control inspectors. All quality control
13 | inspection personnel have authority to stop unsatisfactory work and
| control further processing, delivery, or installation of nonconforming
71 | material, parts or components. The quality control inspector's
| qualifications and certifications are maintained current through the
| NEO training program.
Q421.83 |
14 | Inspections at CPSES are performed in accordance with written
| procedures, instructions, or checklists, appropriate to the

circumstances which provide for the following: | 14

1. Identification of characteristics and activities to be inspected.

2. Acceptance and rejection criteria.

3. Method of inspection.

4. Recording the results of the inspection and identification of the quality control inspector.

5. Indirect control by monitoring of processing methods, equipment, and personnel when direct inspection is not possible.

| Q421.66

6. Identification of any required procedures, drawings, or specifications. | 11

| Q421.67

Station administrative procedures controlling the Measuring and Test Equipment program contain criteria for determining the accuracy of M&TE to be used in performing inspections depending upon the accuracy requirements of the parameters being measured. | 11

| Q421.35

Maintenance, repair, and modification procedures and instructions containing inspection criteria shall be reviewed by a level III inspector qualified in accordance with ANSI N45.2.6-1978 to ensure that adequate inspection hold points are included and that the inspection methods are adequate. Criteria contained in appropriate station administrative procedures and in applicable codes and standards shall be used in determining when inspections and tests are required. | 53 | 11

In addition, all safety related plant procedures and instructions are reviewed by the Operations QA section to assure that required quality requirements have been included. | 55

Q421.58 |
9 | Inspection results are documented in accordance with procedures and instructions developed and approved for that activity. Inspection results are evaluated and then acceptability determined by individuals qualified to perform that function in accordance with the station training program. Records of the evaluations are documented and retained in the station quality records.

4 | Contractors performing work at CPSES and equipment and material suppliers are required to work under inspection programs consistent with applicable codes and standards. These contractors and suppliers are required to provide work plans or inspection and fabrication procedures or outlines, which are reviewed for adequacy by NEO personnel.

### 17.2.11 TEST CONTROL

71 | Requirements are established for the control of testing of safety-related systems, equipment, and structures. These requirements are
37 | consistent with the provisions of Regulatory Guides 1.30, 1.33, 1.58, 1.68, 1.68.2 and 1.116 as discussed in Appendix 1A(B).

#### 17.2.11.1 Test Program

71 | Preoperational and initial startup testing is performed in accordance with Section 14.2 of the FSAR.

Surveillance testing is performed during the operational phase to verify continuing operational readiness and adequacy for those systems and components which are normally in a standby condition and to evaluate whether there has been any degradation of performance, or any departure from the prescribed operating conditions for the systems or components normally in service.

Tests are performed following station modifications or repairs to demonstrate satisfactory performance prior to placing affected items in service. When pressure boundaries are breached functional tests shall be conducted to the extent required to demonstrate acceptability of the repair or maintenance. | 71

17.2.11.2 Test Procedures

Testing is identified, documented, and controlled in accordance with written administrative procedures. Each test is accomplished in accordance with written test procedures by qualified personnel.

The administrative procedures controlling the test program identify the necessary test procedures, the provisions to be included in those procedures, the method of reviewing and approving those procedures, and the methods for documenting and evaluating the results.

Test procedures include the following provisions as appropriate:

1. Prerequisites - those items of work which must be completed prior to establishing initial conditions for the test, including:
   a. Calibrated instrumentation;
   b. Adequate and appropriate equipment;
   c. Initial conditions and completeness of the item to be tested;
   d. Suitable environmental conditions, if applicable; and
   e. Data Sheets.

2. Special precautions - items needed for safety of personnel or equipment. Special situations where caution or extraordinary attentiveness to operational circumstances is required.

3. Instructions for performing the test - steps required to conduct the test, observations to be made, data to be recorded.

4. Acceptance criteria - criteria against which the success or failure of the test can be determined.

17.2.11.3 Test Results

Records of test results are reviewed by qualified personnel to assure acceptability. These records are retained as quality verification records in accordance with the controls described in Section 17.2.17.

17.2.12 CONTROL OF MEASURING AND TEST EQUIPMENT

71 | Requirements are established for control of measuring and test
| equipment. Applicable procedures and instructions prescribe
| calibration techniques and frequency, maintenance requirements, and
| control measures for measuring and test equipment used in the
| measurement, inspection, and testing of safety-related components,
| systems and structures. These measures are consistent with the
provisions of Regulatory Guide and 1.33 as discussed in Appendix
1A(B). Controls for measuring and test equipment include the
transportation, storage, and protection of the equipment; the handling
of associated documents which gives the status of all items under the
calibration systems; and the permanent and unique identification of
each device.

Measuring and test equipment is calibrated at specified intervals
based upon the required accuracy, purpose, degree of usage, stability
69 | characteristics, and other pertinent considerations. Calibrations are
| normally performed against standards which are traceable to nationally
| recognized standards and which have a tolerance (error) of not more
| than one-fourth of the required tolerance of the equipment being
| calibrated. When traceability to nationally recognized standards
| does not exist, or when the 4:1 accuracy requirement is not reasonably
| achievable, the basis for the calibration is documented. This
| documentation shows that the calibration inaccuracies are enveloped by
| the calibration inaccuracy assumed in the applicable engineering
| documents (e.g. setpoint calculations, specifications, etc.), or
| these documents are revised using the new calibration inaccuracies.

Whether the device is calibrated at the power station or at an outside laboratory, a sticker is affixed on a conspicuous surface where practical, identifying the date the next calibration is due and the serial number of the instrument.

When test and measuring devices utilized in activities affecting quality are found to be out of calibration, an evaluation is made and documented concerning the validity of previous tests and the acceptability of items previously tested since the last valid calibration.

| Q421.69

The Manager, Technical Support, Maintenance Manager and Instrumentation and Control Manager are responsible for developing and implementing procedures and instructions to establish a control and calibration program. | 71

Effectiveness of the program is assured through periodic reviews and quality surveillances performed under the direction of the Manager, Quality Assurance. | 65

17.2.13 HANDLING, STORAGE, AND SHIPPING

Requirements are established for the control, handling, storage, shipping, cleaning, and preservation of material and equipment in accordance with established instructions, procedures, or drawings. These requirements are consistent with the provisions of Regulatory Guides 1.33 and 1.38 as discussed in Appendix 1A(B) and include the following provisions, as necessary: | 71

| Q421.70

1. For critical, sensitive, perishable, or high value items, specific written procedures and instructions for handling, storing, packing, shipping, and preserving are used. These procedures and instructions reflect design and specification | 53 | 9

9 | requirements such as inert gas atmosphere, specific moisture content levels, and temperature levels, and reflect manufacturers recommendations in regards to special handling and storage requirements such as shelf life and environmental controls.

2. Personnel responsible for handling these special items are qualified to the extent required by these special handling instructions.

3. Special handling tools and equipment are inspected and tested in accordance with written procedures to verify that they are adequately maintained.

17.2.14 INSPECTION, TEST, AND OPERATION STATUS

71 | Requirements are established for identification and control of the inspection, test, and operating status of safety-related structures, systems, and components. These requirements are consistent with the provisions of Regulatory Guide and 1.33 as discussed in Appendix 1A(B).

53 | Written procedures and instructions prescribe the use of tags, labels, and logs to indicate the inspection, test, and operating status of systems and equipment at CPSES. These procedures and instructions also provide for tagging of nonconforming, inoperative, or malfunctioning equipment to prevent inadvertent use. In addition, these procedures and instructions identify those individuals who are authorized to apply or remove those tags and labels and provide for the use of logs to maintain the status of tags and labels in use at CPSES.

CPSES personnel and contractor personnel working onsite are instructed regarding the purpose of, and precautions associated with, the various tags and labels used at CPSES. Proper use of tags and labels to | 9
indicate inspection, test, and operating status is verified through |
surveillance by onsite Quality Assurance personnel. |

17.2.15 NONCONFORMING MATERIALS, PARTS, OR COMPONENTS

Requirements are established for the control of nonconforming | 71
materials, parts or components. These requirements are consistent |
with the provisions of Regulatory Guides 1.33, 1.38, and 1.123 as discussed in Appendix 1A(B).

Material, parts, or components found nonconforming through review, | 71
inspection, or testing are controlled by administrative procedures. |
These procedures provide for the following:

1. Identification of nonconforming items by use of nonconformance tags, and segregation of those items, if practical, to prevent inadvertent use pending proper disposition and reinspection.

2. Identification of those individuals or organizations responsible for disposition of nonconforming items.

3. Preparation of nonconformance reports which identify nonconforming items and describe the nonconformance, the disposition of the nonconformance, and the reinspection or testing performed to determine the acceptability of the item after the disposition has been completed.

4. Verification of the acceptability of rework/repair of items by reinspection or testing of the item as originally performed or

by a method which is equivalent to the original inspection and testing method.

5. Nonconformance reports which are dispositioned "use as is" or "repair" are made part of the quality verification records associated with the items.

6. Periodic analysis of these reports to be performed and forwarded to management to show quality trends.

Q421.71 |
65 | Responsibility for the definition and implementation of activities
| related to nonconformance control is assigned to the cognizant
| superintendent of the area of concern. Nonconformances which are
11 | resolved by repair or use-as-is dispositions are reviewed and approved
| by the CPSES Engineering Department.
Q421.71 |
65 | Independent review of nonconformances, including disposition and
| closeout, is performed by appropriate Quality Assurance personnel.
Q421.73 |
69 | Marking and segregation of nonconforming items, when required, are
| addressed in station procedures. In addition, station procedures
| require that nonconforming items not be re-installed or placed in
| service except by conditional release until the nonconformance is
| finally resolved or corrected. Conditional releases are temporary
62 | measures which allow limited use, operation or installation of
| nonconforming items pending a final disposition. The Engineering
| Department evaluates each conditional release for the safety impact of
| the nonconformance on the operation of the plant and approves the use
| of the conditional release. Each conditional release also describes
| any limitations or special precautions required. The administrative
53 | controls assure that nonconforming materials are not relied upon for
| safety related service. Compliance with these administrative
| requirements is verified through the station surveillance and audit
| program.

## 17.2.16 CORRECTIVE ACTION

Requirements are established for the identification and correction of conditions adverse to quality. These requirements are consistent with the provisions of Regulatory Guide 1.33 as discussed in Appendix 1A(B). | 71 | 37

Conditions adverse to quality, such as failures, malfunctions, deficiencies and deviations, identified through review of documents, surveillance, audits, or experience during operation, are documented and dispositioned. Significant conditions adverse to quality are evaluated to determine the cause of the condition and the corrective action to be taken to preclude recurrence. | 71

Reports of significant conditions adverse to quality are reviewed by the Operation Review Committee and that committee's decisions and/or recommendations regarding corrective action are forwarded to appropriate management personnel. Follow-up reviews of nonconformance reports to verify proper implementation of corrective action are conducted by quality assurance personnel.

## 17.2.17 QUALITY ASSURANCE RECORDS

Requirements are established for the identification, collection, and storage of quality assurance records. These requirements are consistent with the provisions of Regulatory Guides 1.33 and 1.88 as discussed in Appendix 1A(B). | 71

Sufficient records are maintained to provide documentary evidence of the quality of items and of the accomplishment of activities affecting quality. Records to be maintained include | 71

such items as drawings, specifications, procurement documents, nonconformance reports, corrective action reports, operating logs, personnel and procedure qualifications, results of inspections and test, material certifications and test results, and audit reports.

53 | Quality assurance records are maintained in accordance with procedures
| and instructions which assign responsibilities for the collection,
| maintenance, and protection of records. These procedures and
| instructions provide a system of record identification to assure
| retrievability and prescribe retention periods for various types of
| records.

71 | The Vice President, Administration is responsible for development of
| procedures and instructions to implement the management requirements
| related to QA records.

Quality assurance records are stored in a specially constructed storage facility at CPSES to prevent their destruction, deterioration, or theft. The CPSES record storage facility construction is consistent with the applicable requirements of the regulatory guides referenced above. Access to the records facility is controlled so that only authorized personnel have access to the records area.

17.2.18 AUDITS

71 | Requirements are established for an audit program. The audit program
33 | is consistent with the applicable portions of Regulatory Guide 1.33
| (as discussed in Appendix 1A(B)), and ANSI N45.2.12 (draft 4, Revision
| 2 - January, 1976).

71 | Planned and periodic audits are performed in accordance with written
| procedures to verify compliance with all aspects of the quality
| assurance program. Responsibility for the

audit program has been assigned to the Director, Quality Assurance. | 55
Audits are conducted by personnel of the Quality Assurance Department | 62
and include examination of quality-related activities such as: |

1. Operation, maintenance, and modification of CPSES.

2. Receiving and work inspection.

3. Preparation, review, approval and control of instructions, procedures, drawings, specifications, and other quality-related documents.

4. Indoctrination and training.

5. Control of measuring and test equipment.

Organizations performing activities affecting quality that are subject to audit include the following:

1. The engineering and construction, startup, operations, maintenance, engineering, quality assurance, and support organizations for CPSES. | 55

2. Contractors, consultants, and suppliers of quality related items or service.

| Q421.75

As part of the Quality Assurance program NEO QA: | 33

1. Utilizes an audit planning document which defines the organizations and activities to be audited and the frequency of the audits. | 9

9 | 2. Requires auditors to be familiar with the type of activities to be audited and have no direct responsibilities in the area being audited.

9 | 3. Provide auditing checklists or other objective guidelines to identify those activities which affect quality.

9 | 4. Requires examination of the essential characteristics of the quality activity examined.

9 | 5. Requires an audit report be prepared and that it notes the extent of examination and deficiencies found.

9 | 6. Requires the audit report be sent to management responsible for the area audited for review and corrective action for deficiencies.

9 | 7. Requires corrective action taken as result of the audit be reported.

9 | 8. Requires reauditing of deficient areas when it is considered necessary to verify implementation of required corrective actions.

37 | 9. Requires vendors/subcontractors to comply with items 1-8 above to the extent necessary.

53 | Documentation of audits performed by participating contractors is made available to NEO for evaluation.

Q421.75 |

9 | In summary, NEO verifies conformance of the regulatory audit requirements by three methods:

71 | 1. Review of contractors'/vendors' quality assurance methods for auditing.

2. Review of documentation of the audit report performed by these contractors/vendors. | 71

3. Internal and external audits performed by members of the Quality Assurance staff. | 9

TABLE 17.2-1

(Sheet 1 of 2)

CPSES QA MANUAL COMPLIANCE MATRIX

| COMANCHE PEAK QUALITY ASSURANCE MANUAL | APPENDIX B QUALITY ASSURANCE CRITERIA | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | I | II | III | IV | V | VI | VII | VIII | IX | X | XI | XII | XIII | XIV | XV | XVI | XVII | XVIII |
| 1.0 Organization | X | | | | | | | | | | | | | | | | | |
| 2.0 Quality Assurance Plan | | X | | | | | | | | | | | | | | | | |
| 3.0 Design Control | | | X | | | | | | | | | | | | | | | |
| 4.0 Procurement Document Control | | | | X | | | | | | | | | | | | | | |
| 5.0 Instructions, Procedures and Drawings | | | | | X | | | | | | | | | | | | | |
| 6.0 Document Control | | | | | | X | | | | | | | | | | | | |
| 7.0 Control of Purchased Items and Services | | | | | | | X | | | | | | | | | | | |
| 8.0 Identification and Control Items | | | | | | | | X | | | | | | | | | | |
| 9.0 Control of Construction Processes | | | | | | | | | X | | | | | | | | | |
| 10.0 Examinations, Tests and Inspections | | | | | | | | | | X | | | | | | | | |
| 11.0 Test Control | | | | | | | | | | | X | | | | | | | |
| 12.0 Control of Measuring and Test Equipment | | | | | | | | | | | | X | | | | | | |
| 13.0 Handling, Storage, and Preservation | | | | | | | | | | | | | X | | | | | |
| 14.0 Examination or Test Status | | | | | | | | | | | | | | X | | | | |

TABLE 17.2-1

(Sheet 2)

| COMANCHE PEAK | APPENDIX B | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| QUALITY ASSURANCE | QUALITY ASSURANCE CRITERIA | | | | | | | | | | | | | | | | | | |
| MANUAL | I | II | III | IV | V | VI | VII | VIII | IX | X | XI | XII | XIII | XIV | XV | XVI | XVII | XVIII | |
| 15.0 Nonconforming Items | | | | | | | | | | | | | | | X | | | | |
| 16.0 Corrective Action | | | | | | | | | | | | | | | | X | | | |
| 17.0 Quality Assurance | | | | | | | | | | | | | | | | | | | |
| Records | | | | | | | | | | | | | | | | | X | | |
| 18.0 Audits | | | | | | | | | | | | | | | | | | X | |

TABLE 17.2-2

(Sheet 1 of 3)

## REGULATORY GUIDES AND INDUSTRY STANDARDS

The CPSES quality assurance program is consistent with the applicable guidance of the NRC Regulatory Guides and industry standards listed below. TU Electric will commit to comply with the respective regulatory positions as discussed in Appendix 1A(B). | 71

| Regulatory Guide | Title |
|---|---|
| 1.8 | Personnel Selection and Training | 71 |
| 1.30 | Quality Assurance Requirements for Installation, Inspection, and Testing of Instrumentation and Electric Equipment (endorses ANSI N45.2.4-1972) |
| 1.33 | Quality Assurance Program Requirements (Operations) (endorses ANSI N18.7-1976) |
| 1.37 | Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants (endorses ANSI N45.2.1-1973) |
| 1.38 | Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants (endorses ANSI N45.2.2-1972) |

TABLE 17.2-2

(Sheet 2)

REGULATORY GUIDES AND INDUSTRY STANDARDS

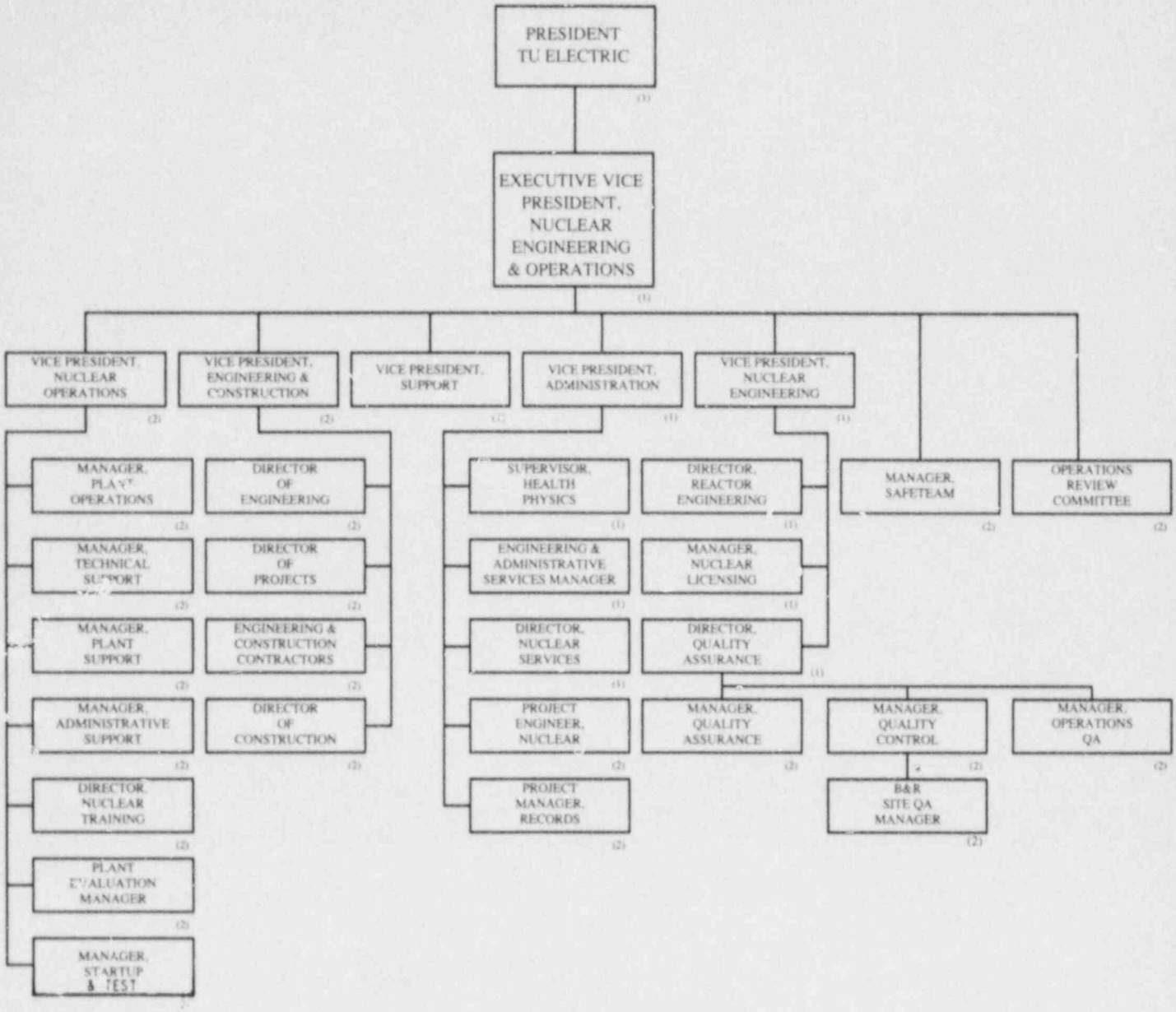
| Regulatory Guide | Title |
|---|---|
| 1.39 | Housekeeping Requirements for Watercooled Nuclear Power Plants (endorses ANSI N45.2.3-1973) |
| 1.58 | Qualification of Nuclear Power Plant Inspection. Examination, and Testing Personnel (endorses ANSI N45.2.6-1978) |
| 1.64 | Quality Assurance Requirements for Design of Nuclear Power Plants (endorses ANSI N45.2.11-1974) \| 40 |
| 1.74 | Quality Assurance Terms and Definitions (endorses ANSI N45.2.10-1973) |
| 1.88 | Collection, Storage and Maintenance of Nuclear Power Plant Quality Assurance Records (endorses ANSI N45.2.9-1974) |
| 1.94 | Quality Assurance Requirements for Installation, Inspection, and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants |
| 1.116 | Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems (endorses ANSI N45.2.8-1975) |

TABLE 17.2-2

(Sheet 3)

REGULATORY GUIDES AND INDUSTRY STANDARDS

| Regulatory Guide | Title |
|---|---|
| 1.123 | Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants (endorses ANSI N45.2.13-1976) |
| **ANSI Standard** | |
| N45.2.12 | Requirements for Auditing of Quality Assurance Programs for Nuclear Power Plants (Draft 4, Rev. 2 -January, 1976) |




PRIMARY LOCATION
(1) Corporate Office
(2) CPSES

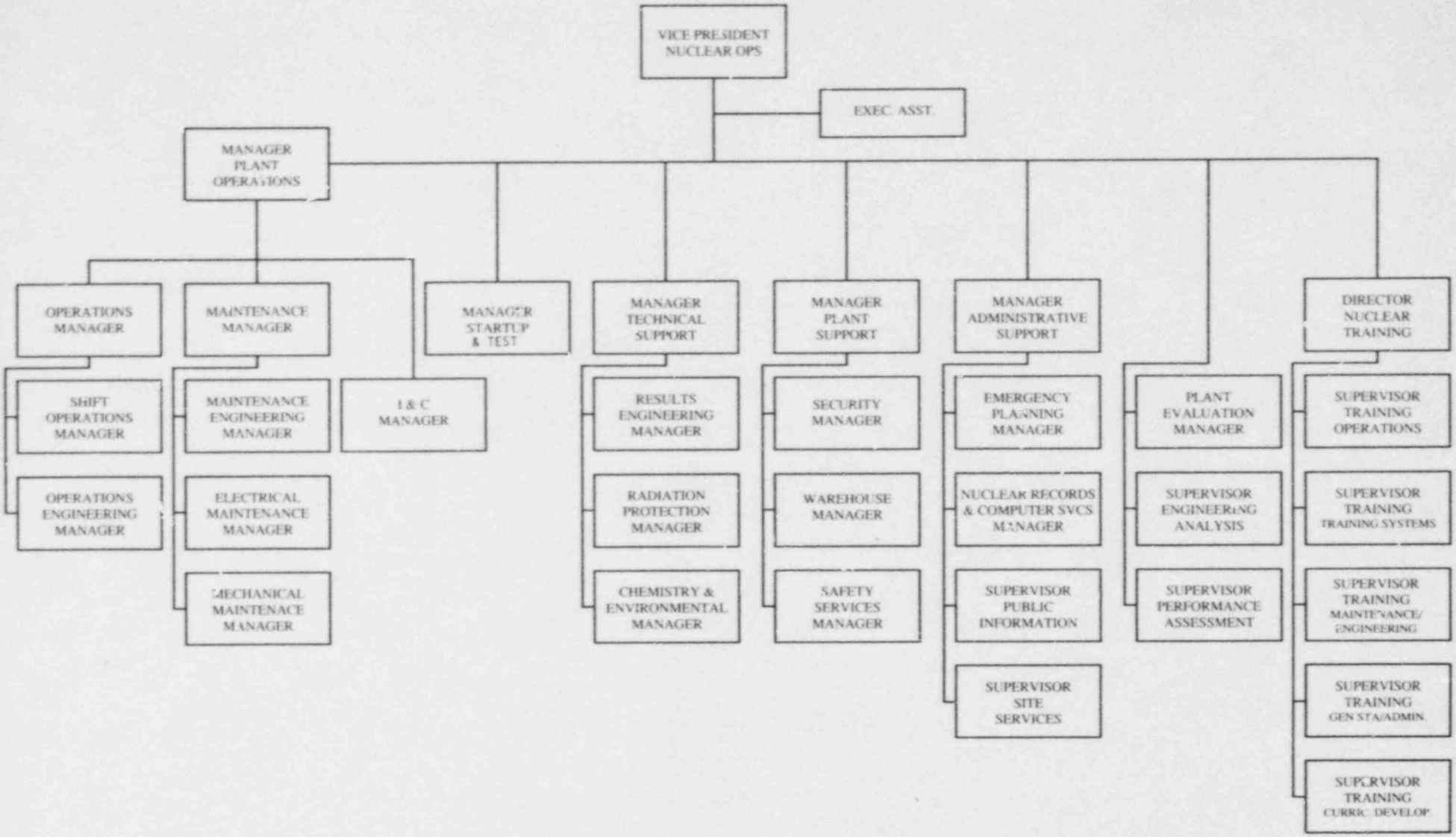
* For other than ASME Sec. III, Div. 1 activities only.

COMANCHE PEAK S.E.S.
FINAL SAFETY ANALYSIS REPORT
UNITS 1 and 2

NUCLEAR ENGINEERING AND OPERATIONS (NEO) GROUP

FIGURE 17.2-1

Amendment 71
May 27, 1988




COMANCHE PEAK S.E.S.
FINAL SAFETY ANALYSIS REPORT
UNITS 1 and 2

NUCLEAR OPERATIONS ORGANIZATIONS

FIGURE 17.2-2

Q040.41 The following questions have been prepared based on our review of environmental and seismic qualification plans provided by the applicant by letter dated December 15, 1978 to S. A. Varga from R. J. Gary.

A. Class 1E process solenoid valves - containment isolation service. It appears from the test report information provided that valves V52600-5292-7 and V52600-5950-1 are to be qualified by tests performed on a different valve (V52600-5291-2). This different valve is hermetically sealed by virtue of all welded construction as stated on sheet 10 of qualification test report on solenoid valves P/N V52600-5292-7 and V52600-5950-1. The two valves being qualified for use at Comanche Peak appear not to be hermetically sealed. Provide qualification test information for the actual valves to be installed at Comanche Peak or provide additional information that shows that valves V52600-5292-7 and V52600-5950-1 are in fact hermetically sealed. | 71

B. Equipment Qualification plans for nuclear strainer motors

1) On page 14 of the Reliance Electric Company summary report dated July 1, 1978 it is indicated that a prototype motor was thermally aged. Describe the extent of this thermal aging.

2) The prototype motor after being aged to end of expected life, should have been tested at the expected extremes of the normal environment, expected extremes in power supply voltage, and

Q423.20 Provide a commitment to include in your test program any design features to prevent or mitigate Anticipated Transient Without Scram (ATWS) that may be incorporated in your plant design.

R423.20 A summary of test program requirements for the Anticipated Transients Without Scram Mitigation System Actuation Circuitry as described in Section 7.8.1, has been provided in Section 14.2. | 71

| | |
|---|---|
| AMENDMENT 50 | July 13, 1984 |
| AMENDMENT 51 | August 6, 1984 |
| AMENDMENT 52 | August 27, 1984 |
| AMENDMENT 53 | November 5, 1984 |
| AMENDMENT 54 | January 21, 1984 |
| AMENDMENT 55 | July 19, 1985 |
| AMENDMENT 56 | October 15, 1985 |
| AMENDMENT 57 | December 20, 1985 |
| AMENDMENT 58 | June 30, 1986 |
| AMENDMENT 59 | June 1, 1986 |
| AMENDMENT 60 | November 3, 1986 |
| AMENDMENT 61 | December 19, 1986 |
| AMENDMENT 62 | March 31, 1987 |
| AMENDMENT 63 | June 15, 1987 |
| AMENDMENT 64 | July 31, 1987 |
| AMENDMENT 65 | November 20, 1987 |
| AMENDMENT 66 | January 15, 1988 |
| AMENDMENT 67 | February 5, 1988 |
| AMENDMENT 68 | February 15, 1988 |
| AMENDMENT 69 | March 14, 1988 |
| AMENDMENT 70 | April 22, 1988 |
| AMENDMENT 71 | May 27, 1988 |

EFFECTIVE PAGE LISTING

| FSAR Section | Front/Back | EPL Effective Date |
|---|---|---|
| EPL PREFACE | EPL-i/ii | April 22, 1988 |
| | EPL-iii/iv | March 14, 1988 |
| | EPL-v/vi thru EPL-xiii/xiv | May 27, 1988 |
| Chapter 1 | EPL 1-1/1-2 thru EPL 1-7/1-8 | March 14, 1988 |
| | EPL 1-9/1-10 | May 27, 1988 |
| | EPL 1-11/1-12 | March 14, 1988 |
| Chapter 2 | EPL 2-1/2-2 thru EPL 2-3/2-4 | May 27, 1988 |
| | EPL 2-5/2-6 thru EPL 2-37 | March 14, 1988 |

| FSAR Section | Front/Back | EPL Effective Date |
|---|---|---|
| Chapter 3 | EPL 3-1/3-2 | May 27, 1988 |
| | EPL 3-3/3-4 thru EPL 3-7/3-8 | March 14, 1988 |
| | EPL 3-9/3-10 and EPL 3-11/3-12 | May 27, 1988 |
| | EPL 3-13/3-14 | March 14, 1988 |
| | EPL 3-15/3-16 | May 27, 1988 |
| | EPL 3-17/3-18 thru EPL 3-33/3-34 | March 14, 1988 |
| | EPL 3-35/3-36 thru EPL 3-37/3-38 | May 27, 1988 |
| | EPL 3-39/3-40 thru EPL 3-47 | March 14, 1988 |
| Chapter 4 | EPL 4-1/4-2 thru EPL 4-5/4-6 | April 22, 1988 |
| | EPL 4-7/4-8 thru EPL 4-11/4-12 | March 14, 1988 |

| FSAR Section | Front/Back | EPL Effective Date |
|---|---|---|
| Chapter 5 | EPL 5-1/5-2 and EPL 5-3/5-4 | May 27, 1988 |
| | EPL 5-5/5-6 | April 22, 1988 |
| | EPL 5-7/5-8 thru EPL 5-9/5-10 | March 14, 1988 |
| Chapter 6 | EPL 6-1/6-2 | April 22, 1988 |
| | EPL 6-3/6-4 | May 27, 1988 |
| | EPL 6-5/6-6 | April 22, 1988 |
| | EPL 6-7/6-8 thru EPL 6-11/6-12 | March 14, 1988 |
| | EPL 6-13/6-14 | April 22, 1988 |
| | EPL 6-15/6-16 thru EPL 6-23/6-24 | March 14, 1988 |
| | EPL 6-25/6-26 and EPL 6-27/6-28 | May 27, 1988 |
| | EPL 6-29 | March 14, 1988 |

| FSAR Section | Front/Back | EPL Effective Date |
|---|---|---|
| Chapter 7 | EPL 7-1/7-2 thru EPL 7-7/7-8 | April 22, 1988 |
| | EPL 7-9/7-10 | May 27, 1988 |
| | EPL 7-11/7-12 thru EPL 7-15/7-16 | April 22, 1988 |
| | EPL 7-17/7-18 | May 27, 1988 |
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RELATED CORRESPONDENCE

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May 27, 1988

Mr. Chase R. Stephens
Docketing & Services Branch
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

FSAR Copy No. 79

SUBJECT: COMANCHE PEAK STEAM ELECTRIC STATION
DOCKET NOS. 50-445 AND 50-446
TRANSMITTAL OF AMENDMENT 71 TO FSAR

Enclosed is 1 copy of Amendment 71 to your assigned copy of the CPSES FSAR. Please complete the attached form acknowledging the receipt of the amendment and return it to this office.

If the copy holder has changed or the mailing address has changed, provide the name of the new holder and/or the new mailing address as requested on the acknowledgement form.

The instruction sheets enclosed shall be used to assist you in incorporating Amendment 71 revisions to your FSAR and as such, these should be retained until the Effective Page Listing is again updated. Retain these instruction sheets immediately behind the tab labeled "List of Effective Pages" in Volume XVII.

If you have any questions, please contact me at (214) 812-4368.

Sincerely,

Mary Ann Smith

Mary Ann Smith

Enclosure

400 N. Olive Dallas, Texas 75201